CHALLENGES FOR EUROPEAN ELECTRICITY MARKETS AND THE NEED FOR A NEW EUROPEAN TARGET MODEL

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Key Challenges

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Increasing doubts about ability of competitive electricity markets to deliver adequate levels of investment, capacity and security of supply. Significant amounts of VaREN (wind, solar) dramatically reinforce two interacting issues:

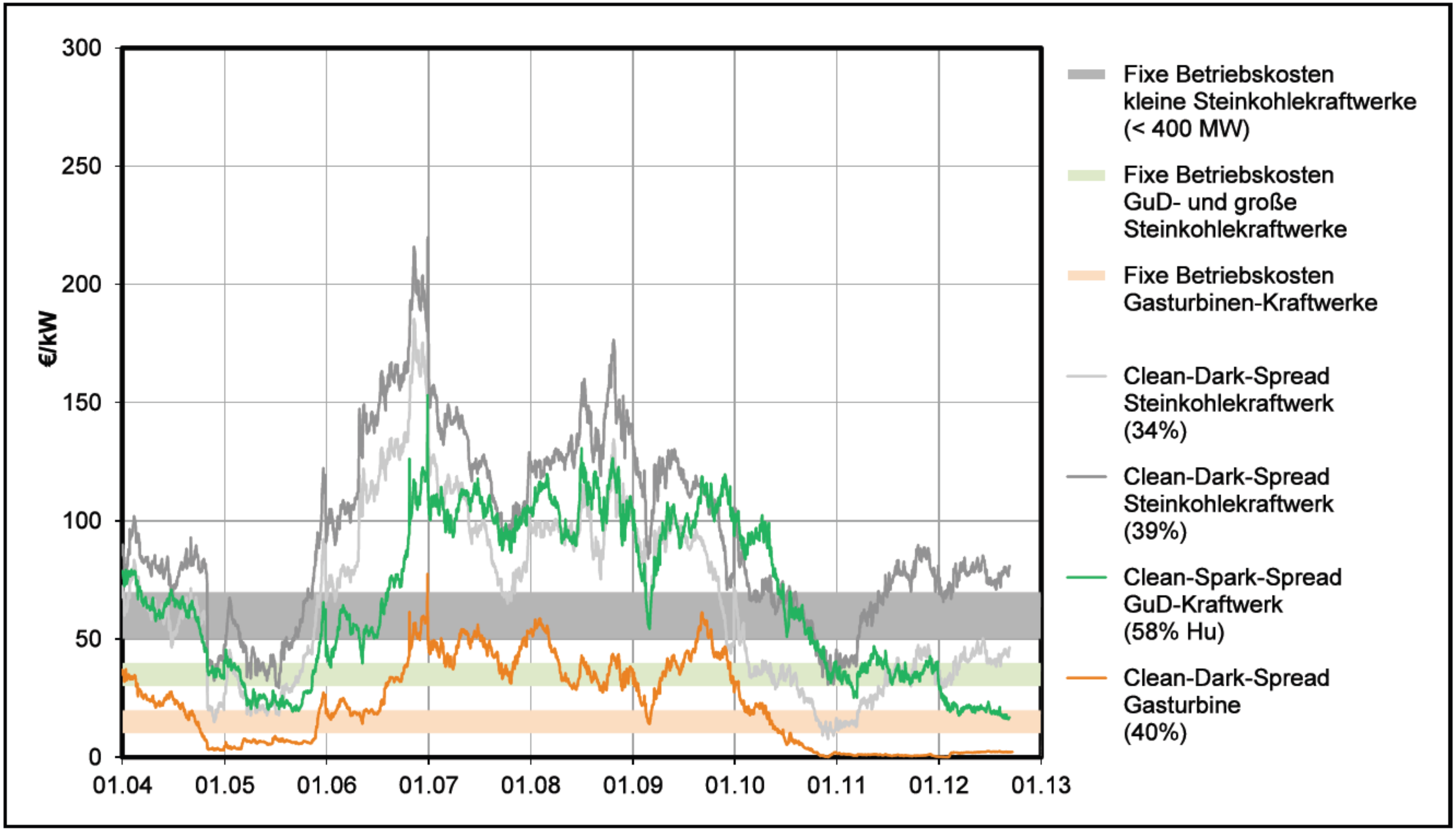
1. **The increasing disconnect of wholesale prices and costs and thus declining investment and premature capacity retirement**
   - Declining average prices, increased volatility, decreasing load factors, capacity reductions and investment delays, risks for the security of electricity supply, unallocated **system effects** exacerbate issues.
2. **The declining integrity of established market areas**
   - Internal congestion at times of peak ENR production creates regional market areas, spill-overs into neighbouring markets, saturation of interconnections with *increasing* price divergence!

The two issues question the current **market architecture** for electricity. At stake is the claim that **deregulated electricity markets can efficiently ensure least-cost pricing and adequate levels of investment.**

Electricity markets urgently require a new European target model to be implemented over next five years in addition to short-run emergency measures!

Empirical Evidence:
Prices no Longer Cover *Fixed Operating Costs*

Matthes , Schlemmermeier *et al.* (2012), *Fokussierte Kapazitätsmärkte*, WWF Studie



OECD NEA System Effects Study

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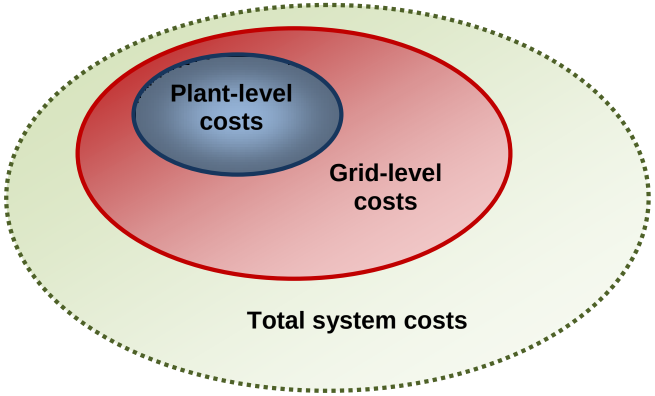
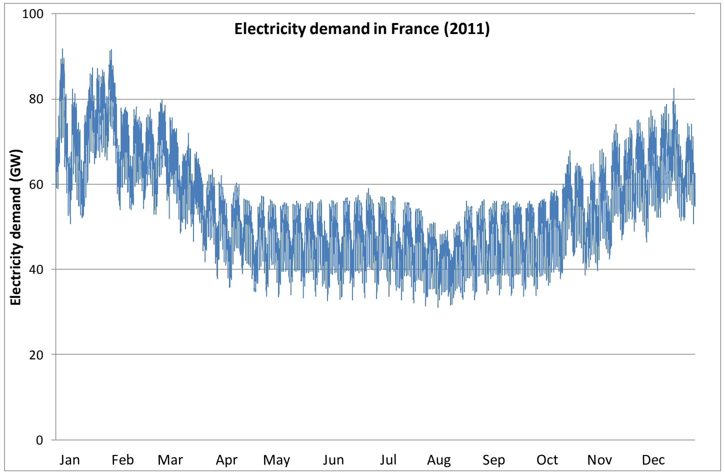
"System costs are the total costs above plant-level costs to supply electricity at a given load and given level of security of supply."



- *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, …)

Calculating a Residual Load Duration Curve with VaRen (Wind 30%)



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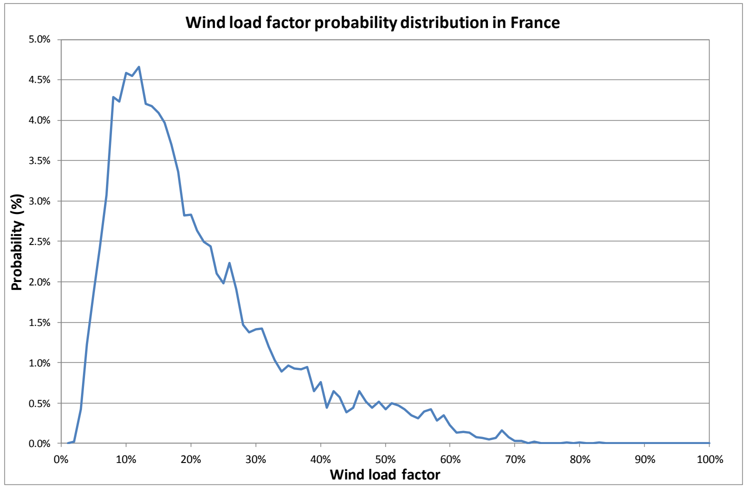
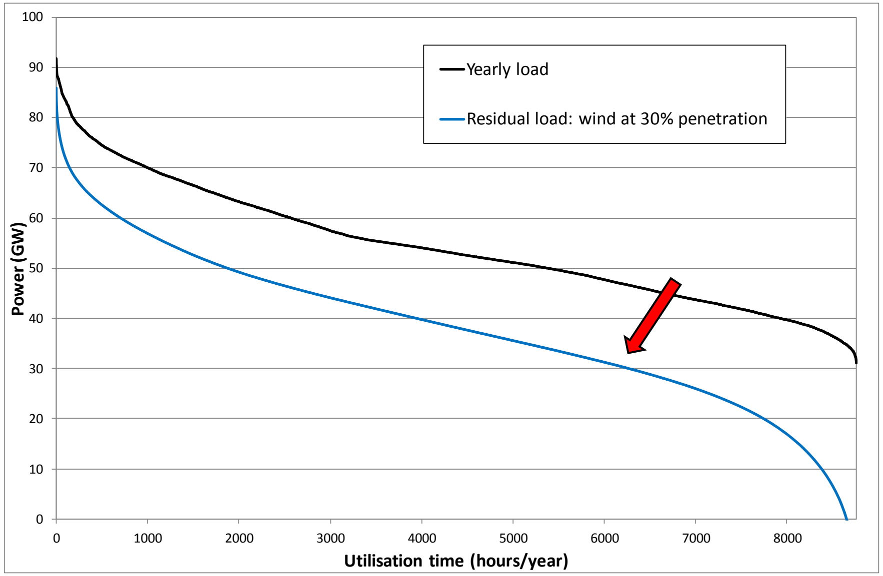
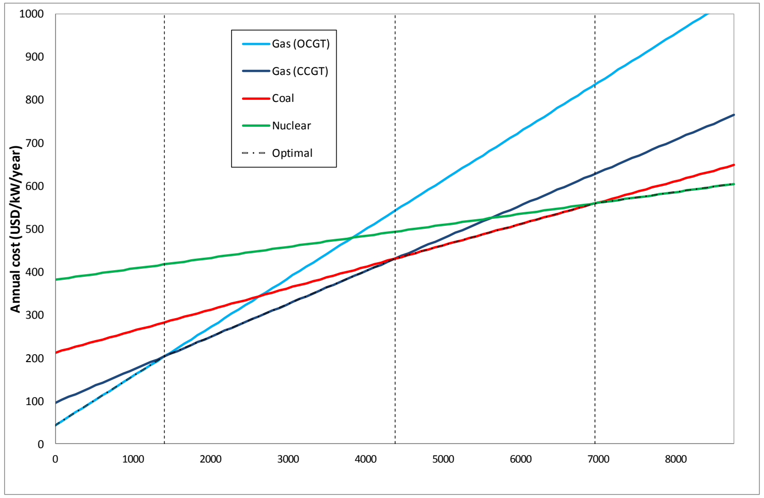




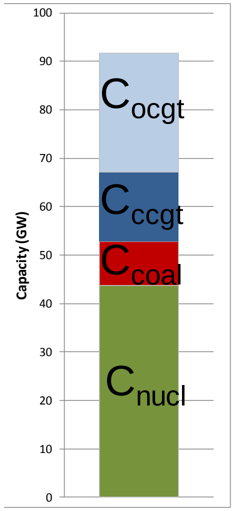
- Statistical analysis (Monte Carlo with 650 runs)
- Non-parallel shift of the residual load duration curve after the integration of low-marginal cost wind.

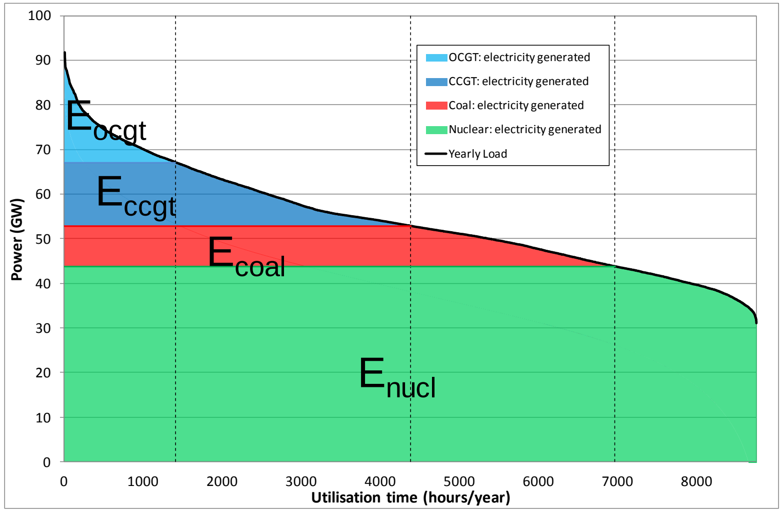
Determining the Optimal Mix

	Fixed costs USD/MW/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



- The optimal generation mix obtained is the one that minimises the generation cost for meeting a given annual load duration curve.
- The cost/MWh depends upon the shape of the load duration curve.



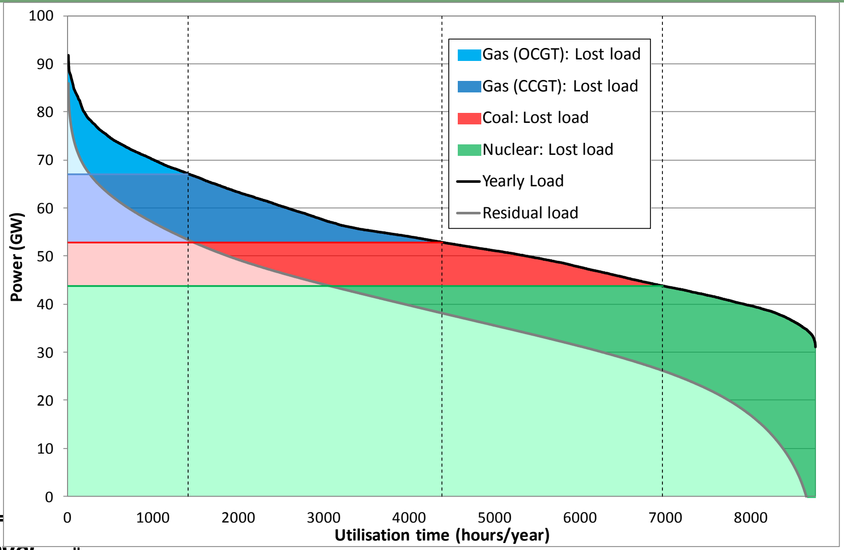


Modelling Evidence 1: Short Run Impacts of VaREN

Keppler and Cometto (2012), *Nuclear Energy and Renewables: System Effects*, OECD NEA.

Renewables with zero marginal costs replace dispatchable thermal power (gas, coal and nuclear):

- Dispatchable power plants face lower load factors (*compression effect*);
- Reduction in the average electricity prices (*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%

- Declining profitability especially for CCGT and OGT;
- Insufficient incentives for new investment;
- Security of supply risks as gas plants close (HIS CERA estimate 110 GW no longer cover AC and 23 GW will close until end 2014).

Modelling Evidence 2: Long Run Impacts of VaREN

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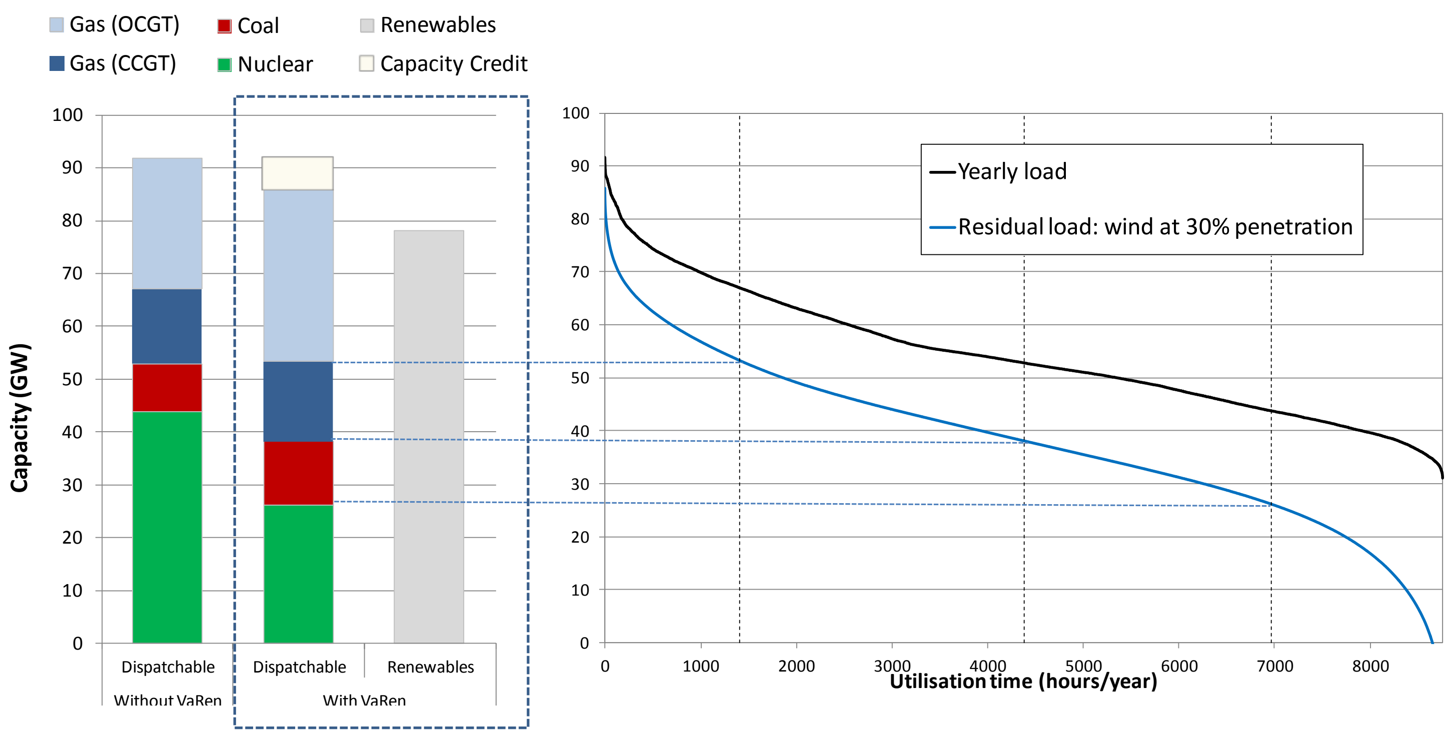
Keppler and Cometto (2012), *Nuclear Energy and Renewables: System Effects* , OECD NEA.

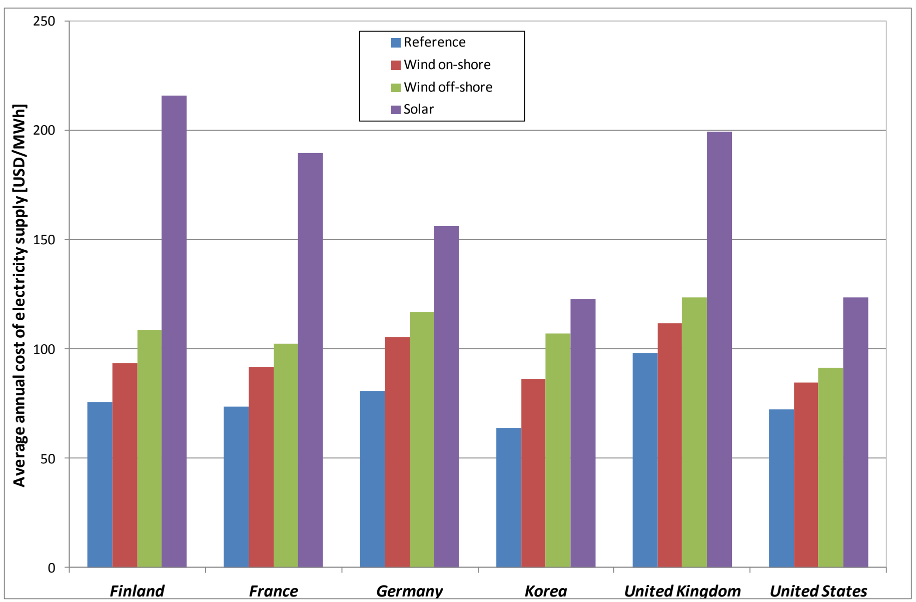


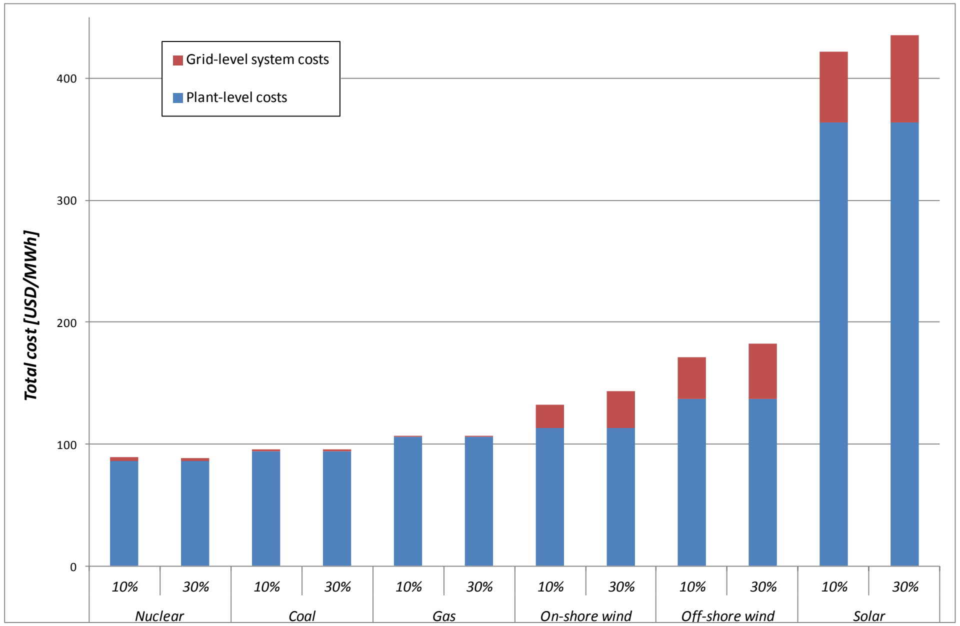
- In the LR, renewable production will change generation mix; w/o countervailing measures (carbon taxes), a **more carbon-intensive mix** of renewables and gas is a distinct possibility.
- The cost for residual dispatchable load will rise as technologies more expensive per MWh are used; however, no LT change in electricity prices for penetration levels < 25%.

Hidden System Costs Make Power Systems more Expensive

Keppler and Cometto (2012), *Nuclear Energy and Renewables: System Effects* , OECD NEA.

- System costs (off-plant costs for transport and distribution grids, balancing (spinning) and back-up costs can be significant):
  - System costs depend strongly on country, load profile, technology and penetration level (15-80 USD/MWh for variable renewables, 0.5 -3 USD/MWh for thermal generation).





De-Optimization of the Mix as Cost of Residual Generation Rises

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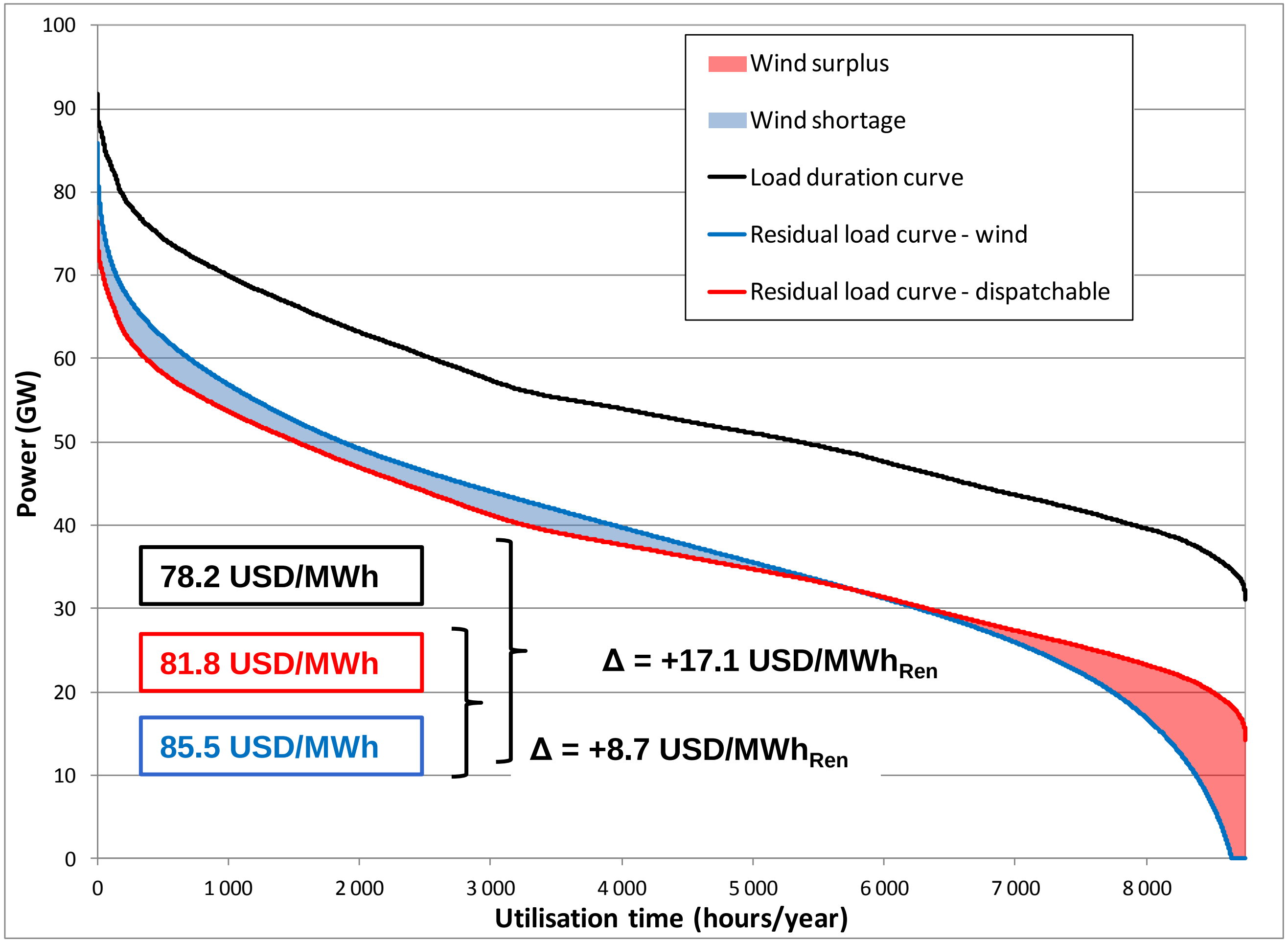
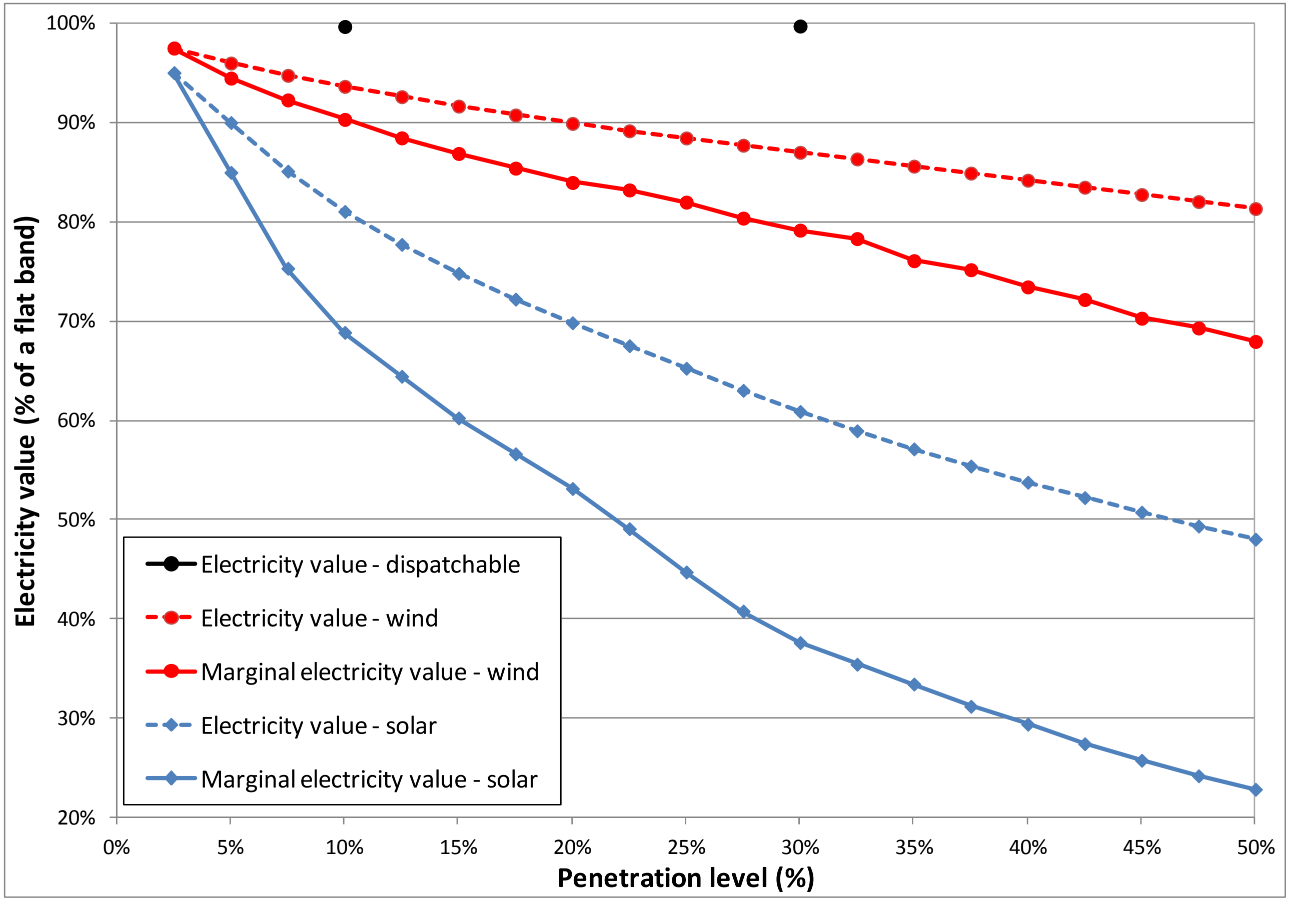
We compare two situations: the residual load duration curve for a 30% penetration of fluctuating wind (blue curve) and 30% penetration of a dispatchable technology (red curve).



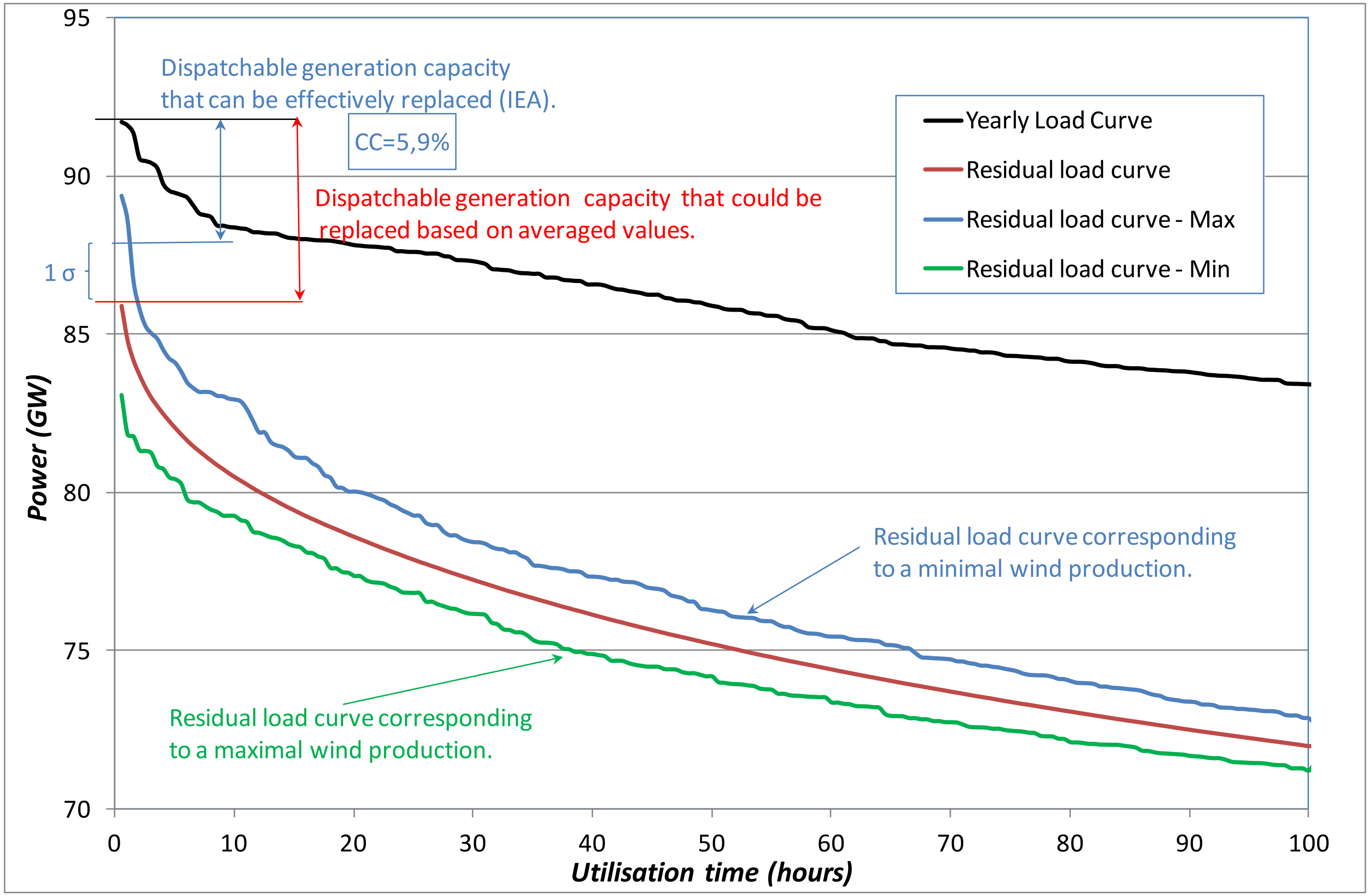
Value of VaRen for the System

The contribution of an intermittent generation source to covering system load declines with the penetration rate. “Grid parity” based on plant-level costs is thus no indicator of true costs at system level.



Estimating Capacity Credit

Residual load duration curves allow for simple and reliable estimation of capacity credit.

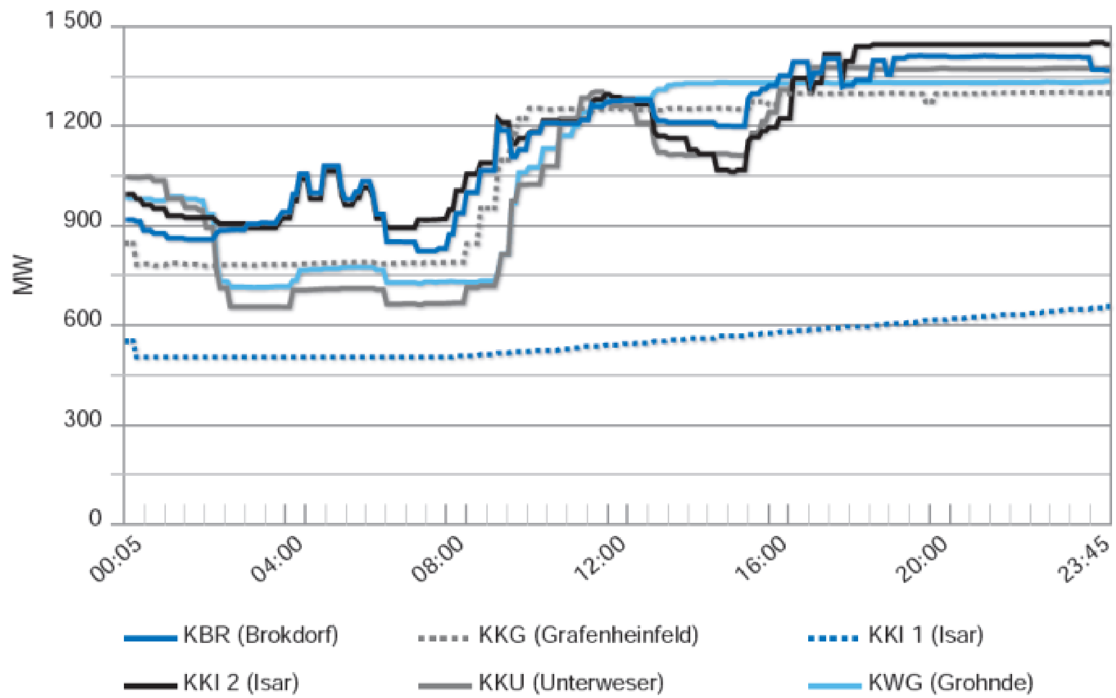


Load-Following of NPPs

In some countries (France, Germany, Belgium) significant flexibility is required of NPPs:

- Primary and secondary frequency control
- Daily and weekly load-following;
- Ramp rates 1-5% per min. at par with coal, but longer start-up times (2days and more)

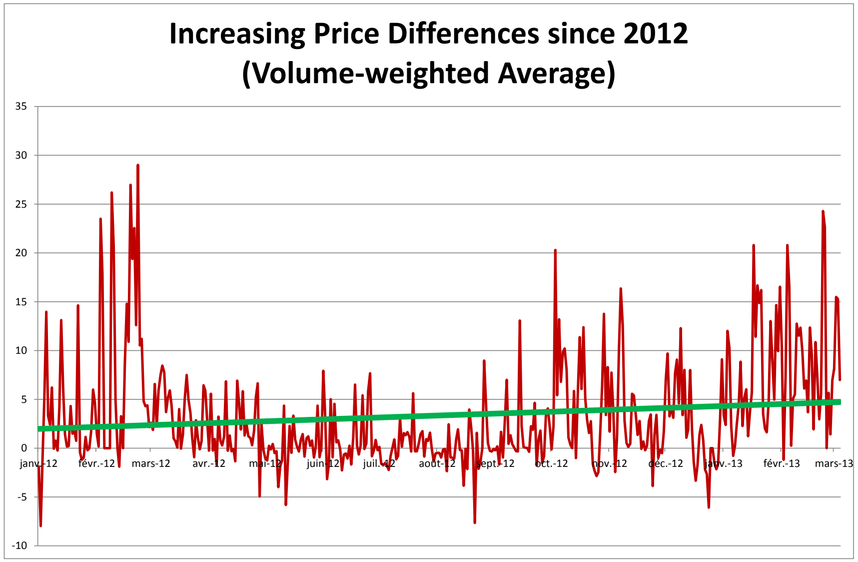
Figure 3.4: Load following operations of E.On nuclear units in Germany

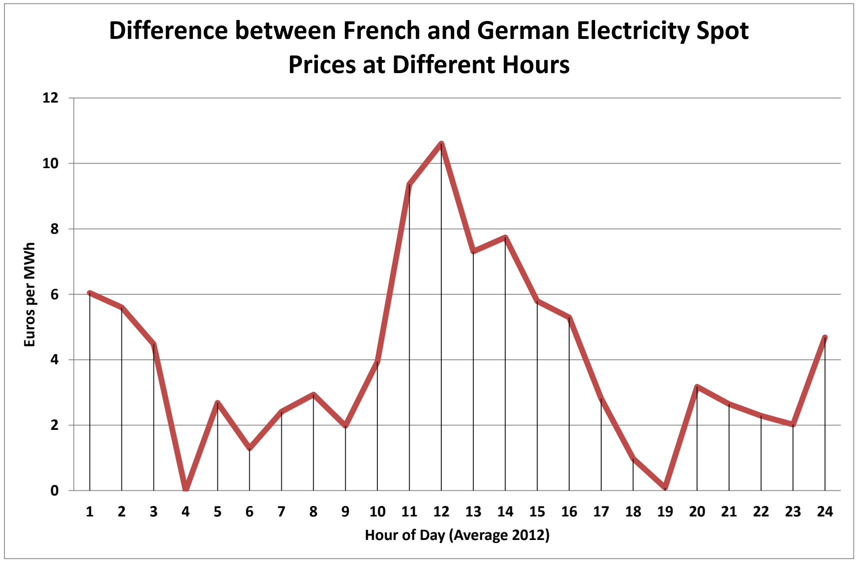


Source: Courtesy of E.ON Kernkraft, Germany.

Risks of Market Disintegration
The French-German Example I

- France and Germany are part of the CWE market area administered jointly by bi-national electricity exchanges EPEX Spot and EEX (futures);
- For years, 10 GW of interconnection capacity have ensured rapid price convergence; this is no longer the case since 2012





- Flows by intermittent renewables, in particular solar, lead to more frequent saturation of internal grids in Germany and external interconnections;

In 2012, with ca. 60 TWh traded on EPEX Spot price differences between France and Germany amounted to losses for French consumers of € 253 million per year.

Risks of Market Disintegration
The French-German Example II

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VARIABLES	(1) Before coupling	(2) After coupling
consumption	0.000252***	0.000245***
	(1.17e-05)	(1.36e-05)
nuclear	-0.000288***	-0.000280***
	(2.49e-05)	(2.53e-05)
delay_gap	0.719***	0.803***
	(0.00694)	(0.00385)
solar	7.23e-05***	2.04e-05***
	(1.31e-05)	(6.26e-06)
wind	3.64e-05***	3.01e-05***
	(4.60e-06)	(4.70e-06)
peak	-1.433***	-1.366***
	(0.171)	(0.214)
weekend	0.977***	0.654***
	(0.142)	(0.173)
Constant	-0.803	-0.563
	(0.715)	(0.701)
Observations	8,974	23,114
R-squared	0.673	0.690

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Why Capacity Mechanisms?

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Currently, it is impossible for consumers to hedge fully against all security of supply risks in many energy only markets:

- Security of supply externalities; competitive suppliers will not contract for the full amount of SoS desired implicitly by retail consumers and public authorities;
- Imperfections in the working of balancing markets, including but not limited to market breakdown at times of "scarcity pricing";
- Tendency towards structural under-capacity in EE-markets due to (a) monopoly power of marginal producer at peak times (b) mothballing of efficient plants;

These issues are inherent to *all* electricity markets. However, they are significantly magnified by the intermittency of variable renewables.

Capacity issues are concretely existing issues existing in specific circumstances that must be treated pragmatically. They are *not* inevitable destiny but subject to structural change. In particular DSM might alleviate the need for CRMs (but causality DSM ↔ CRMs goes both ways).

But Be Careful What You Wish For…

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1. Many CRM designs are complex and have considerable monitoring and transaction costs; the law of unintended consequences applies due to energy/capacity market interaction; regular revision will be needed (*e.g.* PJM);
2. Bad design can lead to
   a) Additional investment retention (caution with strategic reserves!);
   b) Lower energy-only prices and only marginally reduced volatility of profits;
   c) Free-riding between adjacent market areas with different criteria;
   d) Baseload consumers subsidising peakload consumers;
   e) Bias of certain CRMs against high fixed cost technologies (nuclear) and in favour of low fixed cost fossil fuel plants (gas) may require countervailing measures;
3. There is no "ideal-type"; different CRMs must address different issues (peak demand, VaREN, baseload…) in different countries (F, D, UK);

Nevertheless: growing consensus that some support for capacity is required in electricity markets to ensure security of supply. Make sure that it is simple, transparent and regularly revised.

Opportunities: New Markets for New Challenges

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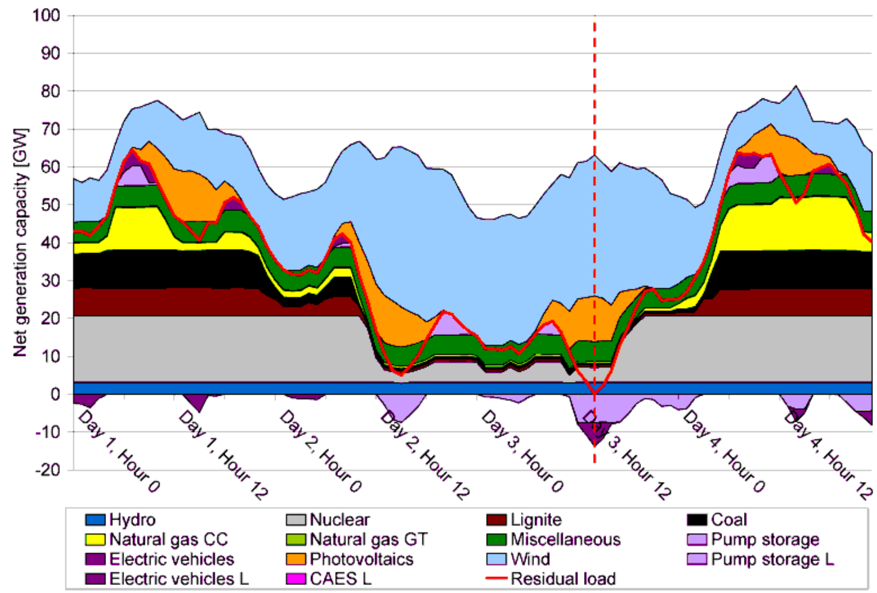
The challenge of integrating large amounts of variable generation offers opportunities for flexibility providers, capacity providers, distributors, DSM aggregators, integrated local planners and equipment providers ("smart grids"). Key question: can they can be organized in a single market framework (*improved balancing markets*) or will additional measures (subsidies) be required.



Opportunities exist in the following areas:

1. Dispatchable back-up capacity (gas, biomass, coal, hydro, nuclear…) with load-following
2. Storage (but technical challenges, PV also has seriously dented business case!)
3. Interconnection and market integration (still sound idea but political challenges)
4. Demand side management and load shifting especially in the industry sector
5. Integrated local and regional heat and power planning

Where Are We Now?

1. Liberalised, competitive and decentralised electricity markets convincingly organize efficient short-term dispatch;
2. However, their ability to ensure adequate levels of investment and security of supply is being questioned. Reasons are
   a) Random short-term prices does not coalesce into credible long-term investment signal;
   b) Asymmetric incentives as penalties for over-investment are high (inelastic demand);
   c) Security of supply externality as social losses are higher than potential private gains from supplying an additional unit of capacity.

Two possible strategies:

A. Muddle through with patches and hope for DSM and storage to deliver;

B. Engage in general re-think about new target model around coherent long-term investment finance with level playing field.

Towards a New European Target Model (Option B)

Current discussions identify following elements for new European target model:

- Review of support mechanism for REN
  - Substitute FITs with quantity targets and auctions for efficiency gains
  - Abolition of grid priority in order to create "balancing obligation"
- Single European market design for balancing markets (not necessarily single market) closely integrated with European-wide Intraday and Day-ahead market
- Capacity obligations coupled with capacity payments (determined through auction or *ex ante*) and penalties in case of non-performance;
- National capacity mechanisms closely coordinated at European level (harmonization of products and margins, rules of reciprocal participation, review of allocation of interconnection capacity); all effective capacity to participate;
- Rehabilitation of long-term supply contracts
- "System levy" for auto-consumers
- Strengthening role of distributors as single point of contact; local concessions by auction (long-term but easily contestable in case of non-performance).