Electricity generation costs and system effects in low-carbon electricity systems

A synthesis of OECD/NEA Work

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Summer School "Economics of Electricity Markets", Ghent, 4 September 2015

Outline of the presentation

A. Introduction to OECD/NEA and its work in the electricity markets

B. Economics of generation technologies: plant level costs

- The concept of Levelised Cost Of Electricity (LCOE)
- Results of the NEA 2010 study
- Sensitivity analysis and key messages

C. Economics of generation technologies: a system approach

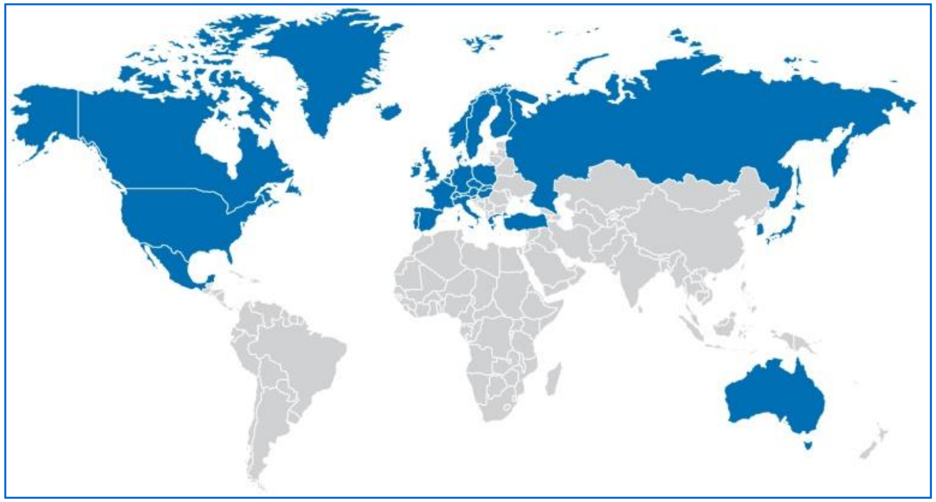
- Introduction on the NEA study on "System Effects"
- The system effects of nuclear energy
- Methodology: residual load duration curves
- Application of residual load duration curves: impacts of Variable Renewable's introduction
- Synthesis of the results and key messages

D. A measure of economic value of Variable Renewables

OECD/NEA History and Mission

- **1947:** U.S. Secretary of State George Marshall proposes a post-WW II European Recovery Program: the Marshall Plan.
- **1948:** The Plan led to establishment of the Organisation for European Economic Co-operation (OEEC) to work on the joint Recovery Program (18 member countries).

  1961: OEEC became OECD (USA + Canada)
- **1958:** European Nuclear Energy Agency (ENEA) set up which became NEA in 1972.



31 member countries (24 in the Data Bank)

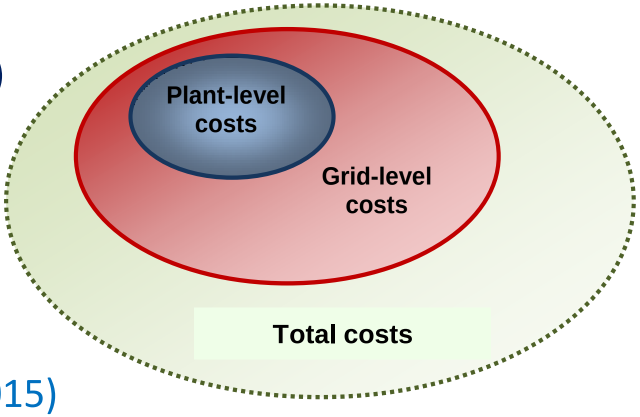
88% of global nuclear electricity capacity

NEA Mission

- To assist its member countries in maintaining and further developing, through international co-operation, the **scientific, technological and legal bases** required for a safe, environmentally friendly and economical use of nuclear energy for peaceful purposes.
- To provide authoritative assessments and to forge common understandings on key issues, as **input to government decisions on nuclear energy policy**, and to broader OECD policy analyses in areas such as energy and sustainable development.

Economics of electricity generation
Work performed at the OECD/NEA

- ***Economics of electricity generation – Plant level costs***
  - Projected Costs of Generating Electricity (NEA/IEA 2010 and 2015)
  - Carbon pricing, power markets and the competitiveness of nuclear power (2011)
  - The Economics of Long-term Operation of NPPs (2012)
  - Nuclear New Built: Financing and Project Management (2015)
  - Costs of Decommissioning Nuclear Power Plants (*forthcoming*, 2015)



- ***System Effects Study – Grid-Level costs***
  - Nuclear Energy and Renewables. System Effects in Low-carbon electricity systems (2012)
  - Dealing with System Costs in Decarbonising Electricity Systems: Policy Options *(planned for 2016)*

- ***Total costs - Externalities***
  - The Security of Energy Supply and the Contribution of Nuclear Energy (2010)
  - Comparing Nuclear Accident Risks with Those from Other Energy Sources (2010)
  - Estimation of potential losses due to nuclear accidents (*forthcoming*, 2016)
  - Social and Economic Impacts of Nuclear Power (*forthcoming*, 2015)
  - The full cost of electricity provision (*planned for 2015-2016*)

NEA Nuclear Energy Agency

OECD

Economics of generation technologies: plant level costs

On the basis of :

Projected Costs of Generating Electricity: 2010 and 2015 Editions

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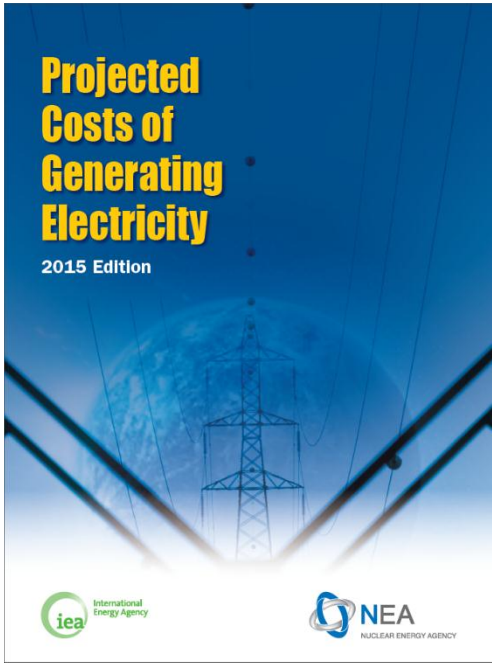
Projected Costs of Generating Electricity: 2010 and 2015 Editions

EGC_{2010} is the **7th Edition** in the series of Joint IEA/NEA studies (since 1983) and was published in March 2010.
The **8th Edition in press** *(1 September 2015).*



- Presents **baseload power generation costs** for 190 power plants *(181 in the 2015 edition)* with different technologies in 17 OECD and 4 non-OECD countries (Brazil, China, Russia, South Africa), including a wide range of technologies:
  - ***Nuclear***: 20 light water reactors *(11)*
  - ***Gas***: 25 plants of which 22 CCGTs *(17)*
  - ***Coal***: 34 plants of which 22 SC/USC *(14)*
  - ***Carbon capture***: 14 coal-fired and 2 gas-fired plants with CC(S) *(No)*
  - ***Renewables***: 72 plants, of which 18 onshore wind, 8 offshore wind, 17 solar PV, 3 solar thermal, 14 hydro, 3 geothermal, 3 biogas, 3 biomass, 1 tidal and 2 wave *(114: 42 PV, 22 On-W, 12 Off-W, 28 H)*
  - ***CHP***: 20 plants, of which 13 gas, 3 coal, 3 biomass, 1 biogas and municipal waste *(18)*
- The study assumes, for the first time, a **CO_2 price of 30 USD/tonne** and long-term fossil fuel prices based on ***WEO 2009*** *(WEO 2014).*
- Extensive range of sensitivity analyses to changes in key cost parameters *(**interest rate, fossil fuel and CO_2 prices, construction costs, lead times, lifetimes, load factors**).*

Levelised Cost Of Electricity (LCOE)

- LCOE is a useful (and widely used) tool to compare the unit cost of generating technologies that use different fuels, have different economic lives, different capital expenditure paths, different annual costs (O&M, fuel, carbon prices), different sizes and load factors.
- The LCOE is the constant unit price of output ($/MWh) that would equalise the sum of discounted costs over the lifetime of a project with the sum of discounted revenues.

$$P_{electricity} \sum_t \frac{Electricity_t}{(1+r)^t} = \sum_t \frac{Invest_t + O\&M_t + Fuel_t + Carbon_t + Decomm_t}{(1+r)^t}$$

- LCOE is basically a NPV calculation -> Electricity price that makes the NPV=0.
- LCOE is a lifetime average cost, corresponding to the costs for an investor bearing no risk (certainty of investment and production costs, certainty of electricity output and stability of electricity prices).
- LCOE is closer to the real costs in a regulated monopoly market (or a market where long-term contracts are possible) than those of a competitive market with variable electricity prices.
- Cost concept: social resource cost (no inclusion of technology-specific or solvency risk) rather than private investor financial cost (WACC).

Basic Methodology of EGC Study

- In order to calculate LCOE per MWh all plants costs and revenues discounted or capitalised to the date of commissioning → **2015 (2020 for CCS).** Results are given in **USD_{2015}/MWh**
- Two discount rates, 5% and 10% **real (net of inflation)** [in the 2015 edition, 3%-7% and 10%].

  In comparison corporate bonds of European utilities (> 6 years) have a **nominal** rate of around 2÷3% (May 2014) and long term government bond (30 years) of around 1.5÷4%. Equity investors would require higher rates of return (WACC utilities is about 7÷9%). #
- Plant-level cost of the production of **base-load** power for nuclear, coal, gas (85% load-factor) and using a local load factor for **renewables** and **hydro.** Load factors: 20÷41% for on-shore wind (*26% median*), 34÷43% for off-shore wind, 10÷25% for solar (*13% median*) and 40÷60% for hydro.
- Costs at the plant gate (including transport of fuel, but not electricity connection and transmission).
- The electricity price and the discount rate are stable during the lifetime of the project. All the electricity produced is immediately sold at that price.
- LCOE does not take into account taxes, transfers, subsidies and any form of government intervention (social cost more than a private investor perspective).

Shortcomings

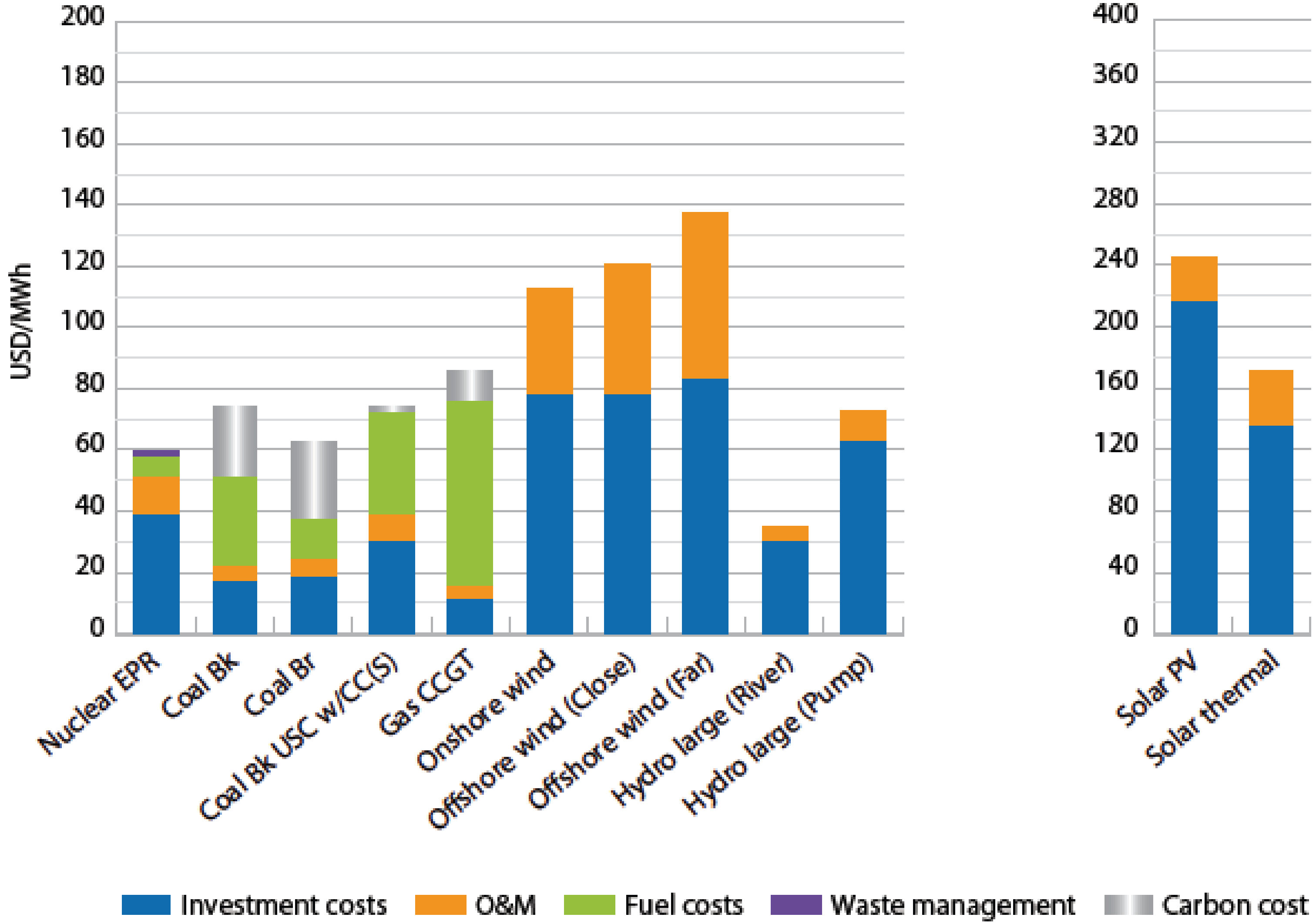
- ***LCOE consider power plants in isolation -> no inclusion of system effects and costs.***
- LCOE indicates the cost of electricity production but does not takes into account the “value” of electricity (*when* electricity is generated).
- LCOE indicates production costs at the power plant gate, and thus does not takes into account for connection, transmission and distribution (*where* electricity is generated).
- LCOE does not indicate the relative stability and predictability in generation costs (fuel price variability + uncertainty in construction costs).
- LCOE does not recognise the size of a power plant and thus the size of cash-flows.
- LCOE is sensitive on the assumptions (discount rate) and **ignores the concept of risk**.
  - *Plant risk* (construction cost, lead time, O&M costs, availability and performances)
  - *Market risk* (fuel costs, demand and consumption, electricity price)
  - *Regulatory risk* (market design , licensing and approval, transmission)
  - *Policy risk* (environmental standards, CO_2 policies, support for specific technologies)
- Risk should be reflected in the discount rate, and be different for each technology, BUT
  - Risk differs strongly over the lifetime of the project
  - Even during operations, risk depends on the level of variable cost

Results

- Examples of LCOE calculations (Eurelectric)
- Regional ranges of LCOE
- Cost structure: capital costs

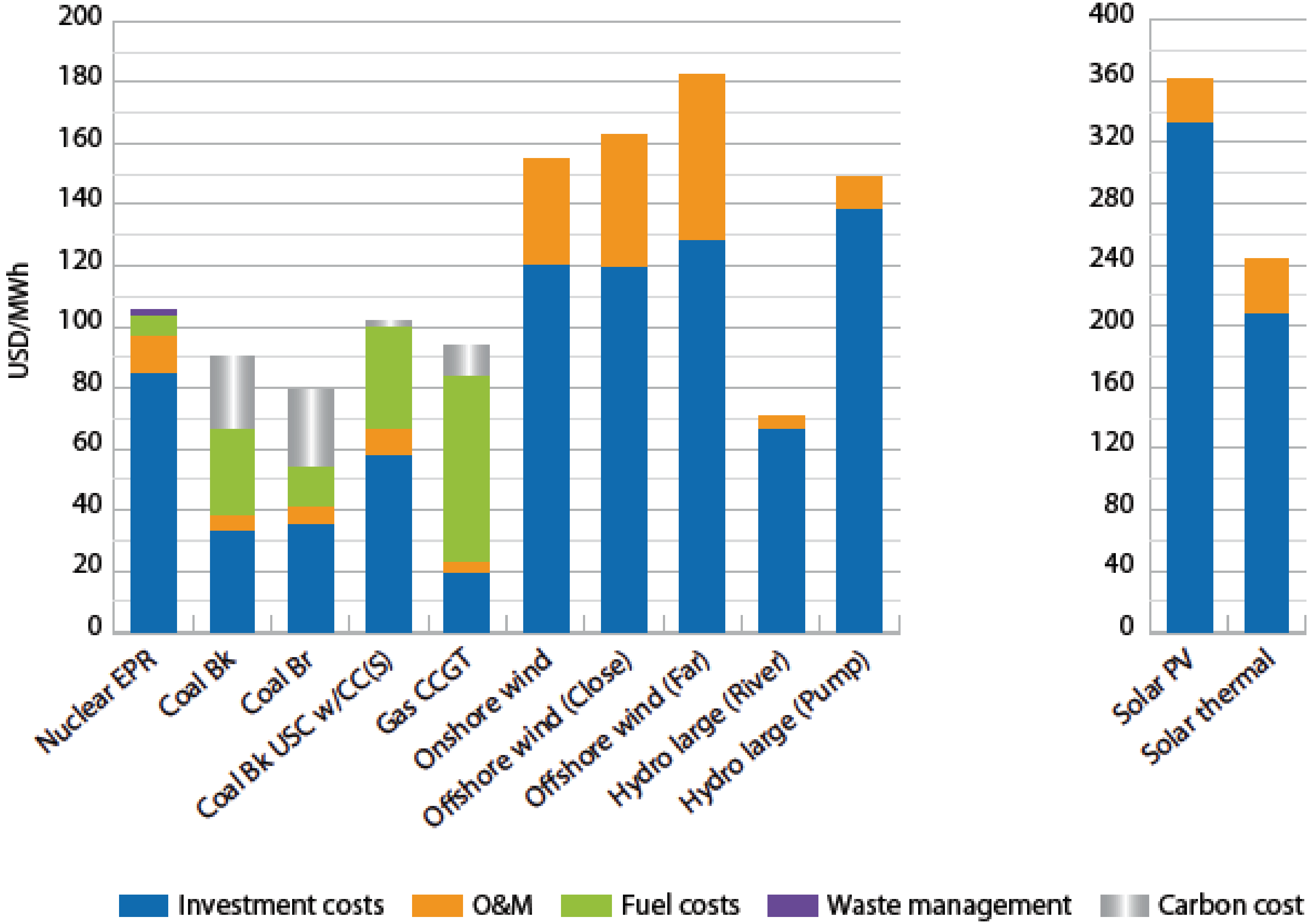
Levelised Costs Of Electricity (EGC 2010): Eurelectric/VGB

At 5% Discount Rate

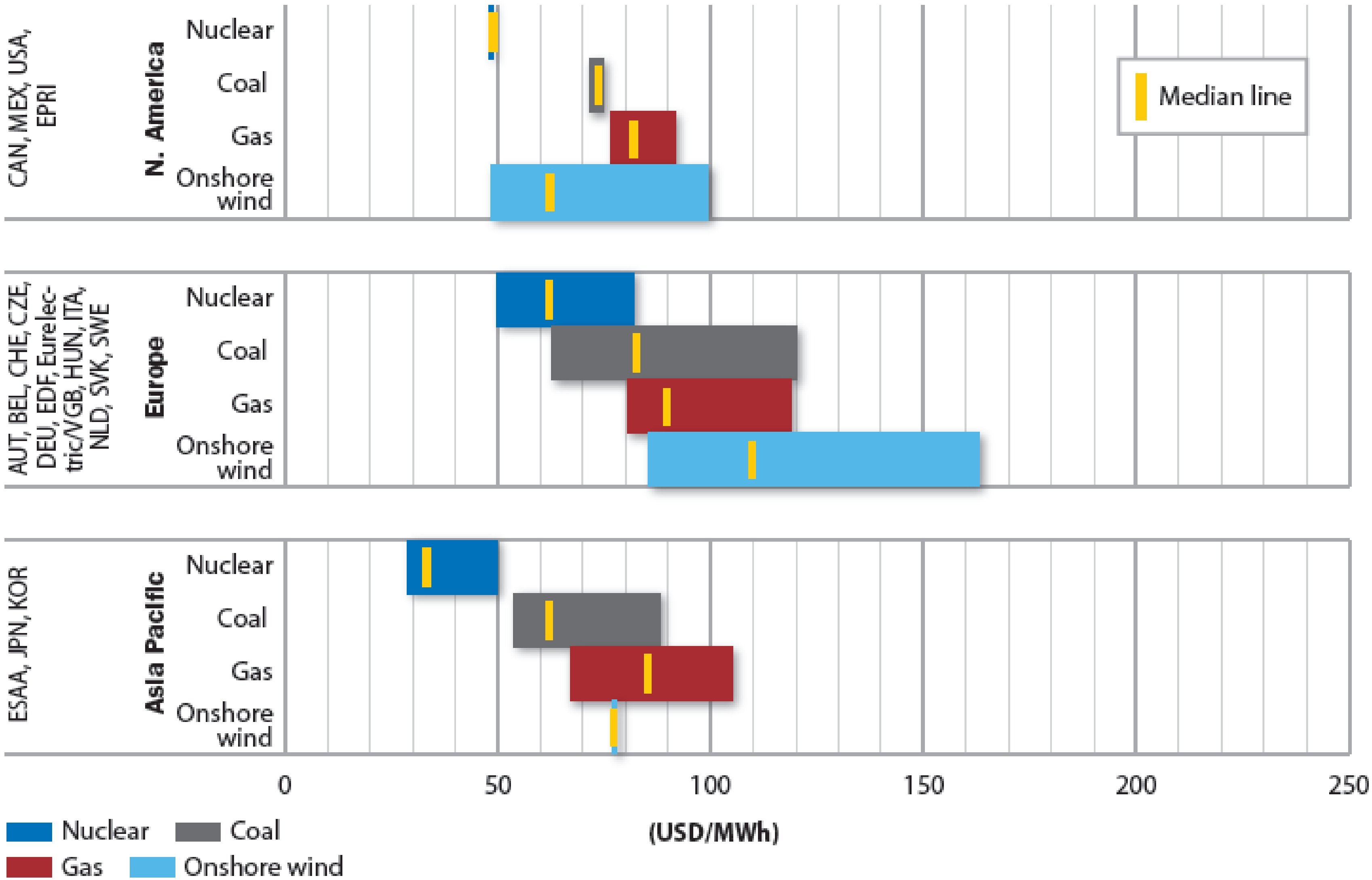


Levelised Costs Of Electricity (EGC 2010): Eurelectric/VGB

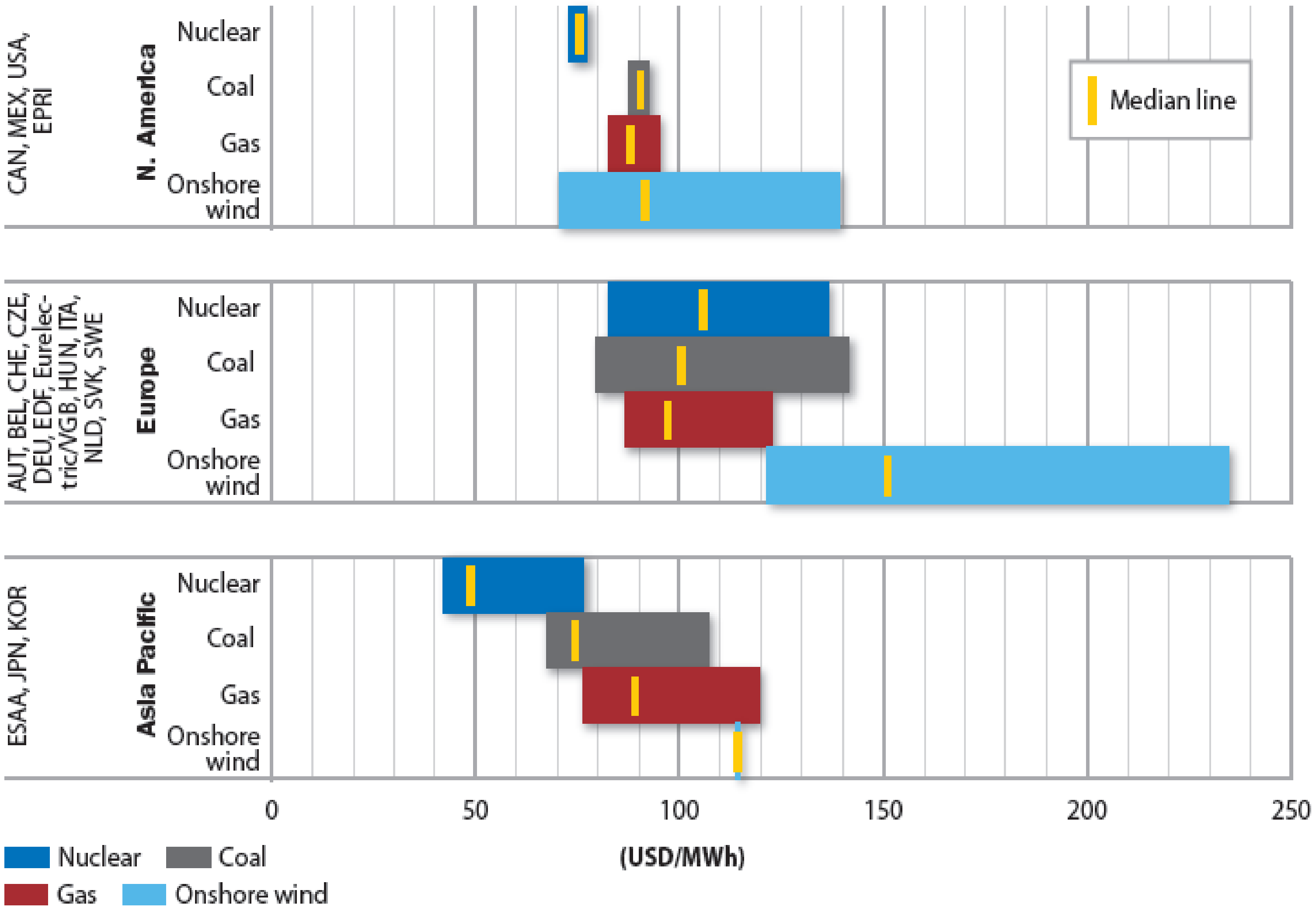
At 10% Discount Rate



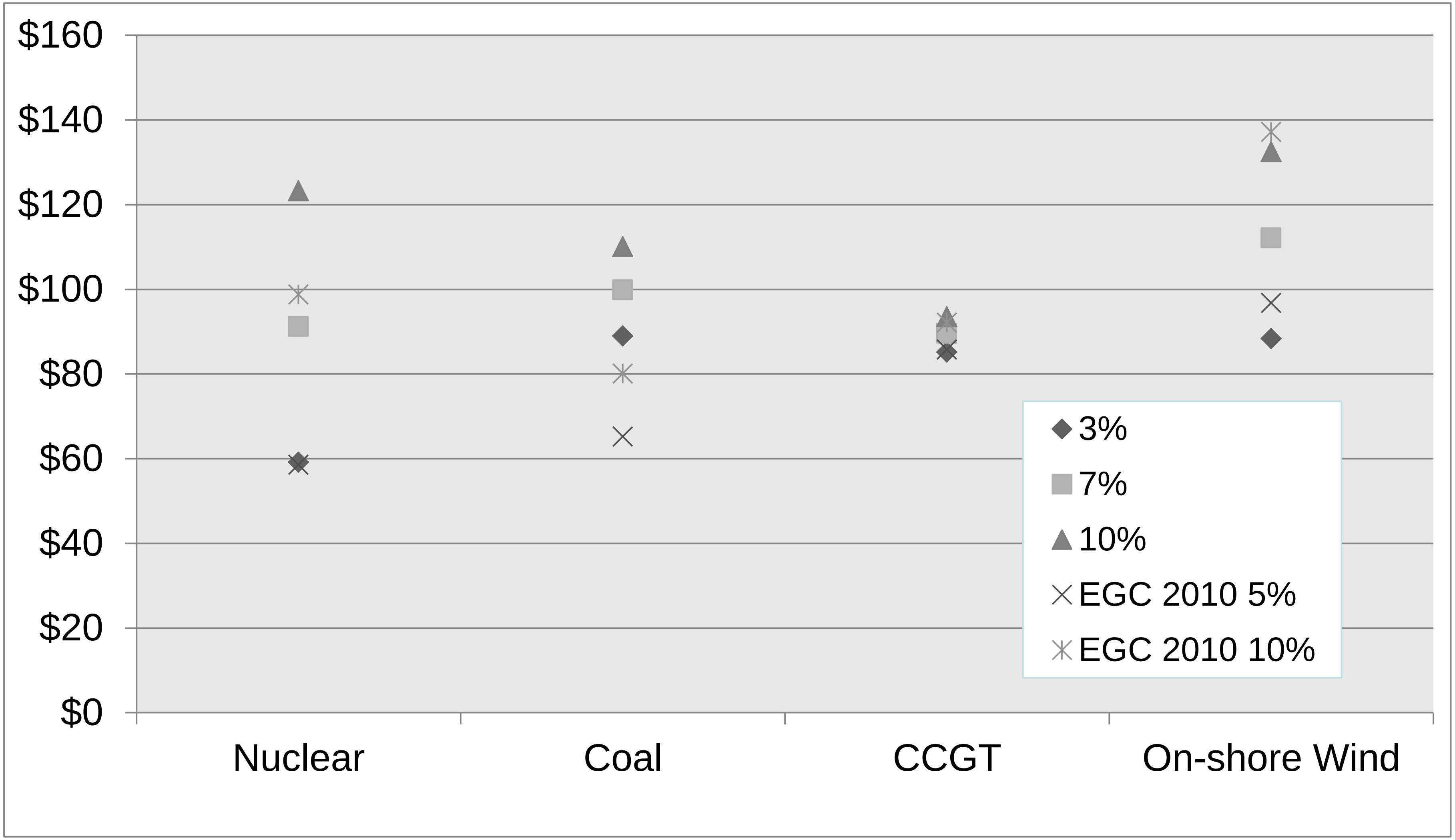
Regional ranges of LCOE: at 5% discount rate



Regional ranges of LCOE: at 10% discount rate



Median Case: comparison between EGC 2010 and 2015



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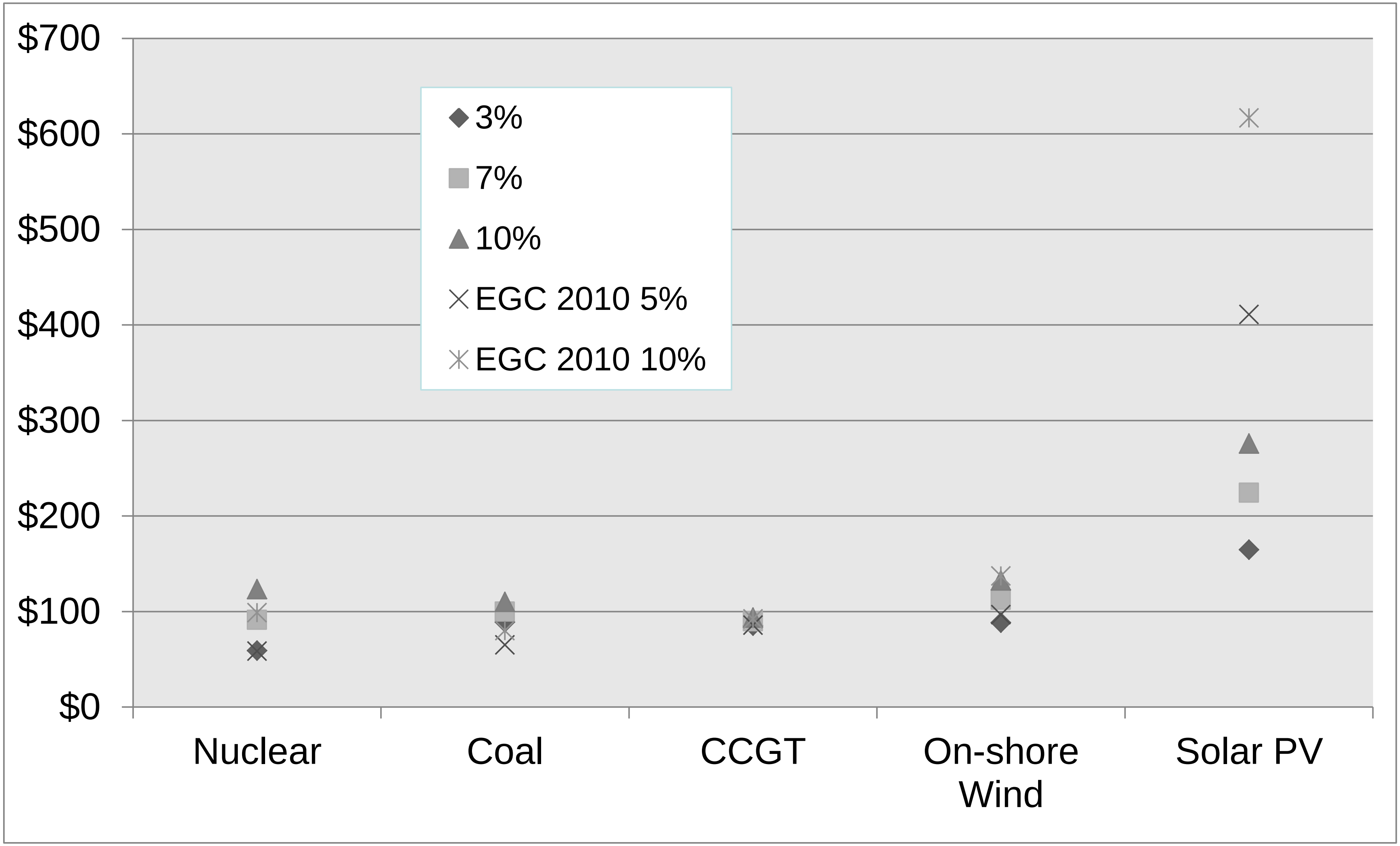


Nuclear power plants: LCOE [USD/MWh]

Country	Technology	Net capacity	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel Cycle costs	O&M costs[3]	LCOE	
				5%	10%	5%	10%			5%	10%
		MWe	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	
Belgium	EPR-1600	1 600	5 383	6 185	7 117	0.23	0.02	9.33	7.20	61.06	109.14
Czech Rep.	PWR	1 150	5 858	6 392	6 971	0.22	0.02	9.33	14.74	69.74	115.06
France*	EPR	1 630	3 860	4 483	5 219	0.05	0.005	9.33	16.00	56.42	92.38
Germany	PWR	1 600	4 102	4 599	5 022	0.00	0.00	9.33	8.80	49.97	82.64
Hungary	PWR	1 120	5 198	5 632	6 113	1.77	2.18	8.77	29.79/29.84	81.65	121.62
Japan	ABWR	1 330	3 009	3 430	3 940	0.13	0.01	9.33	16.50	49.71	76.46
Korea	OPR-1000	954	1 876	2 098	2 340	0.09	0.01	7.90	10.42	32.93	48.38
	APR-1400	1 343	1 556	1 751	1 964	0.07	0.01	7.90	8.95	29.05	42.09
Netherlands	PWR	1 650	5 105	5 709	6 383	0.20	0.02	9.33	13.71	62.76	105.06
Slovak Rep.	VVER 440/ V213	954	4 261	4 874	5 580	0.16	0.02	9.33	19.35/16.89	62.59	97.92
Switzerland	PWR	1 600	5 863	6 988	8 334	0.29	0.03	9.33	19.84	78.24	136.50
	PWR	1 530	3 681	4 327	5 098	0.16	0.01	9.33	15.40	54.85	90.23
United States	Advanced Gen III+	1 350	3 382	3 814	4 296	0.13	0.01	9.33	12.87	48.73	77.39
NON-OECD MEMBERS											
Brazil	PWR	1 405	3 798	4 703	5 813	0.84	0.84	11.64	15.54	65.29	105.29
China	CPR-1000	1 000	1 763	1 946	2 145	0.08	0.01	9.33	7.10	29.99	44.00
	CPR-1000	1 000	1 748	1 931	2 128	0.08	0.01	9.33	7.04	29.82	43.72
	AP-1000	1 250	2 302	2 542	2 802	0.10	0.01	9.33	9.28	36.31	54.61
Russia	VVER-1150	1 070	2 933	3 238	3 574	0.00	0.00	4.00	16.74/16.94	43.49	68.15
INDUSTRY CONTRIBUTION											
EPRI	APWR, ABWR	1 400	2 970	3 319	3 714	0.12	0.01	9.33	15.80	48.23	72.87
Eurelectric	EPR-1600	1 600	4 724	5 575	6 592	0.19	0.02	9.33	11.80	59.93	105.84

*The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Gas power plants: LCOE [USD/MWh]

Country	Technology	Net capacity	Electrical conversion efficiency	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel costs	Carbon costs	O&M costs[3]	LCOE	
					5%	10%	5%	10%				5%	10%
		MWe	%	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	USD/MWh	
Belgium	Single Shaft CCGT	850	58%	1 249	1 366	1 493	0.09	0.03	61.12	10.54	6.33	**89.71**	**98.29**
	CCGT	400	55%	1 099	1 209	1 328	0.08	0.03	63.89	11.02	6.56	**91.86**	**99.54**
	CCGT	420	57%	1 069	1 130	1 193	0.08	0.03	61.65	10.63	4.06	**86.05**	**92.57**
	CCGT	420	57%	1 245	1 316	1 390	0.09	0.03	61.65	10.63	5.71	**89.31**	**96.90**
Czech Rep.	CCGT	430	57%	1 573	1 793	2 043	0.12	0.04	61.65	10.23	3.73	**91.92**	**104.48**
	CCGT w/CC(S)	387	54%	2 611	2 925	3 276	0.18	0.06	65.08	0.54	6.22	**98.21**	**117.90**
Germany	CCGT	800	60%	1 025	1 147	1 282	0.08	0.02	58.57	10.08	6.73	**85.23**	**92.81**
	Gas Turbine	150	38%	520	582	650	0.04	0.01	92.48	15.92	5.38	**118.77**	**122.61**
Italy	CCGT	800	55%	769	818	872	0.06	0.02	63.89	11.25	4.67	**86.85**	**91.44**
Japan	CCGT	1 600	55%	1 549	1 863	2 234	0.12	0.04	72.58	11.02	5.55	**105.14**	**119.53**
Korea	LNG CCGT	495	57%	643	678	713	0.05	0.02	69.79	10.42	4.79	**90.82**	**94.70**
	LNG CCGT	692	57%	635	669	704	0.05	0.02	69.54	10.38	4.12	**89.80**	**93.63**
Mexico	CCGT	446	49%	982	1 105	1 240	0.07	0.02	58.03	12.21	4.53/4.74	**84.26**	**91.85**
Netherlands	CCGT	870	59%	1 025	1 076	1 127	0.08	0.02	59.56	10.27	1.32	**80.40**	**86.48**
Switzerland	CCGT	395	58%	1 622	1 776	1 942	0.13	0.04	60.59	10.35	7.83	**94.04**	**105.19**
United States	CCGT	400	54%	969	1 039	1 113	0.07	0.02	49.27	14.74	3.61	**76.56**	**82.76**
	AGT	230	40%	649	668	687	0.05	0.02	66.52	14.74	4.48	**91.48**	**95.08**
	CCGT w/CC(S)	400	40%	1 928	2 065	2 207	0.13	0.04	67.01	1.47	5.69	**91.90**	**104.19**
NON-OECD MEMBERS													
Brazil	CCGT	210	48%	1 419	1 636	1 880	0.00	0.00	57.79	0.00	5.40	**83.85**	**94.84**
China	CCGT	1 358	58%	538	565	593	0.04	0.01	28.14	0.00	2.81	**35.81**	**39.01**
	CCGT	1 358	58%	583	612	642	0.05	0.01	28.14	0.00	3.04	**36.44**	**39.91**
Russia	CCGT	392	55%	1 237	1 296	1 357	0.00	0.00	39.14	0.00	7.55	**57.75**	**65.13**
INDUSTRY CONTRIBUTION													
EPRI	CCGT	798	48%	727	795	835	0.04	0.01	55.78	12.73	3.39	**78.72**	**83.25**
ESAA	CCGT AC	480	56%	1 678	1 749	1 821	0.11	0.04	41.25	9.98	3.64	**69.89**	**79.64**
	CCGT WC	490	58%	1 594	1 661	1 730	0.00	0.00	39.68	9.60	3.58	**67.03**	**76.36**
	OCGT AC	297	43%	742	761	779	0.00	0.00	52.87	12.80	7.67	**79.82**	**83.91**
Eurelectric	CCGT	388	58%	1 201	1 292	1 387	0.09	0.03	60.59	10.45	3.93	**86.08**	**93.84**

Total generation cost structure

	at 5%						at 10%					
	Nuclear	Coal	Coal w/CCS	Gas	Wind	Solar	Nuclear	Coal	Coal w/CCS	Gas	Wind	Solar
Total Investment cost	58.6%	25.9%	51.6%	11.1%	76.5%	91.7%	75.6%	39.8%	66.8%	17.3%	83.8%	94.9%
O&M	25.2%	9.2%	21.9%	5.2%	22.7%	7.3%	14.9%	7.5%	15.1%	4.9%	16.0%	4.9%
Fuel costs*	16.0%	27.9%	21.0%	71.3%	0.0%	0.0%	9.5%	22.8%	14.5%	66.4%	0.0%	0.0%
CO_2 costs	0.0%	36.8%	5.2%	12.3%	0.0%	0.0%	0.0%	29.9%	3.6%	11.4%	0.0%	0.0%
Decommissioning	0.3%	0.1%	0.2%	0.1%	0.8%	1.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.3%

*Fuel costs for nuclear comprise the costs of the full nuclear fuel cycle including spent fuel reprocessing or disposal.

- Capital intensity of a project indicates the vulnerability to changes in demand and electricity prices.
- Total investments are sunk costs and cannot be recuperated.
- High capital cost technology does not possess the option of exiting the market when prices evolve unfavourably.
- Presently renewables are protected from electricity price risk by FIT or other form of support.

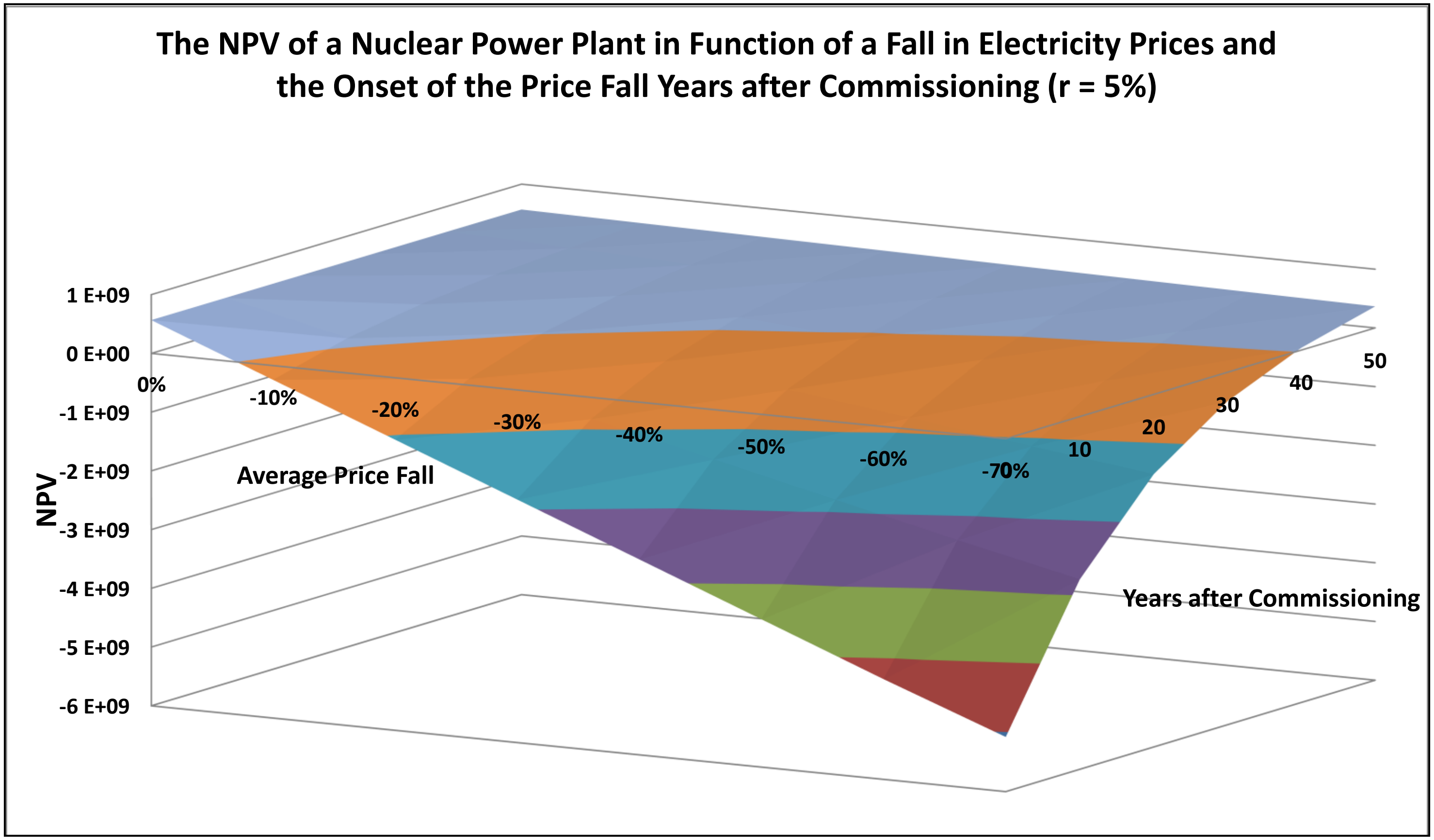
Total generation cost structure and risk: an illustrative example (nuclear)

NPV calculation for a nuclear plant and a gas plant under different electricity price scenarios.

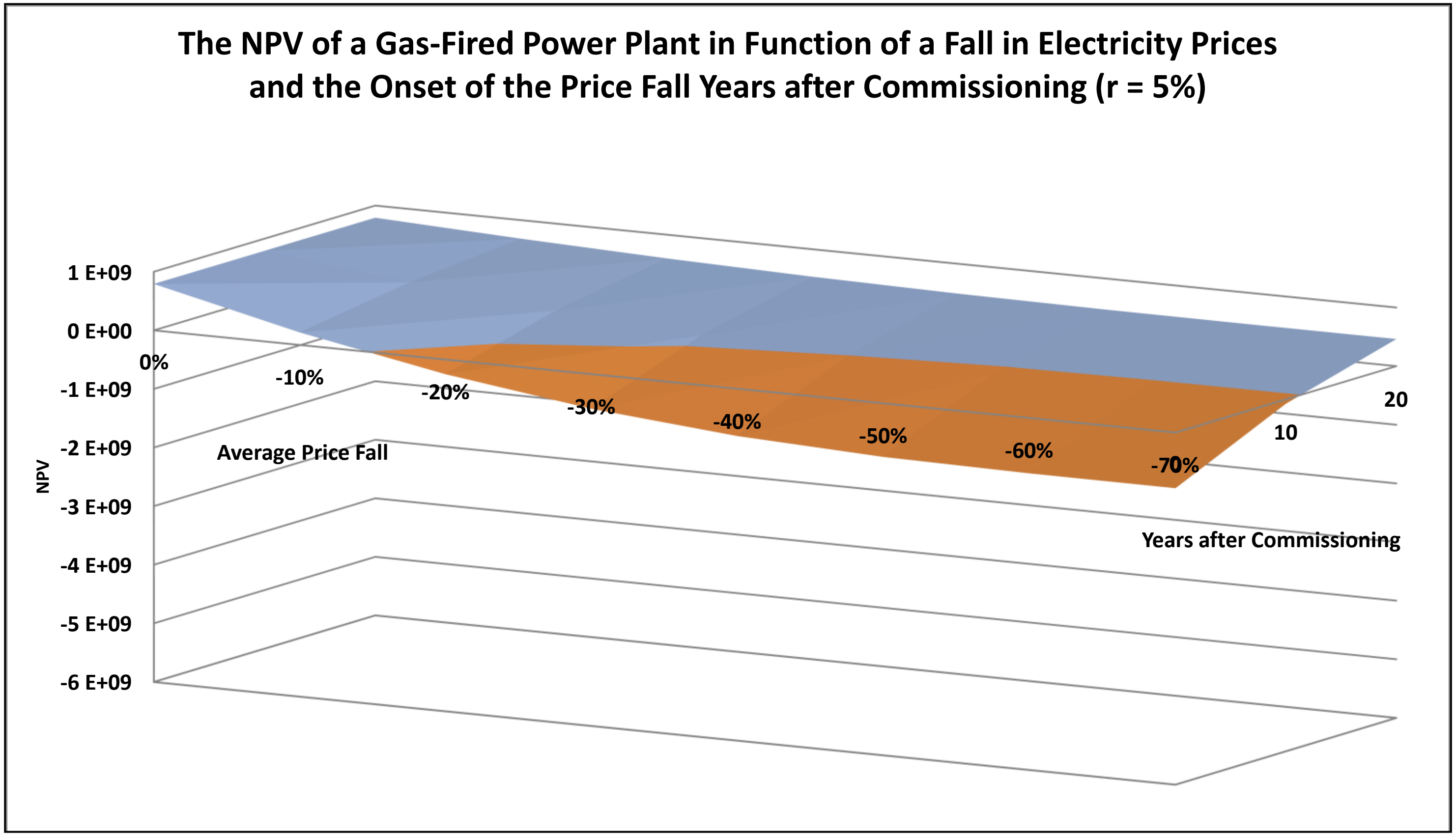
Both technologies yield the **same NPV** at base price (by adjusting overnight costs).

Permanent price fall [-10% to -70%] occurs after commissioning [0-50 years].

Power plants are supposed not operate when electricity price is lower than variable costs.



Total generation cost structure and risk: an illustrative example (gas)



In the worse case scenario, the gas plant leaves the market with losses limited to the investment costs.

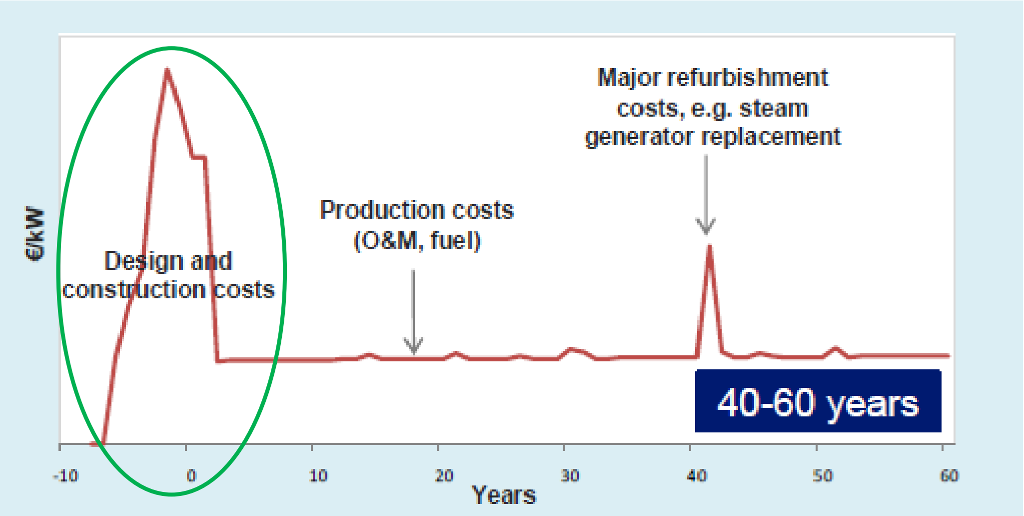
Nuclear will keep producing at decreasing net revenue levels, but losses are consistently higher.

Remember: ***Risk is not captured by LCOE!***

Gas vs nuclear: a comparison

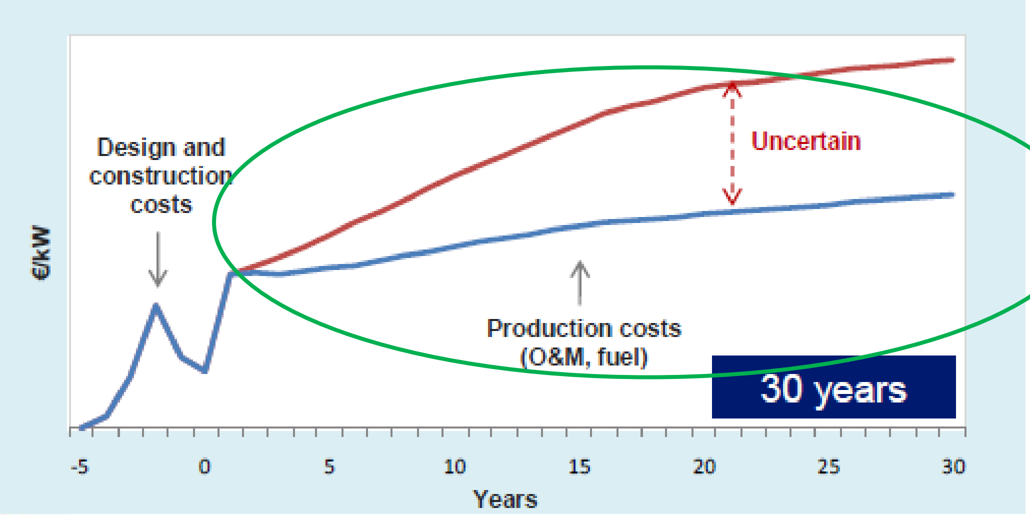
The economic profiles of nuclear and CCGT *(Courtesy of EdF)*

NUCLEAR



- **Very high CAPEX** during the development and construction period
- **Regular and comparatively lower OPEX** during the operating period

CCGT*



- **Very low CAPEX** during development and construction, but comparatively higher production costs due to the significance of fuel costs
- **High and uncertain fuel and CO_2 prices** and consequently high uncertainty on future production costs

Note: CCGT plant in base load operation, 8,000h

Sensitivity Analysis and Key Messages.

- Definition of a median case
- Key factors for each technology
- Sensitivity analysis to major input data

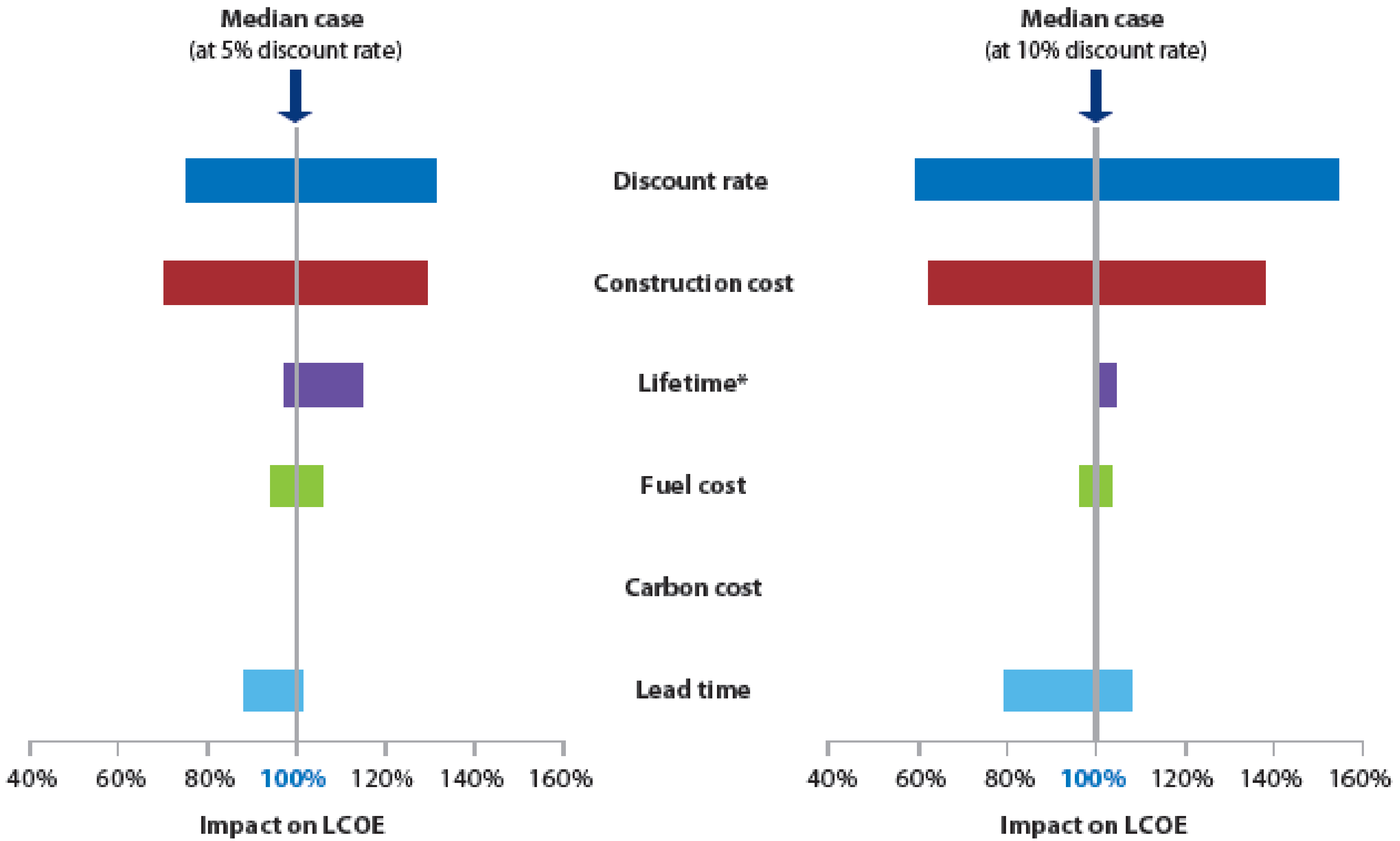
Sensitivity analysis: median case

Median case specifications		Nuclear	CCGT	SC/USC coal	Coal w/90%CC(S)	Onshore wind	Solar PV
Capacity (MW)		1 400.00	480.00	750.00	474.40	45.00	1.00
Owner's and construction		3 681.07	1 018.07	1 915.65	3 336.96	2 236.80	5 759.35
Overnight cost ($/kW)*		4 101.51	1 068.97	2 133.49	3 837.51	2 348.64	6 005.79
O&M ($/MWh)		14.74	4.48	6.02	13.61	21.92	29.95
Fuel cost ($/MWh)		9.33	61.12	18.21	13.04	0.00	0.00
CO_2 cost ($/MWh)		0.00	10.54	23.96	3.22	0.00	0.00
Efficiency (net, LHV)		33%	57%	41.1%	34.8%	-	-
Load factor (%)		85%	85%	85%	85%	26%	13%
Lead time (years)		7	2	4	4	1	1
Expected lifetime (years)		60	30	40	40	25	25
LCOE ($/MWh)	5%	58.53	85.77	65.18	62.07	96.74	410.81
	10%	98.75	92.11	80.05	89.95	137.16	616.55

*Overnight costs include owner's, construction and contingency costs but exclude IDC.

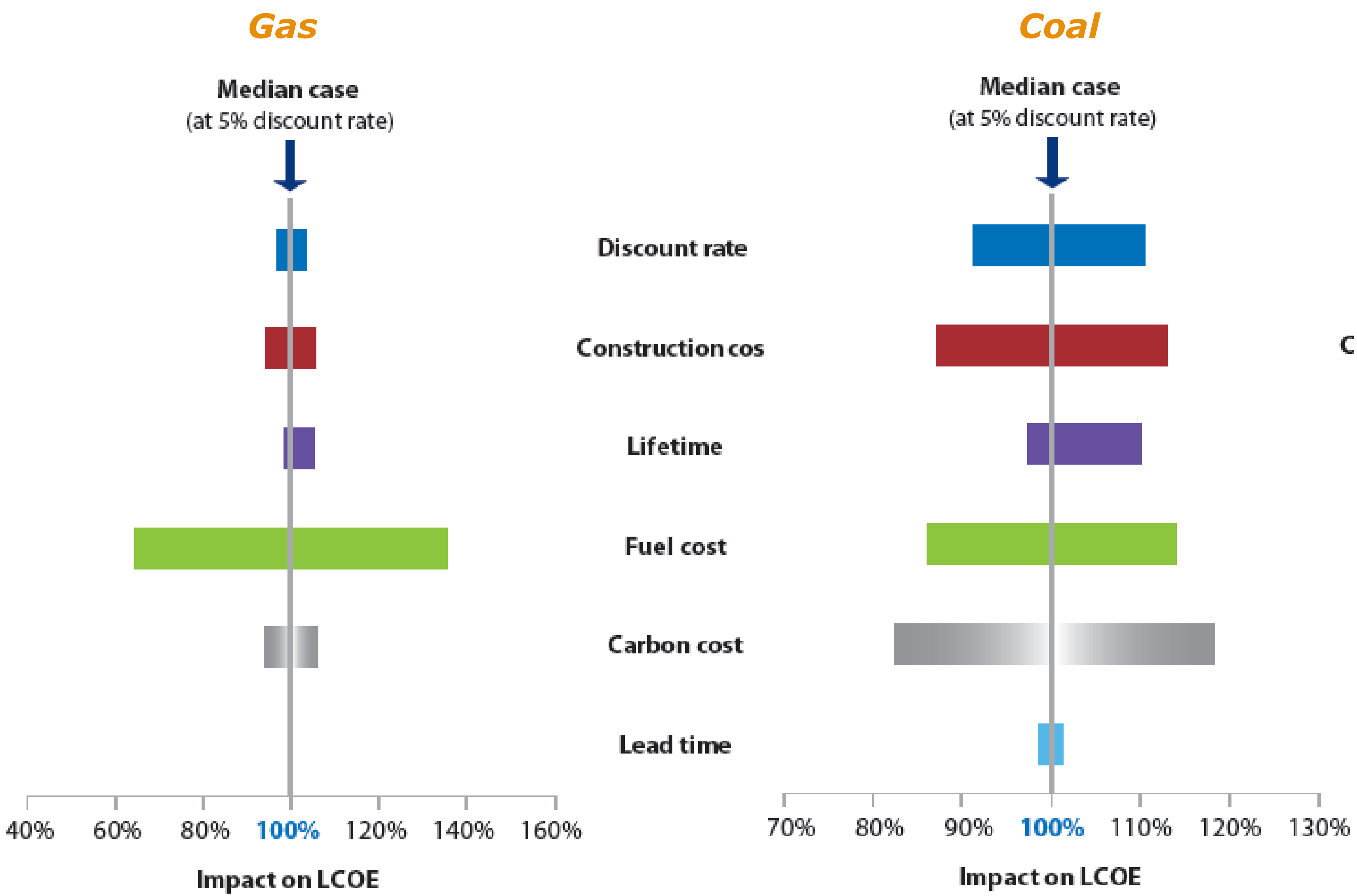
- Sensitivity analysis have been realised assuming an uniform ± 50% variation in each individual parameter.
- Calculations were performed keeping all other parameters constant.

Multi-dimensional sensitivity analysis: Nuclear

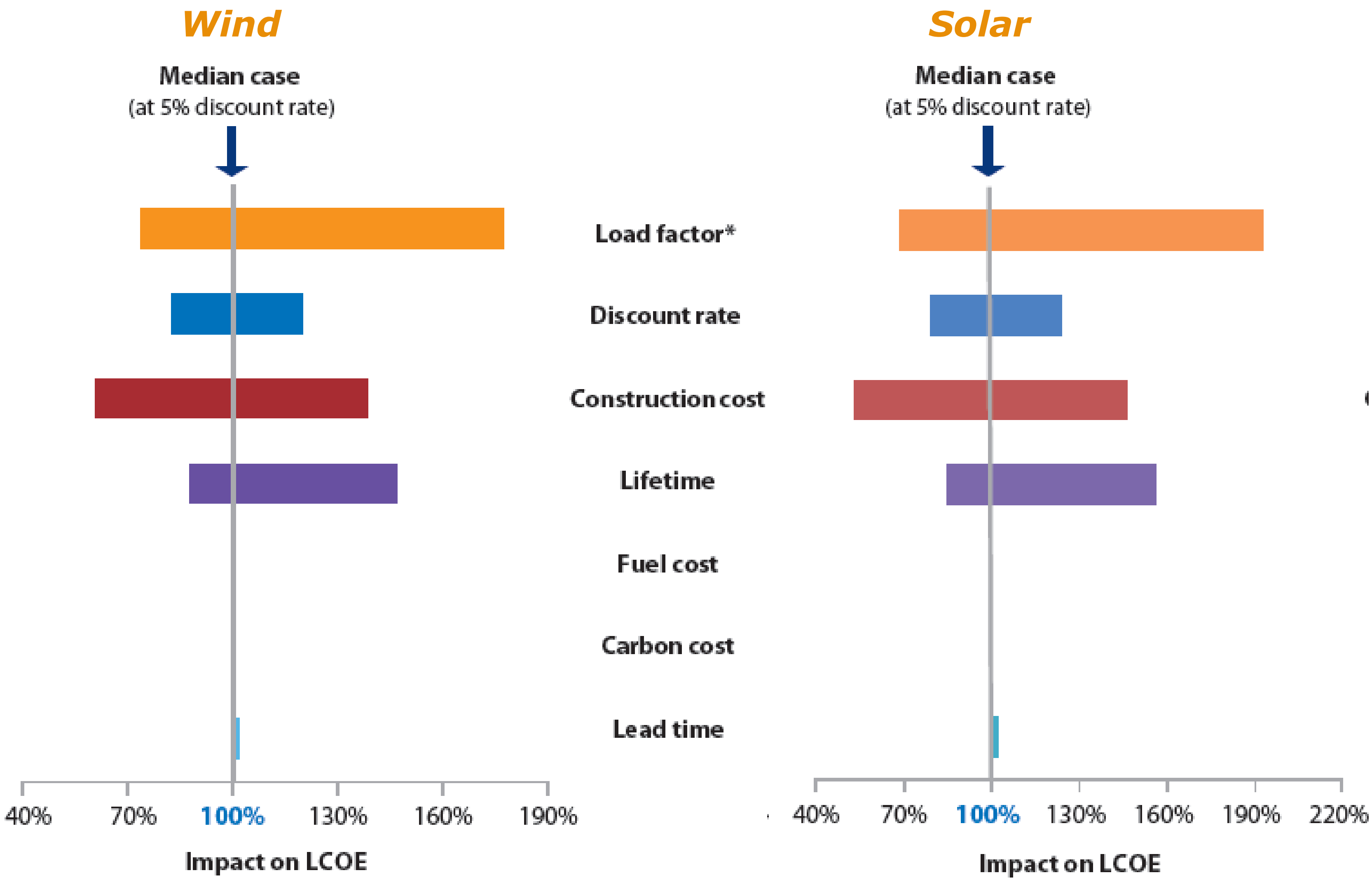


* Lifetime and LCOE are inversely related, as a lifetime extension results in total levelised cost reduction and a lifetime decrease leads to a generation cost increase.

Multi-dimensional sensitivity analysis: Gas and Coal at 5% discount rate



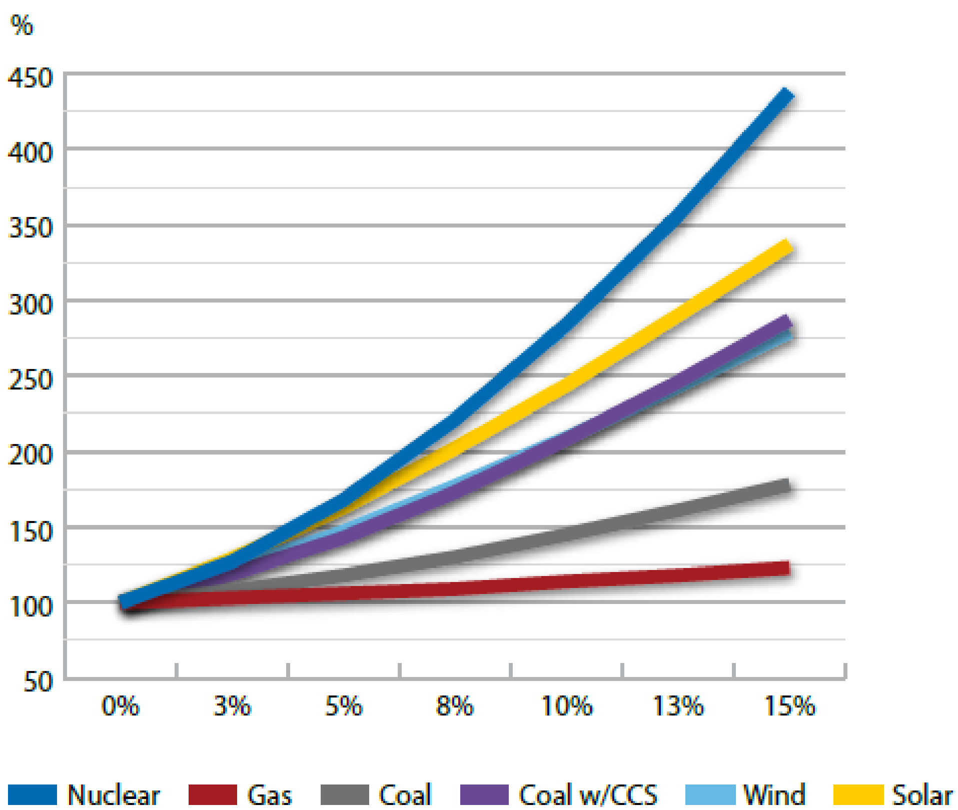
Multi-dimensional sensitivity analysis: Wind and Solar at 5% discount rate



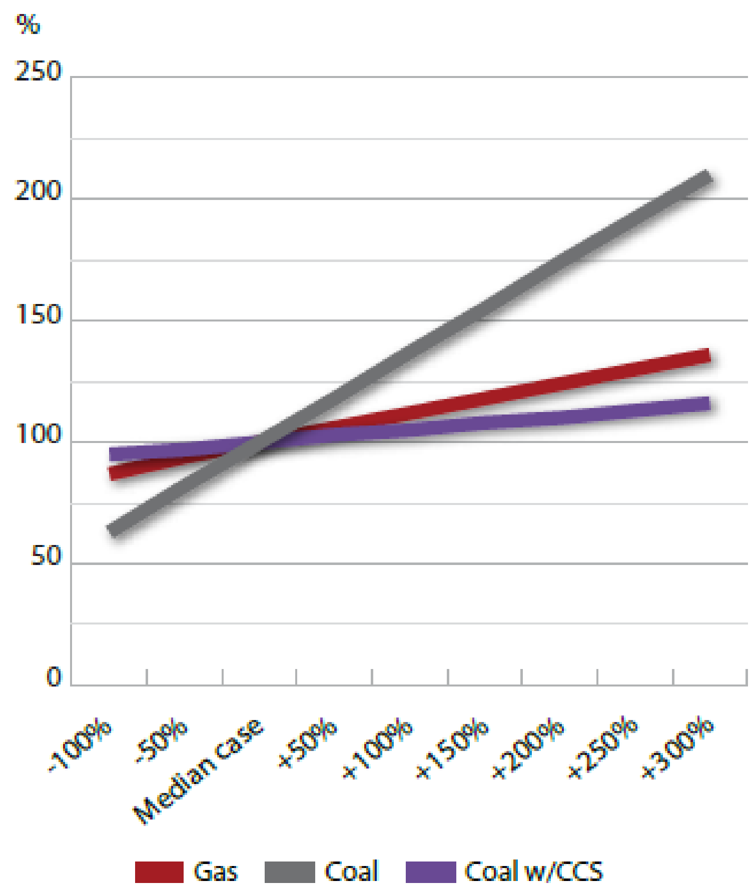
* Load factor and LCOE are inversely related. A higher load factor results in a decrease of LCOE and vice-versa.

Sensitivity to cost of financing and carbon

LCOE as a function of discount rate

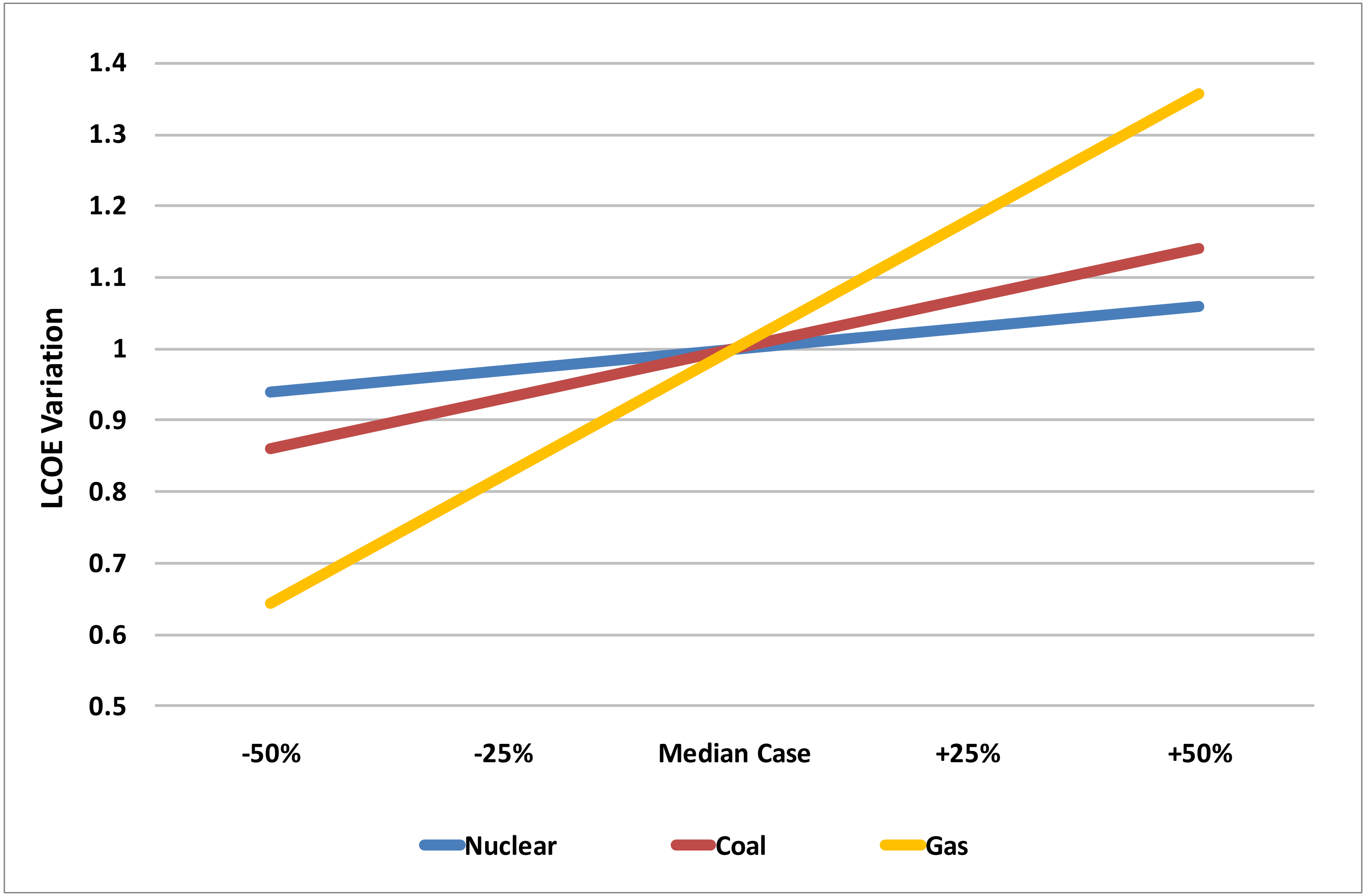


LCOE as a function of carbon cost

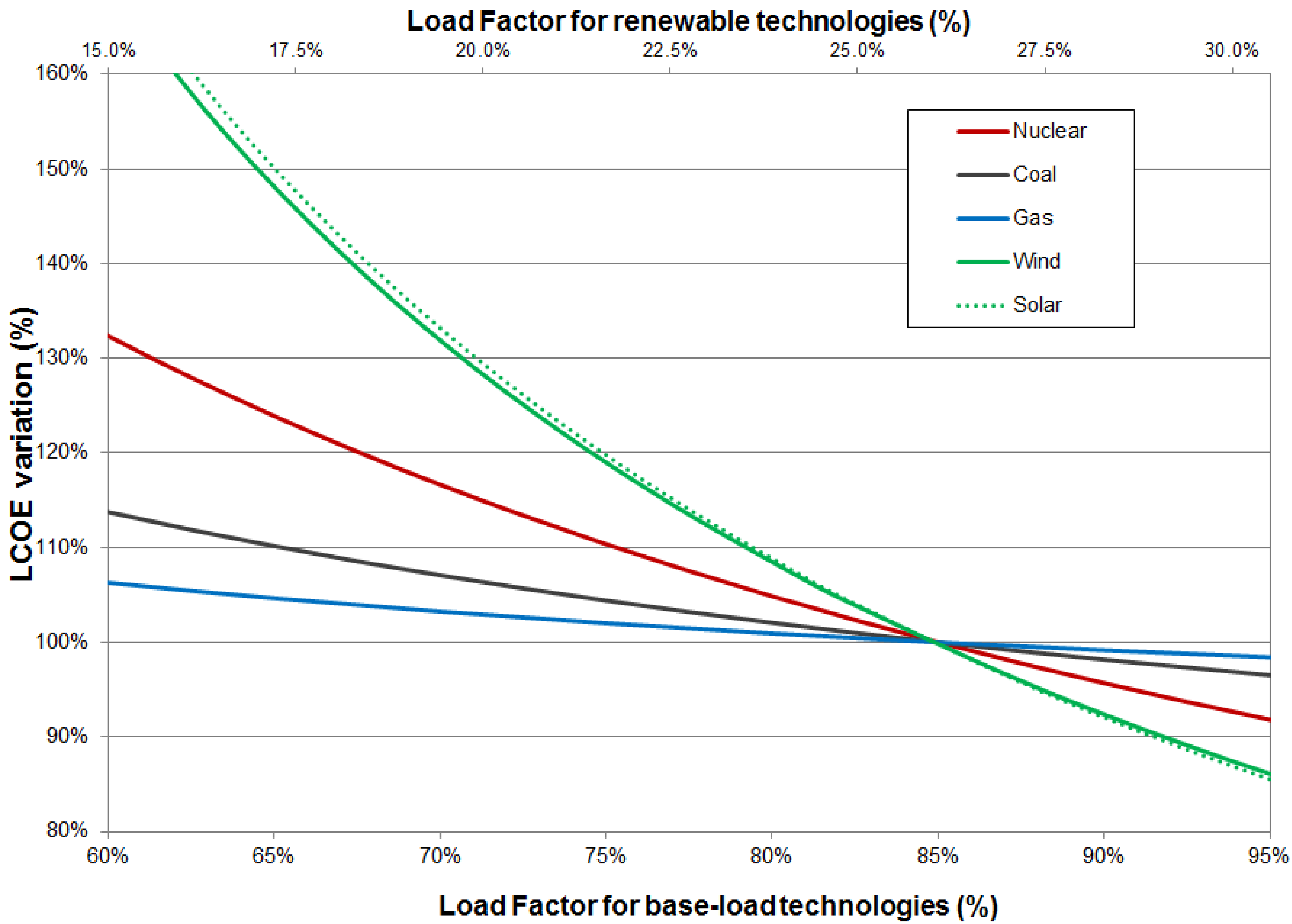


Sensitivity to fuel cost

LCOE as a function of fuel cost



Sensitivity to load factor



* Based on the OECD median case, considering 75% of O&M costs as fixed.

Each technology has strengths and weaknesses

- **Nuclear** delivers significant amounts of low-carbon electricity at stable costs – but has to manage high amounts of capital at risk and is faced with perception issues regarding decommissioning, waste management and proliferation.
- **Coal** is competitive in the absence of a sufficiently high carbon price – but this advantage is quickly reduced as CO_2 cost rises.
- **Carbon Capture** may be a competitive low-carbon generation option – but has not yet been demonstrated at commercial scale for power plants and needs a significant carbon price signal.
- **Gas** key advantages are its low capital cost, low CO_2 profile and high operational flexibility, which make it a low risk option – but costs highly depend on gas price levels which may make it not profitable as base-load power.
- **Hydro** and, for the first time **on-shore wind**, are shown to be competitive in cases where local conditions are favourable – but if not dispatchable, renewables cannot be used for base-load.

Key Messages from Projected Costs of Generating Electricity

1. No technology has a clear overall advantage globally or even regionally.
2. Looking at detailed country numbers, the study show large differences between countries; **national policies and local circumstances matter**.
3. Boundary issues such as **system costs** (which may be substantial especially for intermittent renewables) or specific financing issues must be assessed in a more qualitative manner. The 2015 study offers discussions on:
   - Financing issues
   - Prospects for emerging technologies
   - System costs of integrating variable renewables
   - The future of base-load and role of LCOE
4. **At 5% per cent**, nuclear energy is an attractive option for baseload power generation in all three OECD regions.
5. **At 10% per cent**, nuclear energy remains a competitive option for baseload power generation in the United States and OECD Asia.
6. A **30 $/tonne CO2 price** is not enough to give a decisive advantage to low-carbon technologies in all circumstances.
7. Government action remains key (lower the cost of financing and a significant CO2 price signal to be internalised in power markets).

Points for discussion (after the break)

- Is there still a need for base-load technologies?

  How meaningful is an analysis at 85% load factor which seem unachievable in present (and near-term future)?

- What is really the use of LCOE in liberalised markets?

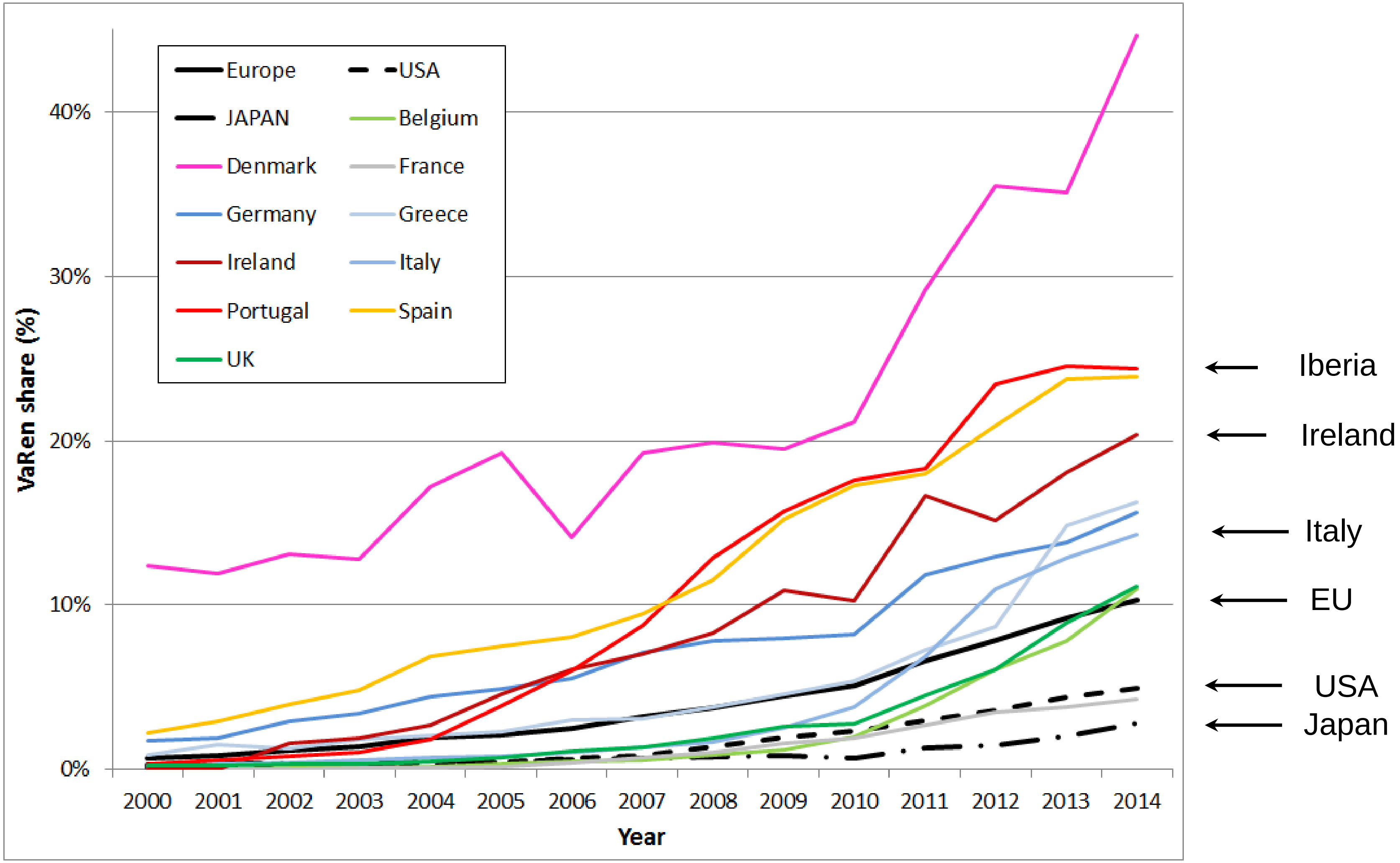
Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems.

Study methodology and key technical findings

Summer School "Economics of Electricity Markets", Ghent, 4 September 2015

Background

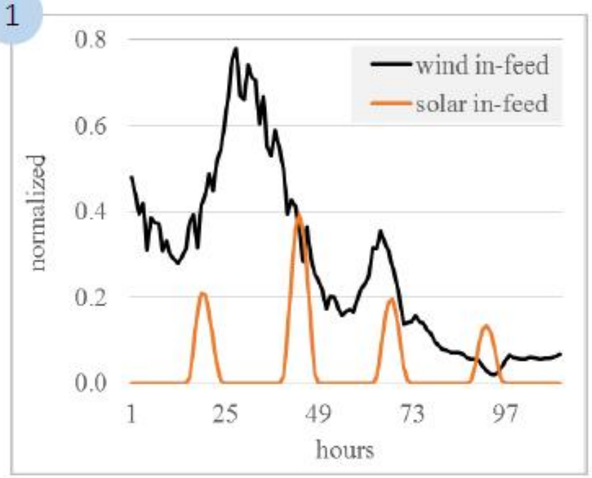
Deployment of intermittent sources (solar and wind) in OECD countries



Source: IEA Electricity monthly reports

Challenges of VRE

1



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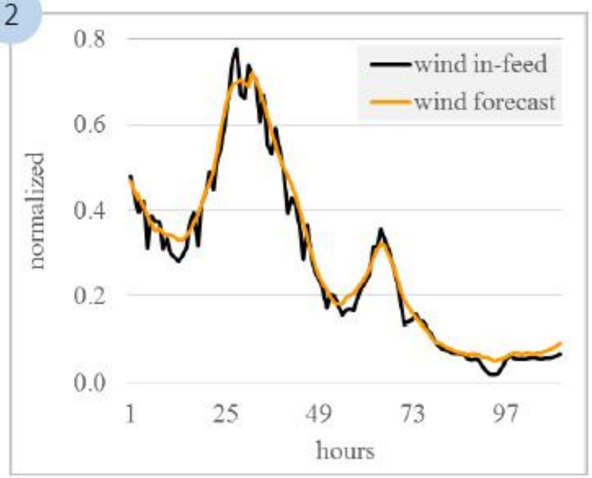

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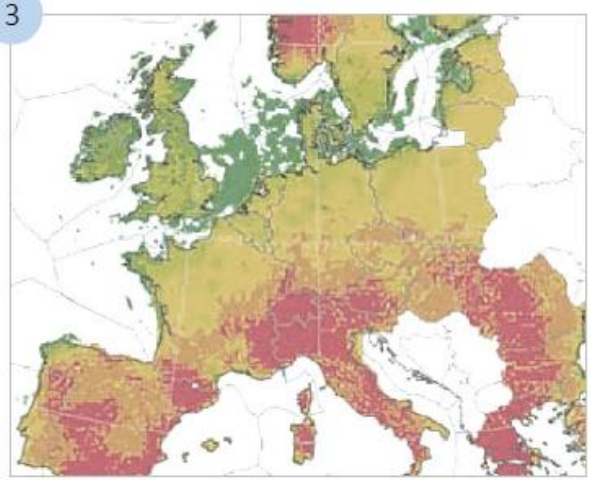


Wind does not always blow

Difficult to predict

Good sites are distant from load centers

"Variable" renewable energy source (VRE)

Source: courtesy of Lion Hirth (neon)

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.

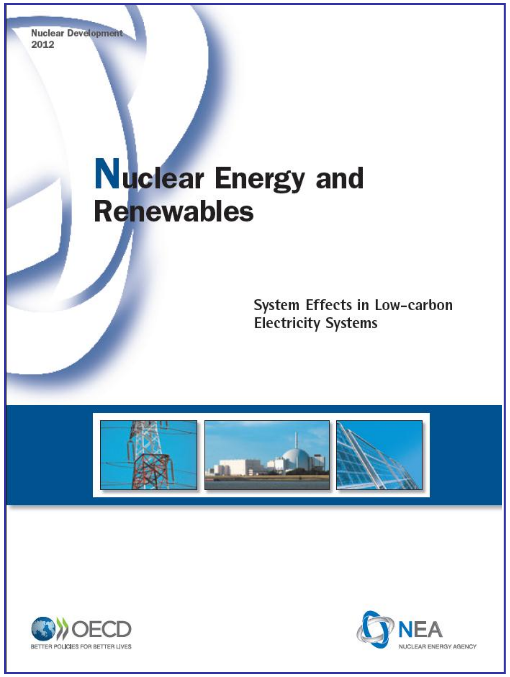
1) Estimation of system effects (and costs) of different generating technologies.
2) Impact of integrating significant amounts of **fluctuating** electricity at **low marginal cost** on the whole electricity system and on nuclear power.

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

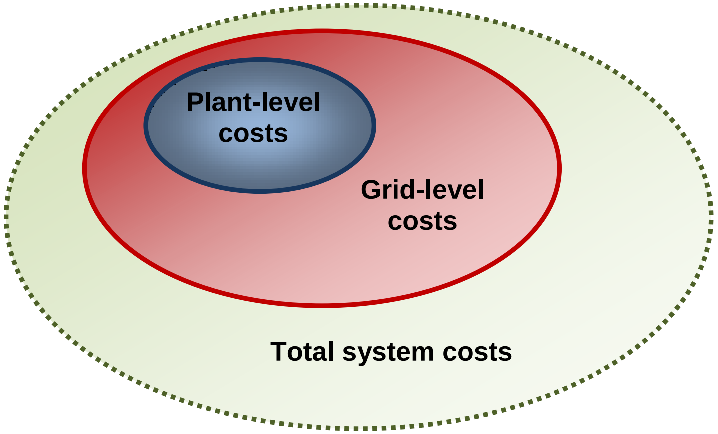
- Impact on electricity markets (lower prices, higher volatility).
- Investment issues in financing new capacity and adequacy concerns.
- Long-term impact on the "optimal" generation structure.
- Significant increase in total costs for electricity supply.



It was the First quantitative study on SE → Large uncertainties in the results.

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, …) are not taken into account

Methodology and Challenges in defining and quantifying system effects

Interconnected power systems yields effects that cannot be explained by considering its components in isolation.

- System effects can be understood and quantified only by comparing two different systems.
- 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.
  - Modelling and quantitative estimation is challenging and there is no "all-inclusive" model.
  - Difference between *short-term* and *long-term* effects, often not 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.

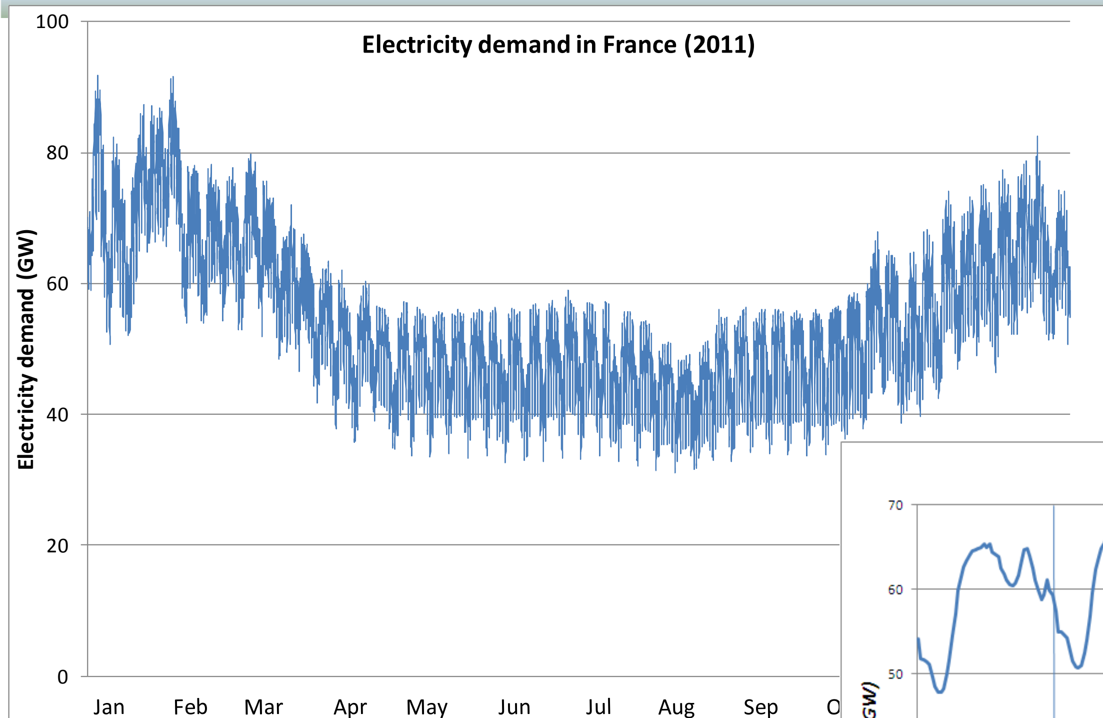
However, a consensus is emerging for considering as System Costs:

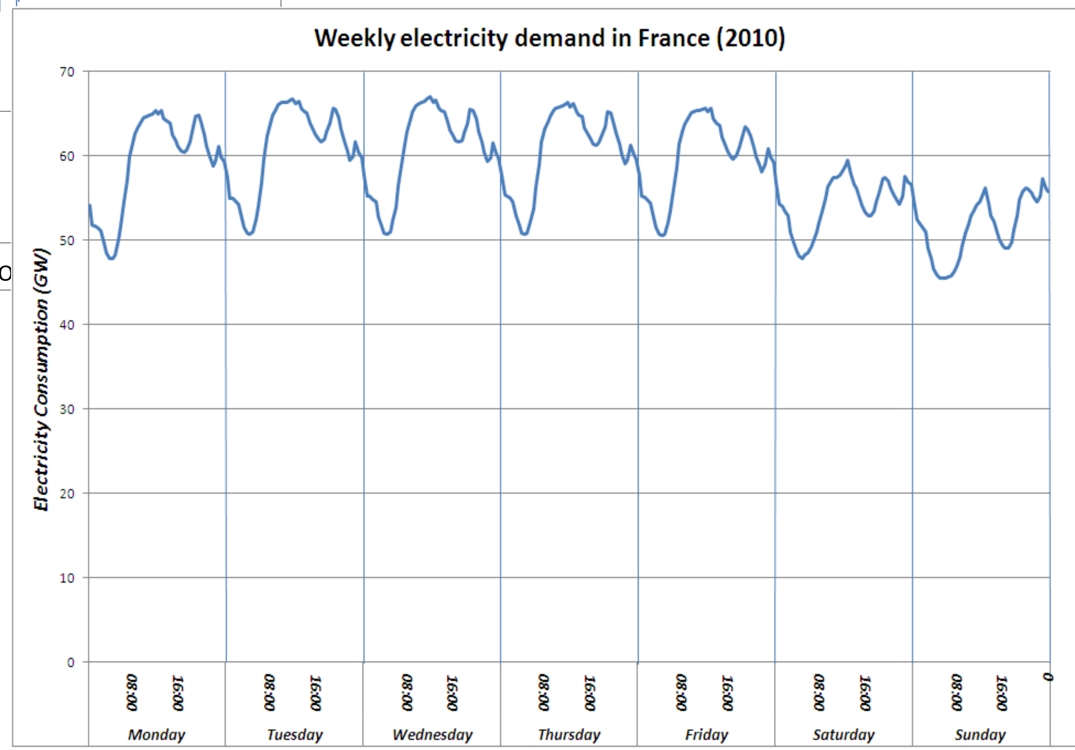
- **Grid cost (including distribution and transmission).**
- **Balancing costs.**
- **Utilisation costs (*profile costs or back-up costs*) including adequacy.**
- ***Still connection costs are substantial and should be considered.***

Methodology: residual load duration curves.

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

Electricity demand curve: France 2011

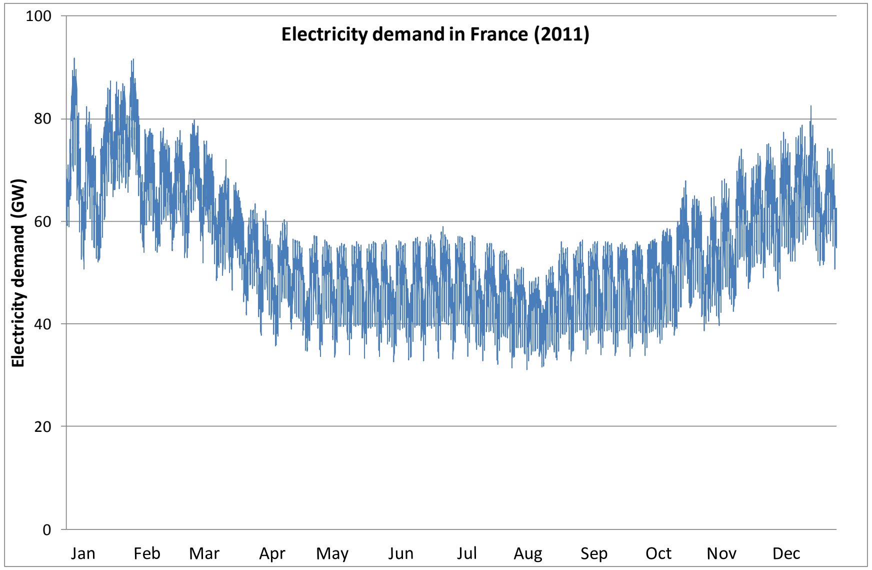


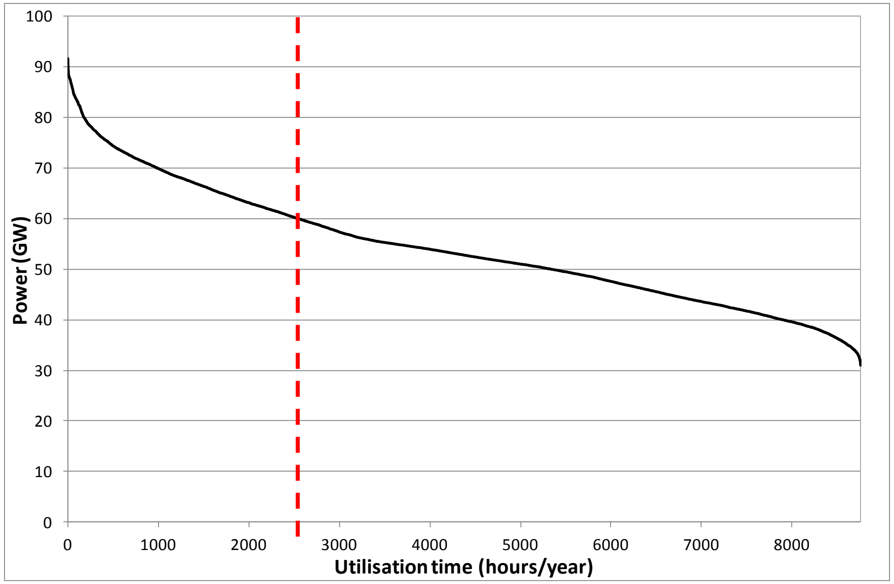


- Peak demand in winter evening.
- Highly sensitive to temperature.

Methodology: Long-term optimal mix I

Yearly load duration curve

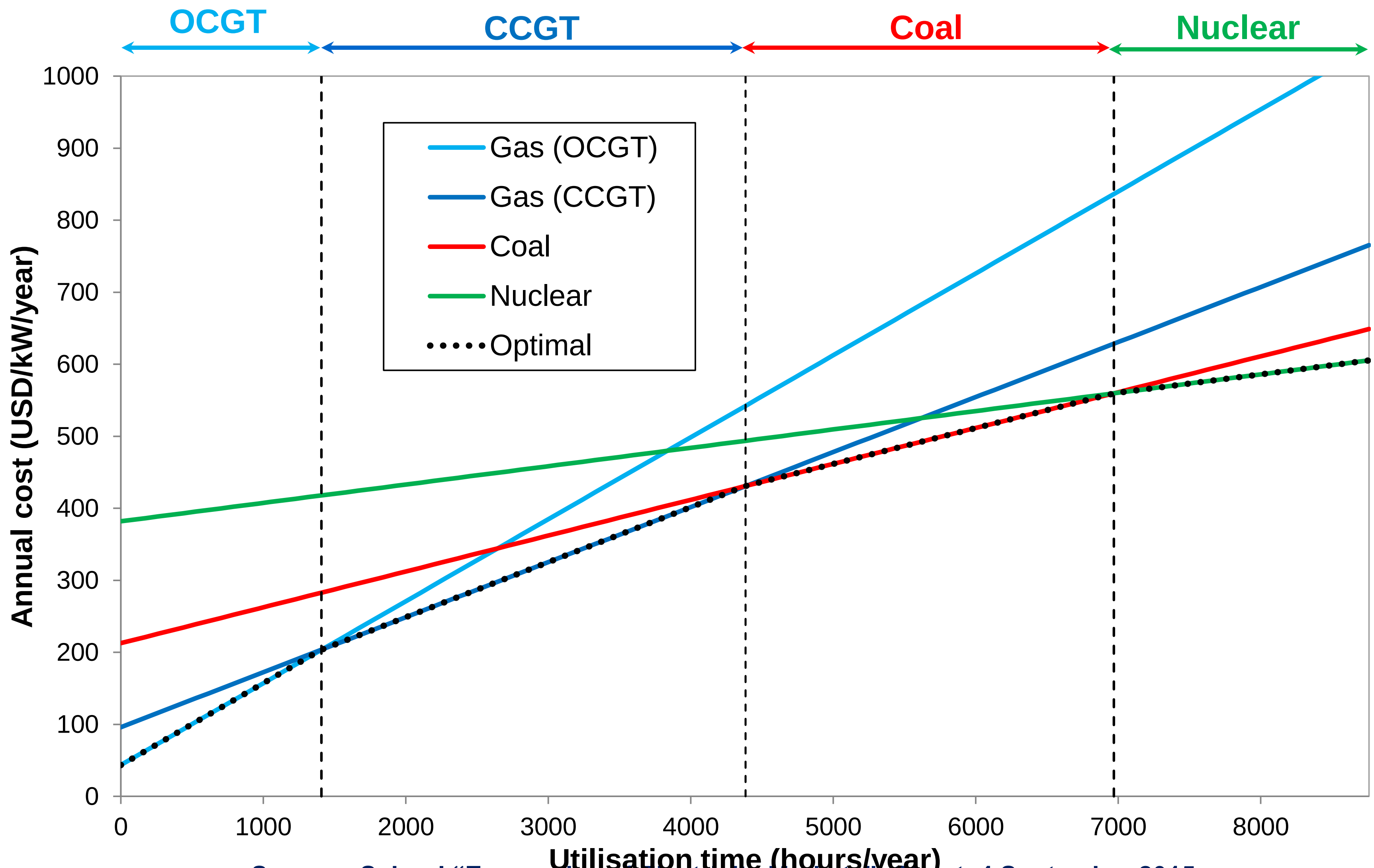




- Simply obtained by ordering demand from highest to lowest.
- The curve shows the number of hours that electricity demand is higher than a certain level.
- Electricity consumed is the integral of load duration curve.
- Load duration curve loses an important information: the time (and thus dynamics).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

Methodology: Long-term optimal mix II

Economics of different generation options

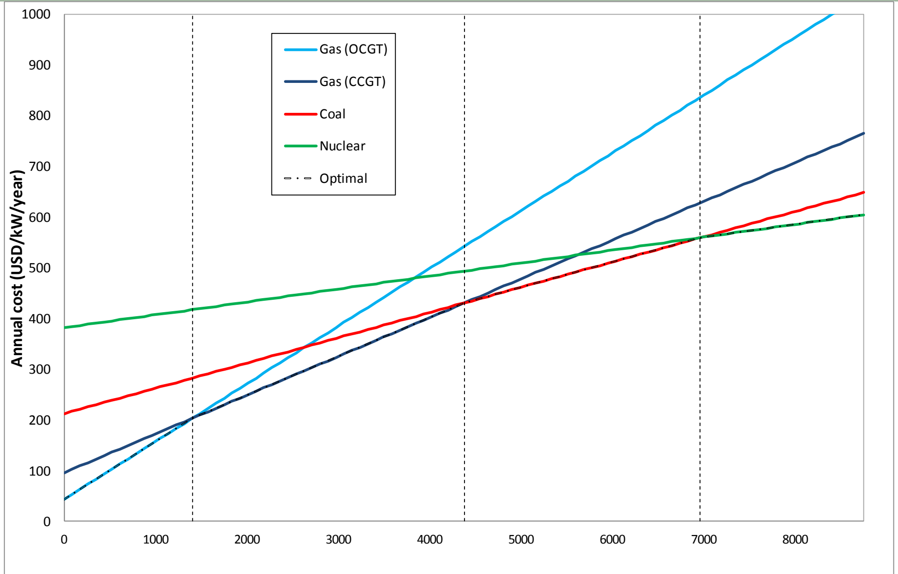


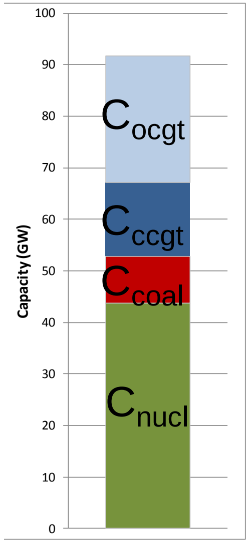
Methodology: Long-term optimal mix III

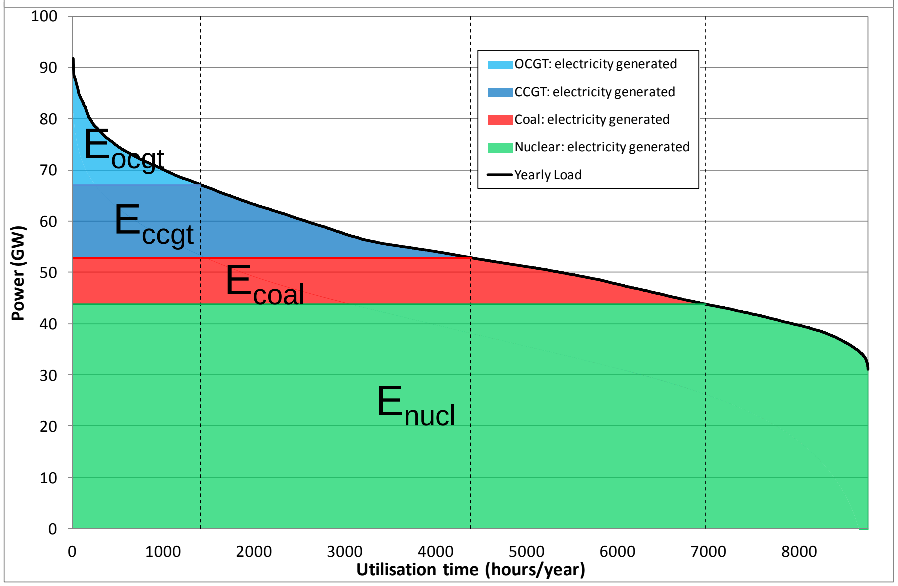
	Fixed costs USD/kW/year	Variable costs USD/MWh	LCOE USD/MWh
OCGT	43.5	113.8	118.7
CCGT	96.1	76.4	87.4
Coal	212.8	49.8	74.1
Nuclear	382.0	25.5	69.1

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

- 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 VRE.
- Difficulty in modelling storage.

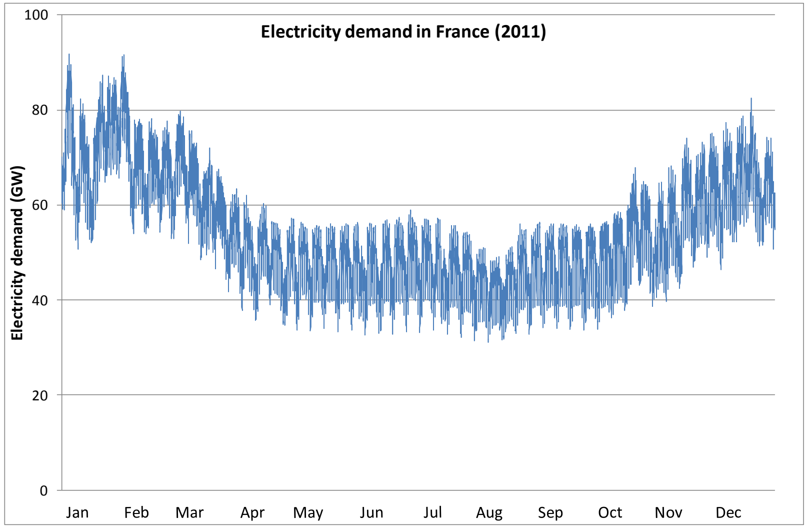






Methodology: calculating a residual load duration curve with VRE (wind)

Residual load duration curve (wind at 30%)



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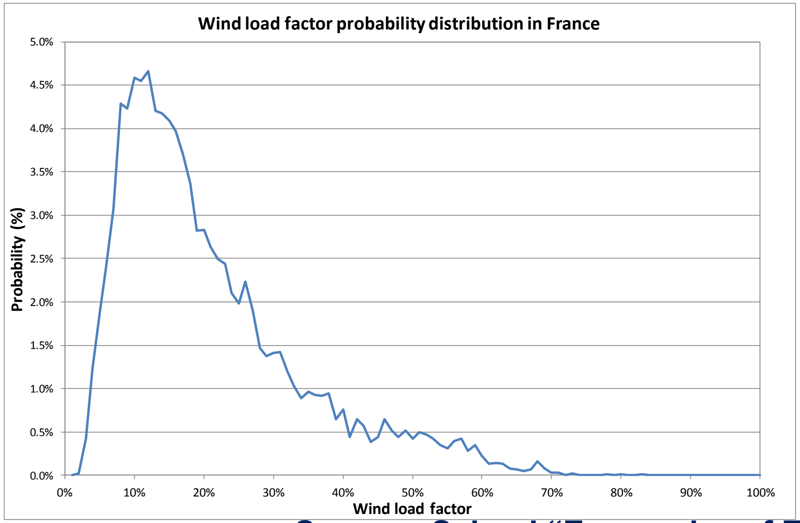
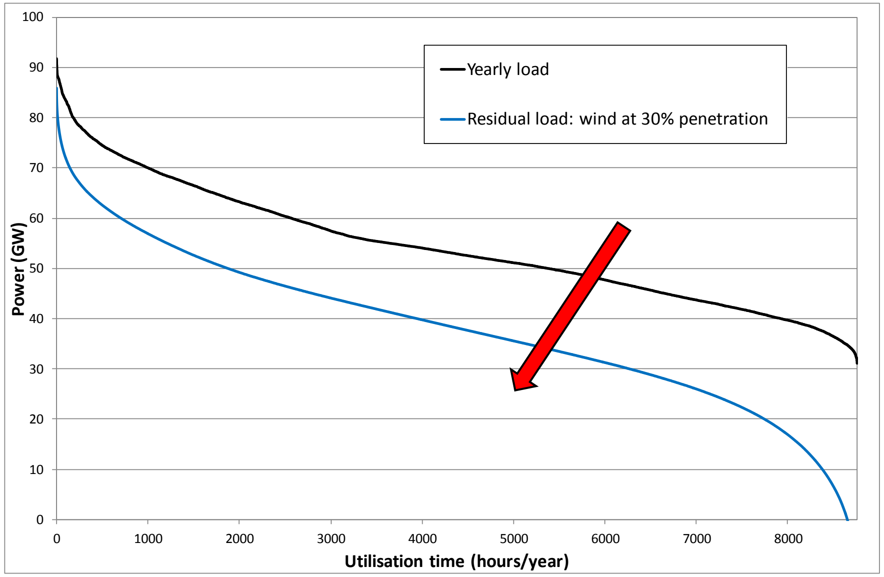


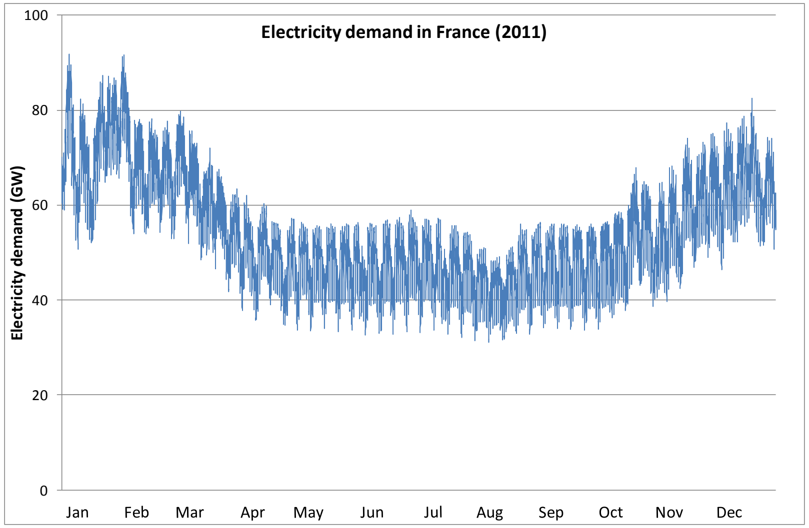


- Represents the load curve seen by the other dispatchable generators after the integration of low-marginal cost wind.
- Statistical analysis (Monte Carlo with 650 runs).
- ***Load factor probability*** derived from real RTE data.

  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 VRE (solar)

Residual load duration curve (solar at 30%)



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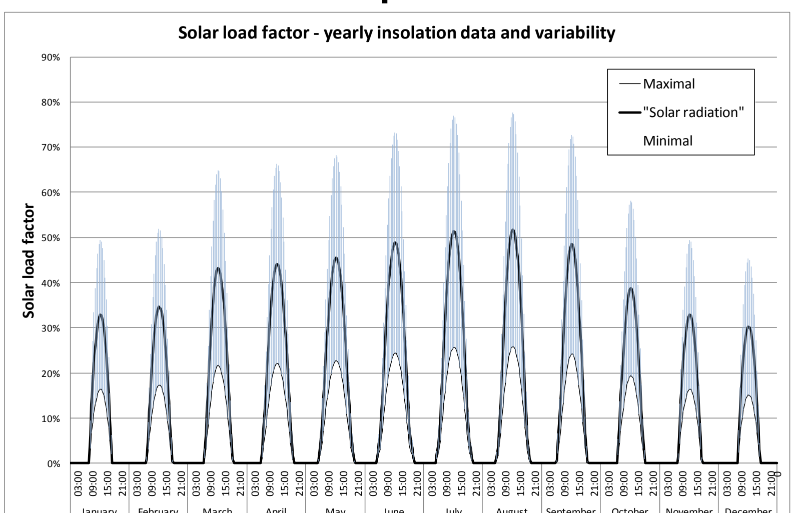
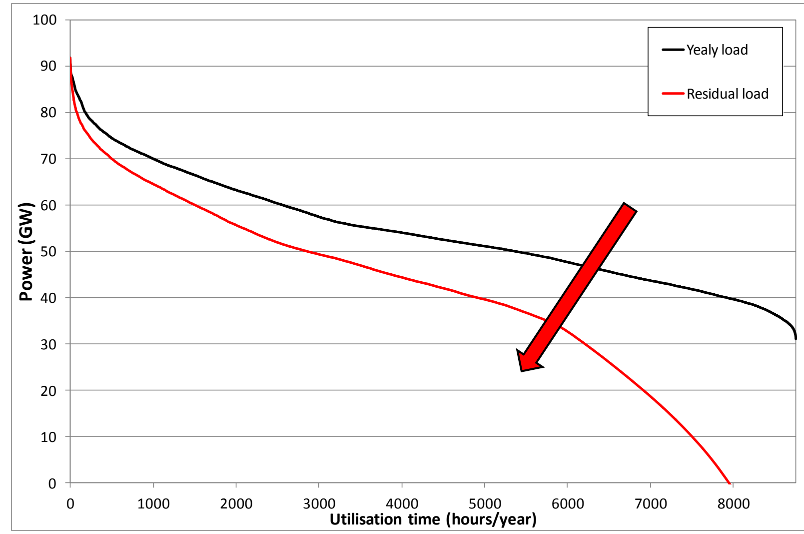




- Statistical analysis (Monte Carlo with 650 trials).
- Load factor probability:
  - Takes into account correlation solar/demand.
  - Educated guess (very smooth & "optimistic").
- The non-parallel shift of the residual load duration curve is more pronounced than for wind.

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

- Effects on the generation structure: short-term and long-term
- Impacts on CO_2 emissions

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.**
- VRE 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 VRE capacity.**
- VRE 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.**
- VRE can also induce investment and fixed O&M cost savings *(the system value of VRE is higher than in the short-term).*
- VRE 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.

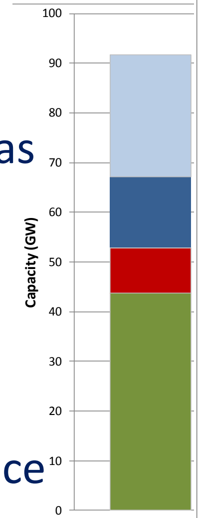
➡ ***Issue for investors and researchers: when does short-run become long-run?***

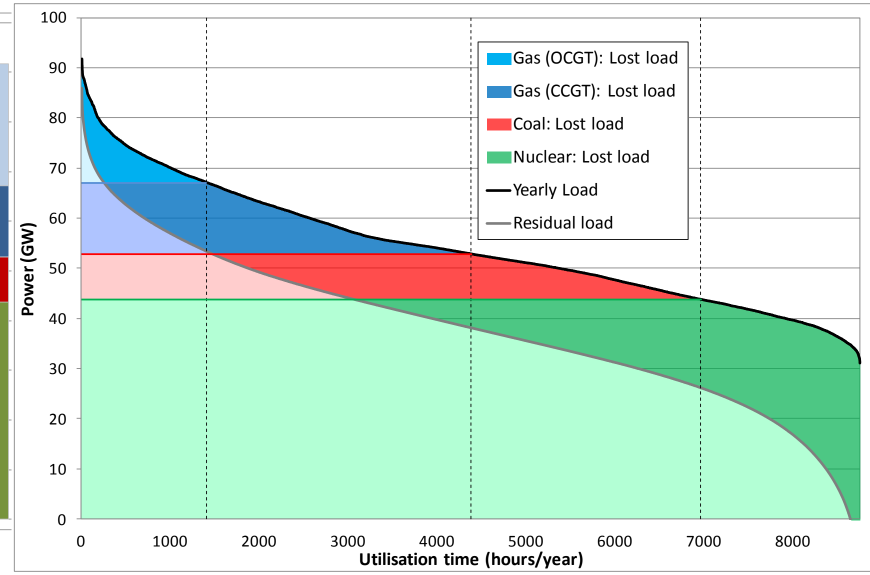
Impacts of VRE deployment depends on the degree of system adaptation and thus the speed of their deployment as well as on evolution of electricity demand.

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*). #

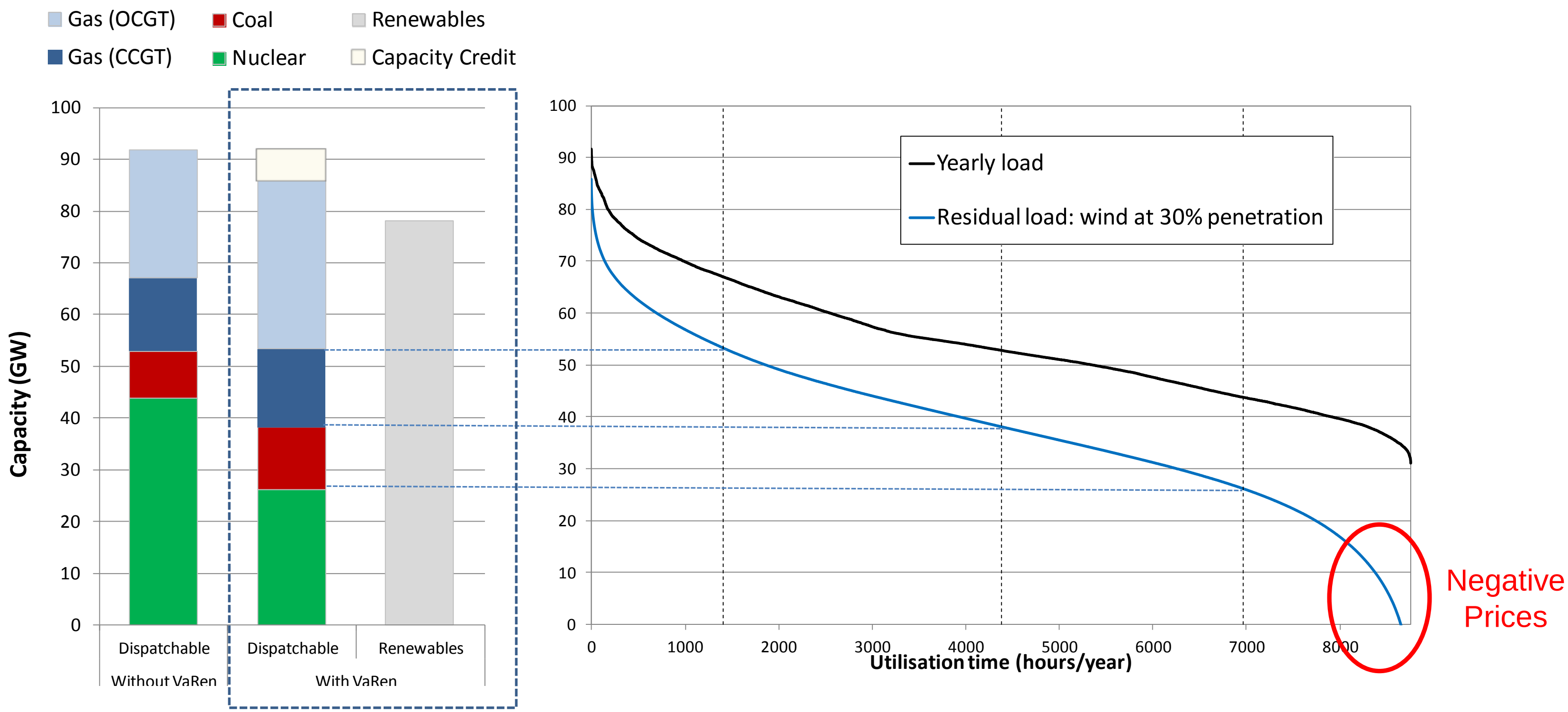




		10% Penetration level		*30% Penetration level*	
		Wind	***Solar***	***Wind***	***Solar***
Load losses	***Gas Turbine (OCGT)***	-54%	-40%	-87%	-51%
	Gas Turbine (CCGT)	-34%	-26%	-71%	-43%
	Coal	-27%	-28%	-62%	-44%
	Nuclear	-4%	-5%	-20%	-23%
Profitability losses	***Gas Turbine (OCGT)***	-54%	-40%	-87%	-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%

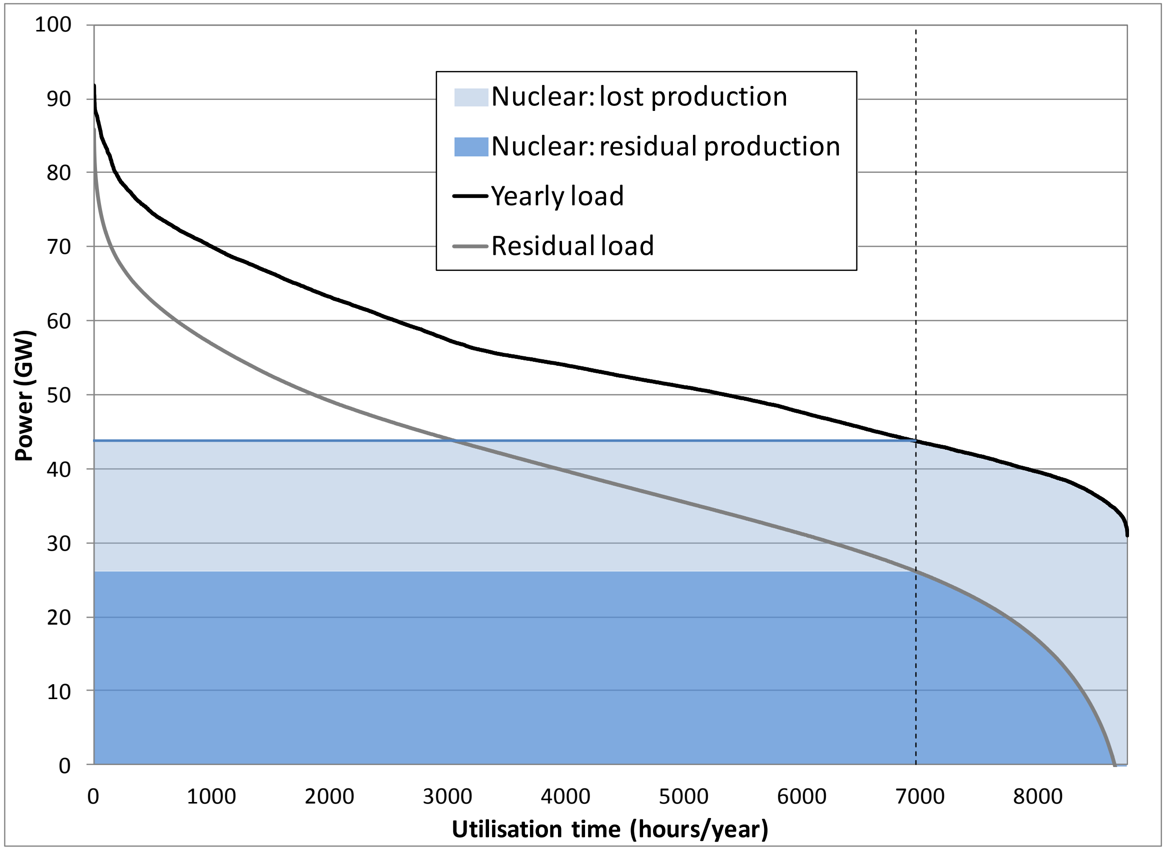
- Together this means declining profitability especially for OCGT and CCGT (nuclear is less affected).
- No sufficient economical incentives to built new power plants.
- Security of supply risks as fossil plants close. *HIS CERA estimate 110 GW no longer cover AC and 23 GW will close until end 2014.*

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 VRE at low penetration levels.
- These effects (and costs) increase with the penetration level.

Long-run Impacts on Base-load technology



Base-load tech. (nuclear energy)

- Less capacity installed and lower electricity production.
- (Small) reduction on average load factor.
- (Limited) reduction on time-weighted average electricity prices.

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

Estimates of “grid-level” system effects

- **Transmission and distribution costs**
- **Short-term balancing**
- **From adequacy concerns to the cost of back-up (profile cost)**
  - Capacity credit and adequacy cost: an “old” paradigm
- **Cost of providing the residual load**

Estimates of system costs components: Grid-related costs

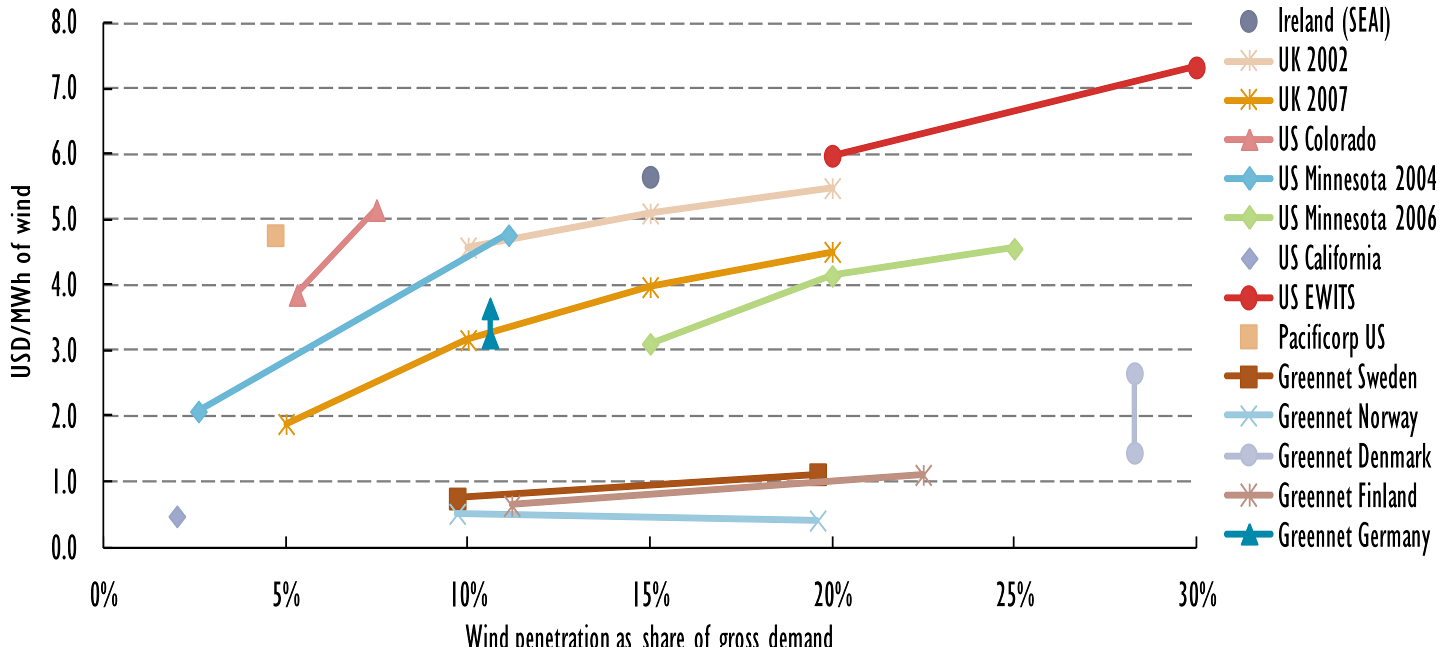
- T&D grid costs are related to **geographic location of VRE output**.
  - Increased investments in construction and reinforcement of transmission infrastructure.
  - Increase in transmission losses due to increased transport of electricity.
  - High penetration of distributed solar PV requires sizeable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

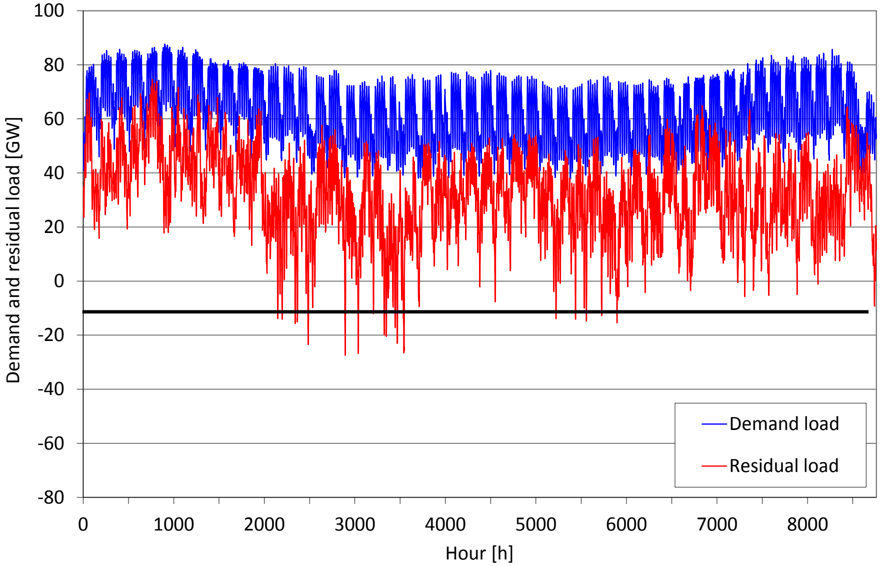


Source, Holltinen, 2013

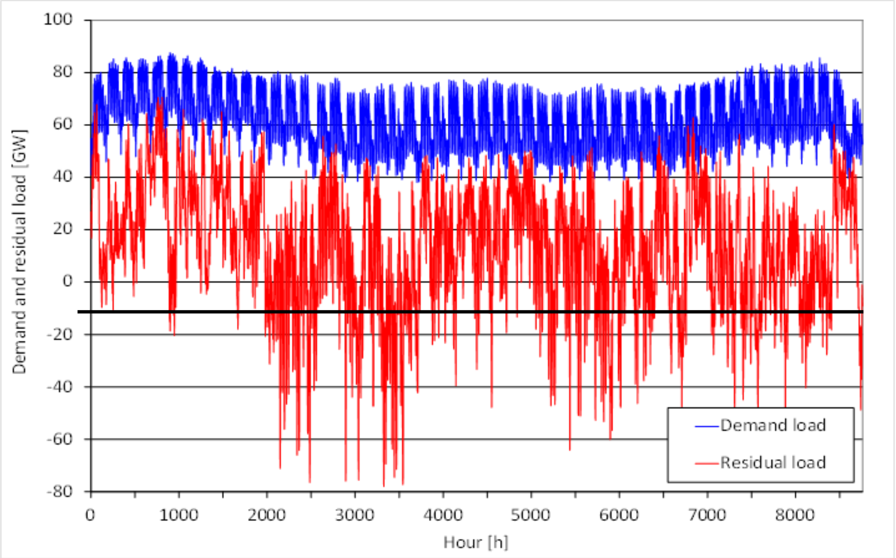
Short-term balancing: Residual Demand Load

- Quantitative analyses performed by IER Stuttgard based on very detailed modeling of the German electricity system.
- Twelve scenarios, with 4 shares of renewables electricity generation.

50% Renewables scenario (35% of VRE)



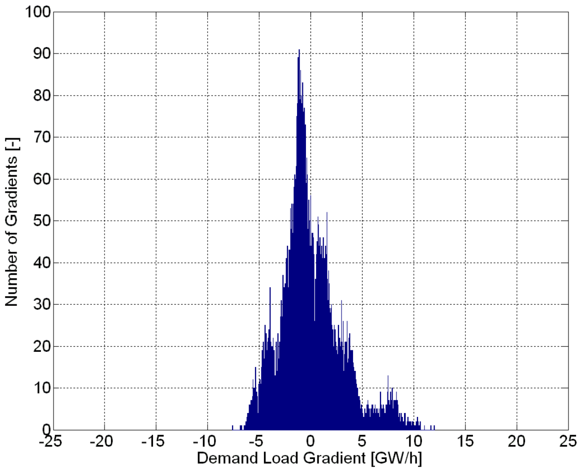
80% Renewables scenario (62% of VRE)



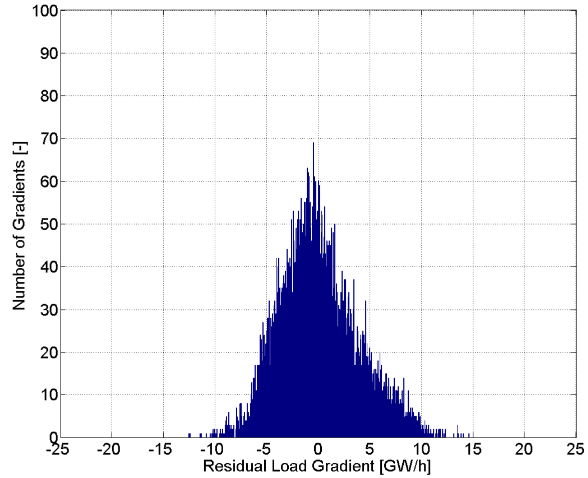
- Residual demand load is determined more by the production of VRE than by the demand.
- Residual demand load loses its characteristics seasonal and daily patterns.
  - More difficult to plan a periodic load-following schedule.
  - Loss of predictable peak/off-peak pattern (ex: impact of PV and effect on hydro-reservoir economics).
- Significant number of hours in which Renewables fully meet the demand.

Short-term balancing: Ramping Rates Requirements

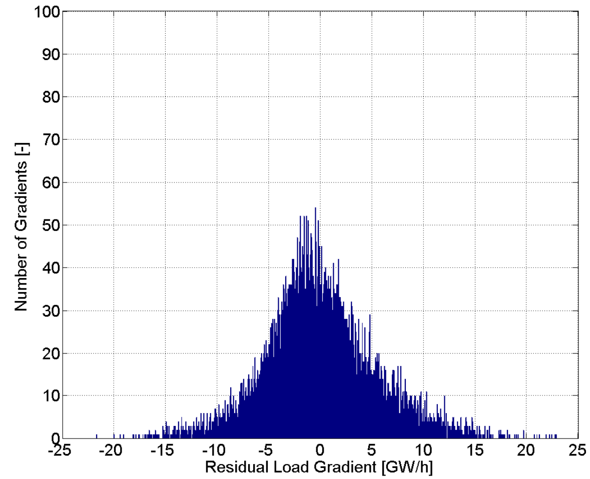
15% Res scenario (0% of VRE)



50% RES scenario (35% of VRE)



80% RES scenario (62% of VRE)



- High gradient of change in residual load (more than 20 GW/h, about 25% of maximal load !).
- Those changes must be assured by a reduced number of dispatchable generators.
- The unpredictability of those changes adds an additional difficulty to the challenge.

More and more flexibility will be required from **all** components of electricity system.

- Significant load-following will be required from all dispatchable generators including base-load.
- Large amounts of storage capacity (250 GWh - 4.2 TWh with a loading power of 54.8 GW).
- Under certain conditions, curtailment of VRE or Demand Side Management are the most cost-effective solution.

Estimates of system costs components: Profile costs (or "back-up" costs)

- Profile costs are related to the **variability** of VRE output.
  - Long-term impact on the cost for providing the residual load.
  - 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:
  - correlation between the VRE production and electricity demand, and
  - 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

Other estimates using dispatch & commitment models are higher (Hirth)

Adequacy costs and capacity credit: an "old" approach (I)

(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".*

Capacity 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 VRE to ensure the same adequacy level of a dispatchable power plant.

Adequacy costs and capacity credit: an "old" approach (II)

1. *Determine the need in term of additional capacity*

For a given capacity of dispatchable power plants (C_{Disp}).

i. Firm capacity guaranteed by dispatchable. $\Gamma_{Disp} = C_{Disp} * CC_{Disp}$

ii. Amount of VRE producing the same electricity. $C_{VaRen} = \frac{C_{Disp} * LF_{Disp}}{LF_{VaREn}}$

iii. Firm capacity guaranteed by the VRE. $\Gamma_{VaRen} = C_{VaRen} * CC_{VaRen}$

iv. Amount of additional dispatchable capacity required. $\Gamma_{Adequacy} = \Gamma_{Disp} - \Gamma_{VaRen}$

$$\boxed{\Gamma_{Adequacy} = C_{Disp} * LF_{Disp} * \left(\frac{CC_{Disp}}{LF_{Disp}} - \frac{CC_{VaRen}}{LF_{VaRen}} \right)}$$

$$\Gamma_{Wind\ 10\%} = 1000\ MW * 85\% * \left(\frac{96.6\%}{85\%} - \frac{8\%}{23\%} \right) = 670\ MW$$

$$\boxed{1000\ MW_{Disp} = 3700\ MW_{Wind} + 670\ MW_{Adequacy}}$$

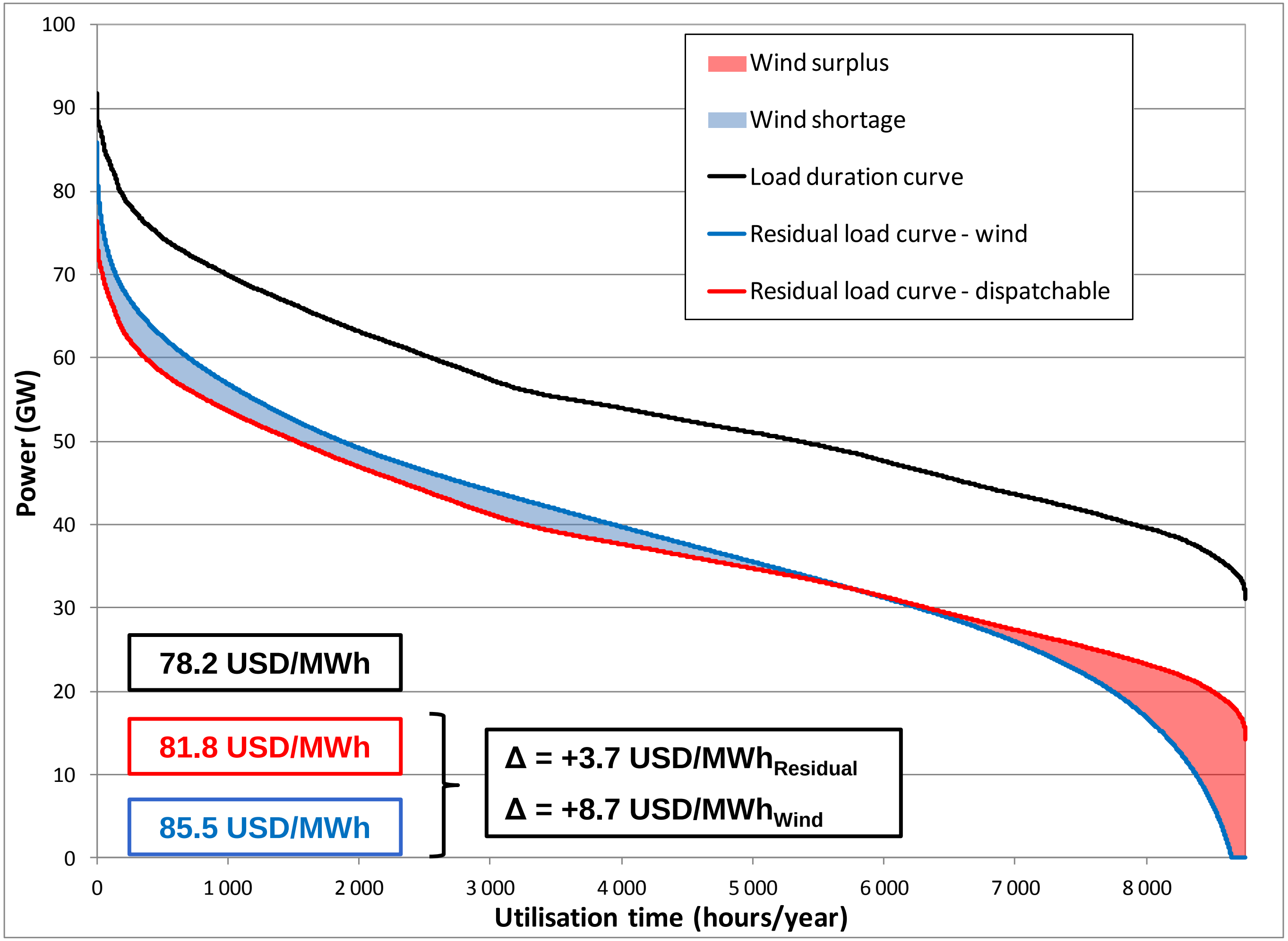
2. *Determine the cost of providing that additional capacity*

What is the least-cost mix to provide back-up capacity?

- Peak-load power plant (OCGT, oil, retained old PP) → Least investment cost
- Other optimised generating mix → Least total cost for the system

A different perspective on "back-up" costs: cost for providing the residual load

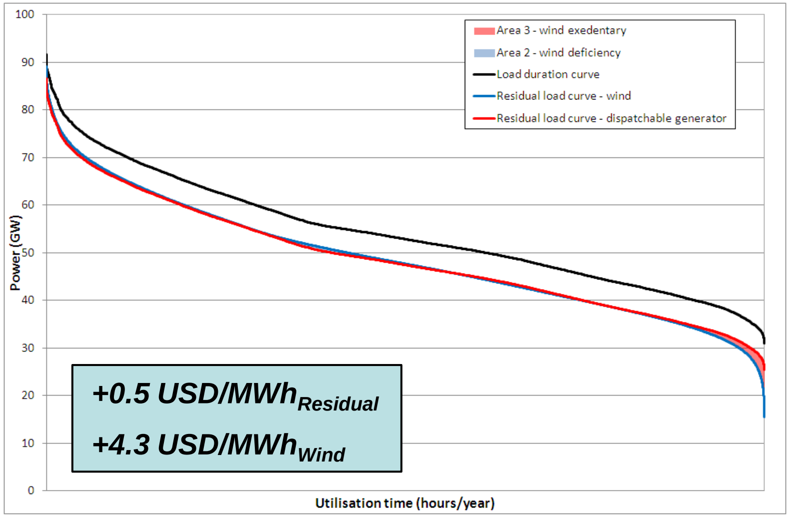
We compare two situations: the residual load duration curve for a 30% penetration of fluctuating wind (blue curve) and 30% penetration of a dispatchable technology (red curve).

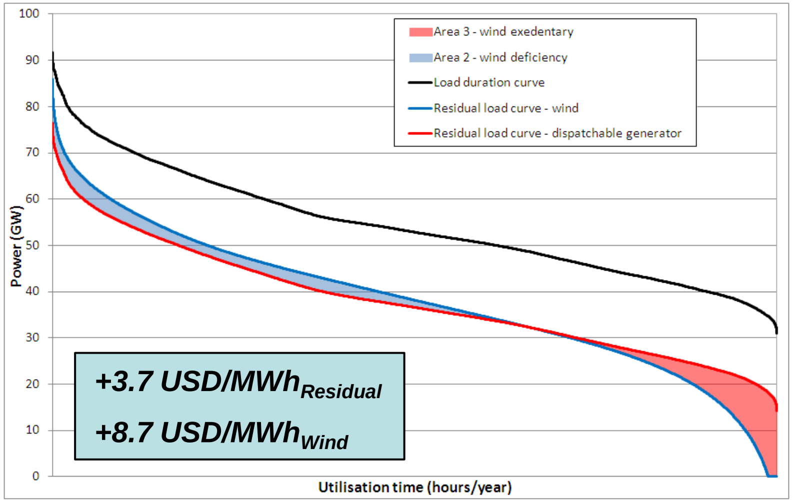


Cost of providing residual load

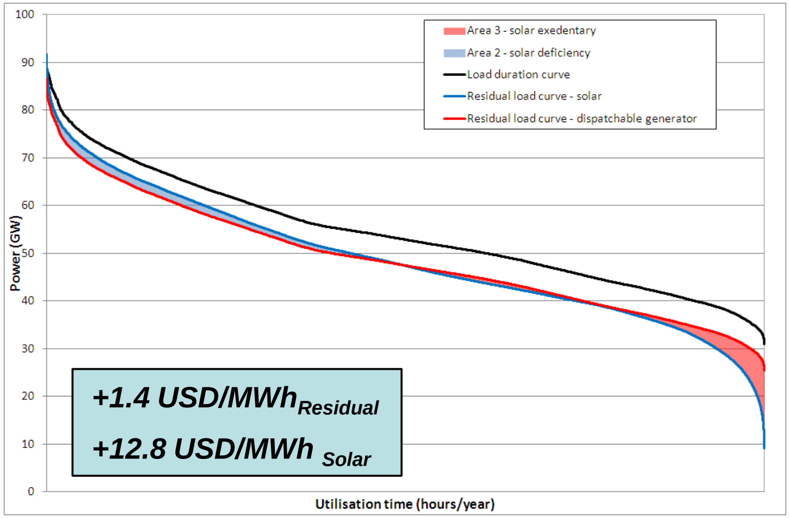
10% Penetration | **30% Penetration**

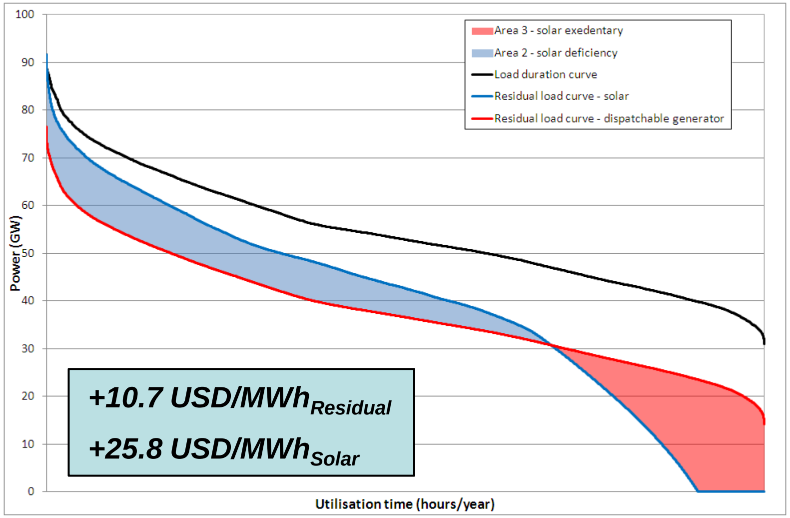
Wind





Solar

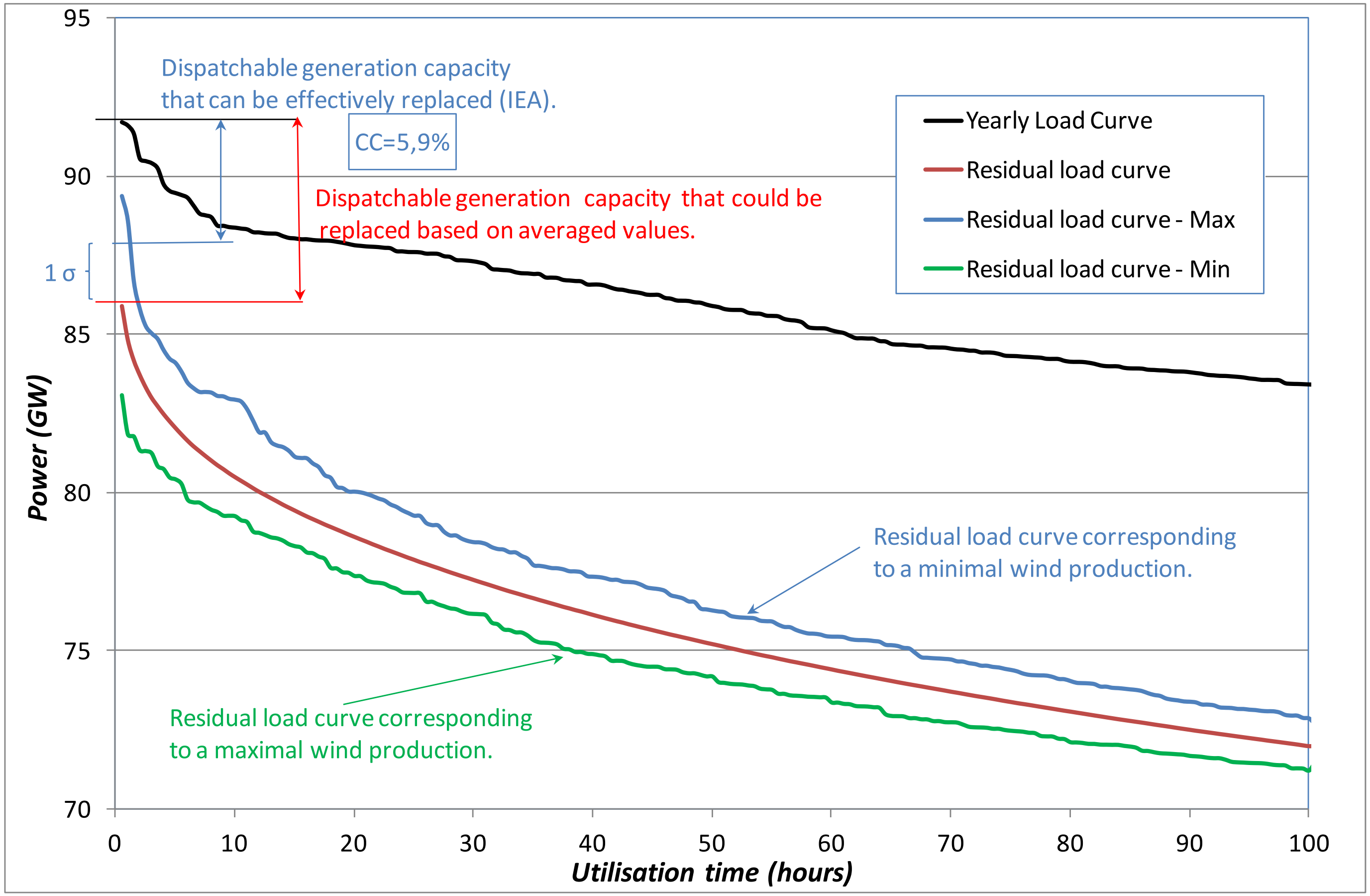




How to use residual load duration curves to estimate capacity credit

- 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*).

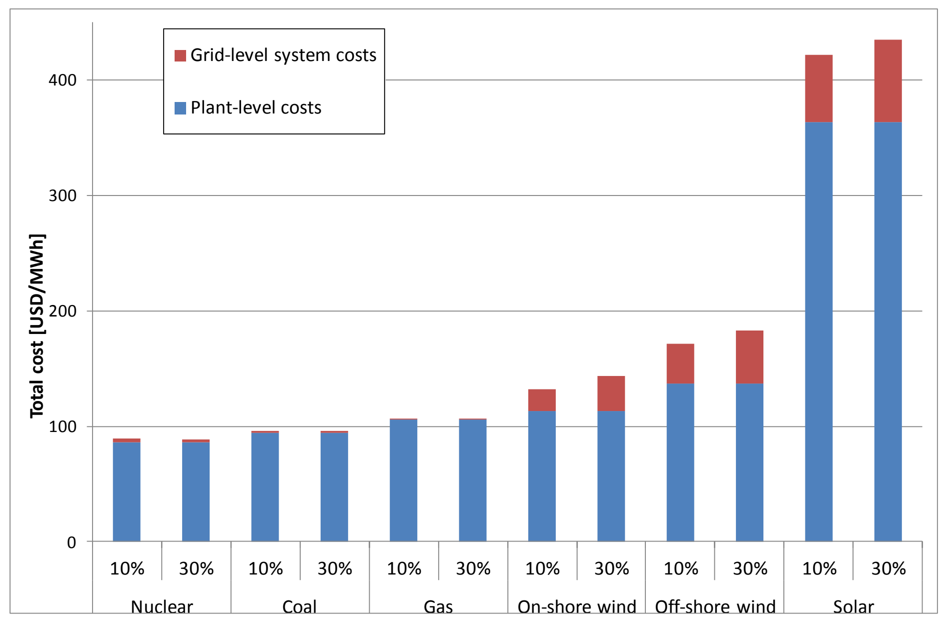


Synthesis of the results, key messages of the NEA System Cost Study and overall conclusions.

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***

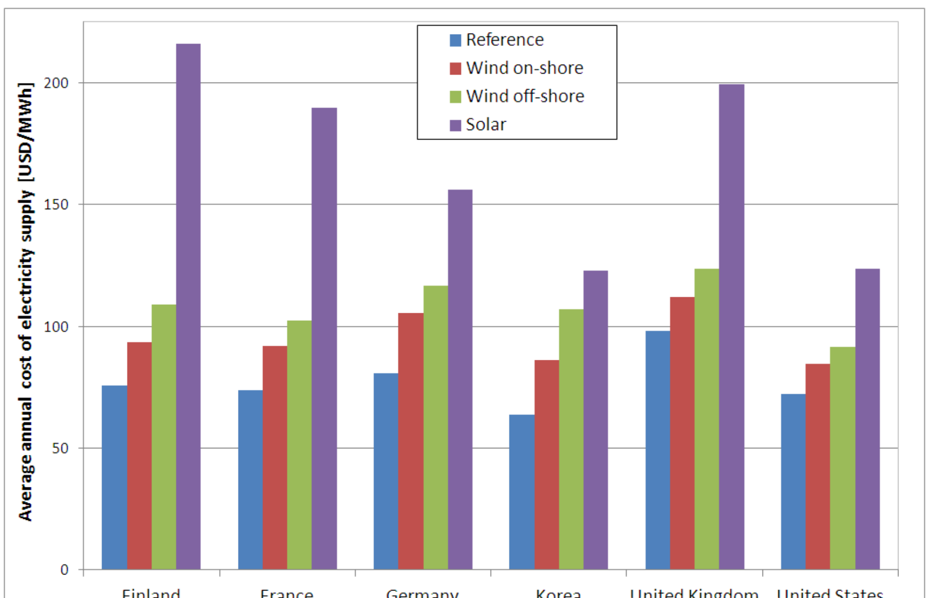
- Six countries, Finland, France, Germany, Korea, United Kingdom and USA analysed.
- Grid-level costs for variable renewables at least one level of magnitude higher than for dispatchable technologies.
  - Grid-level costs depend strongly on country, context and penetration level.
  - Grid-level costs are in the range of 15-80 $/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 $/MWh.
  - Coal and gas 0.5-1.5 $/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.

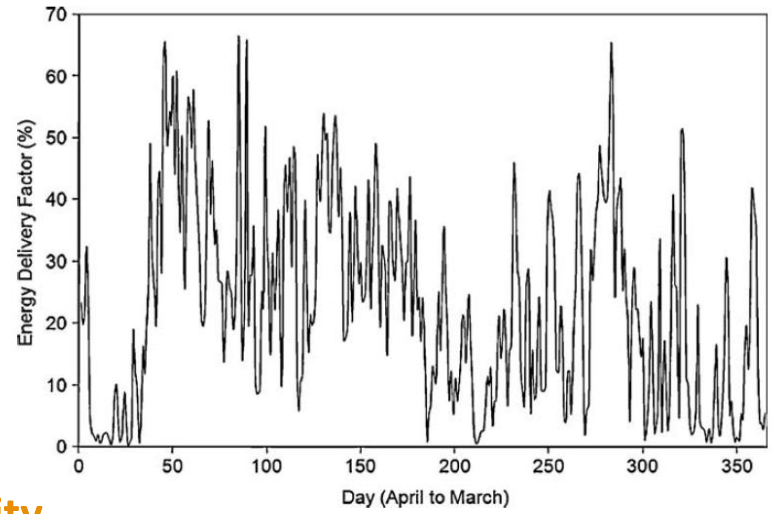
		Total cost of electricity supply [USD/MWh]						
		Ref.	**10% penetration level**			**30% penetration level**		
		Conv. Mix	*Wind on-shore*	*Wind off-shore*	*Solar*	*Wind on-shore*	*Wind off-shore*	*Solar*
Germany	***Total cost of electricity supply***	80.7	86.6	91.3	101.2	105.5	116.9	156.2
	Increase 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.

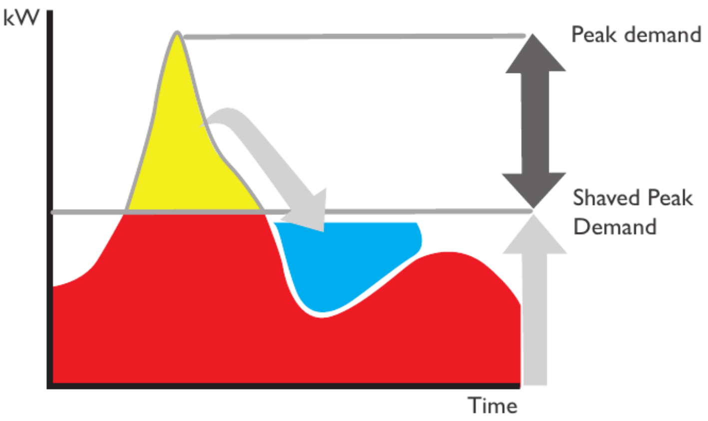
C. A Review of Support Mechanisms for Renewable Energies

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.

Future Visions: Smart Grids

Smart grids are electricity networks that intelligently coordinate the actions of all users (generators, distributors and consumers) and provide flexibility for VRE

- Integrate IT technologies in the operation and control of the power system
- Currently a vision than a defined set of elements that could be implemented everywhere



- Smart-grids provide flexibility through:
  - Demand side management
  - Decentralized storage capacity (Electric vehicles…)
  - Virtual power plants
- Two possible outcomes for base-load technologies:
  1. **Global perspective**: smoother load curves make for more intensive use of baseload technologies such as nuclear
  2. **Local perspective**: decentralised supply and demand balancing is performed in a smaller market with decreasing needs for large centralised power plants.

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 (15-80 USD/MWh) 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 minimize and internalize 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 VRE.**

Points for discussion (after the break)

- What we observe now in Europe is simply due to a too fast integration of renewable energy or there is something more?

  Is there a "**speed limit**" to the deployment of renewable energy?

  It is economical, technical?

- What could be a **technological breakthrough** that would allow a better integration of intermittent generation sources?

- What would be the **optimal level** of a VRE technology if its LCOE would be lower than that of the base-load?

- What is the "**grid-parity**"? Is the concept useful?

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.

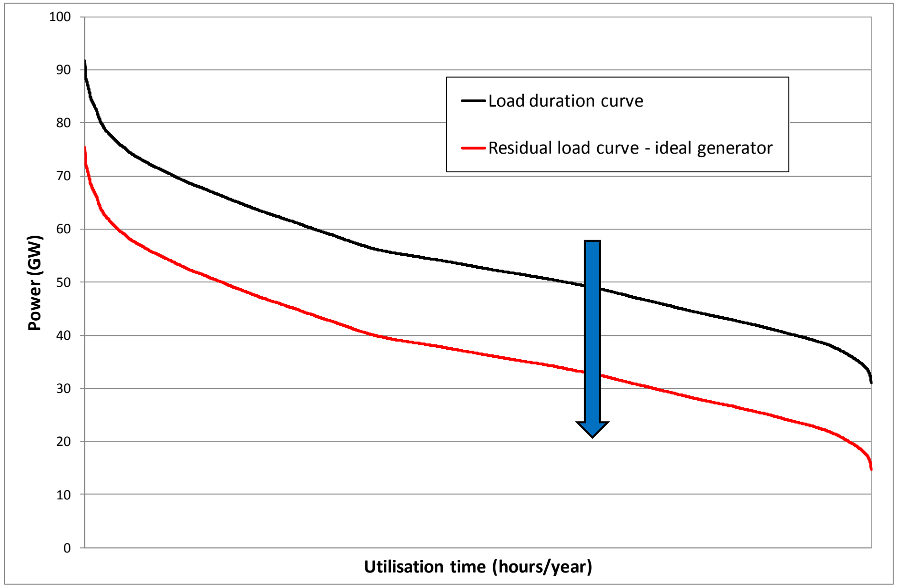
- In absence of large amount of storage, the value of electricity is not homogeneous over time, but depends on ***when*** (and ***where***) it is produced.
- Fluctuating generation does not have the same "value" or utility for the system as dispatchable generation.
- The "value" of fluctuating generation 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 based on residual duration curves to derive the value of electricity produced (which takes into account **when** the electricity is generated). ⇨ **This accounts only for "back-up" (profile) costs.**

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.

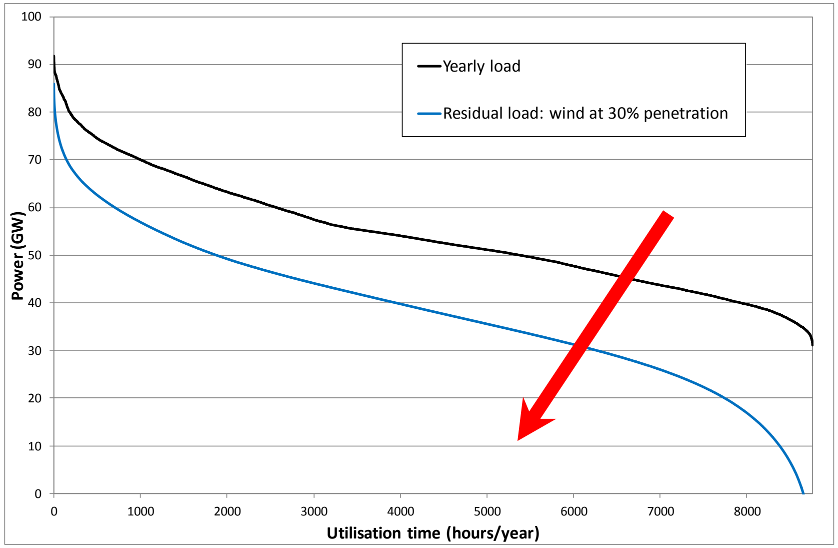
	Total cost [Bil. USD]	***Specific cost*** [USD/MWh]
Original load curve	37.18	78.20
Residual curve	27.32	81.96
Value of flat band	9.86	69.11

- 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.

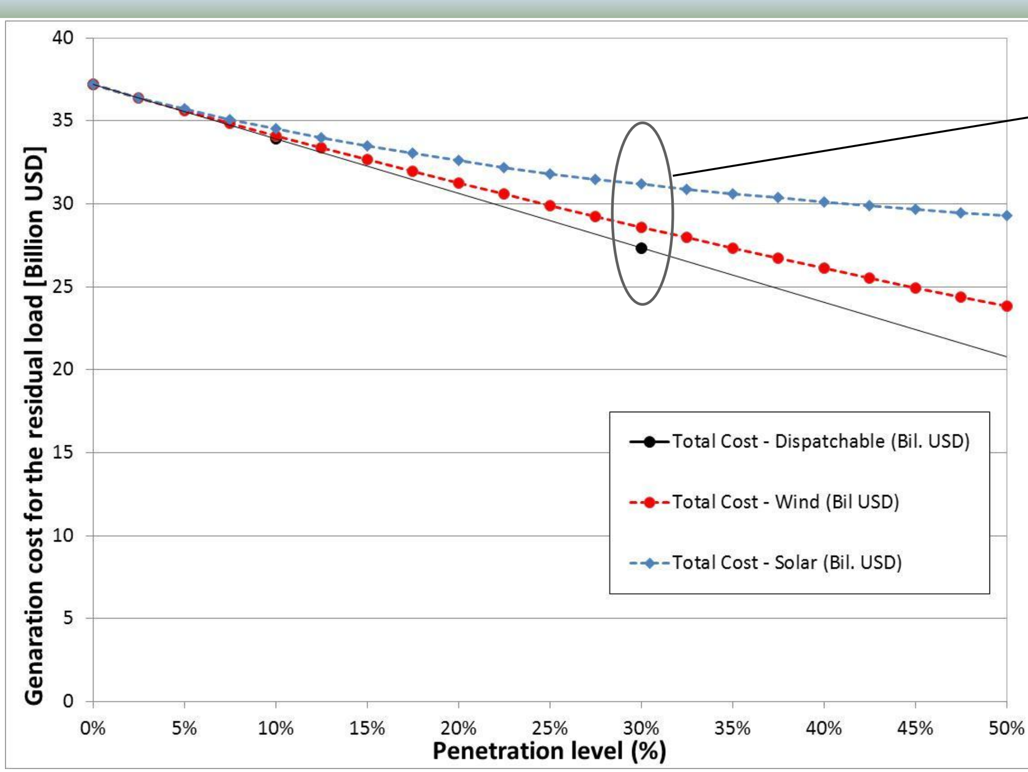
	Total cost [Bil. USD]	***Specific cost*** [USD/MWh]
Original load curve	37.18	78.20
Residual curve	28.60	85.79
Value of wind at 30% PL	8.58	60.16

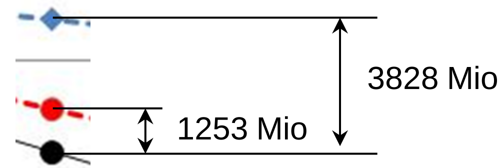
Previous case (flat power band)

	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





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%

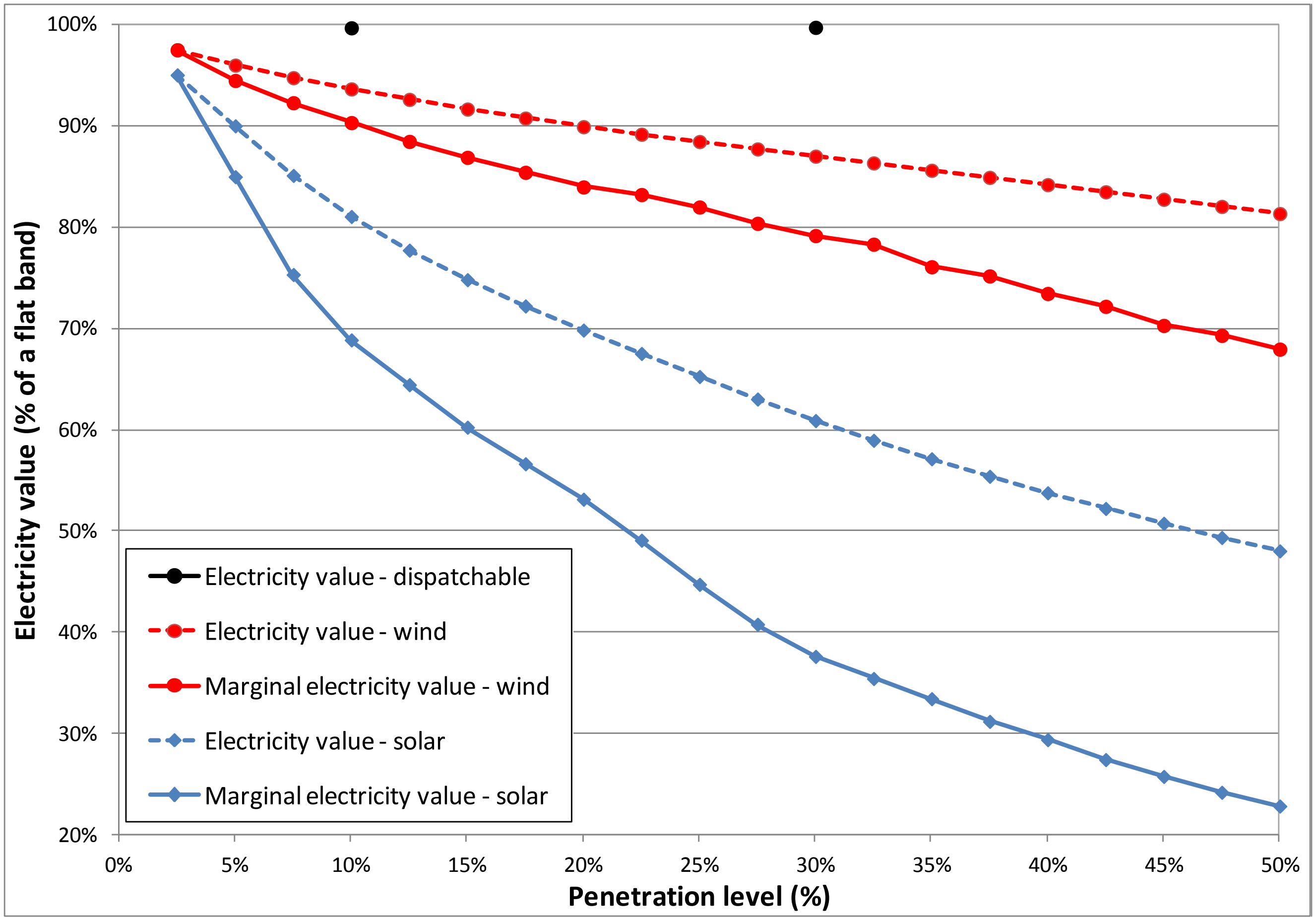
* Yearly generation cost in excess to the reference case (without VRE)

- The auto-correlation of VRE 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 VRE 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

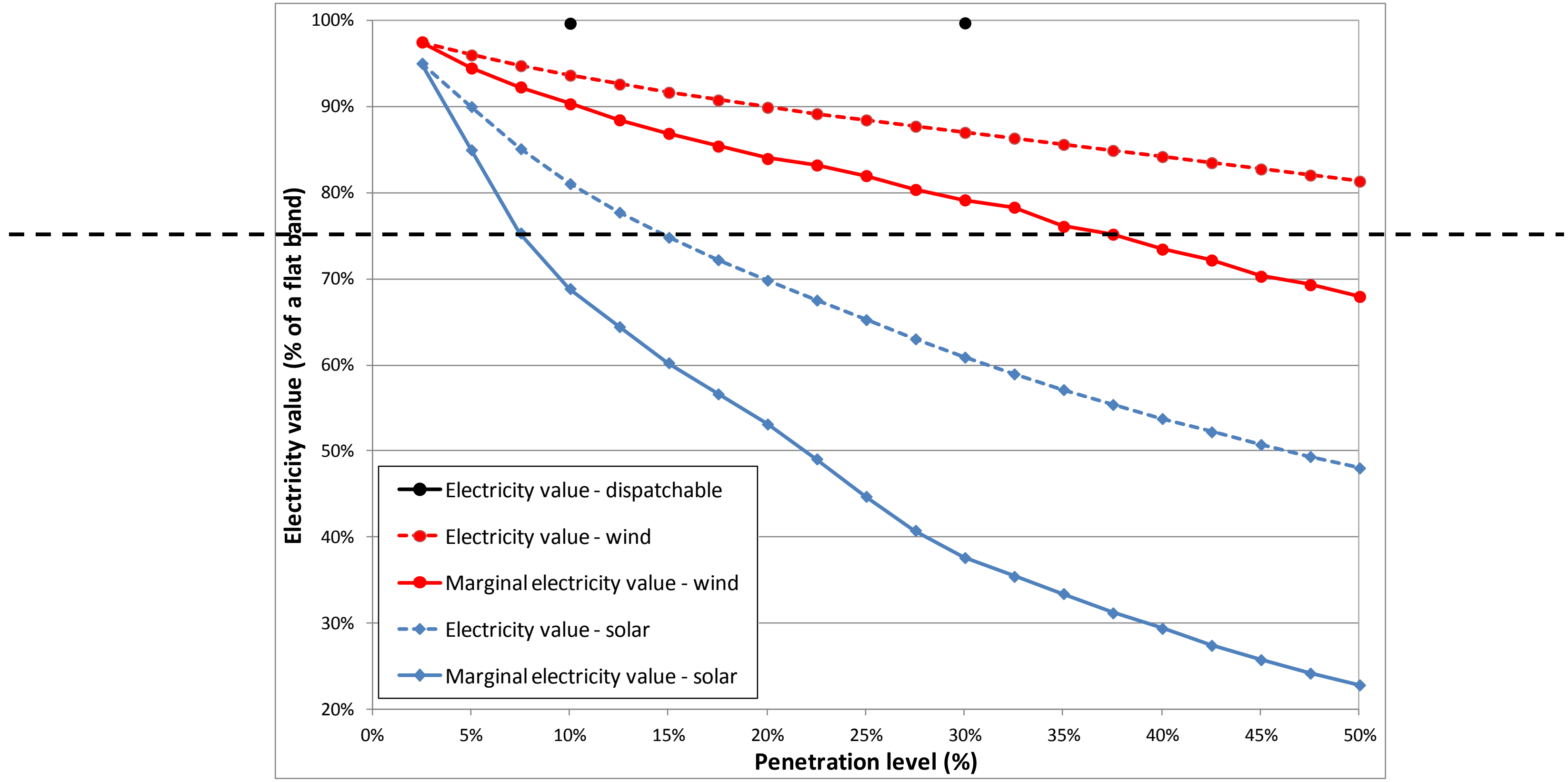
We can look at the impact of the variability from a different perspective:

- 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?

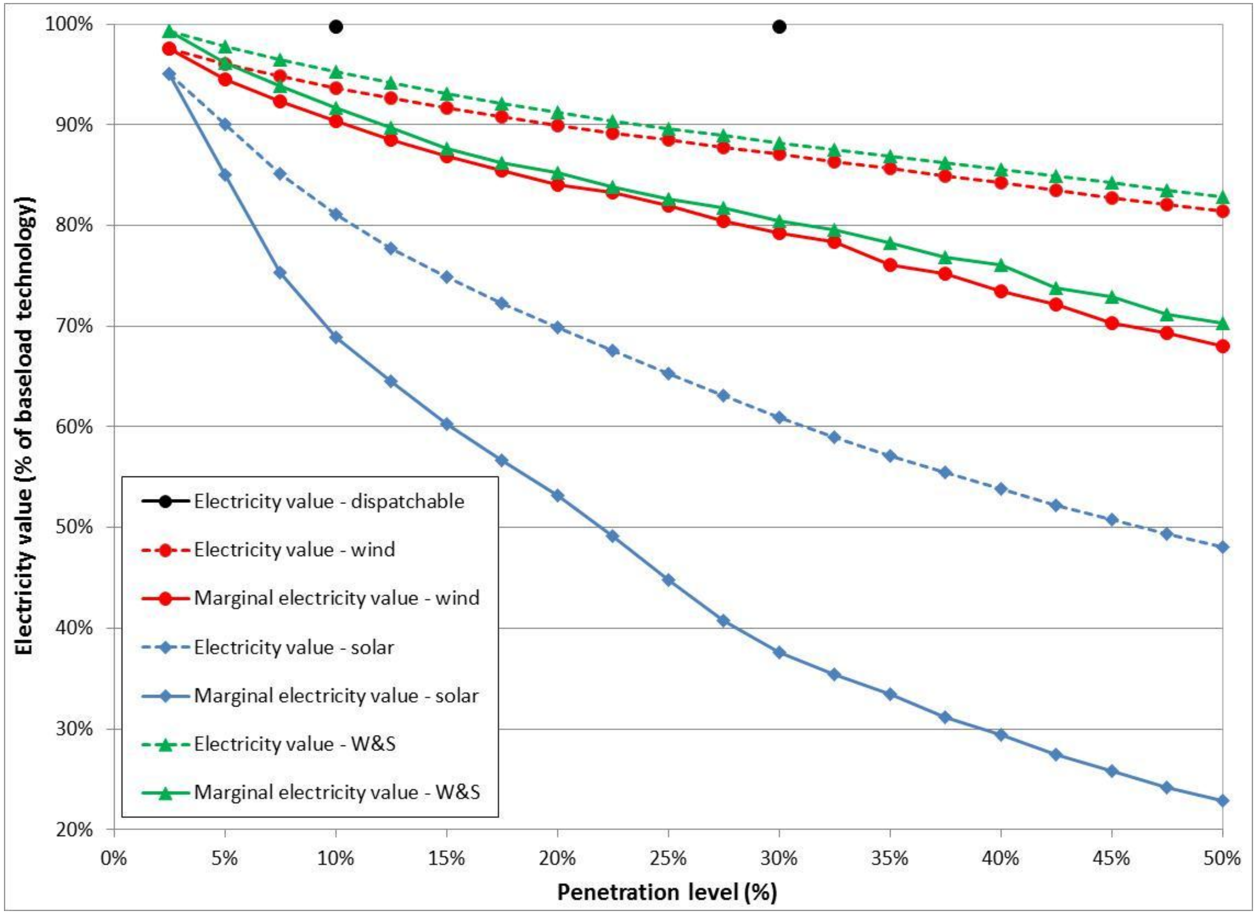


- What is the optimal amount of solar/wind in a system as a function of his levelised cost (relative to the base-load technology).

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%).

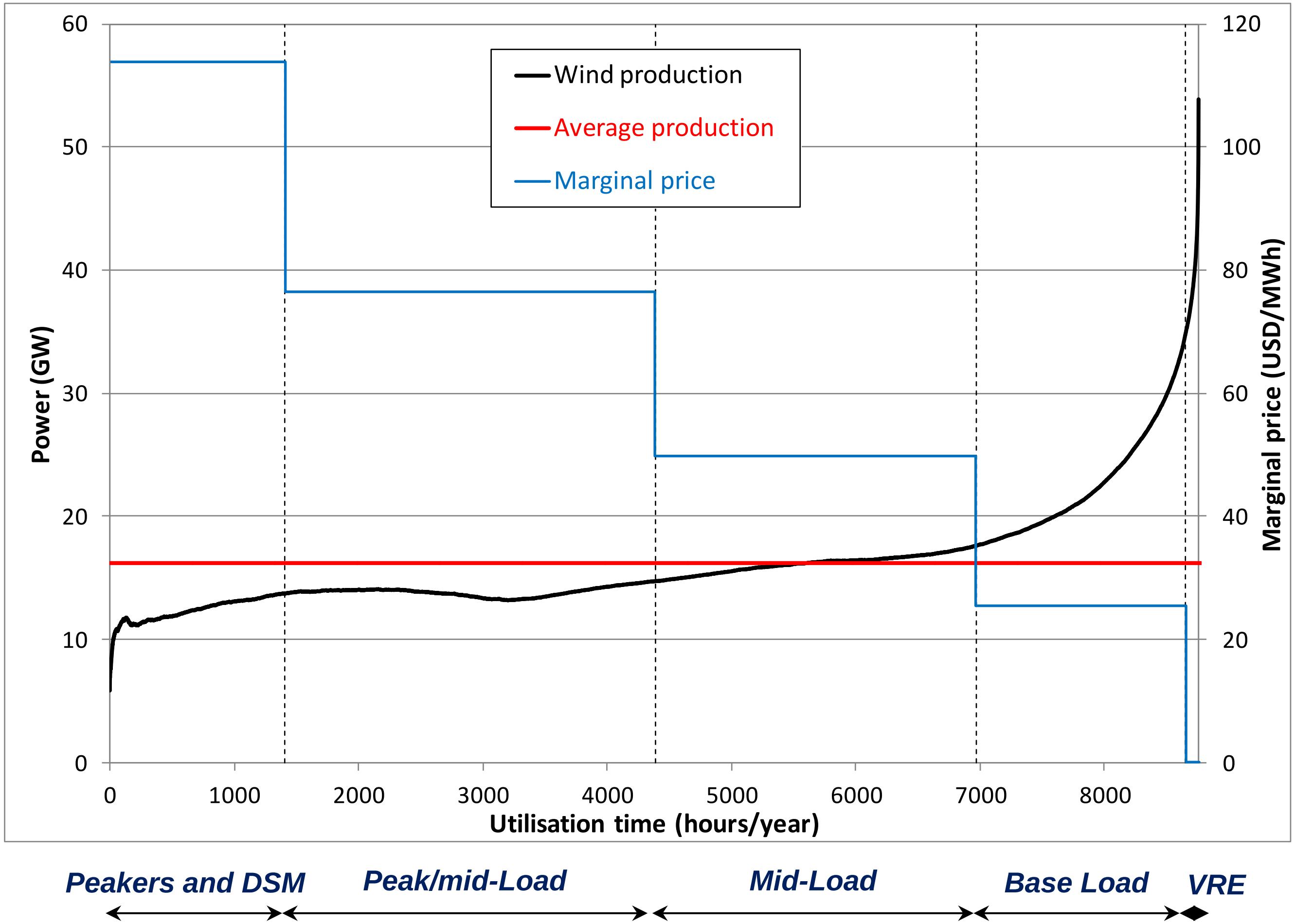
The effects of diversification: Combination of solar PV and wind

- 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.



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



Value factor and correlation with demand

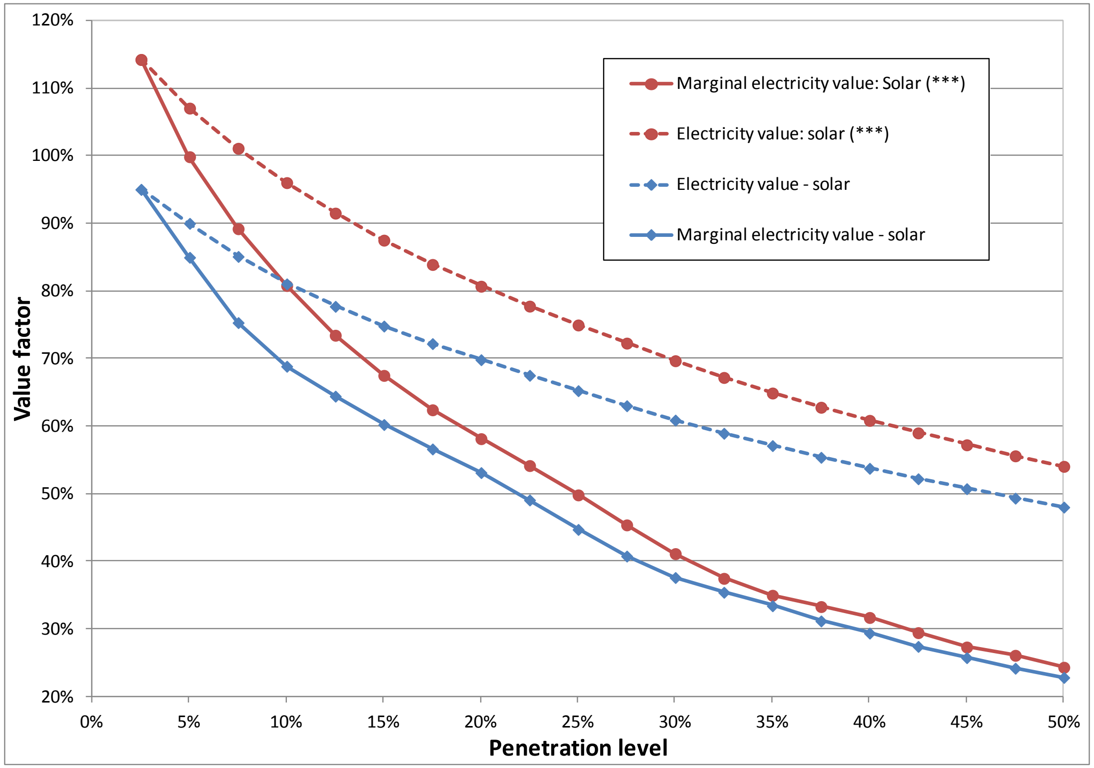
Data on load curves and VRE correlations have been derived from RTE data (France) and are valid only for France.

- 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 very well 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 VRE and the reference.
- The presence of significant amount of storage will increase the value factor of VRE.
- Different systems (depending on Ren type and penetration level) will call for an “optimal” level of storage.
- Increasing VRE 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 VRE (at high PL).

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

Current Limits of Technical Analysis : Value factor and correlation with demand

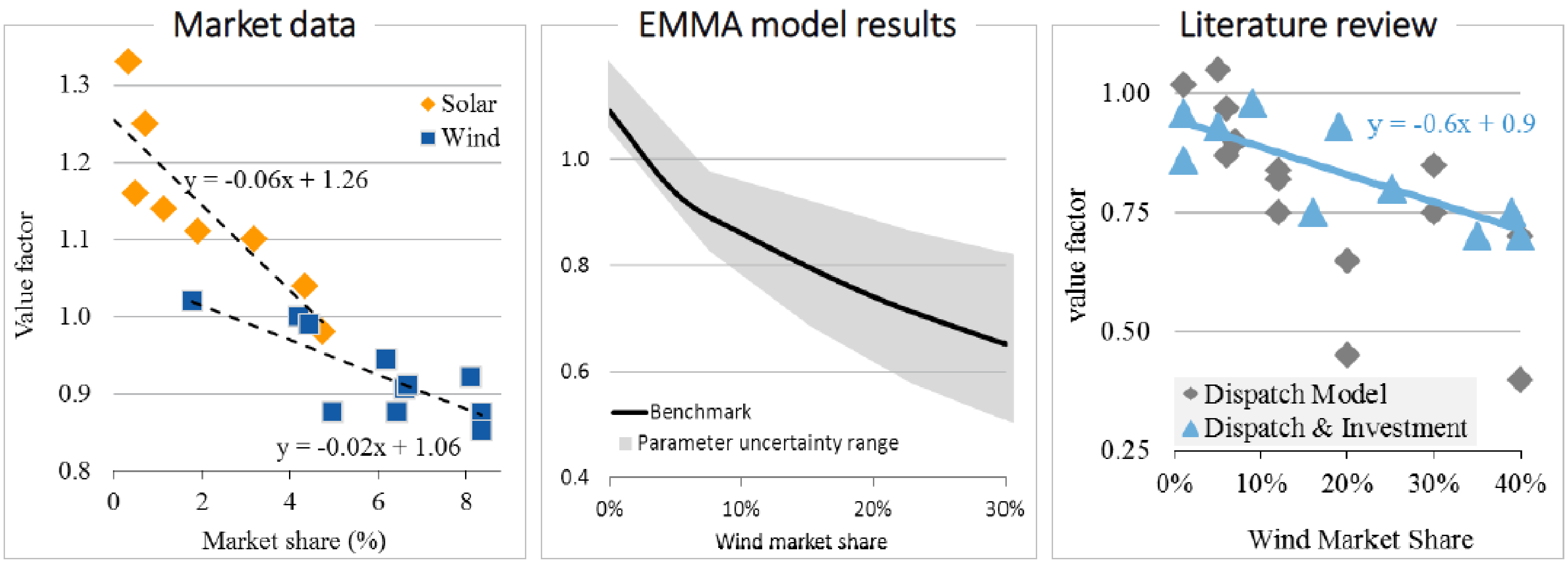
Data on load curves and VRE correlations have been derived from RTE data (France) and are valid only for France.

- 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)*.
- Results could be better if wind production would be positively correlated with demand (as in Ireland) …. But worse the other way around.

California Dreaming – what if solar PV 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 consumption.
- It has simply the purpose to show what could be the solar utility value in a country in which solar output coincides with maximal demand.

Another approach: the market value of variable renewables



Courtesy of Lion Hirth

At 30% penetration, the value factor of wind falls to 0.5 – 0.8 of the base price. In Germany, it has already fallen from 1.02 to 0.89 as penetration increased from 2% to 8%. The value drop jeopardizes power system decarbonization and transformation.

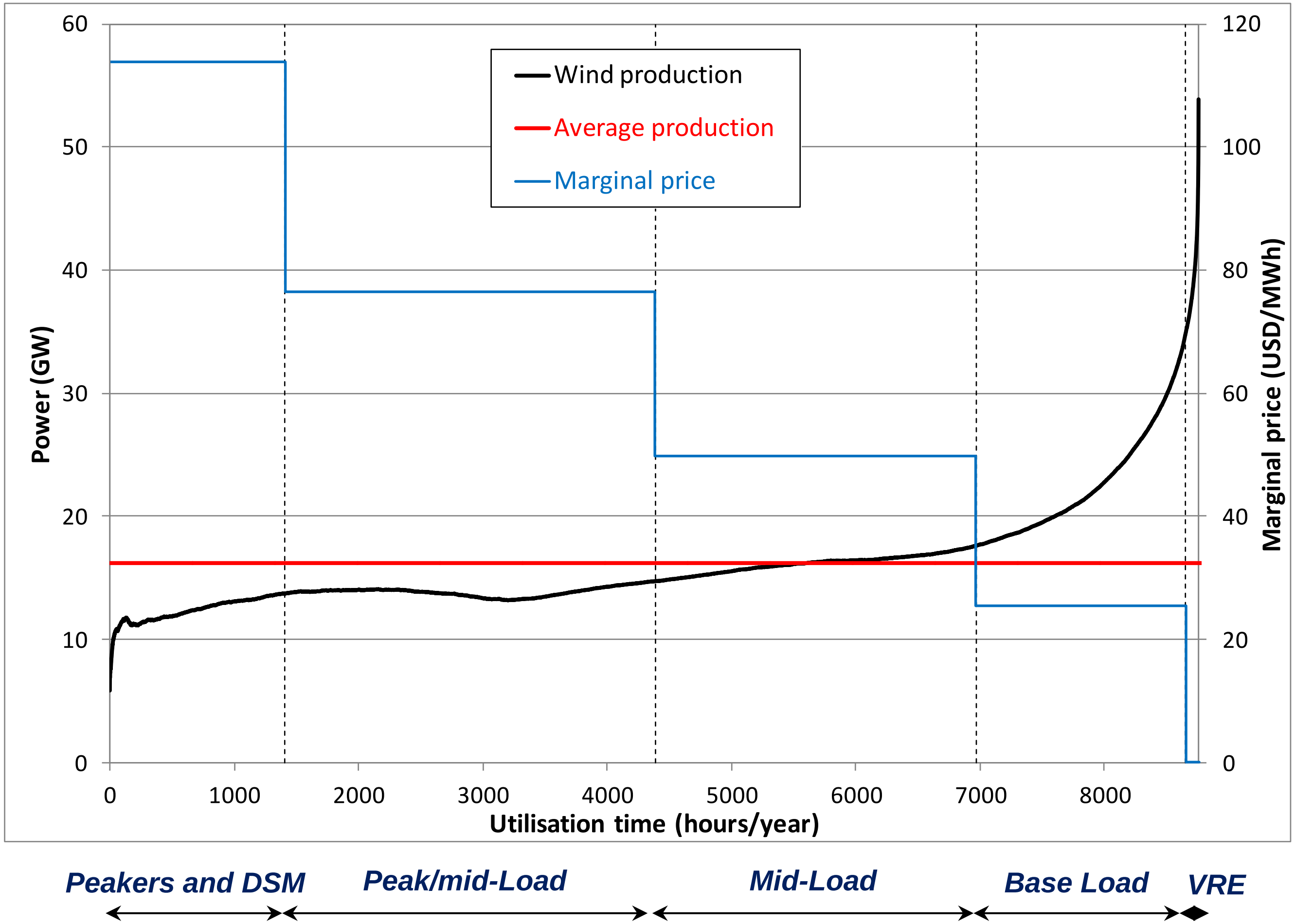
Different methodologies – robust finding: value drops

- 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 VRE: systems with much base load capacity feature steeper drop

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

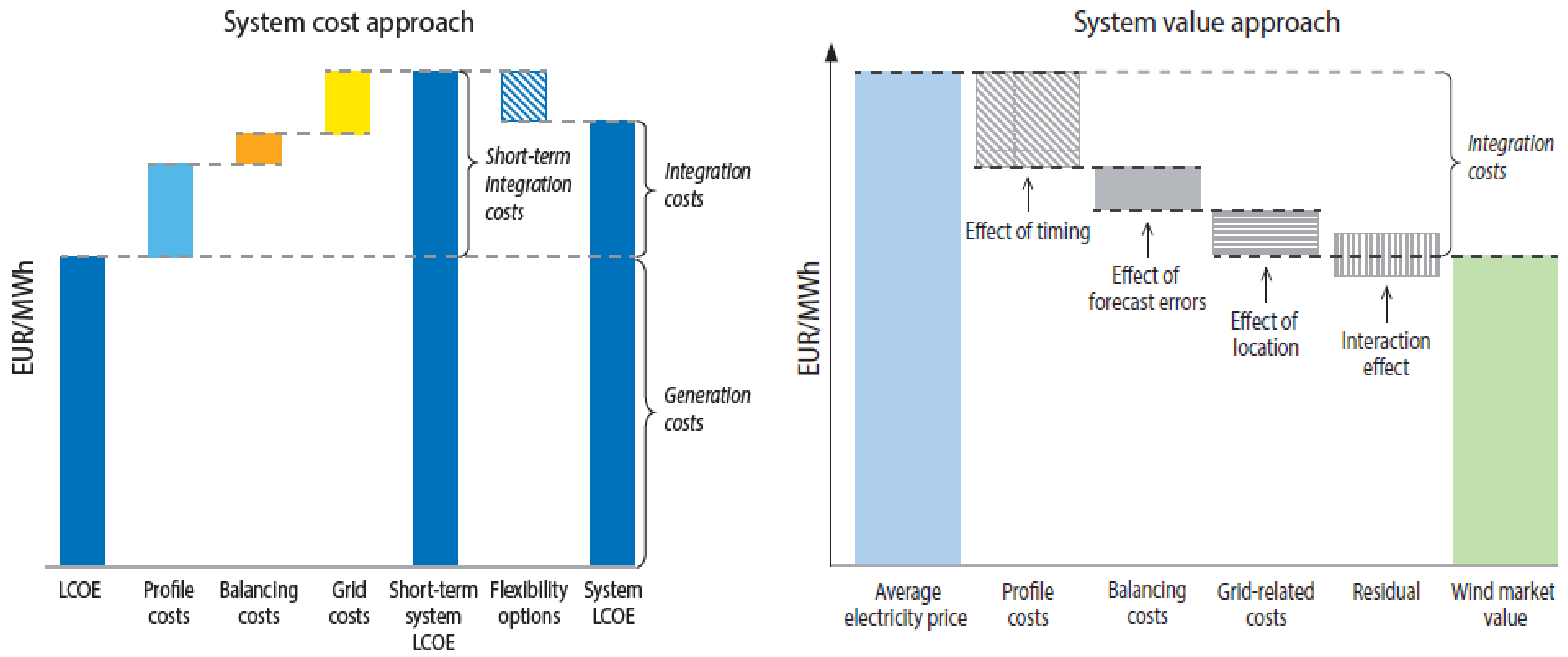


Summary

- ***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 VRE 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 VRE ….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. → The notion of "grid-parity" should be substituted by "system-level" parity.

System cost vs. System value approaches



The "Grid Parity" concept (I)

A decrease of the investment costs of PV installations has make them competitive with the electricity generated from fossil fuels in some particular locations.

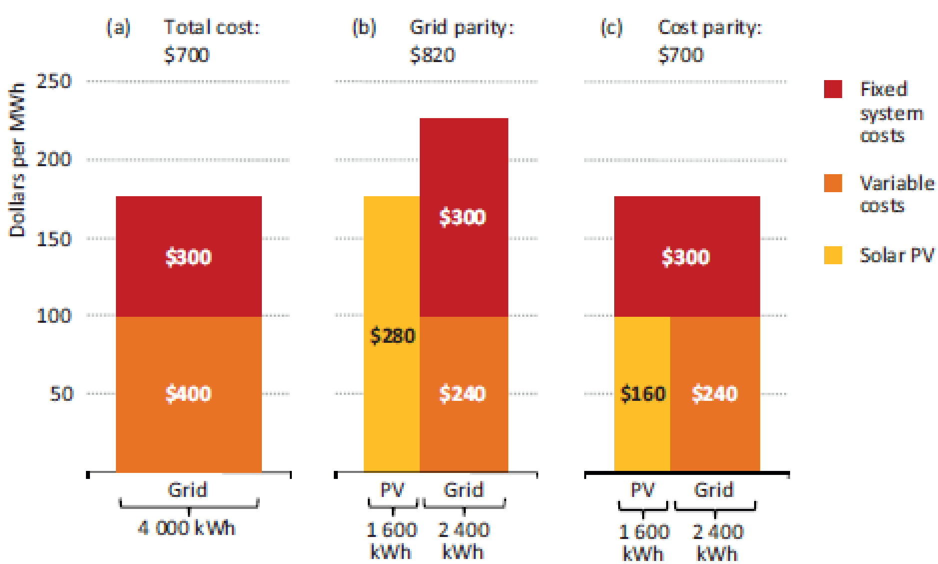
Grid parity aims to measure the competitiveness of distributed generation (residential PV).

PV would reach **grid parity** if its production costs fall below the price of electricity so that a private consumer would invest on it without subsidies.

It is a rather simple and appealing concept, but it is really meaningful?

1. Which price of electricity?

- Total cost of electricity (fixed & variables)
- Only variable part of customer bill ("*Socket parity*" by IEA)



Example from WEO 2013

(a) Costs are 300 € in fixed costs + 400 € for an annual consumption of 4 MWh (100 €/MWh). Total costs are 700 € ➡ (175 €/MWh).

(b) Imagine that PV produces 1.6 MWh with a specific cost of 175 €/MWh. Total costs are 820 €.

(c) To have the same cost for the customer (700 €) PV should have a total cost of 100 €/MWh, i.e the variable part of the electricity bill.

The "Grid Parity" concept (II)

2. This is valid only if all the electricity is self consumed.

Generally electricity not consumed is sold to the grid at a generally lower price, if no subsidies.

- The level of "socket parity" will depend on the "self-consumption" use.
- It will differ strongly from customer to customer.

$$\boxed{Socket\ Parity = Variable\ Price\ *\ \alpha + \ Resale\ Price * (1 - \alpha)}$$

3. This is valid only if all the real fixed costs (system costs) are correctly passed on to the customers in the electricity bill.

"Grid Parity" is based on a individual's perspective and does not takes into account a more global perspective taking into account the whole electricity system.

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" and on the "nuclear new built" studies

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

http://www.oecd-nea.org/ndd/pubs/2015/7195-nn-build-2015.pdf

Contacts: Marco Cometto and Jan Horst Keppler

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Jan-Horst.Keppler@oecd.org

Reserve slides

Corporate and government bonds yields: May 2014

Corporate bond yields (%)
European utilities
(different maturities, >2020)

CEZ	1.8 – 2.0
EDF	1.5 - 2.9
EnBW	2.3 - 3.5
Enel	2.4
E-On	1.6
GDF Suez	1.3 - 1.9
RWE	2.0 - 3.3
Vattenfall	1.8 - 2.9

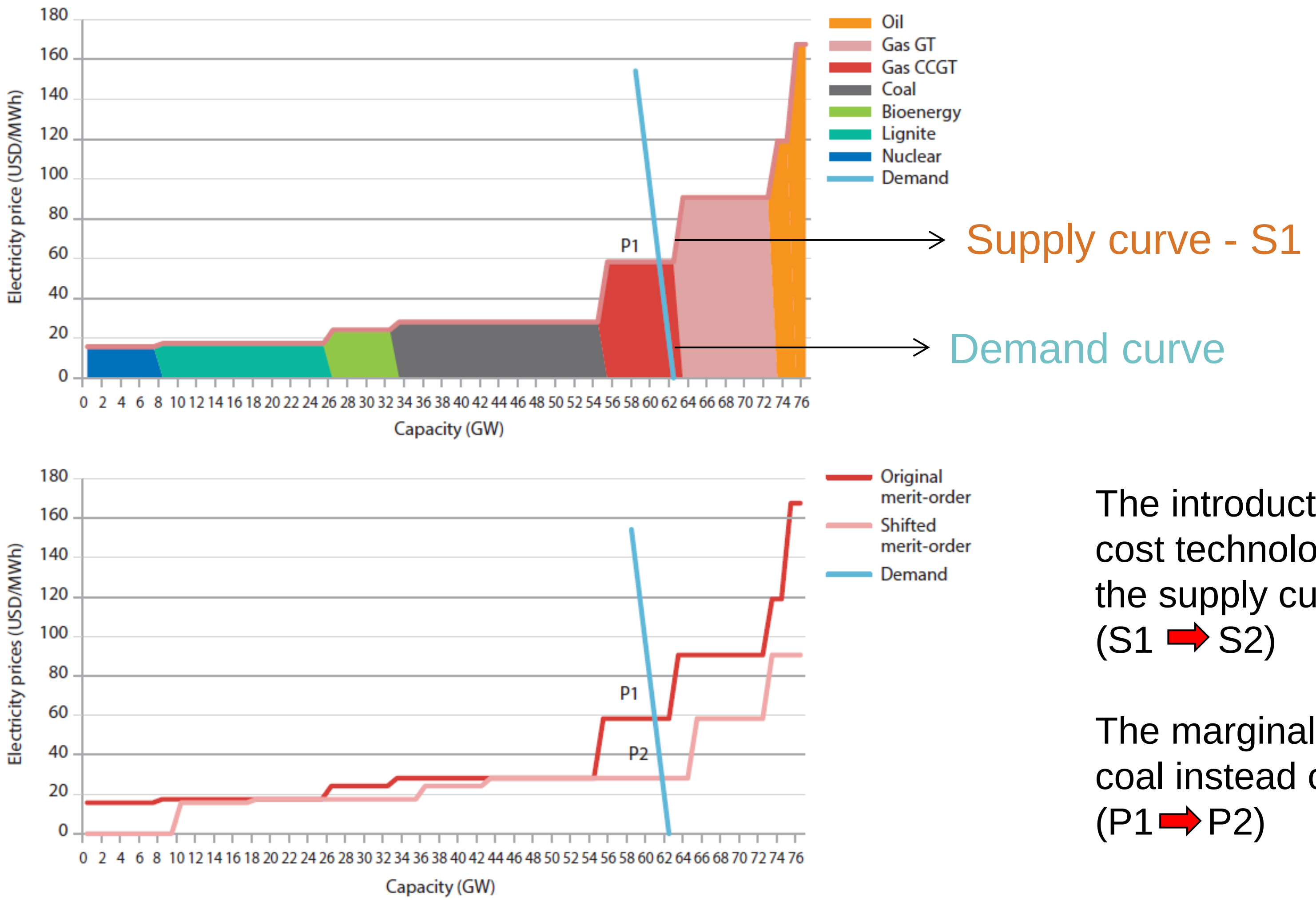
Government bonds (%)

	10 y	20y	30y
US	2.6		3.4
Canada	2.4	2.9	2.9
UK	2.6	3.3	3.4
CH	0.8	1.4	1.4
Japan	0.7	1.5	1.7
Europe	1.5	2.2	2.4
Germany	1.5	2.2	2.4
France	1.9	2.6	3.0
Italy	3.0	3.8	4.2
Spain	3.0	3.6	4.1

#

The "merit order" effect

Figure 10.4: Illustration of the merit order effect



The introduction of low-marginal cost technology (10 GW) shifts the supply curve to the right (S1 ➡ S2)

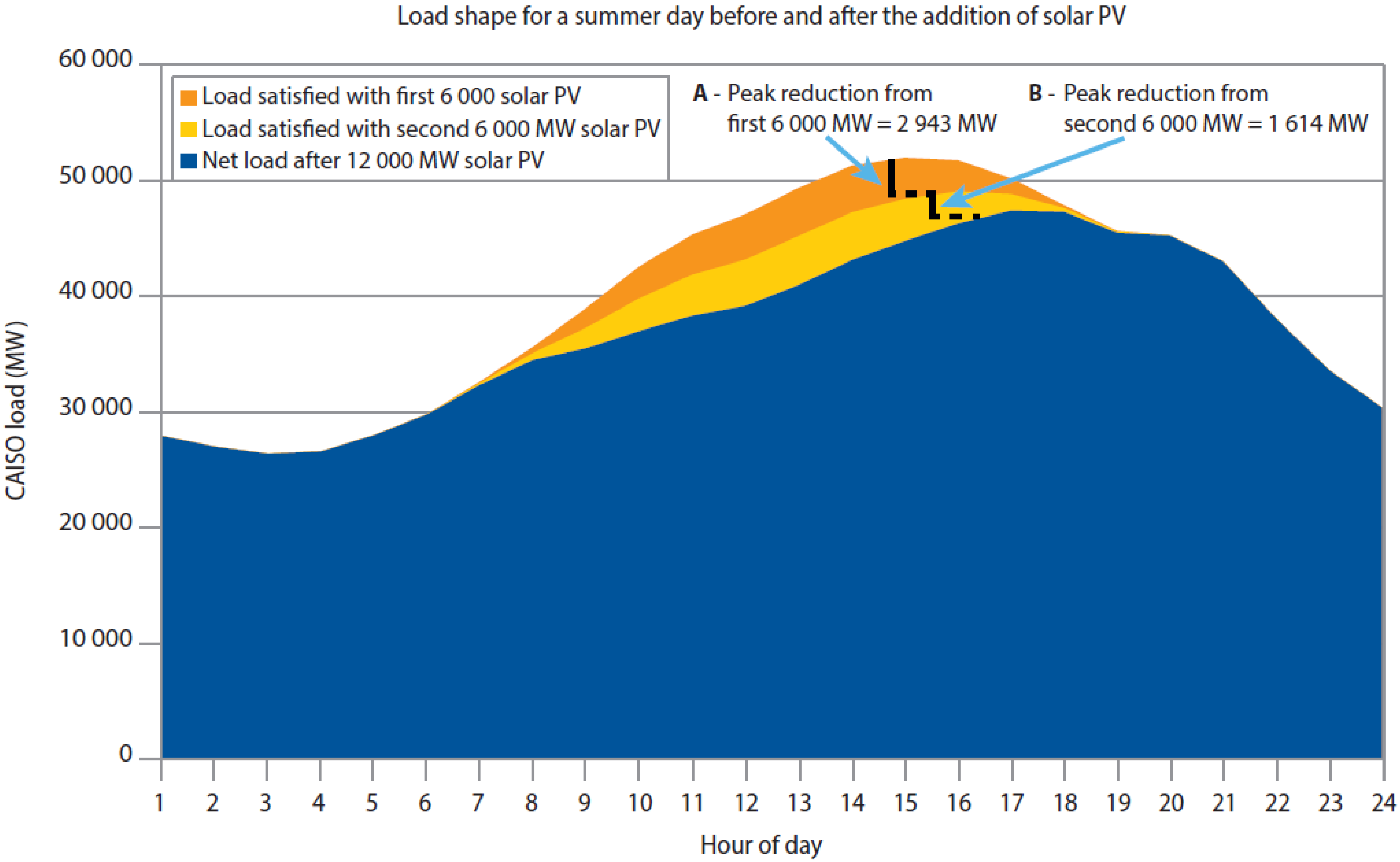
The marginal technology is now coal instead of Gas CCGT (P1 ➡ P2)

Note: CCGT = combined-cycle gas turbine; GT = gas turbine; GW = gigawatt; P1 = price without additional generation; P2 = price with additional generation.

Source: Schaber, 2014.

A (very schematic) illustration: The evolution of the solar capacity credit

Figure 10.6: Illustration of capacity credit evolution after increasing share of solar PV generation



Source: Jones (2012).

#

A special focus on nuclear power: the system effects of nuclear.

- Grid-level system effects *(qualitative)*
- Flexibility of NPP – short-term
- Flexibility of NPP – fleet management

The System Effects of Nuclear Power

While the system effects of variable renewables are at least an order of magnitude greater than those of other technologies, all technologies have some system effects, including nuclear power.

The study identifies the following grid-level effects for nuclear power:

1) Specific and stringent requirements for siting NPPs
    - Vicinity to adequate cooling source
    - Location in remote, less populated areas

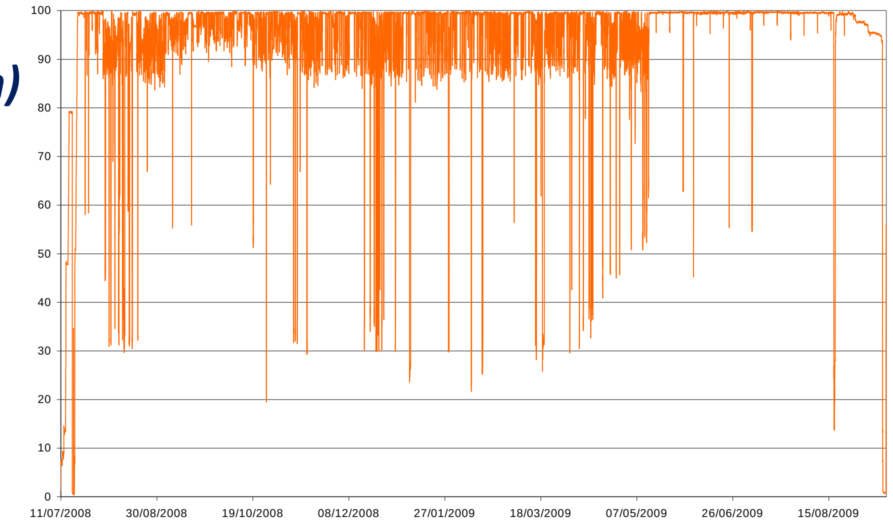
2) Large size of most nuclear units has an impact on grid design and dimension
    - Large minimum size of electricity system (output of a plant < 10% of lowest demand)
    - Significant amounts of spinning reserves to ensure short-term balancing and grid stability

3) Importance of grid stability and power quality for the safety of nuclear installations

    Stable electricity supply is essential for the safety of a nuclear installation
    - At least two independent connections to the electricity grid.
    - Stringent requirements in term of grid availability, frequency and voltage stability.
    - On the positive side, the inertia of the turbo-generator and substantial provision of reactive power contribute significantly to the stability of the electricity system.

Contribution to reduce system effects: flexibility of nuclear power plants

- ***In some countries (France, Germany, Belgium) significant flexibility is required of NPPs:***
  - Primary and secondary frequency control.
  - Daily and weekly load-following.



- ***Good load-following characteristics***
  - No proven impacts on fuel failures and major components.
  - Availability factor reduction due to extended maintenance (1.2 – 1.8%).
  - Economical consequences of load-following mainly due to reduction in load factors.

	Start-up Time	*Maximal change in 30 sec*	*Maximum ramp rate (%/min)*
Open cycle gas turbine (OGT)	10-20 min	20-30 %	20 %/min
Combined cycle gas turbine (CCGT)	30-60 min	10-20 %	5-10 %/min
Coal plant	1-10 hours	5-10 %	1-5 %/min
Nuclear power plant	2 hours - 2 days	up to 5%	1-5 %/min

The costs of flexibility for nuclear: impact on Levelised Cost Of Electricity

LCOE variation as a function of the load factor (5% discount rate)

From an economic viewpoint lost production hours represent the largest cost associated with load following operations:

- Primary frequency control: 2%
- Secondary frequency control: 5%
- Primary and secondary frequency control 7%
- Daily load following: 12-18%
- Increase on outage length: 0.7-1.8%

Daily load following

Primary and secondary frequency control

	LCOE Increase (%)							
	5% Interest rate				10% Interest rate			
	Nuclear	Coal	Coal w. CCS	Gas	Nuclear	Coal	Coal w. CCS	Gas
Primary regulation	1,7%	0,7%	1,5%	0,3%	1,8%	1,0%	1,7%	0,5%
Secondary regulation	4,4%	1,9%	3,9%	0,9%	4,8%	2,5%	4,3%	1,2%
Primary and secondary regulation	6,3%	2,7%	5,6%	1,2%	6,8%	3,6%	6,2%	1,7%
Daily load following	14,8%	6,2%	13,0%	2,9%	16,0%	8,3%	14,5%	3,9%

A decrease of LF of 7% means that LCOE for nuclear increases by 5%.

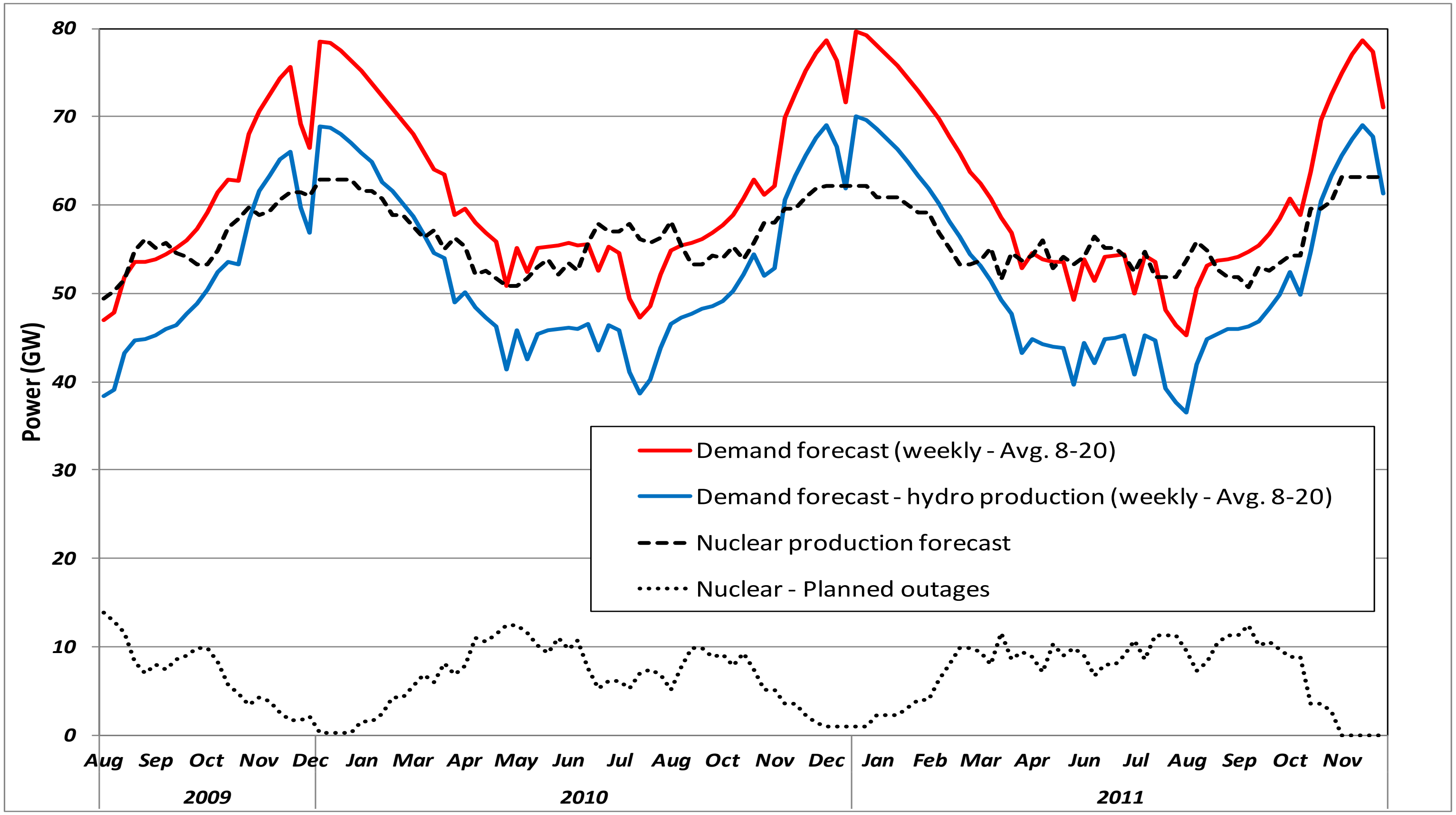
Due to its high investment cost, the LCOE for nuclear is sensitive to load factor variation.

Contribution to reduce system effects: Outage's management of nuclear fleet (I)

Nuclear fleet management: planning outage of each unit of the nuclear fleet in order to minimise the economic losses of the outage.

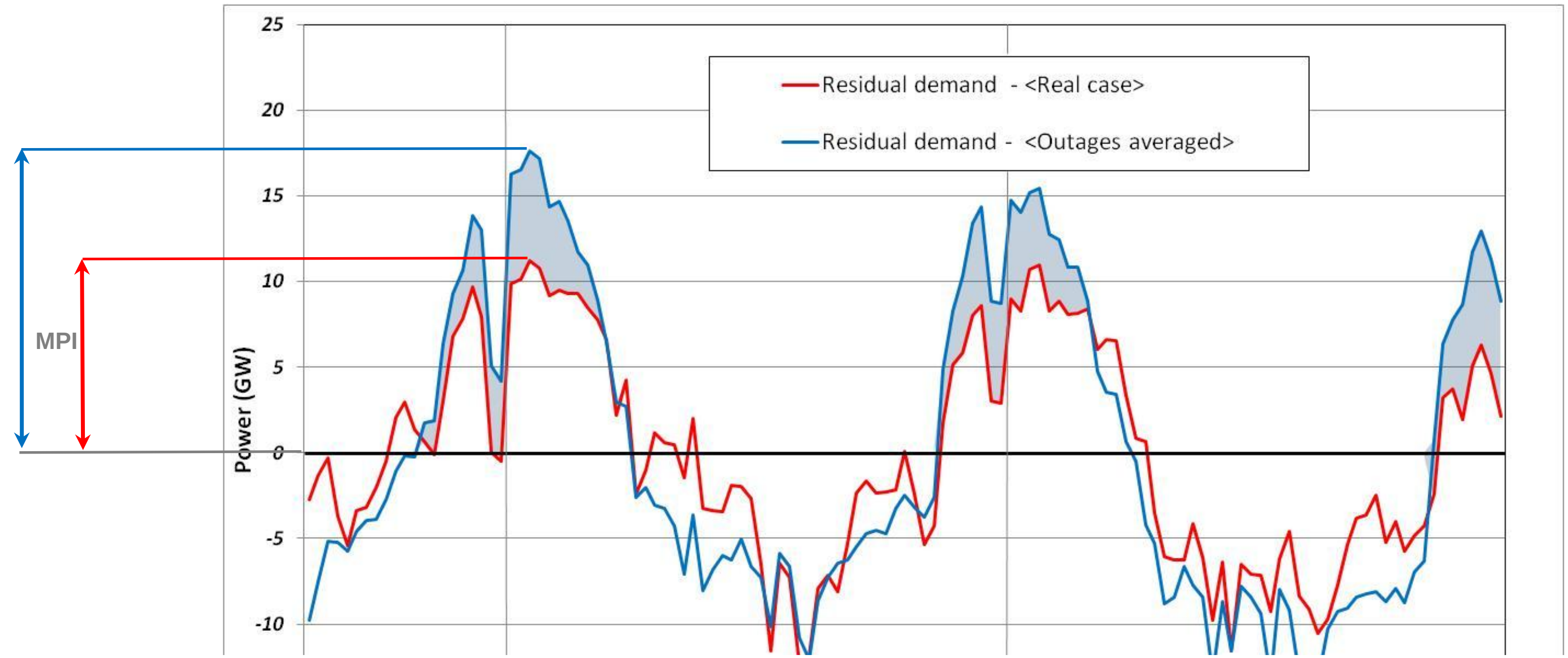
- Performing outages when the electricity is less "valuable" (residual demand is lower).
- Maximise the nuclear power plant availability in the high peak periods.

NPP planned outages and demand forecasts in France



Contribution to reduce system effects: Outage's management of nuclear fleet (II)

Effect of nuclear fleet management on residual demand (incl. import/export)



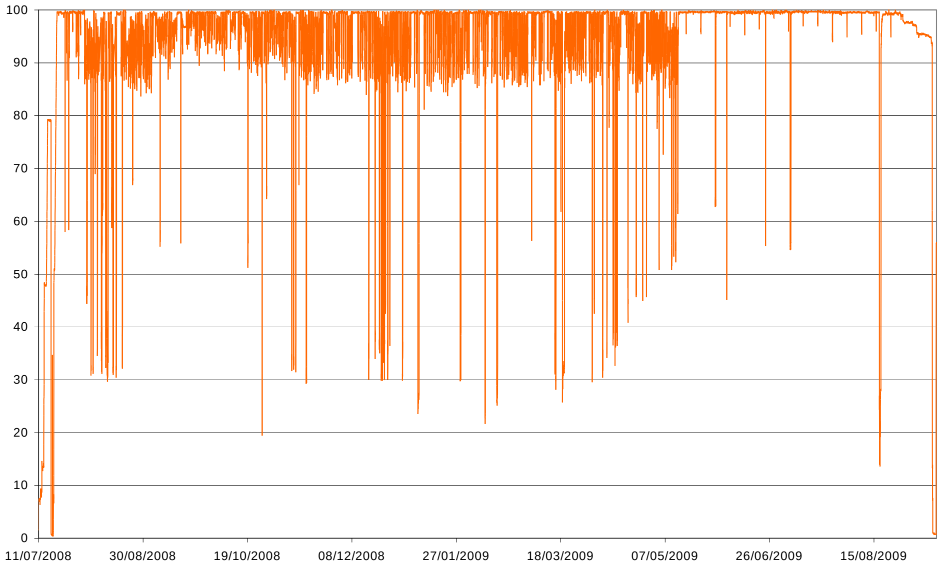
Seasonal nuclear fleet management contributes to flattening the residual demand curve and reduces its volatility.

- Reduces the maximal power imbalance and the need for additional capacity.
- Reduces the residual electricity need provided by more expensive technologies.
- Reduces the volatility of residual demand.
- Allows a more efficient use of more expensive generating capacities.

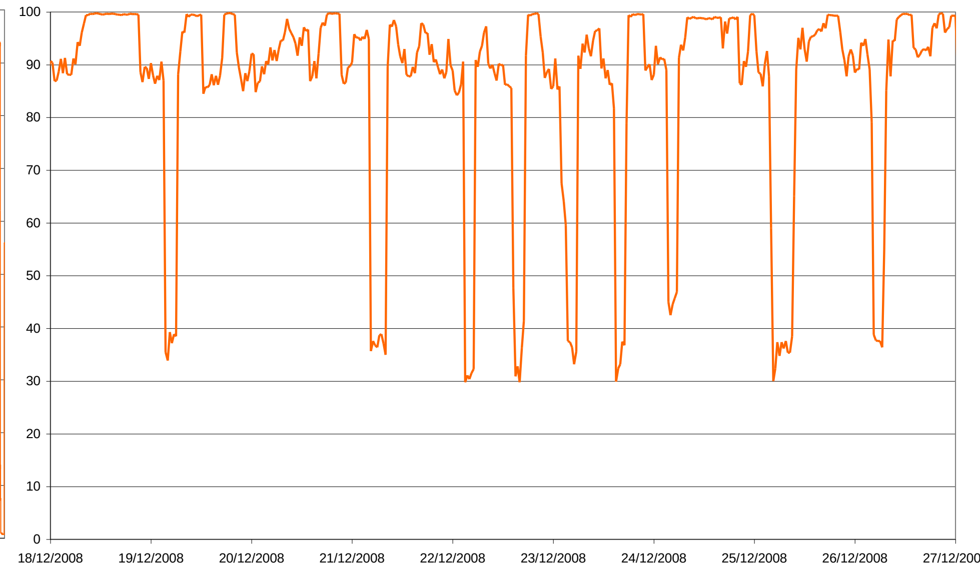
Economical benefit is 0.5 – 1 USD/MWh (1-2% of LCOE) for the whole nuclear park.

Contribution to reduce system effects: flexibility of nuclear power plants (II)

Power history of a French PWR reactor



Whole cycle

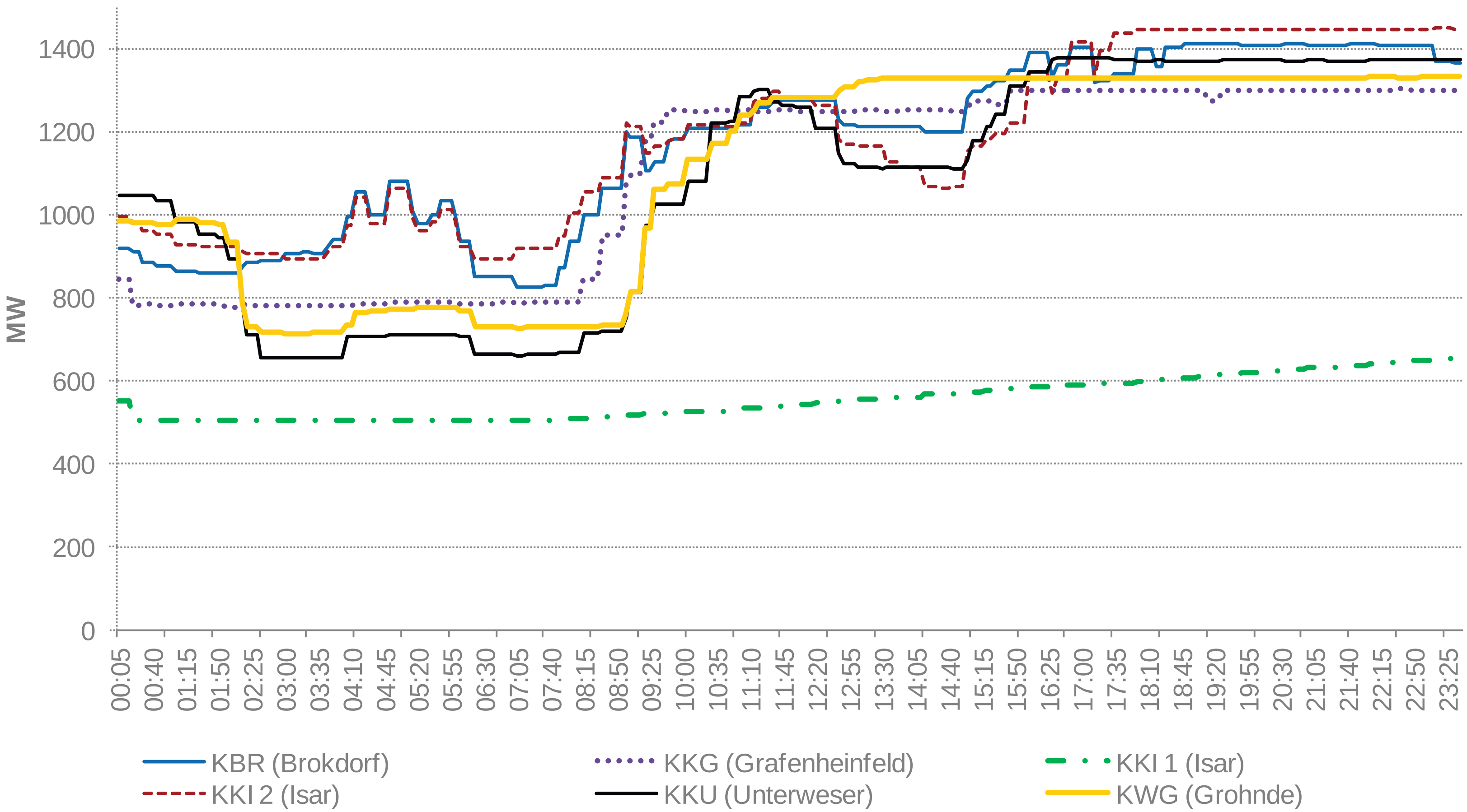


10-day period around Christmas

- For 2/3 of the cycle the load fluctuates between 85% and 100%.
- In the last third of the cycle the plant is operated in a base load mode.
- Daily load following, with power reductions up to 35%-40% of nominal power.
- “Stretch” can be observed in the last few days of operation.

Contribution to reduce system effects: flexibility of nuclear power plants (III)

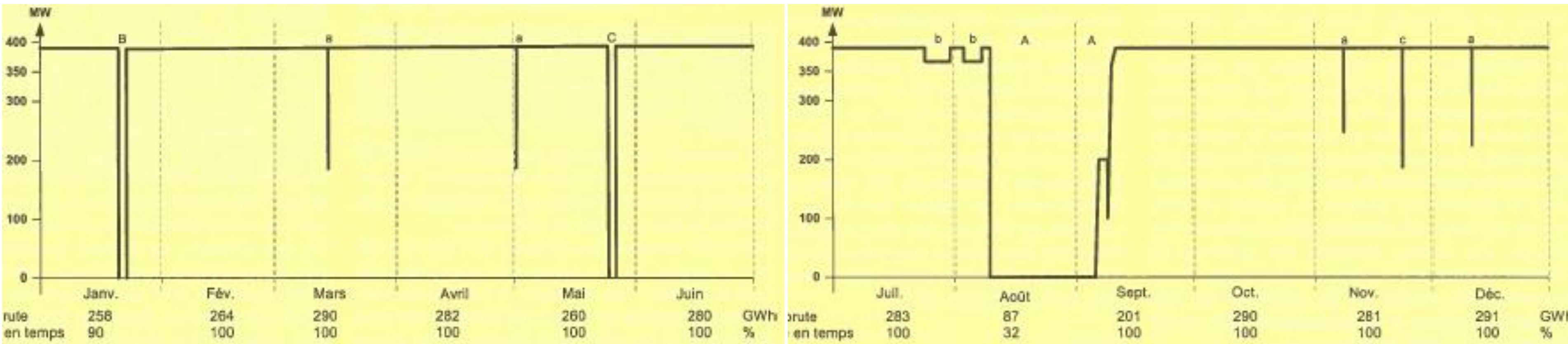
Example of power history for 6 E.ON nuclear power plants during 24 hours



- Significant load-following (up to 50% of nominal power).

Examples of NPPs operating at base-load

Example of power history for the Mühleberg NPP in 2013



Arrêts programmés: **3**

A Remplacement d'éléments combustibles et révision annuelle du 11 août au 7 septembre

B Arrêt temporaire du 19 au 22 janvier, remplacement d'un joint sur la pompe de circulation B du réacteur

C Arrêt temporaire du 24 au 27 mai, remplacement d'un joint sur la pompe de circulation B du réacteur

Arrêts non programmés: **0**

Aucun

Baisses de puissance (supérieures à 1 heure à pleine puissance): **7**

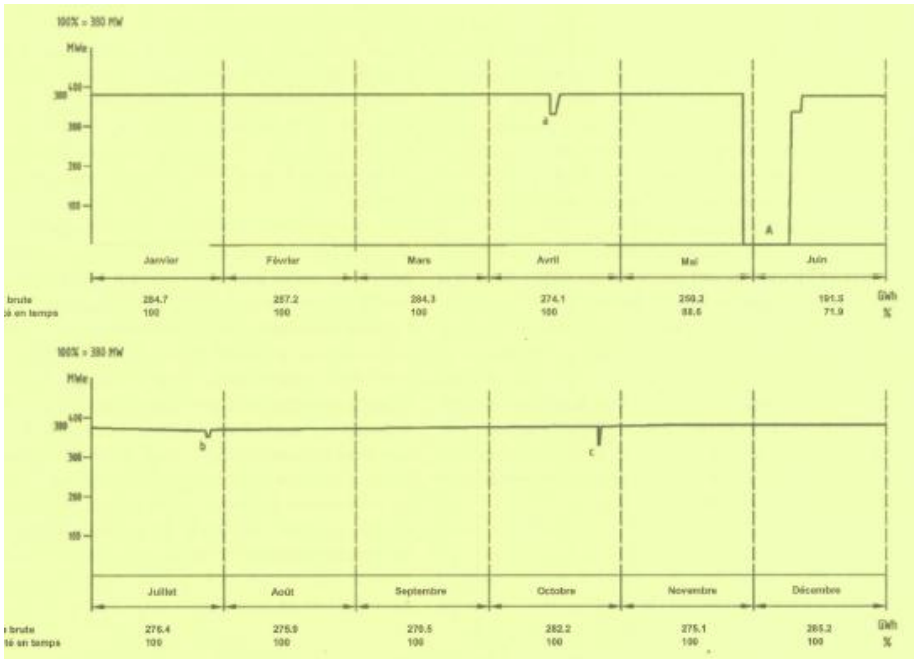
a Contrôles périodiques

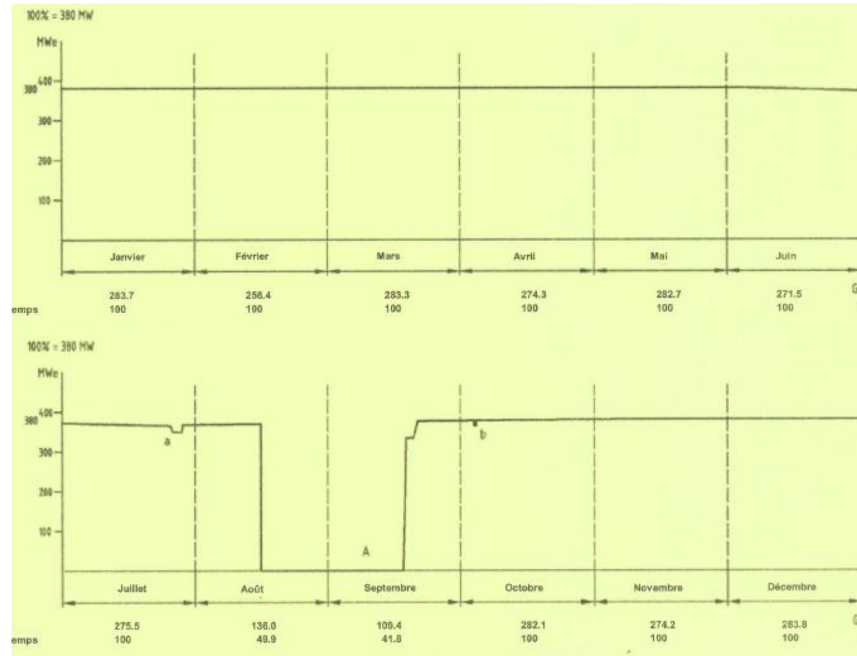
b Température élevée de l'eau de l'Aar

c Panne de la pompe de circulation B du réacteur

Examples of NPPs operating at base-load

Example of power history for the Beznau 1&2 NPPs in 2013





Arrêts programmés: 1

A 41e remplacement d'assemblages combustibles et arrêt pour révision 2013

Arrêts non programmés: 0

Aucun

Baisses de puissance: 3

a Prestation de service système tertiaire négatif

b Réduction temporaire de puissance pour ne pas dépasser la température de sortie maximale autorisée de l'eau de refroidissement

c Réduction de puissance sur instruction du centre de conduite du réseau d'énergie électrique en raison d'un dérangement du réseau en Italie

Arrêts programmés: 1

A 39e remplacement d'assemblages combustibles 2013

Arrêts non programmés: 0

Aucun

Baisses de puissance: 2

a Réduction temporaire de puissance pour ne pas dépasser la température de sortie maximale autorisée de l'eau de refroidissement

b Réduction de puissance pendant la réparation de la fuite de vapeur sur le dispositif de mesure de la température du surchauffeur intermédiaire

#

Coal power plants: LCOE [USD/MWh]

Country	Technology	Net capacity	Electrical conversion efficiency	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel costs	Carbon costs	O&M costs[3]	LCOE	
					5%	10%	5%	10%				5%	10%
		MWe	%	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	USD/MWh	
Belgium	Black SC	750	45%	2 539	2 761	3 000	0.10	0.02	28.80	23.59	8.73	**82.32**	**100.43**
	Black SC	1 100	45%	2 534	2 756	2 994	0.10	0.02	28.80	23.59	8.39	**81.94**	**100.01**
Czech Rep.	Brown PCC	600	43%	3 485	3 989	4 561	0.14	0.03	18.39	25.11	8.53	**84.54**	**114.12**
	Brown FBC	300	42%	3 485	3 995	4 572	0.14	0.03	18.83	25.71	8.86	**85.94**	**115.64**
	Brown IGCC	400	45%	4 671	5 360	6 146	0.18	0.04	17.57	23.40	10.35	**93.53**	**133.24**
	Brown FBC w/Biomass	300	42%	3 690	4 225	4 830	0.15	0.03	27.11	23.13	9.15	**93.71**	**125.01**
	Brown PCC w/CC(S)	510	38%	5 812	6 565	7 417	0.22	0.05	20.81	1.41	13.43	**88.69**	**136.12**
	Brown FBC w/CC(S)	255	37%	6 076	6 872	7 768	0.23	0.05	21.37	1.44	14.69	**92.89**	**142.57**
	Brown IGCC w/CC(S)	360	43%	6 268	7 148	8 148	0.23	0.05	18.52	1.17	12.26	**88.29**	**140.64**
	Br FBC w/BioM and CC(S)	255	37%	6 076	6 872	7 768	0.23	0.05	30.78	1.44	14.98	**102.59**	**152.27**
Germany	Black PCC	800	46%	1 904	2 131	2 381	0.08	0.02	28.17	22.07	12.67	**79.26**	**94.10**
	Black PCC w/CC(S)	740	38%	3 223	3 566	3 946	0.12	0.03	34.56	3.25	20.11	**85.28**	**109.61**
	Brown PCC	1 050	45%	2 197	2 459	2 747	0.09	0.02	11.27	26.12	14.04	**70.29**	**87.41**
	Brown PCC w/CC(S)	970	37%	3 516	3 890	4 304	0.13	0.03	13.70	3.81	20.70	**68.06**	**94.60**
Japan	Black	800	41%	2 719	2 935	3 166	0.11	0.02	31.61	23.88	10.06	**88.08**	**107.03**
Korea	Black PCC	767	41%	895	978	1 065	0.04	0.01	31.53	24.04	4.25	**68.41**	**74.25**
	Black PCC	961	42%	807	881	960	0.03	0.01	30.78	23.50	3.84	**65.86**	**71.12**
Mexico	Black PCC	1 312	40%	1 961	2 316	2 722	0.08	0.02	26.71	23.40	6.51	**74.39**	**92.27**
Netherlands	Black USC PCC	780	46%	2 171	2 389	2 756	0.09	0.02	28.75	22.23	3.97	**73.29**	**91.06**
Slovak Rep.	Brown SC FBC	300	40%	2 762	3 092	3 462	0.11	0.02	60.16	27.27	8.86	**120.01**	**141.64**
United States	Black PCC	600	39%	2 108	2 310	2 526	0.08	0.02	19.60	26.40	8.76	**72.49**	**87.85**
	Black IGCC	550	39%	2 433	2 666	2 916	0.10	0.02	19.63	26.40	8.37	**74.87**	**92.61**
	Black IGCC w/CC(S)	380	32%	3 569	3 905	4 263	0.14	0.03	24.15	2.61	11.31	**68.04**	**93.92**
NON-OECD MEMBERS													
Brazil	Brown PCC	446	30%	1 300	1 400	1 504	0.00	0.00	15.39	0.00	37.89/43.93	**63.98**	**79.02**
China	Black USC PCC	932	46%	656	689	723	0.03	0.01	23.06	0.00	1.64	**29.99**	**34.17**
	Black SC	1 119	46%	602	632	663	0.03	0.01	23.06	0.00	1.51	**29.42**	**33.26**
	Black SC	559	46%	672	705	740	0.03	0.01	23.06	0.00	1.68	**30.16**	**34.43**
Russia	Black USC PCC	627	47%	2 362	2 496	2 637	0.00	0.00	20.41	0.00	10.96	**50.44**	**65.91**
	Black USC PCC w/CC(S)	541	37%	4 864	5 123	5 396	0.00	0.00	26.10	0.00	21.58	**86.82**	**118.34**
	Black SC PCC	314	42%	2 198	2 323	2 454	0.00	0.00	22.83	0.00	10.20	**50.77**	**65.15**
South Africa	Black SC PCC	794	39%	2 104	2 584	3 172	0.00	0.00	7.59	0.00	4.87	**32.19**	**53.99**