Electricity Market Reform

Discussion of basic principles

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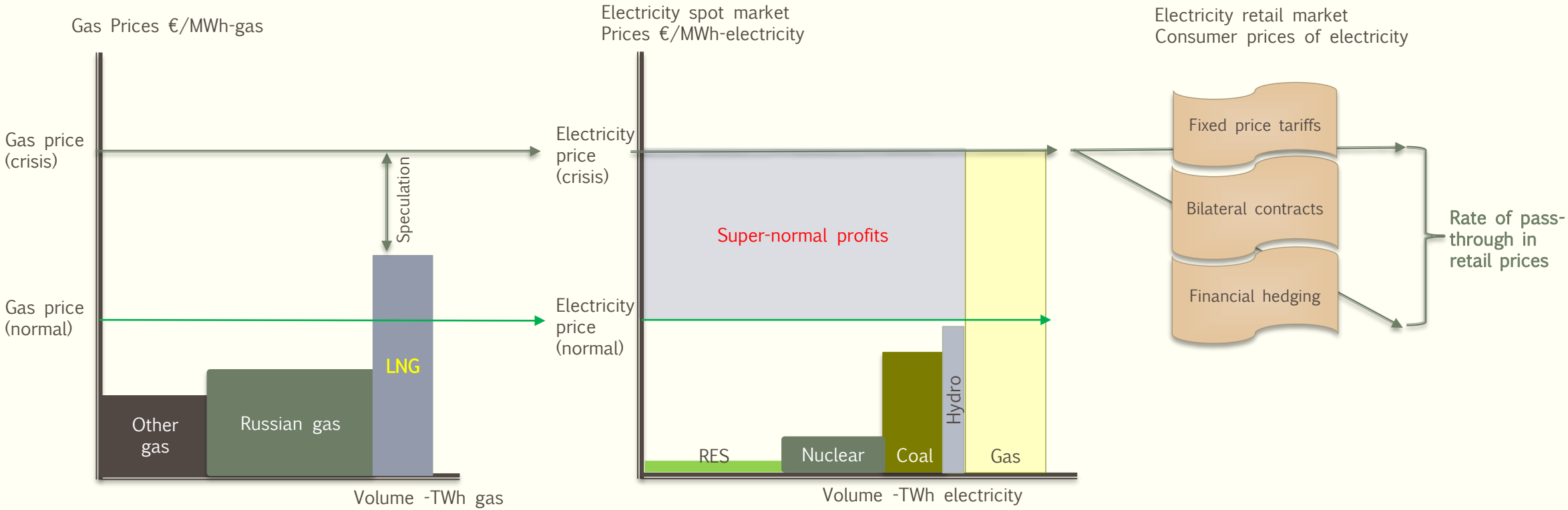
Gas price crisis passing on electricity retail prices



- By applying marginal cost market clearing price (as they should do to ensure an efficient generation schedule), the wholesale market creates supernormal profits when gas prices are excessively high
- Electricity suppliers usually remunerate generators via bilateral contracts reflecting costs that differ by technology; the bilateral contracts may be explicit (between different entities) or implicit (within integrated companies). In addition, electricity suppliers usually employ financial hedging instruments to ensure fixed and smooth prices for consumers.
- These instruments reduce the rate of passing-through wholesale price volatility into retail prices, however, when high gas prices persist, the tendency is to see increasing rates of pass-through in retail prices.

Unprecedented energy price crisis

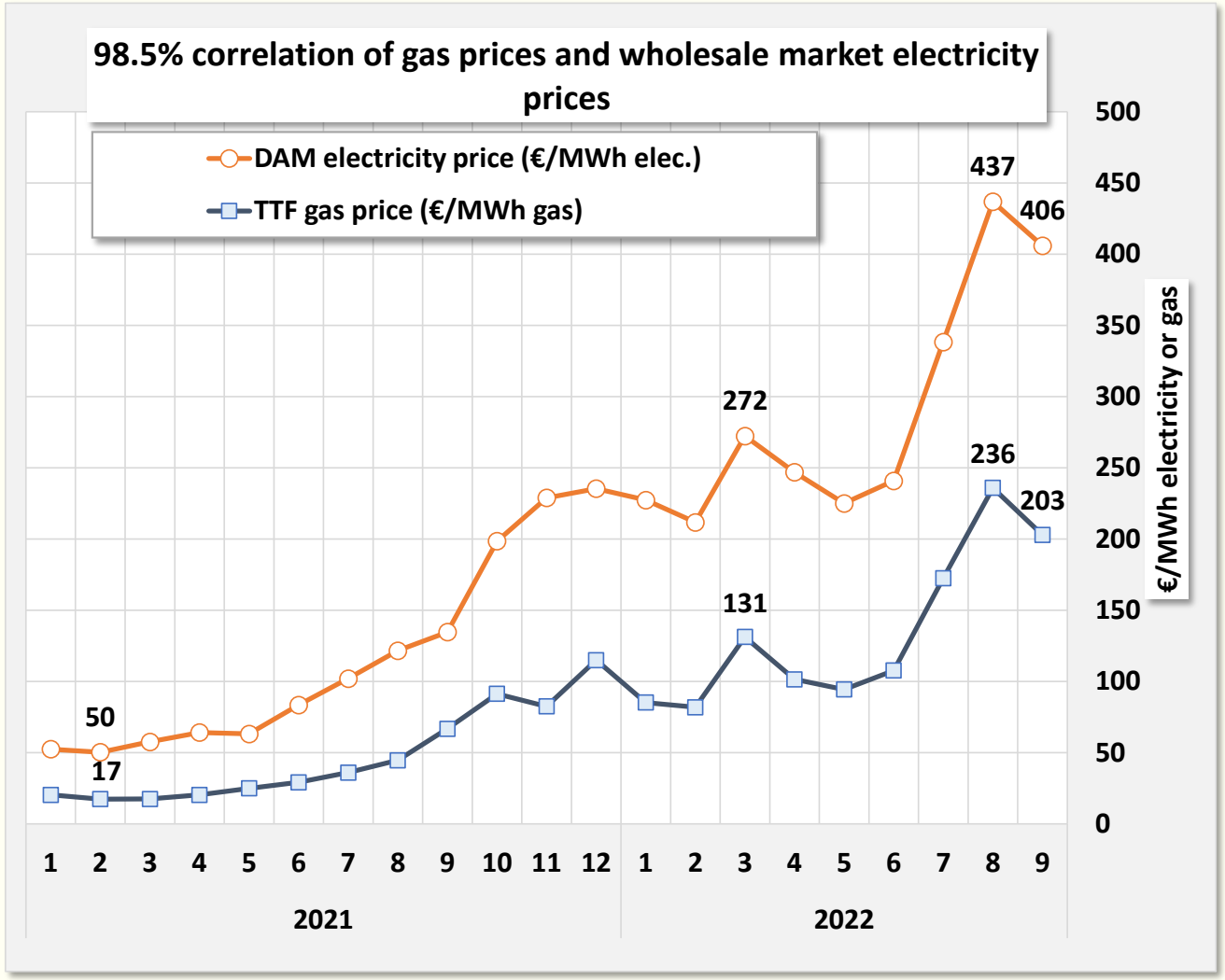
Compared to prices at the beginning of 2021:

- Natural gas x 10
- Wholesale electricity prices x 8

Wholesale electricity prices strongly dependent on natural gas prices

- Natural gas, needed to balance other sources, is systematically the wholesale market price setter
- But less than 1/3 of electricity comes from natural gas

- After a period of relatively modest pass-through of wholesale to retail prices, consumer prices almost aligned with wholesale prices while the financial costs of hedging instruments were soaring.



Explanation of supernormal profits in a wholesale market

- Marginal cost pricing rule for the wholesale market is efficient for the merit order (Pay as bid is less cost-efficient)
- Natural gas is the price setter more often than its share in the generation mix
- If the natural gas price is high,

  Costs of buying energy from the DAM =

  Market Price x Consumption
- which can be higher than

  Total true costs (red polygon)=

  Sum over all plants of

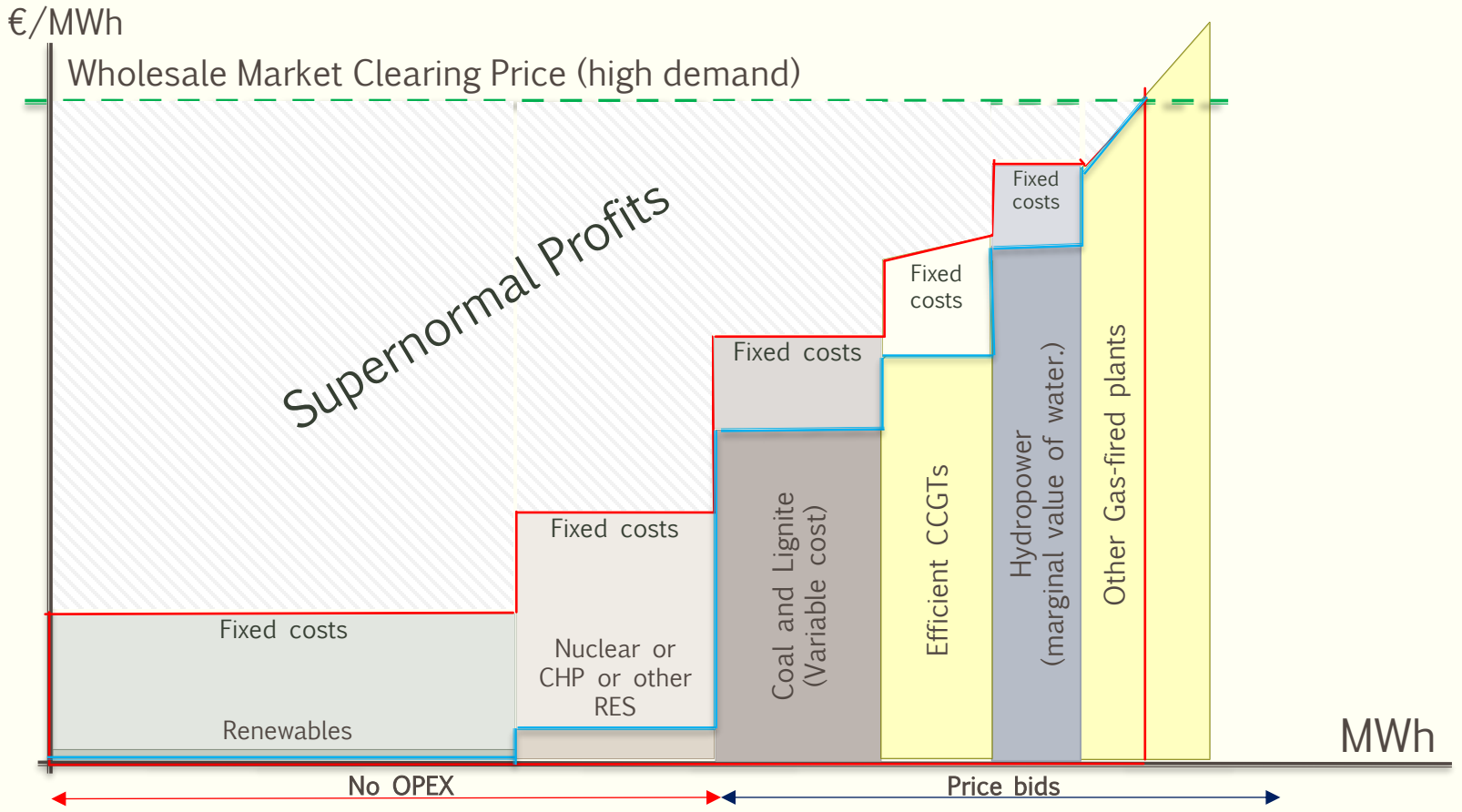
  Capital costs

  Fixed costs

  Fuel and emission costs

Blue polygon: marginal cost reflecting bidding curve

Red polygon: total cost curve, including capital, fixed and variable costs



Alternative ways of decoupling DAM electricity prices from natural gas prices

Options for immediate state intervention

- No state intervention, but only subsidies to vulnerable consumers
- Price cap on natural gas used in power generation (as in the Iberian case)
- Price cap on the DAM market clearing price and apply a pay-as-bid rule for more expensive power generation (the so-called shock absorber mechanism)
- Revenue cap at the settlement of the DAM and bilateral contracts, and then collection of clawback to subside customer tariffs (as in Greece and the European Commission's proposal)

Options for a permanent design

- No change
- Distinct short-term energy and balancing (commodity) and long-term market for contracts (assets)
- Two-stage DAM, with distinct competition and prices for CAPEX and OPEX resources (several design varieties)
- Variants for PPA Renewables: decentralized bilateral PPA market, versus organized markets of PPA for Renewables
- Single buyer or central auctioning for procurement of CAPEX resources and a spot market for balancing resources and reserves
- No split of the DAM, emphasis on bilateral contracts and hedging instruments in the retail market, with State support and probably obligations

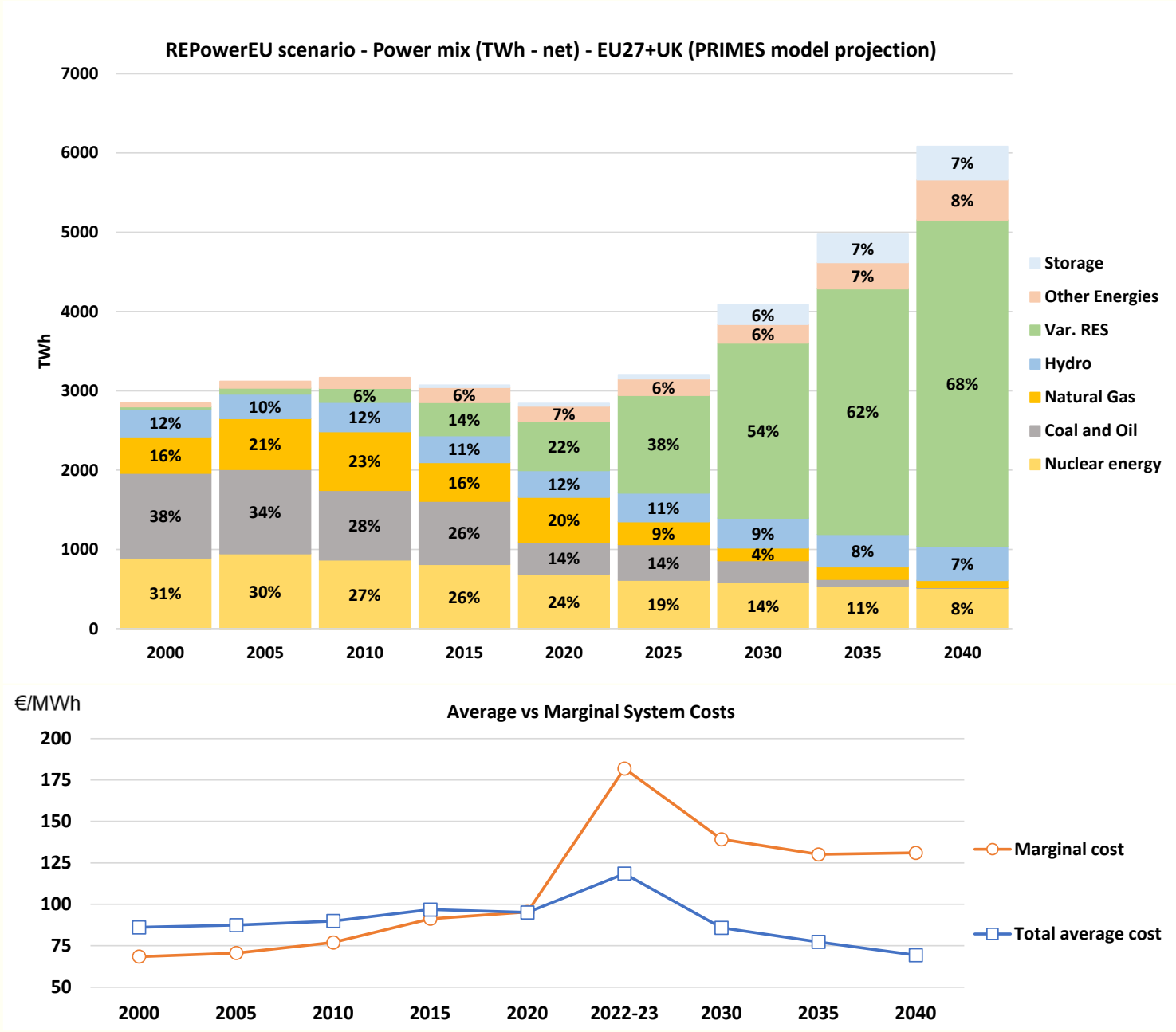
Net-zero carbon transition

(REPowerEU projection)

- The power mix drastically restructures away from fossil fuels with RES covering 70-80% of the mix already in 2030
- Significant storage capacity and contribution from demand-response are needed
- Natural gas plants (or other gases) still necessary for spinning reserves and back up in the absence of seasonal storage
- The marginal cost bidding resources have a diminishing share, below 25% already in 2030

The gas price crisis brought earlier than expected a gap between wholesale prices and true costs of generation

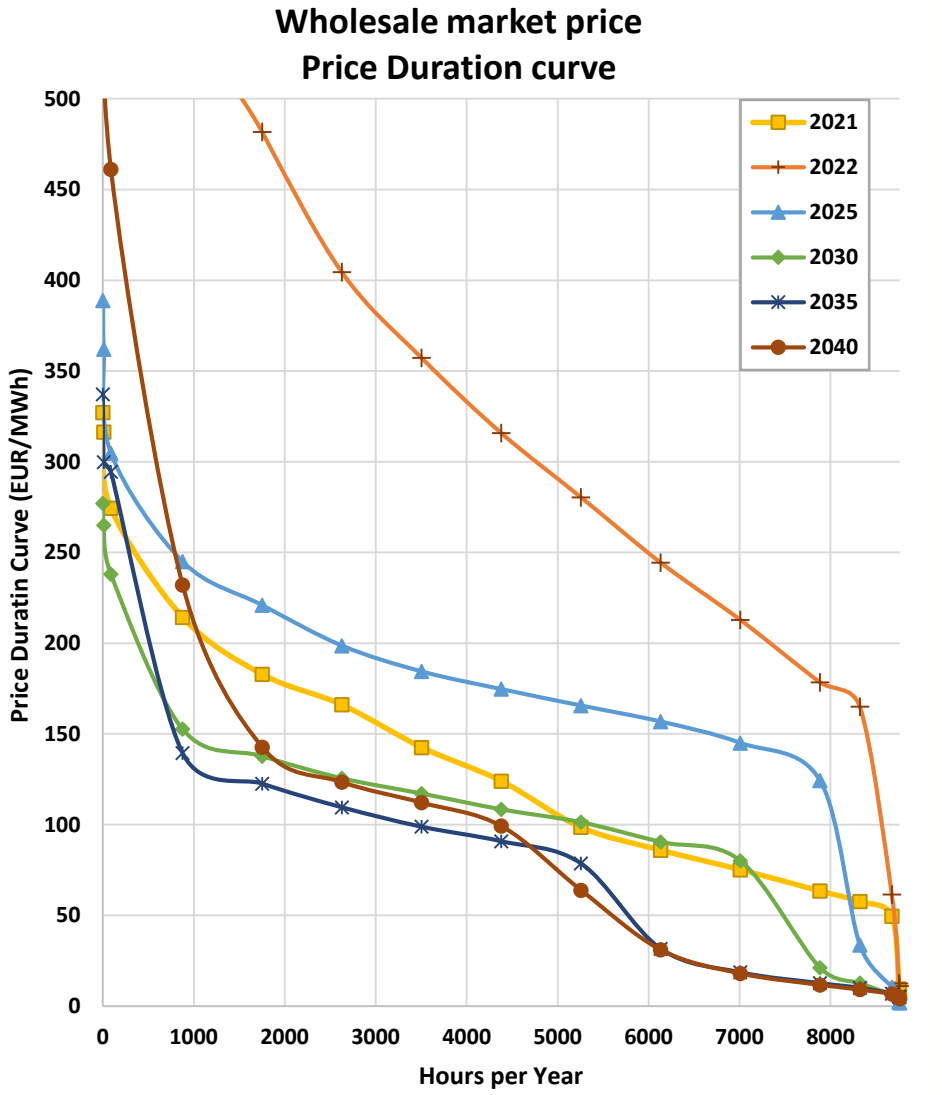
- ➢ marginal system costs are systematically higher than total average costs
- ➢ this is likely to persist in the future within the green transition
- ➢ the opposite was occurring in the past

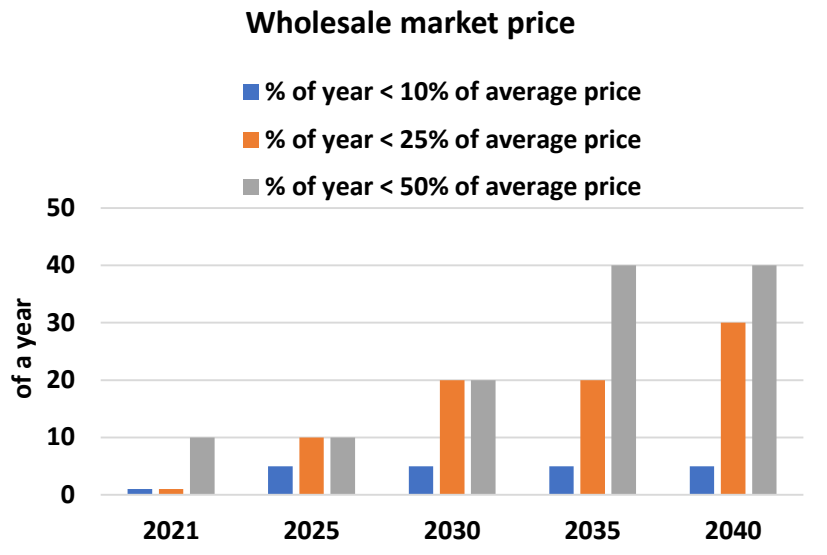


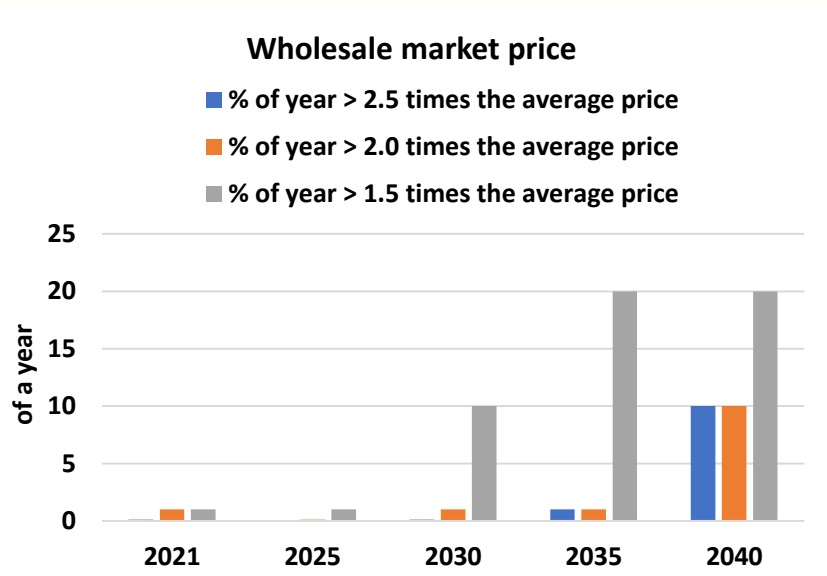
Price volatility due to RES-domination and decarbonisation

Trends seen in simulations

- Increasing periods per year with very low wholesale market prices
- Increasing periods per year with high wholesale market prices
- Thus, increasing price volatility
- Increasing scarcity of balancing, flexibility and reserve resources drive a significant increase in reserve prices

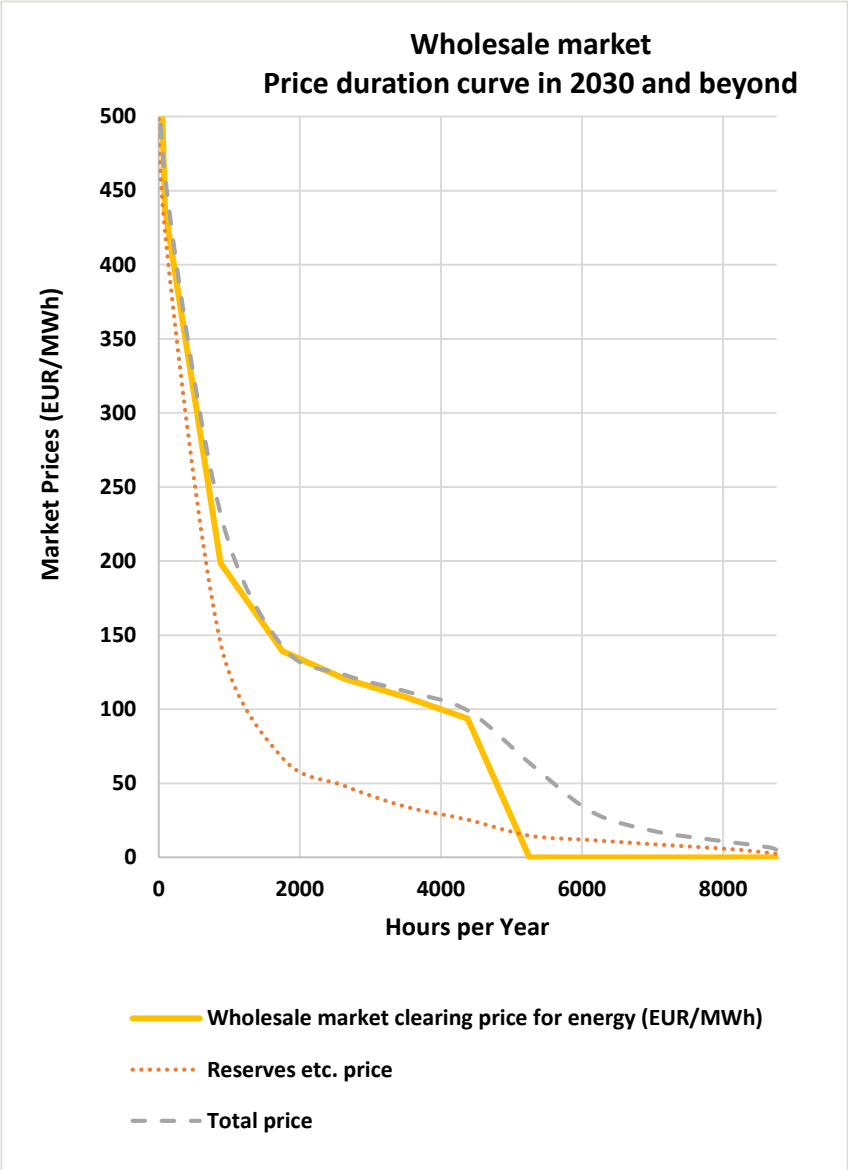






Green Transition Issues that the electricity market design has to address

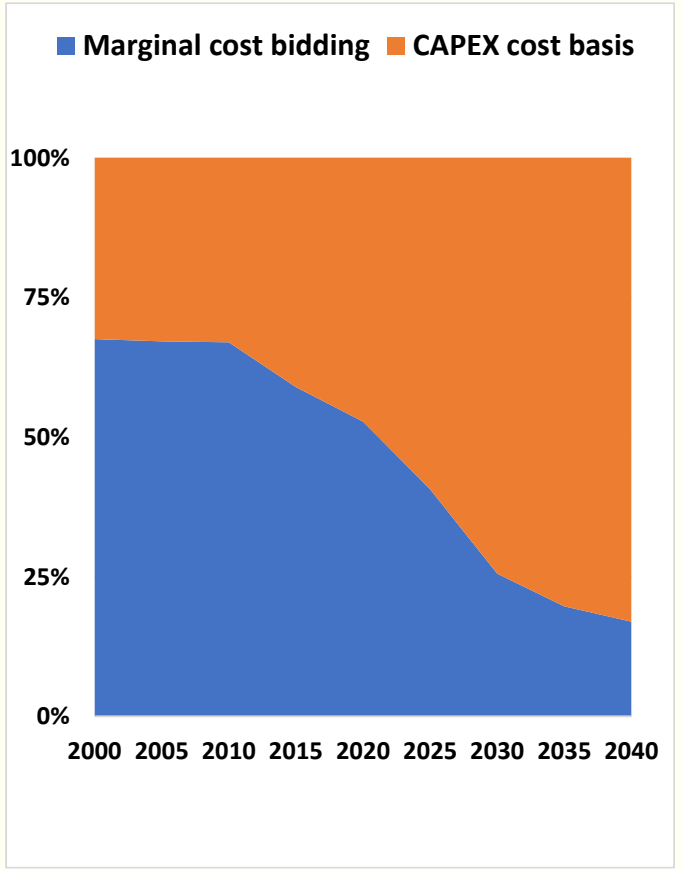
- Wholesale market clearing prices: increasing volatility when RES dominate (as early as 2030)
  - Increasing gap between very low prices due to RES and high or very high prices reflecting scarcity of RES balancing resources.
  - Gas prices are the single remaining market price-setter, and the gas-based influence on prices will be much higher than the share of gas in the power mix.
  - High gas prices will further increase wholesale prices.
- Economic consequences
  - Marginal system costs are likely to exceed total average system costs systematically.
- Investment consequences
  - New investment is principally CAPEX-dependent and requires predictable and stable revenues over a long period to ensure the lowest possible cost of capital financing
  - The volatile spot-market revenues imply a risk premium and increase capital costs.
  - Competition for the market and not competition in the market is more cost-efficient for CAPEX investment
- In the retail market
  - A market failure occurs if the retail market does not succeed in preventing consumers from paying supernormal profits.
  - Consumers, especially industry, perceive high price volatility as a disutility (risk-augmenting). They would prefer stable and fixed prices.
  - Retailers would encounter increasing costs in hedging against risk volatility and uncertainty to offer stable and fixed prices to consumers.



Green Transition Issues that the electricity market design has to address

- The cost structure changes.
  - By 2030, more than two-thirds of the generation assets will be CAPEX-dominated.
  - A small and diminishing fraction of generation will seek revenues from pure energy prices.
  - And still, most of the balancing and flexibility resources will have trouble recovering all costs from the wholesale markets.
- The economics of CAPEX-based resources depend on the cost of capital which further depends on risk factors.
  - A stable and guaranteed revenue stream over a long period is the most effective way to achieve the lowest possible cost of capital.
  - Opportunistic earnings from volatile short-term markets do not imply low financing costs.
  - Spot market volatile prices entail higher risk than long-term revenue streams.
- The CAPEX-based resources are, by far, the lowest-cost technologies for electricity.
  - However, it seems challenging how to ensure that consumers, especially industry, have direct access to this low-cost resource.
  - The difficulty comes from the inability of pure RES resources to sustain “firm supply”.
  - Bundling storage, balancing and backup with RES can be a “firm supply” portfolio.
  - But, the market and the system are currently not yet mature enough to handle RES-based firm supply portfolios.

Shares of generation resources in the REPowerEU projection classified in CAPEX and OPEX depending on their cost structure



Redesigning the electricity market, not only to decouple electricity process from gas prices, but also for addressing the specific features of a RES-dominated system

Principles to respect for wholesale markets

- Preserve cost-efficient dispatching based on marginal costs, which define the merit order and set market clearing
- Do not weaken price signals enabling demand response
- Maintain optimal market coupling and facilitate cross border flows
- The reform should mainly address technology remuneration:
  - Pay CAPEX resources at their true costs via a market enabling long-term contracting (market for assets)
  - Allow balancing resources to earn scarcity rents in short-term market (market for commodity)
  - Provide capital remuneration backing to flexibility and reserve providing resources in exchange of reliability contracts (market for reliability)
- Different opinions for CAPEX-based markets
  - Decentralized market for bilateral contracts
  - Organized pool market for PPAs
  - CfD-derived Green Power Pool (market for PPAs and central procurement of complementary energy and balancing resources)

Principles to respect for retail markets

- Make sure that the wholesale market design allows retailers to buy resources and form supply portfolios where remuneration is specific to the nature of the portfolio component and is cost-reflective
  - Buy from distinct markets, such as for assets, commodity and reliability, and price consumers at the weighted average costs of the purchases
  - Facilitate firm supply portfolios, financially and technically. Two opposite approaches:
    - Promote decentralized bilaterally agreed portfolios
    - Organize a single buyer model for CAPEX and reliability resources
- Facilitate instruments mitigating price volatility
  - Bilateral contracts
  - Futures
  - Hedging instruments
- Possible supports by the state (requires further elaboration)
  - Guarantees for hedging costs
  - Obligations to hold bilateral contracts
  - Centralized market for bilateral contracts

The idea of splitting the markets has various names:

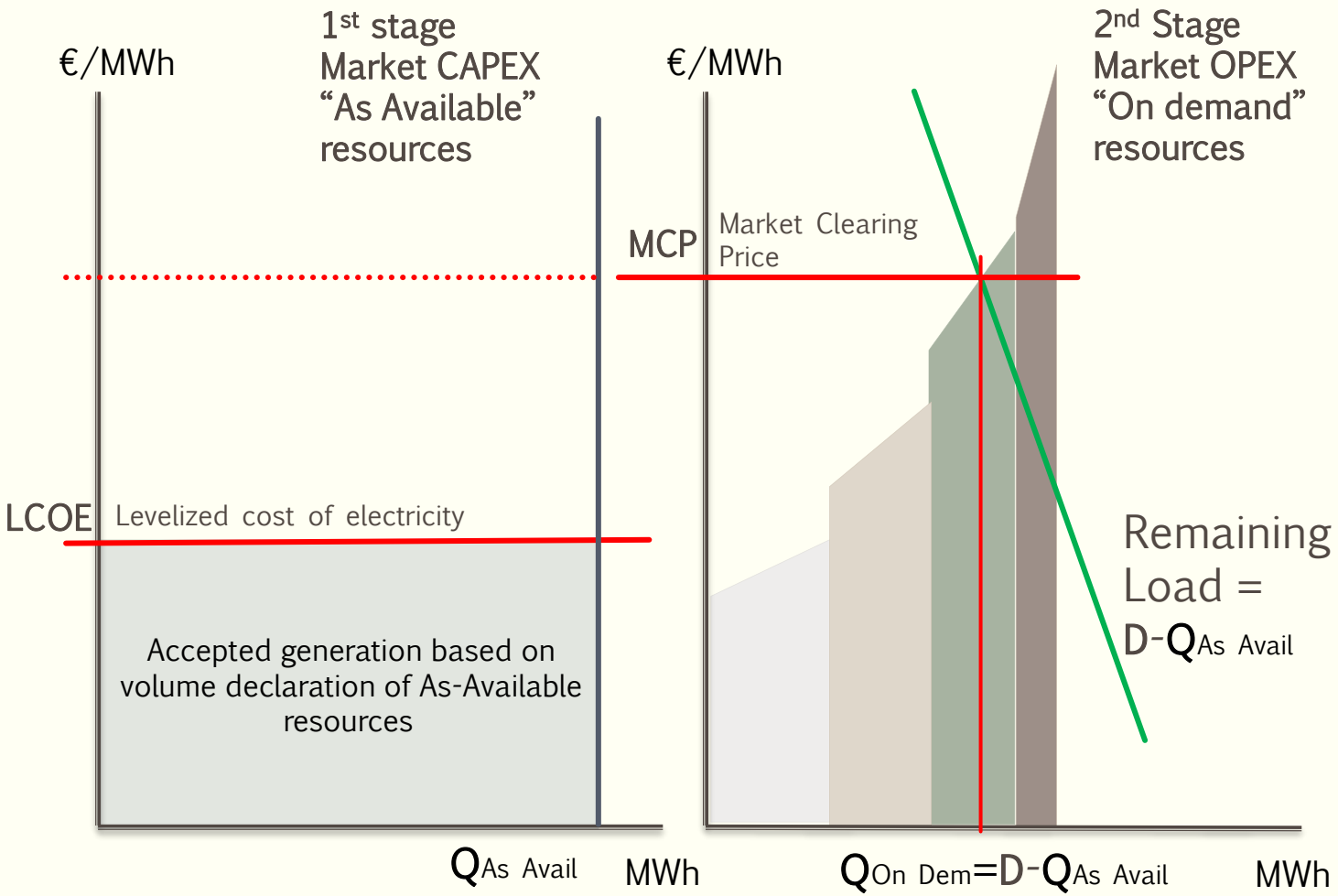
- Short-term market distinct from long-term market
- Asset versus commodity markets
- Dual market
- Two-stages market
- Hybrid market
- Two-sides of the market
- Long-term central buyer
- Spot and frequency market different from a long-term contracts market

All the above aim to remunerate CAPEX-based resources distinctly from OPEX-based and balancing-providing resources

A two-stages market design for the DAM

- "As Available" power resources
  - Have the interest to enter in a schedule for the next day that respects as close as possible their planned generation volumes
  - Have no or insignificant variable costs and do not need to submit marginal cost bidding to be placed in the merit-order
  - Need to recover capital and fixed costs according to a stable long-term program to raise affordable capital financing
  - Examples: stochastic renewables, nuclear energy, mandatory hydropower, biomass, cogeneration of high efficiency serving heat demand, storage associated with specific plants
- "On demand" power resources
  - Typically the dispatchable generation resources, having the technical possibility to increase or decrease power depending on system operation requirements
  - Their marginal cost bidding (or opportunity cost bidding for some of them) induce the optimal merit-order
  - Examples: fossil fuel fired power plants, hydropower with a dam, storage plants, demand response, hydrogen

The Two-Stages Day-Ahead Market idea



- Buyers of electricity pay a weighted average unit cost ($WAUC$)

$$P = WAUC =$$

$$LCOE \cdot \frac{Q_{As\_Avail}}{Q_{As\_Avail} + Q_{On\_Dem}} + MCP \cdot \frac{Q_{As\_Dem}}{Q_{As\_Avail} + Q_{On\_Dem}}$$

- $LCOE$ is a weighted sum of different levelized costs of electricity of the various CAPEX-depending resources
- MCP is the market clearing price
- After the DAM, the market (balancing, reserves, complementary energy etc.) is unified again

How the two-stages Day-Ahead market operates

First stage: the "As Available" market

Including RES, mandatory hydro, nuclear, CHP high efficiency, biomass, ..

- The "As Available" resources submit volume declarations for the next day
- Submissions are per bidding zone – market coupling applies
- Least-cost optimization over the coupled countries determines
  - The accepted volumes per "As Available" resource
  - The cross-border flows
- Objective to minimize: curtailment costs
- Constraints:
  - Net transfer capacities of interconnectors
  - Load to meet
  - TSOs' constraints regarding dispatching possibilities

Second stage: the "On demand" market

Including fossil fuel plants, hydro with DAM, storage, demand response

- The "On Demand" resources submit price-volume bids, as today but cover the remaining load and the remaining capacity of interconnections
- Submissions are per bidding zone – market coupling applies
- Least-cost optimization over the coupled markets (as EUPHEMIA)
- Objective to minimize: social surplus (sum of producer and consumer surplus)
- Constraints:
  - Load to meet: Initial Load minus production by "As Available" resources
  - Net transfer capacities constraint: Initial NTCs minus cross-border flows based on "As Available" resources

Further explanations

Three options for the "As Available" market

A. **Bilateral contracts** – over the counter and any possible form, e.g., long-term PPAs. The off-takers conclude contracts on a bilateral basis independently of the spot markets, so they know the volumes covered by the PPAs

B. **Organized market for "As Available" resources:** the resources submit volume and price bids (equal ot above LCOEs) and get revenues at the "As Available" market clearing price. To mitigate market power a price cap on the "As Available" market is necessary.

C. **Mixed design:** Mainly bilateral contracts as in A, but also a last-resort organized market as in B to accommodate resources lacking bilateral contracts.

"On demand" market

- No changes, the settlement is based on market clearing prices
- Also Intra-Day and Balancing markets remain unchanged
- Market coupling
  - It can be shown mathematically that the two-stages market approach leads to the same merit order and same cross-border flows as the single-stage market
  - In a similar way, both in the two-stages and the single stage market designs, interconnection congestion implies price divergence in the coupled markets

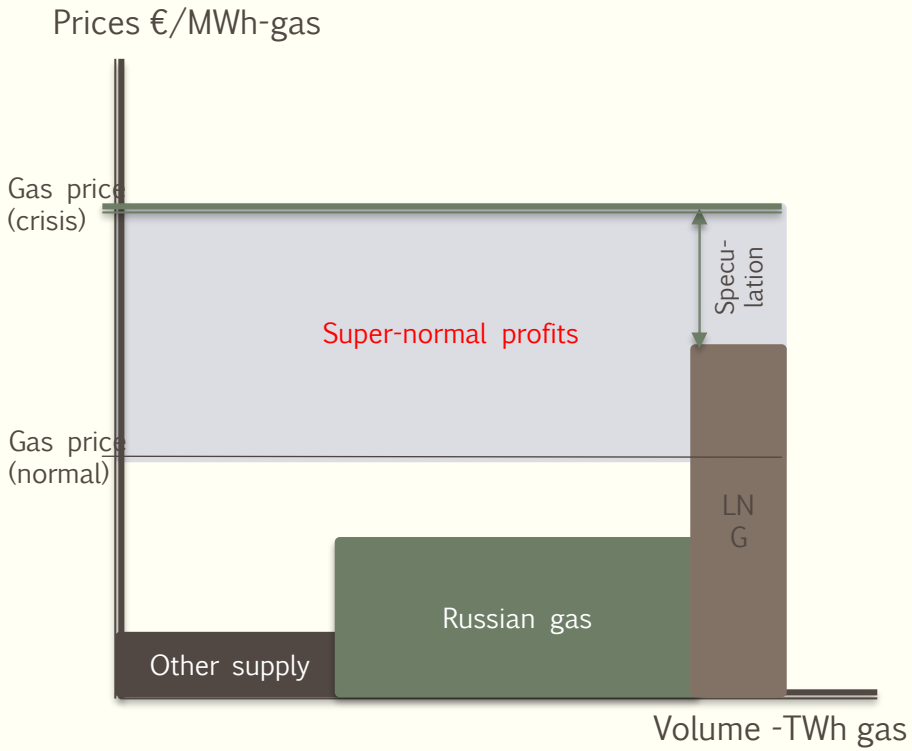
Summary: Principles for the reform of the EU electricity market

Consumer prices:	Pay the actual costs of electricity instead of relying on high marginal cost-based prices. Encourage long-term hedging against price volatility and shocks, potentially with state support.
CAPEX-based resources:	Remunerate via long-term contracts for differences. Prefer public auctions to grant revenue guarantees.
Flexibility, reliability:	Secure investment via capacity remuneration schemes to ensure adequacy. Include storage and demand-response in capacity rewarding schemes
Spot market for energy and balancing:	Maintain the current design based on marginal cost pricing, for the balancing resources to preserve cost-efficient generation scheduling
Internal market:	Maintain and expand interconnection capacity in all market stages without obstruction; introduce location-based pricing.

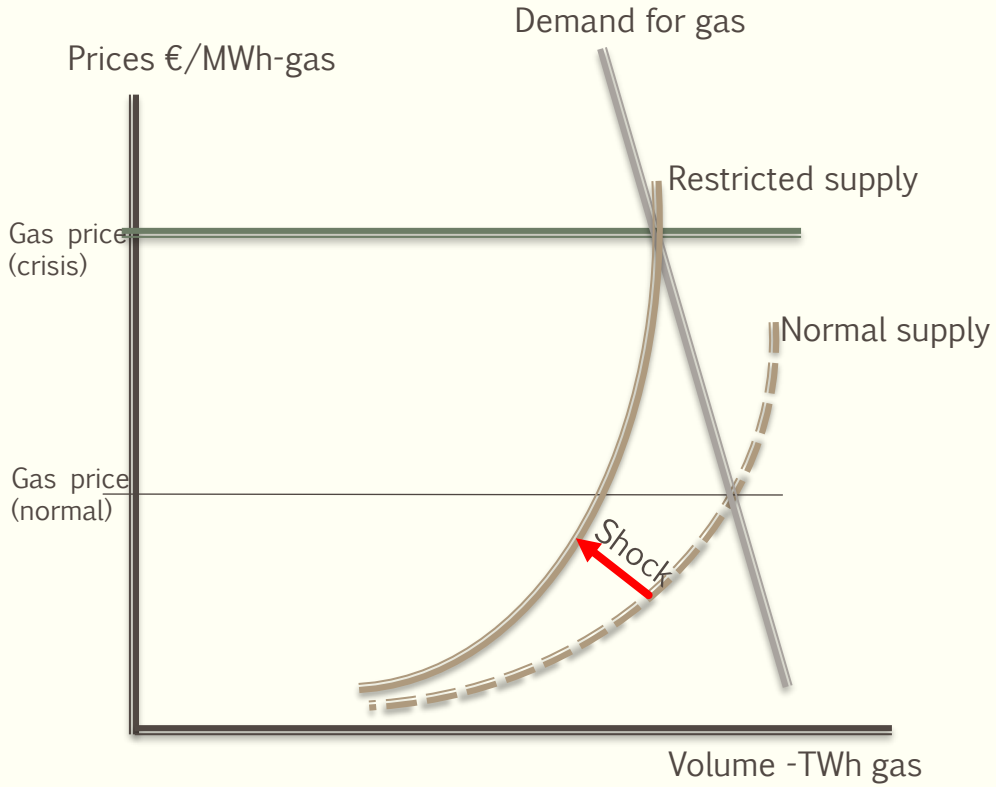
APPENDIX

Illustration of the energy price crisis and the state control mechanisms applied in Europe

Price crisis in gas markets

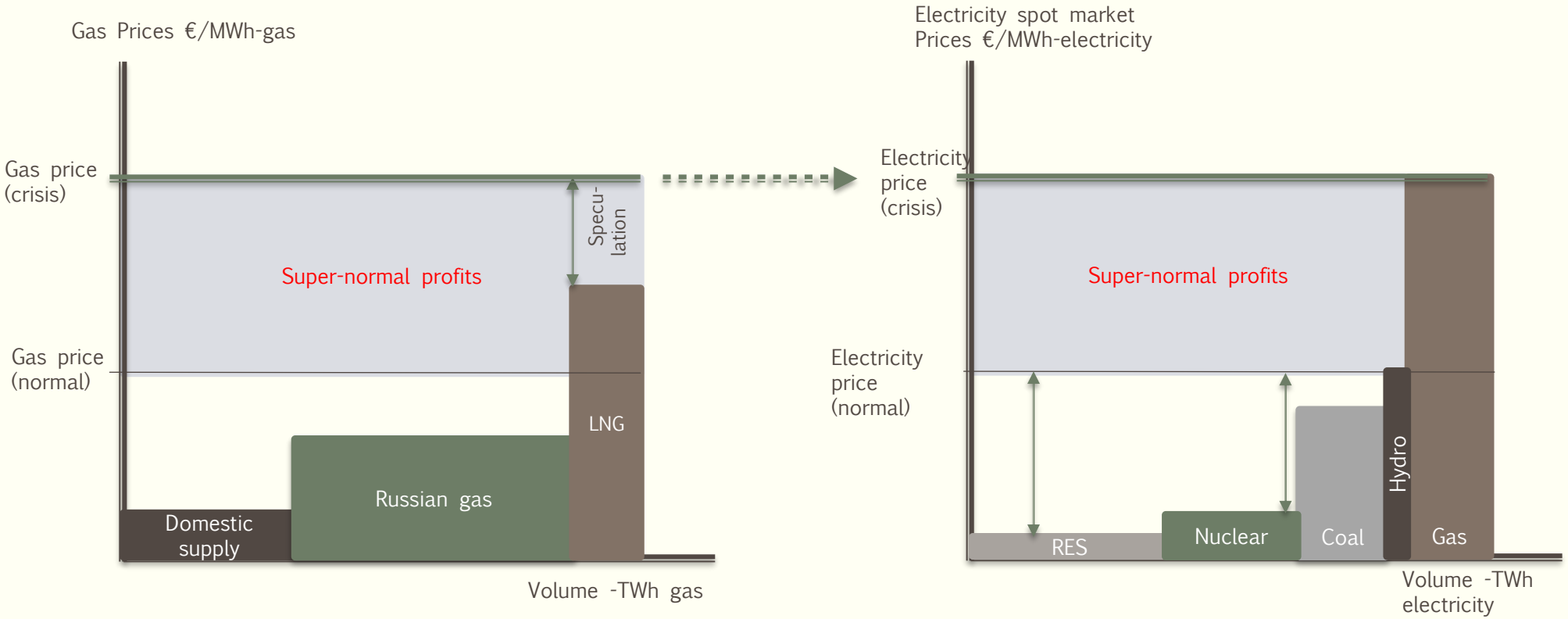


The price effect of high LNG costs adding spot market speculation



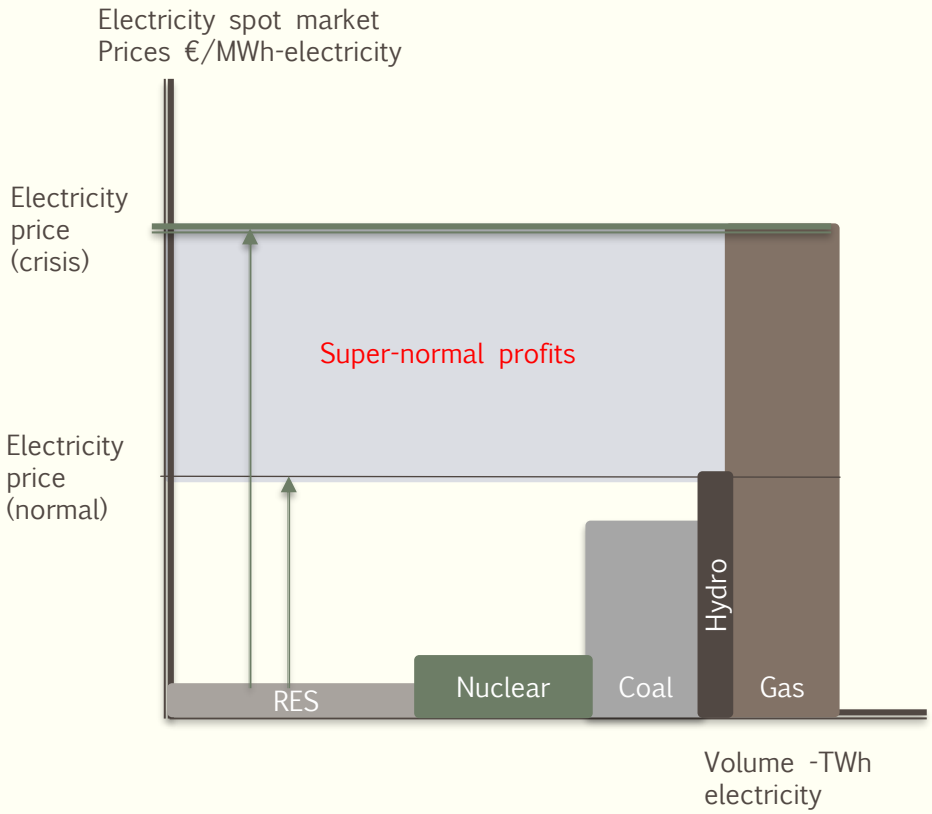
The price effect of supply restrictions due to the war

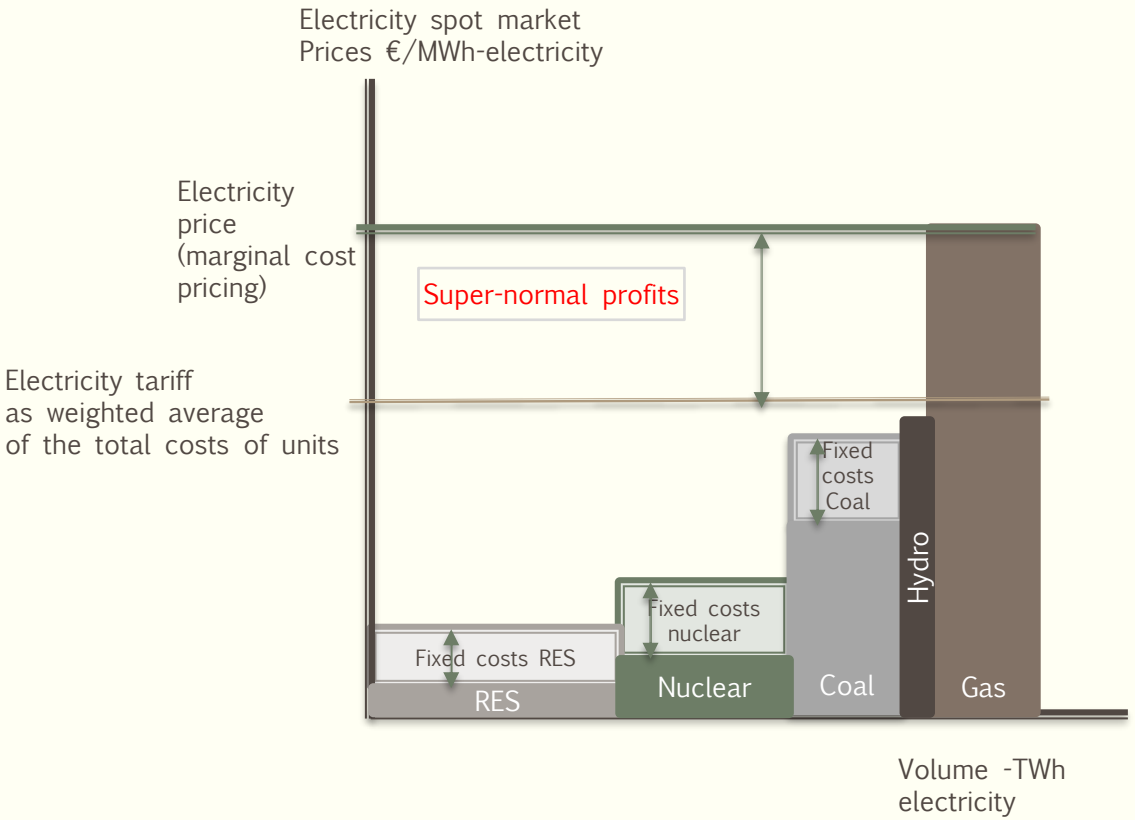
Price crisis in gas and electricity markets



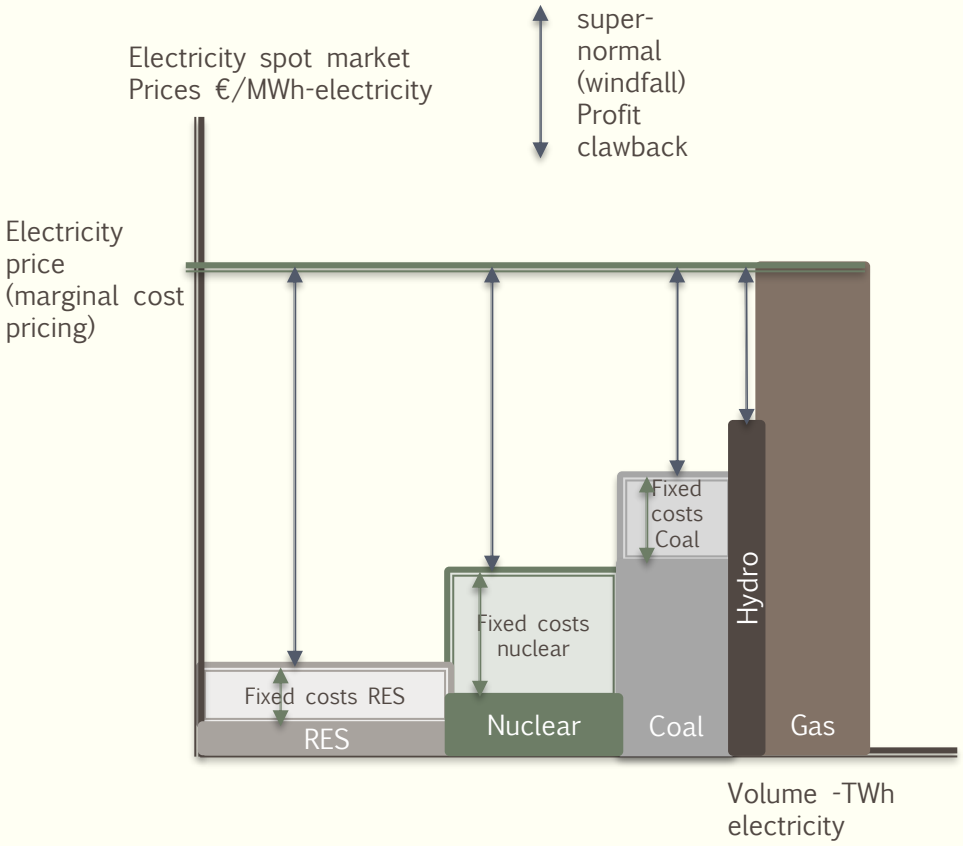
Warning: the above scheme illustrates the Day-Ahead (spot) market
However, note that:
1. The Day-Ahead is not mandatory
2. The consumer retail prices may differ from Day-Ahead market clearing prices
3. 100% passing spot market prices to consumer prices is a symptom of non-well-functioning markets

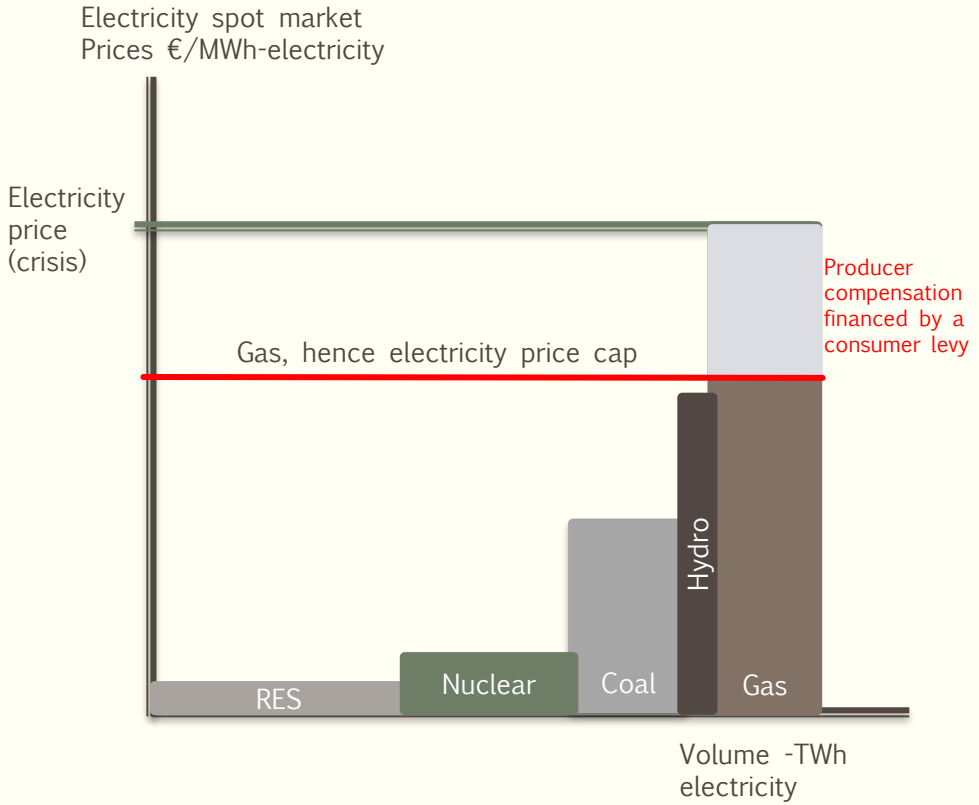
Marginal versus average cost electricity pricing





State intervention to reduce retail electricity prices





The Greek mechanism
Using the clawback amount to subsidize tariffs,
consumer tariffs get close to average costs,
significantly down from marginal costs

The Iberian mechanism
Cap on gas price for power generation,
hence upper limit of electricity prices in the spot market
compensation of more expensive generation
financed by raising as special consumer levy

Price cap on gas supply