cerre Centre on Regulation in Europe

RECOMMENDATIONS FOR A FUTURE-PROOF ELECTRICITY MARKET DESIGN

REPORT

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TABLE OF CONTENTS

Table of Figures

LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
ACM	Authority for Consumers and Markets
ARENH	Regulated Access to Incumbent Nuclear Electricity
CACM	Capacity calculation and congestion management
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CEER	Council of European Energy Regulators
CfD	Contracts for Differences
CMA	Competition and Markets Authority
CNMC	Comisión Nacional de los Mercados y la Competencia
CPI	Consumer Price Index
CRM	Capacity Remuneration Mechanisms
EEA	European Economic Area
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
ETS	Emissions Trading System
FCA GL	Forward Capacity Allocation Guideline
FTRs	Financial Transmission Rights
GDP	Gross Domestic Product
GO	Guarantees of Origin
GW	Gigawatt
HMMCP	Maximum and Minimum Clearing Price
INSEE	Institut National de la Statistique et des Études Économiques
KWh	Kilowatt Hour
LCOE	Levelised Cost of Electricity
LDC	Local Distribution Companies
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
MC	Marginal Cost
MCO	Market Coupling Operation
MIFID	Markets in Financial Instruments Directive

MiFIR	Markets in Financial Instruments
MWh	Megawatt Hour
NBP	National Balancing Point
NEMOs	Nominated Electricity Market Operator
NOME	Nouvelle Organisation du Marché de l'Electricité
NRAs	National Regulatory Authorities
OLTM	Organized Long-Term Market
PPA	Power Purchase Agreement
RED	Renewable Energy Directive
REMA	Review of Electricity Market Arrangements
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RES	Renewable Energy Sources
SDAC	Single Day-Ahead Coupling
SMEs	Small and Medium-Sized Enterprises
TCA	Trade and Cooperation Agreement
TCM	Terms and Conditions
TFEU	Treaty on the Functioning of the European Union
TRV	Tarif Réglementé de Vente
TSO	Transmission System Operator
TTF	Title Transfer Facility
VOLL	Value-of-Lost Load
WTP	Willingness To Pay

ABOUT CERRE

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POLICY RECOMMENDATIONS

Some of the below recommendations are short-term and others are longer-term. Some are at EU level, some are for individual countries to pursue.

1. Core recommendations

EU common energy policy and coordination between Member States

- The single market in electricity (and gas) has so far exhibited an incredible resilience under a historically unprecedented stress test, delivering efficient dispatch and security of supply. It delivers particular benefits to periphery countries and small countries with undiversified energy supplies. Complementarity between interconnected energy system based on different energy mixes has enabled solidarity between Member States. **Actions on the part of the EU or individual countries which weaken the internal energy market in the short- or long-term are to be rejected as they will only increase short-term threats on national energy systems and increase costs for customers.**

- We should distinguish between short-term crisis management and long-term market reform, **recognising that in the exceptional wartime situation we face, some market intervention may be necessary but, equally, that wartime short-term interventions should be proportionate, short-term and reversible.**

- The current energy crisis is fundamentally a European-wide gas supply crisis. **This means that short-term national and EU-wide interventions towards wholesale and retail electricity markets must be evaluated as to their impact on aggregate European gas demand.**

- Low short run demand elasticities for both gas and electricity mean that even small reductions in aggregate gas demand have a disproportionate effect on both gas and electricity prices. Every 1% reduction in aggregate electricity demand will reduce wholesale electricity prices by about 5 to 10%. Thus a policy which raises electricity demand by 10% in a large European country (representing 10% European of demand) could create a 5% price increase for the entire European wholesale market. Therefore, **country level policies which significantly increase electricity (and gas) demand cannot be left unanswered at the European level.**

- **A good example of an action that should have been prohibited by the Commission because it did not address the gas supply crisis is the Spanish cap on the price of gas used for power generation.** This has raised Spanish and European gas demand and significantly distorted electricity trade with France (and Morocco). The measure is not proportional. As detailed hereunder, **alternative measures exist to soften the blow for end users, with smaller effects on the internal market**.

- Similarly, increasing aggregate supply of gas (and alternative sources of power) is important in the crisis (even if long run objectives to reduce gas use remain unchanged). Even a small increase in aggregate supply over the course of the year will have a disproportionate price effect due to the low short-run elasticities of electricity demand. **Thus, the case for removing or reducing regulatory barriers (e.g., restrictions on permitting) to additional low carbon generation and distortionary taxes on marginal electricity production is strengthened by the current crisis.**

- EU harmonisation measures aim to avoid possible distortions to the internal energy market and to ensure a level playing field among actors. In line with the principles of subsidiarity and proportionality, the need for and degree of EU harmonisation may differ between the retail and wholesale levels, because of the difference in the impact on the internal energy market. In the current context, there are concrete risks of seeing governments adopting national intervention measures motivated by national interests that would create barriers to the free movement of goods and services and undermine the benefits of the internal energy market. **A common approach to common challenges through EU harmonisation measures must be in general prioritised to preserve the benefits of the internal energy market for all states and market participants.**

Current market design, incentives and efficiency

- **The single internal market in electricity (and gas) is worth deepening in the long-run**. In a net-zero world, **single market integration will become even more important in reaching our climate and security of supply goals at least cost.** It provides for flexibility, more security of supply and at lower costs. The **completion of the internal energy market** and the **implementation of the existing legislation** should remain a priority. Short-term actions should not distract from that goal.

- The short-run efficiency of the power market should not be compromised by the introduction of long-term physical contracts. **The conclusion of long-term physical contracts should not undermine liquidity on the power exchanges. Hence we should clearly distinguish physical and financial hedging.** Protecting consumers from power cuts is about maintaining the integrity of the wholesale market. Protecting consumer bills is about financial hedging instruments. Financial contracts might also allow for the better pricing of risk. Physical assets with high levels of availability might have to play a more important role as collateral and thus a physical hedge in margin call requirements.

- Private financial hedging of electricity prices is a good idea before prices rise; however in the middle of the crisis with peak uncertainty and prices at potentially the top of the market, it is likely to be bad value. In the current circumstances, **government subsidies (combined with future taxes) to electricity bills are likely to have lower net present value (NPV) cost than**

negotiating private generation contracts with existing generators to smooth consumer electricity bills.

- However, over the longer run, **there are good arguments for signing long-term price hedging contracts with new generators, to provide price stability and certainty to electricity consumers and to lower the cost of capital faced by investors in generation.**

- **Some of the recent suggestions for electricity market reform are sensible but they will not address the magnitude of the energy crisis in the time frame required.** However, accelerating some of them would bring forward their small – but worthwhile –benefits. Such changes have to be looked at in the context of the road to 2030 and 2050 climate goals.

- While Article 194 of the Treaty on the Functioning of the European Union (TFEU) is the special legal basis for EU energy policy based on a shared competence between Member States and the EU, the EU emergency measures adopted to deal with the energy price crisis since July 2022 have been based on Article 122 TFEU. This is a notable development, as it leaves the Council with a large influence on the choice and the drafting of EU measures. **When considering emergency measures grounded in Article 122 TFEU, the European Commission – when proposing them –and the Member States – when negotiating them – should refrain from adopting measures that could have long-term impacts on the energy markets and from adopting more permanent mechanisms outside of the ordinary legislative procedure**, which involves the European Parliament.

Future challenges

- The current energy price and supply crisis also reveals the incomplete energy transition and the lack of coordination between Member States in implementing transition policies. **Better coordination of overall European electricity supply security can be achieved through tighter EU monitoring of the already existing processes for the elaboration of the National Energy and Climate Plans (NECPs)** under the Regulation on the Governance of the Energy Union and Climate Action, and full implementation of internal energy market legislation.

- Europe has become a higher cost of energy region (with the loss of cheap Russian gas), and protection of European industry from high marginal energy prices in the long run is not going to be possible**.** However, **attention should be given to taxes and the carbon border adjustment mechanism (CBAM), to reduce unnecessary distortions, protect European industry from unfair competition from outside Europe, and relieve the pressure to introduce industrial subsidies within Europe.**

- **Allowing for even more flexibility in the adoption of national state aid measures**, as recently proposed by the European Commission will **contribute to further supporting European industries in global markets, but it should not result in a subsidy race and weaker assessment processes at the European Commission level.** This would only result in increased uncertainty in the approval process and increased risks of judicial review of the Commission's decisions.

- The timetable for the energy transition is already very challenging – with ultimately bounded capacity for acceleration – and hence **the level of investment in renewables, nuclear, storage, network and interconnections should be accelerated towards those bounds.**

- Net zero remains challenging and much more investment is required in renewables, nuclear, hydrogen, biomethane and carbon capture and storage (CCS). **Permitting of both low-carbon generation and associated network capacity remains an issue in many countries and should be prioritised. Ramping up procedures for permitting new general capacity under emergency measures must be accompanied by a coordination of grid development and consumption scenarios.** This should not distract from completing the approval of permit applications already in the pipeline.

- New agents and services have gained recognition in the Clean Energy for All Europeans Package (flexibility services, aggregators, energy communities and prosumers), but they still do not yet represent big volumes on the market. **The Commission could make some concrete proposals to rapidly increase new agents' contribution to addressing the current crisis, such as supporting the role of energy communities in the rapid deployment of decentralised renewable energy generation.** The Council Regulation laying down a temporary framework to accelerate the permit granting process for renewable energy projects is an example of how emergency measures proposed under Article 122 TFEU could result in some measures with long-term effects. Measures proposed in this Council Regulation must however be much more precise if they are to be inserted into EU secondary legislation.

- Sector coupling will be a reality by 2050, between power, heating and transport. **Attempts to separate the price of energy between these three sectors should not be done at the wholesale level.** They **can only be separated at the retail level** but, given the existence of prosumers, even this will be **increasingly difficult.**

2. Wholesale market recommendations

Keep market design issues in perspective

- There is a need to clearly **distinguish between what should be a future-proof market design under net zero objectives and medium to long-term constraints, and the toolbox of temporary measures** that can be adopted by governments or market agents to respond to **short-term disruptions**. Likewise, it is important to **distinguish between pure market design elements** (e.g. whether market prices are determined by pay-as-bid vs pay-as-clear) **and complementary mechanisms** aimed to address remaining market failures such as lack of support for renewables or the need for increased security of supply through e.g. capacity remuneration mechanisms.

- Empirical evidence shows the impact of good short-term market re-design on market outcomes is small and the day-ahead auction rules do not matter much. Market outcomes are determined mainly by market fundamentals (generation mix, fuel prices, demand levels), and by market structure (horizontal market concentration, contracting positions and vertical integration). **Thus, monitoring demand, supply and anti-competitive behaviour are more important than changes to electricity market design.**

- An example of genuine market design change is the price setting rule in energy (and ancillary services) markets. **Moving to a pay-as-bid auction from pay-as-clear reduces economic efficiency, without much impact on average price paid, and is not recommended.**

- A more significant move would be to a US standard market design, involving central dispatch and nodal prices. This would be a huge step for Europe, essentially requiring a complete change to the current design. **The net benefits of the US market design in delivering Europe's ambitious energy and climate goals are unproven and not easy to quantify once innovation, market liquidity, private contracting and investment impacts are taken into account. Now is not the right time to do this.**

- While nodal pricing is not the solution to the current crisis, **better locational signals and long-term incentives to invest in transmission and renewables in the right places are to be encouraged.**

- A future-proof market design legislation will need to not only **enable the integration into the market of a higher share of renewables and flexibility**, but also ensure that **market rules function with a higher share of renewables**. This applies to both renewable energy produced onshore and offshore. A comprehensive market design for the whole energy system will need to consider new offshore renewable energy generation capacity added offshore, including hybrid assets. Hybrid projects can develop under the current EU legislative framework, but reforms will be needed to better incentivise them and ensure optimal cross-border cooperation and price formation (e.g., the ability to submit parts of the same windfarm to two different national procurement exercises or the design of offshore bidding zones). Likewise, the remuneration model for both project developers and operators of hybrid projects will require further regulatory certainty.

Two market solutions

- **Two short-run markets – one for *on demand* and one for *as available* power – raise difficult issues whereby market efficiency will almost certainly be reduced,** potentially substantially. This solution reduces incentives for renewables and nuclear generators at the margin, reduces incentives to overcome network constraints facing low carbon power, and encourages expensive investments in arbitrage between the two short-term markets. **Such a solution should be rejected.**

- **While two short-run market solutions make little sense now, they make even less sense in the long-term when power, heat and transport fuel markets will be fully integrated** and there will be more, not less, concern about efficient pricing across all sources of energy and final uses of energy.

- Hybrid market solutions which concentrate on **locking in low long-term (often government-backed) contract prices for new low-carbon generation, while continuing with shorter-term private contracting for fossil fuel generation, make more sense.** This is because they facilitate the financing of low-carbon generation, while not reducing short-term dispatch efficiency. Thus **long-term corporate, retailer or government power purchase aggrements (PPAs), often in the form of fixed price contracts for differences (CfDs)** for an extensive period (say 15 years or more), **can be sensible financial instruments**.

The use of long-term PPAs

- **Long-term PPAs for low carbon generation are a proven way of financing investment and locking in fixed prices for a long period.** For instance, they have successfully supported the roll out of offshore wind and new nuclear in the UK, and have been instrumental in developing new onshore wind projects in Scandinavia.

- **Auction-based competitive PPAs to bring forth new investment are a good way to introduce competition for all types of PPAs**. These lower costs of low carbon generation.

- **The use of auctions for long-term PPAs combined with current short-run power markets** can lead to a **desirable hybrid market arrangement**, introducing **competition for the market** in combination with **competition in the market**. Auctions have been very successful around the world in driving down the cost of solar and wind procured by governments.

- **Corporate renewable PPAs make sense for companies that are long-lived and can commit to, say, 15 years of purchasing the output of their generation counterparty** (e.g., Microsoft, Amazon or the Finnish paper industry). They have proven to be attractive and, again, instrumental in developing new projects for greening the energy supply of large consumers.

- **Retailer PPAs make sense for large incumbent retailers with relatively stable customer bases for part of their demand.** Secondary markets for PPAs and additional risk regulation for retailers is likely to grow this market. Secondary markets might be driven by demand for packaging of portfolios of PPAs for large consumers and retailers.

- **Government PPAs have been successful in driving down the cost of capital, particularly for emerging technologies (such as offshore wind)**, and where retailers or corporate PPAs are not competitive or available in sufficient quantity. **Well-designed government PPAs can significantly improve on older support schemes such as feed-in tariffs**, by better reflecting incentives for short-term efficiency and allowing procurement to occur via a competitive auction. The **UK's Low Carbon Contracts Company (LCCC) provides an example of the legal entity that governments could create to procure low carbon power under fixed price long-term contracts**.

- **Where government PPAs are used, the way they are implemented should ensure that electricity consumers benefit from lower prices when PPA strike prices are below market prices.** This is the case with the LCCC arrangements in the UK.

- **Corporate and retailer PPAs will become increasingly desirable in the future as a way of diversifying the contract terms of the PPAs signed**, because government PPAs often offer a one-size-fits-all standard contract (e.g., 15 year term, price indexed to the consumer prices index (CPI), take all output of the project) and because we would expect private investors to offer increasingly competitive PPA contracts as the market develops (and if government finances worsen).

- **So far, legal barriers to corporate PPAs have stemmed from certain national legislation, not EU legislation. To remove such barriers, the Renewable Energy Directive now contains some facilitating provisions that could be further reinforced as part of reform proposals.** PPA drafting and provisions should remain an issue for negotiation between parties to the agreement, but the EU can encourage their adoption to support the deployment of renewable generation.

- If governments are to be involved in the PPAs, as it has been the case previously, this would require an assessment under state aid rules because of the involvement of state resources. **If the EU wants to support government PPAs and facilitate their approval under state aid rules, it should clarify the acceptable design features of these agreements in the state aid**

guidelines for climate, environment protection and energy, as a way of facilitating their approval.

- **While the European Union can recommend the use of PPAs and make observations on which types of PPAs have worked well (e.g., by publishing a best practice guide in a non-binding guidance document), it is unwise for the Commission to recommend the use of a standard PPA contract to cover a fixed proportion of all national output.** This would be contradictory to the principle of Member States' sovereignty over the energy mix and their free choice of structure of energy supply (Article 194(2) TFEU). This would also have the additional downside of locking the whole of the EU into a single contractual position, as opposed to diversifying over a range of Member State government contracts.

- Whether and to what extent Member States provide **long-term government-backed financial PPAs, should be left to the subsidiarity principle, and depends on the preferences of individual Member States. Clarifications as to best practices and favoured approach can be provided by the European Commission in the form of soft law guidance.** If so required, EU harmonised rules should only be proposed as to avoid possible distortions on the internal energy market, but should let Member States decide whether or not to introduce government-backed PPAs.

- The use of PPAs of different types and to different degrees will reflect the preferences of consumers and their governments. The signing of retrospective PPAs with existing generators is simply a way of smoothing payments at private sector discount rates and should be a matter of national preferences. **Therefore the signing of PPAs with existing generation on a voluntary basis will not offer significant reductions in discounted prices (energy costs) for consumers in most jurisdictions.**

Completing and extending the single market in electricity and gas

- **As emphasized above, the European Commission should continue pursuing the completion and extension of the internal energy market.** Completion of the single market in both electricity and gas will increase their benefits for all participants, in line with ACER's recommendations on improvements to the current energy market.

- **The primary action to pursue is to ensure the full and correct implementation of EU energy market legislation**, including through own investigations and legal actions (infringement procedures). **Full and correct implementation of existing EU legislation should be a priority** area for the Commission and the Member States, and a prerequisite to the adoption of additional harmonised requirements.

- A further priority is to **speed up the provision and use of physical two-way transfer capacity in gas within Europe. This can notably rely on the use of both existing and newly established solidarity mechanisms between Member States.** The current energy scarcity situation has had huge influence on energy price and leads to risk of further price spikes. It is **fundamental**

that enough cross-border interconnector capacity is made available for trade to reduce localised price spikes or supply shortages. Growing congestion in the European transmission system for electricity has been of increasing concern over time and had already triggered a series of amendments to the Electricity Regulation. Of particular importance in Regulation (EU) 2019/943 are the new rules on capacity allocation, the requirements for bidding zone (re)configuration and the obligation for TSOs to provide a minimum cross-border trading capacity.

- Another area of cross-border collaboration for expanding the benefits of the internal energy market is collaboration around capacity remuneration mechanisms (CRMs). **The regulation of CRMs has already been streamlined at EU level, and harmonisation efforts should be kept up in order to prevent the use of these mechanisms** from raising barriers **within the internal energy market.** Such barriers can happen, for example, through the differential treatment of of cross-border capacity. **The inefficient coordination of capacity markets raises total European electricity system costs.**

- **Action should be taken to remove remaining trade barriers in energy between the EU and neighbouring third countries such as the UK, Switzerland and Morocco**, all friendly countries with whom there is already physical interconnection. The EUPHEMIA market coupling algorithm could easily be extended to include these countries.

- To that respect, **the external dimension of EU regulatory model for market design should be carefully assessed when contemplating changes. Market design solutions should be compatible with cross-border cooperation with non-EU countries, to ensure a broader area of energy cooperation and security of supply around the EU territory.** This area includes countries part to the European Economic Area Agreement, such as Norway, close European partners like Switzerland and the UK, but as well Energy Community countries that do implement EU energy market legislation. **The extent to which market design solutions enable cross-border cooperation between EU countries and neighbouring countries is to be taken into account from the start of any market design reform.**

Linking wholesale and retail prices

- We need to make effective use of price-induced demand reduction. It is therefore important that wholesale prices are reflected in retail prices at the margin. Thus **ensuring that consumers have a strong incentive to reduce electricity (and gas) consumption, even while they may be receiving generous bill support, is critical for actually addressing the crisis.**

Dealing with excess generator profits

- **In the current extreme circumstances, sensible measures to recoup excess generator profits – where these exist – are essential to address concerns about economic justice.**

- This is best done through **non-discriminatory profits taxes which target excess profits and do not blunt incentives to efficient dispatch. Profits taxes should be targeted on inframarginal**

rents wherever possible. High profits tax rates are preferable to arbitrary price caps on certain types of generators.

- **Excess generator profits taxes should be directly recycled to consumer bills and direct income support** in order to finance bill reductions and hence mitigate the inflationary effects of high average wholesale market prices.

- **Similarly, positional rents from renewables can be extracted via site auctions (e.g., for access to the seabed), auctions for long-term PPAs, and profits taxes.**

- However, **excess profits taxes should be imposed for no longer than necessary**, due to their impact on long run innovation incentives, particularly towards new entrants, and governments should clearly frame the temporary nature of such measures.

3. Retail market recommendations

The need for change

- **We need to facilitate behavioural change in energy consumption that increases energy efficiency and supports the energy transition.**
- A key priority in wartime is that retail customers do reduce their electricity and gas demand, while combatting energy poverty. Retail tariffs and behavioural interventions must reflect this. **All European countries need to engage in campaigns to reduce demand and have associated tariff settings which encourage large reductions in consumption for non-vulnerable customers.**
- Prosumers are to be encouraged to increase the installation and use of photovoltaic panels, battery storage and electric heating systems. **Large amounts of distributed installation can be done relatively quickly with beneficial aggregate demand and fiscal effects. Prosumption should be further facilitated through regulation, particularly where regulatory barriers have been identified (e.g., prosumption in block housing).**
- **Smart meters need to be used more effectively in an energy crisis to encourage demand reduction and demand management, and more needs to be done to work** towards **smarter contracts** (by companies with the encouragement of regulators and governments) which could be used to **engage in deep demand reduction** (which substantially increases current short run demand elasticities) and allow **targeted allocation of lower priced energy**. Where necessary, the **roll-out of smart meters** to facilitate this needs to be **accelerated**.

Minimising the impact of energy prices on inflation

- A key insight from the current crisis has been that very rapid rises in energy prices have a macroeconomic aspect. This crisis is about more than simply what is happening in the energy sector. **Countries should look carefully at how bill support can be paid in such a way as to also reduce the measured inflationary impact of energy prices** (e.g., as reductions in fixed charges or allocations of cheaper units of energy). This would mean that fiscal measures to support consumers also reduce the contribution of energy price inflation to general inflation.

Combining demand reduction, linkage to wholesale prices and equitable energy bills

- Equitable compensation of retail bills is important, however this should be combined with **high marginal prices for the final uses of energy.** A German energy expert group outlined a scheme for reducing German gas consumption using **rising block tariffs** which both **addressed high energy costs and incentivised deep reductions in domestic gas demand**. The scheme offered tailored price reductions for up to 80% of household consumption and 70% of industrial consumption, with the rest being priced at market prices. **A scheme of this type could be more generally applied to electricity at the Member State level.**
- According to the theory of optimal taxation, consumer support is best administered through the regular tax and welfare system. The current crisis has shown that this system did not

respond adequately – or, at least, it was not seen to do so – and various *ad hoc* schemes (e.g., capping price hikes) were introduced. **Governments should build integrated welfare and energy data systems that deliver effective and timely financial support to consumers.** This would allow **direct adjustments to bills on the basis of need, temperature and wholesale prices** as well as allowing **mitigation of inflationary impacts.**

- **Retailers need to design tariffs that allow customers to hedge market risk while encouraging demand flexibility and energy conservation.** A possible solution is to **encourage (or mandate) the development of retail contracts that locks in part of the energy consumption at fixed prices while retaining some price variation on the margin**. One way to do that would be to **combine real-time pricing with an insurance contract that offers financial difference payments for a fixed quantity of energy.**

- **Tariff models by which retail prices are calculated can help stabilise bills by allocating the benefits (and costs) of fixed-price long-term contracts to all consumers or all of a particular group of consumers.**

Regulation of retail offers

- The crisis has caused retailer bankruptcies (e.g., in the UK, the Netherlands and Belgium) and highlighted the importance of regulation of the business model of retailers. Since energy retailing is essentially a financial service, there are lessons to learn from financial sector regulation. **Stricter requirements on the financial position of suppliers are likely warranted, including supplier stress-testing and specification of minimum forward hedging requirements. Regulators should ensure that suppliers are prepared for the wholesale price shocks they might face.**

- In addition, there may be room for improving the methods for dealing with consumers who find their supplier going bankrupt or leaving the market for other reasons. **Consumers must, to some extent, be held responsible for their choice of supplier** – otherwise the door would be wide open to offers that are "too good to be true" – **but they must also have ways of entering into a new contract on reasonable terms when warranted.**

- There is a trade-off here; on the one hand, ensuring that suppliers do not fail reduces the need for customer protection; on the other hand, a sound system for customer protection makes financial regulation of suppliers less important**. Given that both financial regulation and customer protection come at a cost, finding the right trade-off between the two should be a priority for national energy regulators.** Another important trade-off in the retail market is balancing competition and innovation versus stability. Measures that increase switching rates by lowering the financial requirements for new suppliers might increase aggregate market risk. **Regulation of contractual terms must however be carefully considered, given that the availability of contractual types and the terms on which they may be offered are closely related.**

- In the Netherlands, the cap on penalties that consumers pay for early contract termination seems to have undermined the market for long-term contracts. Similarly, the opportunity for French consumers to switch back and forth between a regulated price and market offers may limit the incentive of suppliers to offer innovative contracts, especially of longer duration. **Regulation of contractual terms should better balance the incentives of suppliers to offer longer term contracts and the need to protect consumers from being locked in to longer term contracts unfairly, with the aim of encouraging longer term contracting.**
- Retail contracts for final consumers should further evolve, but the extent to which Member States regulate the matter has primarily been an issue of national jurisdiction. Industry associations have often been active in promoting good practices and elaborating standard agreements (e.g., in Scandinavia). **Good commercial practices corresponding to national circumstances should continue to be the preferred approach (supported by standard agreements), while the requirements for hedging of suppliers should be reinforced via harmonised EU legislation.**

The monitoring of retail's effects on the wider single market in energy and other goods

- National preferences with respect to the stabilisation of retail prices or the willingness to enter into long-term PPAs on behalf of consumers differ a lot. While the final after tax price of energy for households can be allowed to vary across Europe (and did vary substantially before the crisis), the impact on aggregate European demand for electricity of **highly subsidised marginal prices of electricity consumption in one country does produce negative externalities for the citizens of other European countries. This should be policed properly by the European Commission.**
- The possibility to regulate retail prices is strictly limited in EU legislation, and represents an exemption to the general rule of non-regulated prices and liberalised markets. Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices has extended the possibility given to member states in the Electricity directive to regulate the retail energy process. However, the implementation of such measures should be closely monitored by the European Commission. **The Commission should intervene where retail market interventions are increasing European wholesale market demand.**
- Market interventions which have large detrimental cross-border effects should be prevented. **It is therefore to be welcomed that the EU has recently implemented regulation to reduce electricity demand across Europe, as this will encourage member states to have suitably cost reflective marginal consumer electricity prices.**
- **Meanwhile, retail market interventions which differentially impact Member State commercial and industrial prices have competitive effects and should raise standard state aid concerns.** This is because differential national levels of support for retail electricity and gas prices for non-households translate into differential prices of goods and services and distort competition between European countries.

EXECUTIVE SUMMARY

Background

The aim of this report is to examine **wholesale electricity market design** and **proposed changes and interventions** in the light of Europe's current **energy crisis** and **climate neutrality goals**. While much of what we discuss is motivated by the crisis we are facing, **any short-term action may have lasting repercussions**, and we draw out some initial learnings on what this means for energy market regulation as Europe tries to move out of this crisis and towards net zero. **Wholesale and retail electricity markets are closely linked**, and this paper combines and builds on our two earlier papers on retail energy markets (von der Fehr et al., 2022) and on wholesale electricity markets (Pollitt et al., 2022).

This European energy price and supply crisis started in 2021, as the gas demand recovered more sharply from COVID than expected, and was considerably exacerbated by Russia's invasion of Ukraine in February 2022 and the weaponisation of gas deliveries to Europe. It is severe and unprecedented in the history of the single market in gas and electricity. It is impacting households, industries, and energy companies experiencing liquidity issues and/or bankruptcy risk. It is a wake-up call for energy analysts, regulators, and policy makers on the need for and the implications of a net zero energy system, which will have high-priced marginal units of energy.

Several points about the operation of both European gas and electricity markets are clear from the start:

- First, Europeans are in this together at the level of the wholesale market, and this crisis calls for a **joint approach**. Despite diverging national proposals, **EU solidarity mechanisms have been activated**, and new common approaches proposed by the European Commission and backed by the Council of the EU.

- Second, as we enter a winter when gas supply could be very tight, it will be previously **Russian gas-dependent countries** that will **especially need the integrated energy market** to support them.

- Third, the gas and electricity price crunch has been worsened by the **effect of climate disasters** on the **energy value chain and electricity output**. Weather conditions are important considerations in the design of future electricity markets.

- Fourth, **markets deliver security of supply by raising prices** in times of scarcity, creating **windfall profits for some**, and leaving **some market parties exposed** to unhedged high prices or certain customers' inability to pay.

- Fifth, **political concern** about the **distributional impact of high prices on European households and industry is inevitable**, especially in a context of high inflation and monetary policy tightening. The **competitiveness of national industries is a concern for the whole internal market. Such impact should be adequately addressed with appropriate emergency measures and in a coordinated manner across the EU.**

- Sixth, such a large rise in prices and volatility has raised **concerns about whether the current market design for electricity is working and fit for Europe's net zero ambitions**.

The current wholesale market design

The current market design is based on a set of fundamental principles including separation of monopolistic and competitive activities, decentralised decisions, and the availability of marketplaces where participants can trade. It has resulted in an **integrated, or "coupled", European market** where generation and supply is undertaken by a range of different companies competing for customers, and trade takes place both on and outside organised marketplaces.

Together, these marketplaces always ensure a **balance of demand and supply, and cost-efficient dispatch and supply security**. They drive the price up or down to signal scarcity or abundance and encourage producers and consumers to adjust accordingly. They also expose participants to swings in their revenues and costs. Participants are free to move between marketplaces, so **prices tend to be equalised** across them, and any **policy attempting to influence one, will affect the others**.

Energy prices vary considerably (although not always as widely as recently), and market participants often wish to hedge against the price risk. An open question **is how well the markets for risk hedging work**, and hence whether the current market design does provide **sufficient hedging opportunities**, especially for generators who have to **invest in plants with a long lifetime**.

Investment in generation capacity is **in principle market-based** but has in recent years to a very large extent been **driven by government interventions**, including capacity markets and various forms of incentives for renewable energy. If the ambitious **climate and energy targets** are to be achieved, **government support will be required**. In the longer run, as installed capacity approaches the end of its subsidy period, and as the cost of renewable generation becomes competitive, one would expect **unsubsidised renewable generation** to be dominant.

Discussion of suggested wholesale market interventions

We examine the proposals put forward by **ACER, Great Britain, Spain, Greece**, and the **European Commission** to deal with the crisis, as these are either implemented or well documented.

Some suggested design changes to the operation of current electricity markets are **sensible in the long-term**, but even in aggregate they **do not offer the likelihood of significant short run reductions** in prices.

A frequently suggested change both well before and during the crisis is for governments to **sign longer term contracts with generators on behalf of customers**. The point about this sort of contracting to reduce bills now is whether it is efficient because it effectively **borrows money at a high cost of capital** from private energy firms.

There have been **several versions of a 'two-market' solution**. Long-term markets already offer a form of two-market solution, via long-term auctions for renewables. **Two markets in the short run** raises difficult issues whereby **market efficiency is likely to be reduced**, potentially substantially. In the short-term, the marginal cost of extra low carbon electricity from a given facility can be high and this should be priced (e.g, exporting wind from a capacity constrained part of the network or bringing nuclear back quickly from an outage).

A move to a **US standard market design based on** capacity markets, central dispatch and nodal pricing, is a **long-term option for Europe**, but it is not a solution to the current crisis. However the **evidence** for the superiority to US standard market design over European market design, based on self-dispatch and zonal pricing, **is weak.**

Two surprising observations are that: (1) despite the European Commission's efforts and sensible recent proposals for electricity and gas demand reduction, more has not been done across Europe to **prioritise actual demand reduction for electricity and gas**; and (2) that **completion of the single market** to protect periphery countries in both electricity and gas is not being further accelerated.

A missing element in suggestions for changes to market design is the **macroeconomic aspect** of energy markets. This crisis is about more than simply what is happening in the energy sector. High prices which are outside the normal range of prices require some **tough political decisions** to be taken on how to **ration energy for European industries and households**.

A final point is that many of the proposals for market design **mix up sensible long-term measures** for net zero **with interventions in the current design** driven by the **nature of the war economy**. Sensible long run design suggestions will take time to have an effect, whereas short run market interventions will not be sensible in the longer term. **Being clear about the timeframe** of suggested interventions and their likely **impacts** is important.

The energy crisis, net zero, and electricity wholesale market design

Empirical evidence shows the **impact of market design on market outcomes is small**, the day-ahead auction rules do not matter much. Market outcomes are determined mainly by **market fundamentals** (generation mix, fuel prices, demand levels), and by **market structure** (horizontal market concentration, contracting positions, and vertical integration).

Policies aimed at paying firms different short run prices for what is in essence the same product, by creating **multiple separate markets in the short run** or by **moving from a uniform-price to a pay-as-**

bid to a pay-as-bid auction, inherently **increase system cost** and in expectation consumers will have to pay for the overall system costs, which are higher if markets are inefficient.

RES production relies on the availability of scarce natural resources. Large quantities of RES in the electricity system does not require a change in market design. **High returns caused by marginal pricing** can be captured by **profits taxes**.

One option is to require all **RES** investors to sign **long-term energy contracts with the government** which include some risk and output sharing agreements. **Auctions for PPAs for new lower carbon generation** are a good way to lock in lower costs for consumers.

Auctions for long-term contracts can be used to **reduce the scarcity rents of RES production**, as they provide incentives for firms to reveal additional information about the cost of RES production sites. For this to work, **auctions must be organised before firms invest**, as otherwise investments costs are sunk and screening becomes impossible. They may **have to be compulsory**, if society is to benefit from RES locational rents (e.g., for offshore wind).

Economic theory provides a **rich framework for designing auctions**, which can lead to **complexity**, and might make it harder to harmonise across Europe. Ideally, government information about cost, such as engineering estimates should be taken on board, and auctions might need to be **technology specific**. Screening can be improved by offering different types of contracts, and **allowing for multi-attribute bids**, for instance contracts could differ not only in price but also the volume they cover.

We expect that the use of **long-term contracts** by **private parties will increase in the net zero scenario**, due to the higher price volatility, capital intensive generation assets, the phasing out of government price guarantees for RES, and stricter regulation of the retailers' risks.

There are **good arguments for government intervention in the contracting marke**t such as: regulating the risk of retailers, standardising contracts to simplify netting, improving transparency on contract prices and positions, and contracting on behalf of small consumers. However, an **important role remains with private parties to sign long-term contracts, price risk correctly, and innovate in contracts** between generators, large customers, retailers, and financial investors.

Whether Member States provide **long-term government backed financial PPAs**, should be left to the **subsidiarity principle**, and depends on the preferences of individual member states. As there is no consensus among economists on how to best to organize the electricity market, some flexibility should be be left to Member States.

Many countries already have hybrid markets where governments intervene in long-term markets by using auctions for certain investments, followed by allowing all generation to compete in the short run market. For instance, generators participate in capacity markets and support for RES producers can be **auctioned off in the form of contract for differences (CfDs)**. **We do not see the need for a market design revolution**, but there are challenges at the EU-level regarding state-aid and the functioning of the internal market.

The current short-term capacity markets can exist in parallel with long-term contracting frameworks. We can take some lessons from capacity markets for future types of long-term government-backed contracts: cross-border participation remains limited and it is difficult to design a capacity market that treats provides correct incentives for different technologies (storage, flexibility, intermittent generation) and different locations.

There are potential **drawbacks of government-backed long-term contracts**, which might have implications for the internal market. Generators with long-term contracts no longer have as strong incentives to take part in short-term markets (day-ahead, intra-day, reserves, balancing) and liquidity decreases. Competition for long-term contracts becomes national, instead of European. Less competition may lead to higher costs. Contracts might distort the portfolio of investments, especially for demand side flexibility and storage. The existing financial market might be crowded out by the government contracts. Contract innovation and portfolio investment could disappear. Risk might be priced incorrectly and financial investors no longer take up some of the market risk (for instance through securitization), and banks have less incentives to monitor project managers.

The **EU may try to limit the downsides by providing guidelines** on the **procurement process and contract design**. A **market-based procurement of contracts-for-differences** which allocates some risk and rewards to investors might be more conducive to the internal market, but could lead to a higher cost of capital. The **technology neutrality of contracts, the existence of secondary markets and the extraction of scarcity rents are important considerations in the design**.

The energy sector currently has some characteristics of a war economy and skimming the **windfall profits** of RES and nuclear generators might be justified for **equity reasons**. The best method to tax windfall profits is one that keeps incentives to **efficient operation of the spot market intact**, and focusses on the **additional inframarginal rents** of firms. One approach to keep operational efficiency is an an additional tax on profits above a potential no-war reference scenario calibrated on past performance. However, to limit investment distortions, new assets should receive a carve-out from this regulation.

Legal aspects of wholesale market (re)design

The legal architecture supporting wholesale market design has evolved remarkably over time through the adoption of different legislative packages. EU rules have become more detailed, prescriptive, and technical in nature. They also increasingly reflect elements of **co-regulation**, with a shift marked in the third energy package with a **more decentralised approach of law-making** resulting in the adoption of network codes, guidelines and terms and conditions (TCMs). Much of these rules now regulate detailed aspects of wholesale energy trading, and wholesale market intervention would require the involvement of a series of different entities.

While **Article 194 of** the Treaty on the Functioning of the European Union (TFEU) is the specific legal basis for EU energy policy based on a shared competence between Member States and the EU, the EU emergency measures adopted to deal with the energy price crisis since July 2022 have been based on **Article 122 TFEU**. This is a notable development, as it leaves the **Council with a large influence on the choice and the drafting of EU emergency measures.**

A central question to the market design legislation today is whether it is still **fit for purpose** for the main part and just **needs the adoption of complementary mechanisms** to deal with specific, temporary challenges, or if it requires a **broader revision**. We argue for the second approach, consisting in targeted improvements. There is therefore a need to clearly **distinguish** between what should be a future-proof market design under net zero objectives and **medium- to long-term** constraints, and the toolbox of **temporary measures** that can be adopted by governments or market actors to respond to short-term disruptions.

New actors and services have gained recognition in the Clean Energy for All European Package (flexibility services, aggregators, energy communities and prosumers), but they still do not yet represent big volumes on the market. As an additional challenge, a future-proof marked design should contribute to the **resilience of the energy system** to respond to more structural risks related to e.g. repetitive and extreme heat waves, or long-lasting periods of drought resulting in low hydro-electric water levels. Short-term interventions should reflect this ongoing evolution.

In the context of the current debate on market design, and when assessing the need to revise EU market design legislation, regulatory intervention can be split between **short-term** (toolbox for crisis management), **mid-term** (risk management and adjustments), and **long-term** (towards market reform) processes. Any short-term intervention should not jeopardise the functioning of the internal energy market, in a time where solidarity and complementary are required. As concerns market reforms, two main sets of proposals are identified, focusing on "**price formation**" and "**market behaviour**".

The EU regime of PPAs will probably further evolve as part of the Renewable Energy Directive (RED), rather than as an element of market design legislation. **Legal barriers to corporate PPAs** have primarily stemmed from certain **national legislation**. PPA drafting and provisions will remain an issue for negotiation between parties to the agreement, but the **EU can encourage their adoption** to support the deployment of **renewable generation**. If governments are to be involved in the PPAs, this would require an assessment under state aid rules, and clarifications by the European Commission (soft law guidance, revision of stae aid guidelines) or the adoption of EU harmonised rules in the view of avoiding distortions on the internal energy market.

The **external dimension** of the EU internal energy market legislation should be **preserved and strengthened**, taking into account the necessarily alignment of associated countries through bilateral or multilateral agreements (EEA Agreement, TCA Agreement with the UK, bilateral cooperation with Switzerland or the Treaty on the Energy Community). The external dimension of the EU regulatory model for market design should be carefully assessed when contemplating changes. Market design solutions should be **compatible with cross-border cooperation with non-EU countries**, to ensure a broader area of energy **cooperation and security of supply** around the EU territory. This area includes countries part to the European Economic Area Agreement, such as Norway, close European partners like Switzerland, the UK and Morocco, but as well Energy Community countries that do implement EU energy market legislation. **The extent to which market design solutions enable cross-border cooperation between EU countries and neighbouring countries is to be taken into account from the start of any market design reform.**

Concluding thoughts on wholesale markets

- **Maintaining and deepening European electricity market** solidarity is important. Short-term changes to the single electricity market should not undermine its continuing long-term operation and threaten the central part it needs to play in a net zero energy system in Europe.

- Any **short-term action** aimed at high energy prices to protect European households and industries should therefore be **carefully designed and executed at European level**. It is critical to avoid go it alone decisions that undermine solidarity and market integration.

- **Reducing the demand** for gas is key to reducing electricity prices and reducing electricity demand has a disproportionate effect on prices. Every 1% reduction in wholesale electricity demand, will reduce prices by of the order of 5-10%. **Ambitious policy and regulatory approaches can drive such reduction**, and it is important that gas supplies to Europe are improved.

- A consistent suggestion is that **low carbon generation should be moved to long-term fixed price contracts**. It is important to recognise that all such contracts represent a **bet on the future** and the nature of discount rates. While this might be sensible for new contracts it is **not obviously beneficial for existing contracts**. The extent of the signing of long-term contracts by the state for power should be a matter of **national preference**.

- The only way to reduce the net present value of the flow of financial payments to existing low carbon generation over the longer run will likely involve some sort of **appropriation of revenue via increased profits taxes**.

- **Marginal regulated (i.e., unit prices actually paid on the last unit of consumption) retail prices should reflect wholesale prices**, to incentivise demand reduction and energy efficiency investment. This could be done this winter with well-calibrated **rising block tariffs**.

- **Regulatory barriers** to additional **low carbon generation** and **distortionary taxes on marginal electricity production (such as additional carbon taxes)** should be **removed**.

- **Some of the suggestions** for electricity market reform are **sensible** but they will not address the magnitude of the energy crisis in the time frame required. However, accelerating some of them would bring forward their benefits (e.g., the introduction of CfD auctions for new lower carbon generation). Such changes would have to be looked at in the **medium run** in the context of the road to **2030 and 2050 climate goals**.

Retail markets under stress

The real final electricity price rises that would have occurred between April 2021 and today without intervention are historically unprecedented in the recorded history of the electricity and gas sectors. **Thus we have now moved into levels of scarcity where some form of price or quantity capping has become inevitable.**

A key issue that has arisen is the impact of energy prices on general inflation and the fact that prices have been high and volatile. This raises additional pressure for intervention beyond what might be desirable in terms of signalling resource scarcity. **Worries about actually being able to pay bills and the inability to plan for the future on the part of households and businesses are legitimate concerns which must be addressed.**

The rise in the cost of energy has put retail markets under considerable stress. The most obvious implication is the increase in consumer bills, but, more fundamentally, retail markets have been shaken in their foundations. Contracts have been broken, suppliers have gone bankrupt and governments have rushed in strong measures to support the market and compensate those who have been adversely affected.

Although we are still living this crisis and many questions remain open, enough time has passed to draw lessons. The crisis has mobilised EU policymakers and national governments since the autumn of 2021. Throughout the winter of 2021-22, and with the additional shock of the Ukrainian war, governments stepped in with various national-level measures aimed at cushioning the short-term impact of the price hike, and have turned to European institutions to request guidance on how to address the crisis or, at times, to request exemptions to the single market's rules or formulate criticisms of its design and rules.

The impact of energy prices on inflation has become a significant concern, even in countries where there was initial reluctance to intervene with energy prices (such as the UK and Germany). This has given way to actual retail price capping, reductions in VAT or government payment of prices above a certain level in most countries.

National approaches to the retail crisis have varied

Although energy prices have increased all over Europe, **the impact of the price shock and the reaction by the regulators and governments at national level have differed.** This can, to a large extent, be explained by differences in the design and regulation of the retail markets. Some retail-market elements seem to have worked as intended while others did not. In some markets, the overall design appears consistent, while in others it does not. By comparing experiences across retail markets, we can learn how different designs performed under the test. **We consider France, Italy, Great Britain, the Netherlands, Norway and Spain, which exemplifies the range of different experiences.**

The crisis has demonstrated that the preparedness for high or variable energy prices varied considerably, between consumers, suppliers and governments.

While there is no doubt that many consumers were ill-prepared for the rise in energy prices, in the sense that they were on retail contracts that provided little or no hedge, they certainly would have had difficulty foreseeing the lack of preparedness of their suppliers.

Suppliers often rely on sourcing energy on short-term wholesale contracts, thereby exposing themselves to margin risk. This is a problem for companies whose gross margins (on all wholesale and network costs) are very small. When the wholesale market turned up, some of them paid the price, in the form of bankruptcy.

Unfortunately, **the lack of retail hedging strategies also had consequences for third parties**; in the Netherlands, it was the customers of the failing suppliers that bore the cost of having to enter into new and less favourable contracts; in Great Britain, much of the cost of failing suppliers was socialised on energy consumers as a whole. Suppliers with a closer maturity match between their retail and wholesale contracts or who, through vertical integration, had access to their own energy resources, such as in France, have fared better, partly because costs have fallen on returns to generation assets.

In Great Britain, Ofgem seem to have been unaware of the implications of having large wholesale price rises, interacting with the price cap, for supplier financial sustainability. The situation was similar in the Netherlands. The Dutch regulator did test the risk exposure of retailers, but the test could have been more stringent, even within the existing regulatory framework. The effect for Dutch customers was exacerbated by the lack of any financial compensation for customers that saw their suppliers disappear. In Norway, government authorities had been more concerned about what consumers pay on average than what risks they are exposed to.

The crisis has also demonstrated how well-intentioned regulatory measures to improve market performance in general, and competition in particular, may undermine the workings of the market.

In Great Britain, the price cap intended to avoid excessive prices and exploitation of consumers became generally binding, **driving margins to levels where suppliers no longer want to actively compete for customers**.

In the Netherlands, the cap on the penalty for customers breaching their contract has meant that suppliers are unwilling to offer long-term contracts, **hence leaving consumers with no means to hedge against volatile wholesale prices.**

In some countries, such as France, Norway and Spain, market interventions have partly or fully muted price signals and hence reduced incentives to save on energy. In other countries, notably Italy and the Netherlands, but also Great Britain, prices have been allowed to rise (although, in the case of Great Britain, with a lag) and support for consumers have been administered outside of the market.

The French model, with a hard cap on retail prices, has shielded both suppliers and their customers more or less completely from the increase in energy prices. **A consequence of the muted price signal is that there will be little or no consumer response to what is effectively a scarcity in the availability and supply of energy.** Moreover, **by letting generators cover much of the cost, the incentive and ability to fund new investment is undermined**.

The Spanish solution, to intervene at the wholesale level has fuelled energy consumption and created huge costs not born by the energy consumers themselves, though it has reduced retail prices somewhat. It has also substantially distorted trade in electricity with France and Morocco.

The Norwegian tax reductions and rebate to consumers also have the effect of limiting the incentive to save on energy, but there the price to generators was not distorted.

In Great Britain, the default cap meant a temporary, but not a permanent, delay in the increase in retail prices, and the measures for relieving the impact of higher energy bills have been implemented outside of the market. The same is true in Italy, where prices have mostly been allowed to rise, and where compensation has been in the form of tax reductions and direct economic support. In the Netherlands, the reduction in the energy tax was modest. The tax was reduced in percentage terms but remained about the same in absolute levels. Part of the tax reduction was given through a reduction of the income tax, which does not affect incentives to save energy. Part of the energy tax is used to provide subsidies for renewable energy.

As such, **although approaches have differed, all countries have introduced measures to protect households, especially vulnarable consumers, from experiencing the full force of rising prices.** As alluded to above, in some countries, such as France, Norway and Spain, this has mostly been done through direct intervention in the energy market, while in others, such as Great Britain, Italy and the Netherlands, the main instruments have been found in the areas of tax and welfare policies.

Concluding thoughts on retail markets

The recent unexpected higher energy prices have highlighted the challenges of designing well-performing retail markets. On the one hand, one would like consumers to have access to energy at competitive prices that reflect underlying costs and that provide a hedge against undesired risk. On the other hand, one would like consumers to respond to varying electricity prices when the availability and supply of energy is limited.

It is difficult to keep retail prices low and stable while encouraging flexibility and energy saving. It is also **not possible to induce a change in behaviour without exposing consumers to the costs of their actions** and, to raise the revenues that will be necessary **to fund the energy transition, prices have to reflect the actual costs of renewable energy**. A good retail market design must balance these different considerations, where the **balance may well depend on the specificities of individual countries.**

It is possible to **encourage demand flexibility by exposing consumers to short-term price variations while at the same time locking in a significant part of their energy costs at fixed prices.** It is also possible to **protect vulnerable consumers through the general tax and support system**, rather than through interventions in the energy market.

Despite government actions mainly directed at households and small businesses, we observe **load reduction in several countries**. Therefore, it is possible that the load reduction was **partly driven by consumers who were not protected by government measures, like the energy-intensive industries**. However, there also have been demand reductions even where price rises were limited by government intervention; for example, a recent study suggests demand reductions among Norwegian households of up to 20 per cent due to higher prices.

The experiences described above allows identification of a number of important issues:

Regulators should ensure that suppliers are prepared for wholesale price shocks and can handle the risk they face.

Governments should build integrated welfare and energy data systems that deliver effective financial support for consumers while maintaining price signals to save energy.

Retailers need to design tariffs that all allow customers to hedge market risk while encouraging demand flexibility and energy conservation.

To deal with these issues, we recommend:

- **Continued national variation in commercial practices** corresponding to national preferences.
- **Careful regulation of contractual terms**, given that the availability of contractual types and the reliability of terms on which they may be offered are closely related.
- **Combining equitable compensation of retail bills with high marginal prices for the final uses of energy,** allowing the facilitatation of behavioural change in energy consumption that increases energy efficiency and supports the energy transition.
- **Stricter requirements on the financial position of suppliers**, including supplier stress-testing and specification of minimum forward hedging requirements, with hedging requirements being reinforced and harmonised at the EU level.

INTRODUCTION

The aim of this report is to examine **wholesale and retail electricity market design** and proposed changes and interventions in the light of **current energy crisis** in Europe, and to draw some learnings on what this means as Europe tries to **move out of this crisis and towards net zero**. It combines and builds on our two earlier papers on retail energy markets (von der Fehr et al., 2022) and on wholesale electricity markets (Pollitt et al., 2022a).

Part I begins in **Section 1** with a discussion of **how wholesale electricity markets in Europe are supposed to work**. In **Section 2,** we consider some of the **proposals that have been made** to reform the electricity market. In **Section 3,** we elaborate in more detail the **theory of market design changes aimed at reducing the price and bill impact**, as well as **volatility**. We next discuss the **legal implications** for the future of the single market in electricity in **Section 4**. The last section offers some concluding thoughts.

Part II starts with a **brief, general discussion of energy retailing**. We then present **six country experiences in Section 1 – France, Italy, Norway, the Netherlands, Great Britain and Spain**. **Section 2** discusses **demand response across the six countries. Section 3** subsequently attempts to **draw some more general lessons.** We conclude in **Section 4** with a **discussion of opportunities and challenges** going forward.

PART A: WHOLESALE ELECTRICITY MARKET
INTRODUCTION TO THE WHOLESALE ELECTRICITY MARKET

The nature of wholesale electricity markets

Electricity is one of the most important commodities in the economy. It is an intermediate good which is the energy carrier of the modern world, valued both for its flexibility and lack of environmental impact at point of use and because it can be produced in a variety of ways. The hopes for complete decarbonisation rest on the **extension of electrification** (to heating and transport) and the production of **hydrogen from electrolysis** (see Pollitt and Chyong, 2021).

Electricity is subject to a lot of **government energy policy**. Indeed, the **energy trilemma**, or how to simultaneously provide secure energy at reasonable prices with good environmental outcomes, plays out in electricity strongly. In addition, electricity can be a key part of national industrial policy, being a substantial share of fixed capital formation, with the potential to promote regional policy if investment can be directed to areas of high priority for jobs and new investment. What constitutes 'good energy policy'[1] with respect to electricity varies in time and place, with some jurisdictions favouring more use of market signals and others favouring less, and some jurisdictions favouring closer government direction of investment and others favouring less. These differences between European states often reflect **national preferences** with respect to the operation of the market and the desirability of state intervention.[2]

The physics of electricity presents a challenge for the design of markets. Supply must equal demand at all nodes in the electricity market in real time, with storage being expensive unlike fossil fuels, where it is relatively cheap. Electrification has been considered by governments as something to be encouraged, and electricity prices have been subject to regulation since at least the 1920s in many countries[3]. High capital costs, inflexible demand, and the need for physical balancing of supply and demand led to widespread integration of generation, transmission, distribution, and retailing, with separation occurring in the presence of long-term contracts. In 1975, a radical idea was noted (by Weiss): that there was the potential for competition between generators and the creation of a wholesale market for power. Meanwhile, power exchanges trading electricity between integrated companies subject to long-term contracting gradually developed. When formal power markets began to appear (e.g. in Great Britain in 1990 and Norway in 1991)[4] these were based on concepts of short-term merit order dispatch developed in France in the 1950s within large generators (see Boiteux, 1960).[5] By 2015, ACER noted that 85% of all day ahead power in Europe was effectively part of a single

[1] See Ozawa et al. (2019).
[2] This varies considerably across European states, see: Janik et al. (2021).
[3] See Priest (1993) on the rise of regulation of electricity in the US.
[4] See Newbery (2021) and Le Coq and Schwenen (2021).
[5] The Norwegian market, which traces its origins back to the 1960s, was not based on merit-order dispatch, but rather operated as an exchange where hydro generators could swap energy on a daily basis, much like today's power exchanges.

short run market for energy, via the EUPHEMIA market coupling algorithm, which links power exchanges across Europe[6].

While there has been an impressive and long-running development of short run power markets, both for energy and ancillary services (such as balancing services and frequency response), long-term power markets have developed much more slowly. Up until 1990, much of the generation capacity built in Europe had been financed with explicit or implicit state support. The choices of generation technology were typically made with the approval of government energy ministries. There then began a brief period when much new capacity was combined cycle gas turbines, built on a merchant basis, under shorter term (e.g., 15-year) often private contracts.[7] This period lasted until the early 2000s, when new capacity increasingly started to be wind and solar added as the result of government support schemes arising from renewable targets (themselves motivated by successive renewable electricity - 2001/77/EC - and renewable energy directives - 2009/28/EC). In this environment, it was once again the case that much new capacity was being directed and supported by state governments. Unsurprisingly, continuing government interest in new generation technologies has limited the development of longer-term private power markets. **Net zero extends government interests** in new technologies to heating and transport and suggests more, not less, interest in what investments are occurring in the heating and transport sectors.

The reality of government direction of longer-term investment in the electricity sector does not undermine the role for **efficient short run markets** in energy and ancillary services to make **best use** of the **available generation** capacity (minimising short run system cost) and to provide **real time energy security** (to ‘keep the lights on’) in conditions where reserve capacity is expensive and supply interruption is very costly. Indeed, many ‘competitive’ markets operate in conditions where significant government-backed investments influence incentives for long run investment and skew the operation of short-term markets.

Equally, it is important not to overstate the potential for disconnection between short and long run prices in electricity. While much investment is determined by governments, longer-term investors – even governments – clearly do pay attention to **short run market prices** for electricity. They make use of these within their own planning and use them in guiding prices that they might be willing to pay for longer-term investments. Short run market prices are very visible and can and are used to justify increased longer-term government commitments to support new capacity when high, and reduced commitments when low. Electricity competes with gas and oil at the margin in industrial power, in heating and in transport[8]. Hence the **price of electricity** is **influenced** directly in production and in use by the **prices of other energy sources** in the **longer run**. If these other types of energy are subject to global market forces, then electricity will be influenced by them.

[6] See Pollitt (2019).
[7] As noted by Helm (2004). See also Roques (2021a, slide 4).
[8] For an early discussion of this see Felton (1965).

High prices are a potential problem in short run wholesale electricity markets. This is because consumer willingness to pay to avoid an instantaneous short run interruption to supply (the value of lost load) is very high and the very short run demand response to high prices may be very low. Every short run electricity market in the world has made decisions about the maximum bid value that is allowed in the market and prices can, at times, rise towards this value. As prices rise there is the potential for gaming, whereby any individual generator, by withdrawing a small amount of their capacity, can raise the price significantly. While high prices for very short periods do not make much difference to average annual consumer bills, they can catch out unhedged consumers (and other counterparties to short run contracts, such as market makers). The early infamous case of this is California in 2000-2001 (see Sweeney, 2002). High short run electricity prices sustained for long periods are more likely to attract government intervention to reduce them.

Wholesale and retail electricity markets are **closely linked**. A key reason for this is that a dominant industry model that has emerged is the **generator-retailer**, whereby generators active in wholesale markets are also integrated with retail businesses selling directly to customers (see Pollitt, 2019). Stand-alone retailers without electricity generation (or being incumbent gas companies) have struggled in many markets. The current crisis, which has precipitated the failure of stand-alone retailers, only seems to have strengthened the attractiveness of the dominant business model (see von der Fehr et al., 2022).

Net zero, the longer term and the current crisis

While much of what we discuss is motivated by the **current crisis**, we draw out lessons for the longer term and the electricity market on the path to **net zero**. We note two important starting points relative to the longer term. First, many used to worry that we were creating an electricity market where the short run prices would be too low compared to the level required to facilitate long run investment in low carbon generation. This was the theme of a 2018 CERRE report (Pollitt and Chyong, 2018). In this report we discussed the '**missing money**' problem facing generators, whereby short run market prices would not recover long run average costs, potentially requiring capacity markets and 'subsidised' long-term contracts for new generation. We pointed out that with declining renewable generation costs and reasonable expectations of carbon and gas prices, short-term prices could be high enough to support merchant investment in new low carbon generation. Second, **modelling of net zero** does give some guidance on what technologies need to be developed to decarbonise the energy system completely by 2050 and guidance on the interaction between gas and electricity markets in net zero. This was the topic of a major CERRE on net zero and how to achieve it in the European energy system by 2050 (Chyong et al., 2021; Pollitt and Chyong, 2021).

Our 2021 report highlighted some important points about the long run nature of the net zero energy system, which are essential in considering the short-term actions proposed to address the current energy crisis. This report concentrated on the fact that **green gas and electricity markets remain coupled in net zero**, with electricity being used to produce hydrogen, and hydrogen also being produced by steam-reformation of methane with carbon capture and storage (CCS). This implies that even in net zero, **wholesale electricity prices will be linked to global hydrogen and methane prices**.

Our modelling of net zero showed:

- a large increase in energy efficiency (relative to business-as-usual);
- a large increase in fixed costs of energy system and hence in the level of investment;
- a very large increase in long run system marginal cost of energy relative to 2018;
- the need to address substantial payment issues, whereby a system where much of the costs are fixed (as opposed to driven by variable fossil fuel costs) but need to be covered from variable energy charges;
- and the likely need for support from general taxation and cross-subsidies between energy sources, especially as the new technologies of net zero are scaled up (i.e., low carbon renewables, hydrogen, biomethane and CCS).

This energy crisis is a **wake-up** call on the **need for and the implications of a net zero energy system** which will have very **high-priced marginal units of energy**.

We suggested that carbon prices might need to be EUR 350 per tonne of carbon dioxide. This implies EUR 64 / MWh gas at TTF, CH_4: 189c / therm of gas at NBP and that is just the CO_2 climate externality, not the security externality. All of this implies a big rise in the true system marginal price of energy if gas at margin, relative to 2019 (c. TTF: EUR 20 / MWh; NBP: 41c / therm).

At the time of writing, **prices are above even long-term net zero levels**. This implies that we do not need prices as high as this for net zero, let alone the pathway to it. However, **sustained high prices for fossil fuel-based energy** are a feature of net zero. Hence, some attention to what we can learn about how to adjust to high fossil fuel prices is important and we should not necessarily aim to get prices or policy settings back to 2019 levels. We should instead **prioritise dealing with the distributional implications** of high prices, **increasing energy efficiency**, promoting the required **low carbon technology investment**, etc.

Electricity and gas prices are currently not only **high average**, but they are also exhibiting **high volatility**. This has created **liquidity problems** in short run markets and sparked an increase in bilateral trading.[9] High volatility exposes market makers and purely financial players – who may over derivative products –to **increased risk**. These players may leave the market or require greater capital.

Net zero modelling shows that flexibility will be a key challenge for the 2050 energy system in Europe. A **requirement to dampen price volatility** in response to national preferences for price smoothing or

[9] For a discussion, see: https://www.esma.europa.eu/sites/default/files/library/esma24-436-1414_-_response_to_ec_commodity_markets.pdf

in order to reduce risks to investors would seem to require **long-term contracting** and **deep demand flexibility**.

The background to the current crisis

The energy price and supply crisis in Europe is severe and it is unprecedented in the history of the single market in gas and electricity, which dates from around the end of the 1990s, following the first electricity (96/92/EC) and gas (98/30/EC) market directives.

The war in Ukraine and the consequent significant curtailment of European gas trade with Russia has sharply raised the price of gas and consequently the price of electricity, further exacerbating the price increase driven by post-covid recovery in global gas demand.[10] The wholesale electricity prices in Europe are now around double (in real terms) the level they have been at any time since 1999.[11] They have been around this level for an unprecedented number of months. What is more, **high prices are expected to continue** for at least two and a half years by **forward markets**. The forward price of electricity at the time of writing in 2025 is expected to be over twice its normal level[12], while the forward price of gas (TTF) is expected to be over four times its normal level in March 2025.[13]

Such an unprecedented and prolonged price rise **cannot be characterised as a temporary price spike**. It is an **enormous micro and macro-economic shock** similar in magnitude to the first oil shock of 1973-74. It is testing current market arrangements and causing them to be reconsidered, as we discuss below.

Some starting points for our discussion are detailed below. Several points about the operation of both European gas and electricity markets are clear from the start.

First, **Europeans are in this together** at the level of the wholesale market. This is true of both single market countries (EU27 + Norway) and the UK and Switzerland which are part of European gas and electricity networks and whose prices largely move in line with those in the EU. This implies that **wholesale market security** is a **shared public good** and **attempts to intervene in one country** to suppress the price or to limit flows of electricity or gas across interconnectors **reduces market efficiency** and **shared insurance**. For example, Norway has supported other European countries through increased gas and electricity flows, France has benefitted from exports of electricity from the

[10] For a review of current electricity prices and national measures in Europe, see: https://cdn.eurelectric.org/media/6053/overview_national_situation_18082022-h-D24BA028.pdf

[11] For recent and current prices see: https://ember-climate.org/data/data-tools/europe-power-prices/. The previous prices for GB are shown in Levi and Pollitt (2015) for the period 1990-2014, in real terms; and see Ofgem for more recent data (2011-: https://www.ofgem.gov.uk/wholesale-market-indicators

[12] From a high of 258 Euro / MWh in January 2025 to a low of 123 Euro / MWh in July 2025 (https://www.barchart.com/futures/quotes/ZUG22/futures-prices on 6 December 2022), against a maximum monthly price in 2019 in the EU of less than 70 Euros / MWh (see Ember: https://ember-climate.org/data/data-tools/europe-power-prices/)

[13] 91.0Euro / MWh in March 2025 (https://www.barchart.com/futures/quotes/TG*0/futures-prices on 6 December 2022), against prices hovering around 20 Euro / MWh for most of the decade from 2010 (see https://www.spglobal.com/commodityinsights/en/market-insights/blogs/natural-gas/070521-ct-european-gas-lng-ukraine-co2-emissions-us-henry-hub-aluminum-coal)

UK during nuclear shutdowns, while LNG terminals in the UK have been used to land gas for onward flow into the continental European grid. This emphasizes the value of integrated European energy markets for both electricity and gas.

Second, as we approach the winter when gas supply could be very tight, it will be **Russian gas-dependent countries** that will especially need the integrated market to support them, including via reverse flows of gas procured by LNG and pipeline from other countries. Otherwise, there is **a real risk of compulsory rationing and curtailment of demand**.

Third, **markets deliver security of supply** by raising prices in times of scarcity, creating **profits** for some and **leaving some market parties exposed** to unhedged high prices or some customers unable to pay. Higher wholesale prices are inevitable for gas in Europe while Russian gas imports are restricted.

Fourth, the electricity price crunch has been **worsened by the effect of climate disasters** across the energy value chain and on electricity output. So far 2022 has seen much lower output of electricity from hydro across Europe.[14] This is in addition to problems with output from nuclear power plants. The reduction in hydro has been due to drought (itself likely caused by climate change). Some of the reduction in nuclear is also related to the lack of river water for cooling. This illustrates that **climate and weather conditions** are important considerations **in the design of future electricity markets**.

Fifth, **political concern about the distributional** and wider economic impact of high prices is **inevitable**. Something must be seen to be done in a democracy to respond to legitimate political concern about fuel poverty, industrial uses of gas and about potential health impacts from a lack of winter fuel. This need to do something is heightened by the fact that rising energy prices are **macroeconomically significant,** reducing aggregate real GDP and contributing to the inflation. In Germany, the estimated loss of GDP from sustained high energy prices is up to 12%[15], while inflation is now expected to peak at 11% in the UK, following large price rises in electricity and gas on 1 October 2022[16]. Meanwhile industrial electricity demand is being significantly affected by higher prices. In the UK, for instance, industrial electricity demand is down 8.2% relative to Q2 2019 (in Q2 2022)[17], against a real price rise of 45%.

Sixth, such a large rise in prices and volatility has raised **concerns about whether the current market design for electricity**, in particular, is **working**. Sustained high prices for electricity, gas and liquid fuel always raise concerns as to whether energy companies are making windfall profits or acting anti-competitively in some way. It is clear that **gas producers are making large profits** (following recent announcements from Shell and BP), but it is **less clear** what the **size of profits is within the electricity sector** itself.

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[14] See Heussaff et al. (2022).
[15] See Bachmann et al. (2022)
[16] See https://www.bankofengland.co.uk/monetary-policy-report/2022/november-2022
[17] Industrial Electricty Price (BEIS Table 3.3.1); Industrial and Domestic Sales (BEIS Table 5.5).

SECTION 1: THE CURRENT WHOLESALE ELECTRICITY MARKET DESIGN

The current market design traces its origins back to the reforms in England and Wales and Norway in 1990, although important elements, such as a competitive power exchange, have an even longer history. In this section, we present the current design and discuss the rationale behind it.

Market architecture

A fundamental principle of the current market design is the **separation of activities** that may be subject to competition and activities where effective competition cannot be achieved. In the former category falls generation (production) and supply, while in the latter category fall networks and other infrastructure, including system operation.

The idea behind this separation was to reap the benefits from competition where possible, and to rely on regulation only where competition was either ineffective or non-existent.

This was a new idea for the electricity industry when it was first introduced, and it stood in sharp contrast to the prevailing market architecture in many European countries, where generation and networks where integrated into the same companies, sometimes in a single market-wide monopoly. In some countries, the reform led to the creation of new transmission and distribution companies which took over responsibility for networks. In other countries, it led to the divestment of generation and supply from existing utilities. Vertical separation was accompanied by horizontal separation, through the breaking up of monopolistic structures in generation and supply, in order to facilitate competition.

Movement away from monopolistic structures were accompanied by a movement away from "**self-governance**" through the establishment of **dedicated government agencies** responsible for regulating the industry. In some countries, such regulatory agencies already existed, but their tasks now went from general oversight of all activities in the value chain to concentration on the monopolistic activities (infrastructure) and measures to promote competitive markets.

While, when new, the current market architecture met with considerable opposition, it now seems well accepted and essentially uncontroversial. Specifically, none of the current proposals for reform address market architecture.

Decentralised decisions and markets

Another fundamental principle of the current market design is **decentralised decision making**. This principle applies to consumers and generators, traders and suppliers and other intermediaries, as well as to marketplaces. The idea behind this principle is that individual agents are better placed to make informed decisions on their own behalf than some central (government) authority.

In generation, each individual company decides on how much electricity it wants to produce at any given time, subject to contractual obligations, market prices and other relevant internal and external conditions. This is contrary to the historic organisation of generation in many European countries, as well as in many other parts of the world, where dispatch was or is centralised.[18]

The decentralised decision model requires means for **balancing generation with consumption**. Balancing is crucial in electricity (less so in gas), since imbalances between what is fed into the grid, and what is drawn from it, will create fluctuations in voltage levels and frequencies that may damage not only the grid itself, but also electrical equipment connected to it.

The bulk of the balancing takes place through trade between buyers and sellers of electricity. Some of this trade is based on bilateral contracts and some occurs in specific marketplaces or power exchanges, where buyers and sellers bid in their demand and supply and trade through the marketplace.

It is notable that the organisation of trade and markets has been developed largely by the market participants themselves. While marketplaces may be subject to regulatory oversight, their establishment and design are first and foremost a result of what market participants have wanted. An exception to this rule was the original pool in England and Wales, which was built on the former central dispatch mechanism, and where participation was mandatory, but this was eventually abandoned and replaced by a voluntary power exchange. More generally, marketplaces evolve over time depending on the needs of participants.

At the core of the electricity market is the **day-ahead or spot market**, where market participants daily make hourly (or half-hourly) bids for the coming 24 hours, and where market clearing prices determine how much each participant will sell or buy. Fundamentally, the market operates as any other commodity market, where prices are determined by bids and offers. This is not to underplay the fact that electricity has certain characteristics, such as the need to match demand and supply at every instant, and the fact that flows of the physical commodity is determined by physics rather than contractual relations, that complicates both the organisation of electricity markets and the difficulty of making them operate efficiently, including avoiding market power. Nevertheless, the basic functioning of electricity markets may be analysed by standard tools, bearing in mind the complexity of the practical reality - more on that below.

The operation of the spot market is illustrated in the figure below. The figure shows “snapshots” of the market in three different circumstances, with low, medium, and high demand, respectively. For simplicity, we have assumed that there are two different generation technologies, base-load and peak-load respectively. Base-load generation has low running costs (and correspondingly high-capacity

[18] The details of European wholesale markets, including the extent to which generators are mandated to participate and how dispatch is organised, differs across Europe; indeed, some, such as Italy and Spain may perhaps best be characterised as "semi-decentralised". For a discussion of the merits of different organisations, especially between centralised and decentralised dispatch, see Ahlqvist, Holmberg and Tangerås (2022).

costs, e.g., think of nuclear or renewables), while peak-load generation has high running costs (and correspondingly low-capacity costs, e.g., think of gas). In the market, offer prices reflect costs and hence bids will be stacked in order of increasing running costs, the so-called "**merit order**".[19] Along the horizontal axis we measure volume of supply and demand (e.g., in MWh), while along the vertical axis we measure price and unit running costs (e.g., in Euro/MWh).

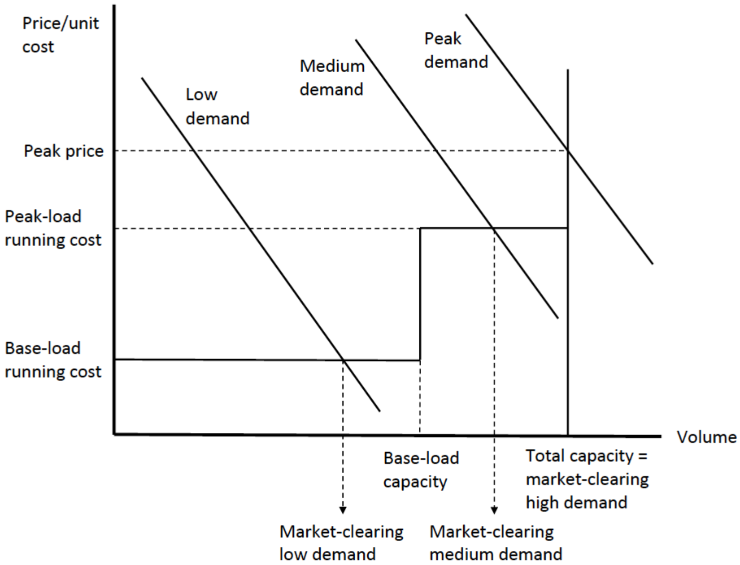

Figure 1: Spot market clearing

In low-demand periods, only base-load generation is required to cover demand, and so price will equal the running cost of this technology. In medium-demand periods, also peak-load generation is required to cover demand, and so price will equal the running cost of this technology. Finally, in peak-demand periods, price will have to be set sufficiently high that demand does not exceed total capacity, and hence exceeds the running costs of both technologies; in other words, in such periods generators earn a "**scarcity rent**". We say that the plant (technology) setting the price is the "marginal" plant (technology) and that its cost is the **"marginal" cost** of the market (in scarcity periods, price instead reflects consumer willingness to pay or value of lost load).

It may be noted that the market delivers both **short run efficiency and security** (we return to the issue of long run security and efficiency, which is determined by investment, below). It delivers efficiency in the sense that demand is satisfied in the least-cost manner, i.e., by generation with the lower cost.[20] It also delivers efficiency in the sense that the composition of generation is cost effective. The low-cost base-load is running all of the time, while the more expensive peak-load technology is only

[19] We have ignored the issue of market power here – specifically, the ability of generators to set offer prices above costs – as this is not essential to the main points. In practice, market power is a real concern and market design, including expanding and integrating markets, needs to pay careful attention to it.

[20] Strictly speaking, cost efficiency is guaranteed only if the market is truly competitive; when there is market power, the merit order may be affected by the extent to which generators bid above costs, in particular, if generators with low costs bid higher than generators with higher costs.

running when needed (the peak-load technology has relatively low-capacity cost, so it is the overall cheapest option to ensure sufficient capacity at all times). The market delivers security in the sense that it always ensures balance between demand and supply, and hence prevents situations of uncovered demand or rationing.

Moreover, if environmental costs of different generation technologies are reflected in their costs, the market also provides environmental benefits. The interaction between the CO_2 permit system – the **Emissions Trading System (ETS)** – and the electricity markets ensure that environmental costs are reflected in the merit order. Specifically, the permit system increases the cost of thermal generation based on hydrocarbons, thereby affecting their competitiveness against other generation technologies. In recent months, coal has made its way back onto the market to compensate for lack of gas (and other generation), **pushing CO_2 permit prices up**. This has **made gas even more expensive** and **impacted further on the electricity price**.

The fact that the merit order reflects the costs of different technologies, implies that changes in costs impact the merit order. An increase in the cost of a particular technology, may move plants based on this technology up the merit order, thereby ensuring that cheaper technologies are operating in its place. Even when the merit order is not altered, the cost increase is reflected in the market price whenever the technology sets the price, thereby signalling to the demand side that the cost of electricity has gone up.

The fact that market prices are set to clear the market implies that prices reflect 'marginal cost', i.e., the cost of the most expensive generation plant that has its offer accepted. Since all sellers receive the same market-clearing price, sellers who would be willing to produce electricity at a lower price, will obtain a positive margin on what they sell. This allows for **remuneration not only of variable costs,** but also of the **fixed costs of generation**. It is the fact that prices are sometimes set by peak-load plants with high variable (but low fixed) costs (and possible scarcity rents) that allow base-load plants with high fixed (but low variable) costs to have their costs covered.

The fact that prices reflect marginal cost also means that increases in the cost of the marginal generation technology are transmitted to the whole market. In Figure 1, if the running cost of the peak-load technology goes up, prices will be higher whenever this technology is on the margin, and all the capacity operating at such times will receive this price. This is what is currently taking place in the European electricity market, where the higher cost of gas has increased the running costs of gas-fired plants, the technology that is on the margin when the market is tight. Since generators always have the option of selling in the spot market, any increase in the price in the spot market tends to be transmitted to the bilateral market, and *vice versa*, and therefore the increase in cost is driving up prices in the entire market.

Changes to the composition of the generation park may also affect the merit order and hence prices. In recent years, large amounts of renewables have come onto the market. They have the characteristics of base load, with very low running costs and correspondingly high capacity costs and have consequently taken their place at the bottom of the merit order; wind and solar farms produce whenever they can. This has had two important effects: on the one hand, renewables have reduced the running time of other types of generation, **especially** thermal technologies based on hydrocarbons, and hence made them less profitable, sometimes to the extent of pushing them out of the market. On the other hand, whenever renewables constitute the marginal technology, prices are very low.

So far, we have only seen relatively few instances when demand may be covered entirely by renewables (e.g., in Denmark and Germany), but this will be much more frequent as the amount of renewable generation increases. In a **net zero** world, we are likely to see **extended periods of time** in which **prices are very low**, interspersed by **periods** in which **prices raise to high levels** to remunerate peak-load technologies (e.g., gas), that are required to compensate for lack of wind or sun or cover peak demand. The price swings will be **moderated by the presence of storage** facilities, such as pumped storage and batteries.

The bilateral market (which is typically for longer-term contracts) and the day-ahead market are complemented by other markets that allow for continuous adjustment of positions and overall market balance. In the **intra-day market**, market participants can trade up to only a few minutes before actual delivery. In the **balancing market**, where market participants offer to deviate from their generation (or consumption) plans, the system operator can adjust generation (and consumption) to ensure that there is always complete physical balance.

In other words, the peculiarities of electricity alluded to above, which necessitates a range of different contracts, especially in the time dimension, means that generators (and consumers) have the opportunity to trade on different marketplaces. Under ideal conditions, arbitrage and competition ensure that prices are equalised across markets. However, since generators (and consumers) differ in their ability to provide services – particularly with respect to adjusting plans on short notice – **efficiency may not always be ensured**. Much effort has gone into the development of measures to reduce the risk that market participants do not use market power to distort prices within or across markets, most notably the **Regulation on Wholesale Market Integrity and Transparency (REMIT)** that came into force in 2011 and for which ACER has main responsibility.

The fact that the different marketplaces are closely, if not perfectly, interrelated, means that any attempt at influencing the price in one market is likely to spill over into the others. Moreover, attempts to control the price in one marketplace will move trade between this market and the others; for instance, an **attempt to reduce or cap prices on the day-ahead** spot market, is likely to **shift trade from this market to the bilateral** or "over-the-counter" **marketplaces**.

Gradually, markets across Europe have been integrated – or, more precisely, **coupled** – allowing for trade between different areas.[21] Specifically, day-ahead markets are cleared simultaneously across Europe, thereby ensuring that interconnectors are efficiently utilised, and prices are brought as closely

[21] See Pollitt (2019) for an account of the history of the European single market in electricity, including the evolution of cross-border trade.

together as possible. This ensures that electricity is supplied from the cheapest sources and consumed where it has the highest value, thereby maximising value added across Europe.

The integration of electricity markets should be seen as the realisation of the more general idea of the "**single market**", whereby gains from trade can and will be realised across Europe, in this case for electricity (and gas). The facilitation of cross-border trade has been accompanied by rules to ensure that competition, both within and across markets, is effective, i.e., a ´level playing field´, to maximise overall gains.[22]

A consequence of the integration of different areas is that **events in one area will have an impact in other areas** also. For example, when generation is reduced in a certain area for one reason or another, imports from other areas may partly or wholly make up for the difference. A recent example is how the unavailability of nuclear capacity in France has made the country go from being a net exporter to a net importer of electricity. Other examples include low water in Norway, cold winters in Northern Europe and high temperatures in Southern Europe. As such, integration acts as a form of shared insurance that makes each part of the market more resilient to shocks, whether of domestic or external origin. The single market area ensures the security of its constituent parts against energy threats to one Member State, such as the cutting of electricity exports to Finland from Russia and Russian gas exports to Poland.

The fact that the transmission networks in general, and interconnectors in particular, have **bottlenecks** means that it is not compatible with complete price equalisation across Europe. Prices will be lower in areas where there is surplus supply (and hence export to neighbouring areas) than in areas where there is surplus demand (and hence import from neighbouring areas). These price differences, which reflect **lack of transmission capacity**, may occur both within and between countries. They provide a signal of the value of reducing or removing bottlenecks. The signals have led to large increases in interconnector capacities, for example between Norway and the EU and between the UK and other European countries.[23]

While market manipulation and market-power abuse has been a recurring topic in European electricity markets, it seems that the general view among industry experts is that these markets perform quite well and have delivered what they were supposed to. Even during the present tumultuous times, the price mechanism has ensured that **rationing was avoided** (this is not to suggest that the consequences for those who have felt the implications of high prices are not severe).

Risk and hedging

When most physical trade takes place on a day-to-day basis in markets where prices fluctuate, market participants are subject to price risk. In the current market design, market participants are assumed

[22] Challenges associated with market integration, and how they may be resolved, are discussed in von der Fehr (2017).
[23] Ensuring efficient investment in interconnectors meets with many challenges; for a recent analysis and references to other literature, see Crampes and von der Fehr (2023).

to handle this risk themselves. The idea is that they know best, both their ability to withstand risk and how much they are willing to pay to hedge against it.

Hedging takes place both through bilateral contracts and through financial markets. In the bilateral market, parties are free to negotiate any form of contract they see fit, including its duration and indexation of price. Bilateral contracts may have quite long durations, of five years or more.

The financial marketplaces offer standardised products, such as futures and options, with different durations. These products may provide hedging against variations in the spot price in any given market or against price differences between different price areas. Duration is typically relatively short; it is rare that standardised financial contracts for electricity have a duration of more than five years.

By having access to a wide selection of contracts and marketplaces, market participants can choose not only the amount, but also the type of hedging they prefer. In practice, we see **different hedging strategies** both across types of market participants and across different parts of Europe, presumably reflecting different needs. While most generators and energy-intensive industries tend to be fully, or almost fully, hedged, many smaller businesses do not hedge at all. Among household consumers, there are remarkably large differences in the extent of hedging across Europe, as documented in the second part of this report.

It remains an **open question how well the markets for risk hedging actually work** and hence **whether the current market design does provide sufficient hedging opportunities**, especially for generators who must undertake investment in plants with a long lifetime. Financial markets evolve freely, responding to the needs of market participants, and hence one would expect the availability of products to reflect demand. The fact that financial markets do not offer contracts of very long duration may therefore simply suggest that there is limited appetite to pay for such contracts. Also, bilateral contracts, often of quite long durations, are common in parts of Europe, for instance in the Nordic region, suggesting that they will be available when there is a need for them.

Critics will respond that the lack of **long-term contracts** reflect a market failure, rather than a lack of demand. The liquidity of financial markets was affected by the tightening of financial regulations following the financial crises (and, of course, in the current turmoil many have become more reluctant to trade in what is seen as highly uncertain assets). In particular, the requirements on market participants in financial marketplaces means that they will only be of interest to generators and large consumers of electricity (as well as traders with sufficient financial resources). Also, bilateral contracts are mostly of interest to generators and large consumers of electricity. To enter into such contract, volumes have to be sufficiently large and time horizons sufficiently long.

The current energy crisis has revealed that **many suppliers were not well hedged** against a rise in wholesale prices. These suppliers had instead relied on buying in the wholesale spot market even when offering retail contracts to their customers of duration of a year or more. The reason these suppliers did not hedge their positions may of course be that their experience was that hedging was unnecessarily expensive; after all, hedging comes at a cost. However, it may also be that since their

customers are free to move after their contracts are expired, or indeed before that, if their contracts allow (maybe at a modest penalty), **suppliers may have been reluctant to commit** to long-term purchases. In jurisdictions where customers are allowed to switch suppliers at short notice, suppliers will naturally be unwilling to enter into long-term contracts.

It should also be emphasised that while hedging reduces the exposure to price swings – particularly in periods of high prices – they do not protect against prices being high for a long time. Prices in long-term contracts reflect expectations of future average prices, and hence prices will only be low if future prices are expected to be low.

Moreover, in periods of high uncertainty – such as right now – it may well be worth waiting for a reduction in uncertainty. Currently, long-term contracts are offered only at relatively high prices, reflecting the huge uncertainty about how the market will develop, and so the cost of reducing risk is very high. Instead of locking into a certain, but high, price now, it may be better to pay the current high price and wait for a reduction in prices of long-term contracts.

Investment and technology

Just as decisions on generation are decentralised, so are decisions on whether to invest in new generation capacity, including both the size of the plant and its technology. It is the **individual company who decides** how much and in what they want to invest. This is notwithstanding the fact that investments are **heavily dependent on government intervention** (see below).

Investment incentives depend on market prices, in particular the premium between market prices and variable or running costs. This is illustrated Figure 2, which builds on Figure 1 above and shows the capacity premium in three different circumstances.

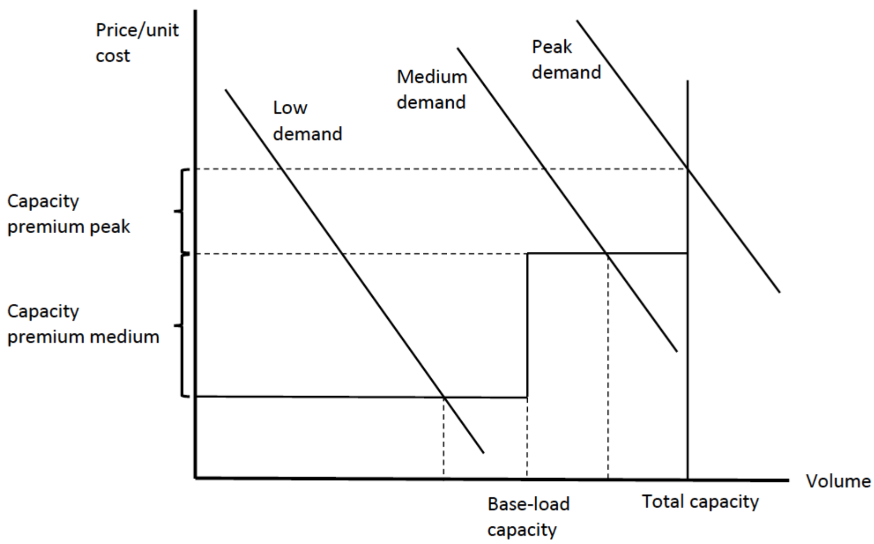

Figure 2: Capacity premium

In low-demand periods, the market is cleared at a price that equals running costs, and hence there is no capacity premium for either technology. In medium-demand periods, when the price is set by the peak-load technology, the market is cleared at a price that exceeds the running cost of the base-load technology. Consequently, the base-load technology receives a capacity premium, in the figure denoted ´Capacity premium medium´. In peak-demand periods, when price must be set so high that demand does not exceed total capacity, price exceeds the running costs of both technologies (reflecting instead willingness to pay or value of lost load). The peak-load technology receives what in the figure is denoted ´Capacity premium peak´, while the base-load technology receives the sum of the ´Capacity premium peak´ and the ´Capacity premium medium´. The fact that the base-load technology receives capacity premia more often and of a larger magnitude than the peak-load technology, reflects the higher capacity costs of the former technology, and so ensures there is incentive to invest in both technologies.

This model is clearly extremely simplistic. For example, it does not consider that there are many different generation technologies and that both demand and available capacity varies in a (partly) unpredictable or stochastic manner. However, the main insight, that capacity investment incentives arising from the market requires that prices exceed running costs, which mostly occur when the market is relatively ´tight´, is robust. Over time and on average, **in a well-functioning market, the capacity premia will reflect capacity costs of relevant generation technologies**.[24]

More specifically, a well-functioning market ensures that long run profitability of generators will reflect normal returns on capital (considering industry specific risks). If prices go up, and profitability with it, new capacity will be attracted to the market and push prices and profitability down again. Similarly, in periods of low prices and low profitability, generation will be taken off the market, thereby pushing prices back up. There may of course be periods of both unusually high or low profitability, but over time neither excess nor deficient profit levels can be sustained.

As such, the current spike in electricity prices rewards installed investment in generation. Curbing prices (or taxing the resulting profits) will not only reduce the reward to installed capacity but may also reduce incentives to invest in new capacity if investors fear that similar interventions will take place whenever prices spike in the future. However, one could reasonably argue that the current spike is not only extreme, but also unprecedented, and that measures taken in such unique circumstances do not set a precedent for future, more normal events.

Investment does not only depend on expected profitability, but also on risk. Generation capacity is generally long-lived, sometimes with very long lifetimes, and hence subject to considerable risk, especially concerning future prices. This risk drives up the cost of capital and hence undermines investment incentives. As explained above, **generators can hedge at least some of this risk, either by bilateral contracting or in financial markets, or a combination of the two**. In many parts of Europe,

[24] The conditions for this result are strict, but not entirely unreasonable; they include free movement of prices (no effective price caps) and free entry of new capacity. Classic references to the theory are Boiteux (1960) and Turvey (1968); see also Crew and Kleindorfer (1976).

for example in the Nordic region, investment is undertaken entirely on this basis (admittedly, at times with some government support, see below). However, this may not always be possible, especially where a large part of demand is unwilling or unable to enter into long-term contracts.

While investment in generation depends on price levels (and the risk associated with these), Investment in hydro reservoirs, pumped storage, batteries, and hydrogen facilities depend on intertemporal price differences (and the associated risk). These capacities derive their profits from drawing electricity from the system (or not producing, in the case of reservoirs) when prices are low and injecting electricity into the system when prices are high. The profitability of these investments is therefore highly dependent on the extent to which prices vary over time. As explained above, when large quantities of wind and solar capacity comes on the market, prices are expected to vary more, increasing the profitability of technologies that benefit from price variation. Of course, such investment will also depend on the extent to which investors can hedge their risk, in this case by contracts related to differences in prices over time.

In practice, investment does not depend only on incentives arising from the wholesale market; **investment in generation is to a considerable extent regulated**, both directly and indirectly.

Investment requires approval of relevant government authorities (typically many different ones, representing both local and national interests). The approval may not only depend on where the new plant is built, but also upon its capacity and generation technology. As such, investors face real constraints on their investment decisions. This is true also of disinvestment or capacity reductions; governments sometimes intervene to take capacity off the market, such as has been the case with nuclear generation capacity in Germany and Sweden.

Moreover, **governments regulate investment indirectly, through various economic incentives.** These indirect means of regulating investment are sometimes general, available to all of generation. The so-called capacity mechanisms, which in one way or another pay generators for making capacity available, are often of this type. Others are directed at encouraging specific technologies, typically renewable energy. These measures have taken the form of guaranteed prices (**feed-in tariffs**), subsidies to output (green certificates) and investment contributions. In addition, the Emissions Trading Scheme (ETS), which puts a price on carbon emissions, discourages thermal generation based on coal, gas, and other petroleum products.

Increasingly, governments have also **regulated investment directly by procurement of specific types of generation capacity**. These procurement contracts are often offered through auctions, in which participants compete on how much they require (or are willing to pay) to enter contracts.

As a result of active intervention by government authorities, the current (and future) configuration of generation capacity is not so much a result of market forces as of deliberate government plans. This is true both for the size of the overall capacity, as well as for the technological composition of the generation park.

Consequently, electricity prices have been driven down to levels where purely market-based investment is not profitable (this is of course not true at the moment, where prices are at levels where, should they last, almost any investment would be profitable). Consequently, if the ambitious climate and energy targets are to be achieved, **government support will be required** for the necessary investment to be forthcoming.

In the longer run, as installed capacity approaches the end of its subsidy period, and as the cost of renewable generation becomes competitive, unsubsidised renewable generation is expected to be dominant. Whether this will require **further development of long-term contractual arrangements is an open, important question**. Specifically, investment in large-scale and long-lived projects, such as nuclear and offshore wind, may well require better hedging opportunities than is currently available to investors. **Whether this should be offered by governments** underwriting specific investments (which would require acceptance under state-aid rules), or **whether there is a need for developing markets for long-term contracts, needs careful consideration.**

Infrastructure and regulation

While generation and supply are based on decentralised decisions and subject to competition, networks, and other infrastructure, including system operation, are not. They are vested in companies which hold a monopoly right to operate, and often own, the relevant part of the infrastructure.

These monopolies are consequently subject to strict regulation. This concerns their day-to-day operations, but especially their investment decisions. New lines and other network elements need acceptance from the relevant authorities. When lines cross from one jurisdiction to another, they are subject to approval from both sides of the border.

The strict rules and regulations concerning infrastructure, and the considerable opposition with which new infrastructure is often met, has meant that building new infrastructure has become difficult. This is particularly true for cross-border interconnectors, where there may also be difficulties in reaching agreements on the financing of investments (Crampes and von der Fehr, 2023). Cross-border offshore projects, which may also act as interconnectors, and consequently raises a range of regulatory questions, is a point in case. Such **obstacles may have important implications also for future investment in generation and the ability to achieve a single market for electricity (and gas).**

At the European level, The Council of European Energy Regulators (CEER) provides a forum for cooperation and exchange of best practice between national regulators. Moreover, The EU Agency for the Cooperation of Energy Regulators (ACER) has been given the task of fostering integration and completion of the European internal energy market for both electricity and gas. Regarding infrastructure, the European Network of Transmission System Operators for Electricity (ENTSO-E) every two years presents a 10-year plan on how to develop the power grid (a similar plan for gas infrastructure is provided by ENTSO-G). The plan is the basis for selection of Projects of Common Interest, which are eligible to receive public funds.

While these institutions are clearly important, **it is still the case that development of the internal market is to a large extent dependent on decisions taken at the national level**.

SECTION 2: A DISCUSSION OF SUGGESTED INTERVENTIONS

What proposals have been made for dealing with the crisis at the wholesale level?

We will examine a number of proposals that have been made for dealing with the electricity crisis at the wholesale level. We look at the proposals from **ACER, Great Britain, Greece, Spain** and the **European Commission** as these are either implemented or well documented. The first three of these proposals also seek to address wider questions of future market design of the electricity market on the path to net zero, as well as seeking to reduce prices in the near term. The final four are discussed in both their short- and long-term context. As part of this, we discuss aspects of US Standard Market Design, such as nodal pricing. A number of companies and trade bodies (e.g., EnergyUK[25]) have also made statements on what they think should be done about electricity market arrangements; we comment on some of these below.

Although the topic is covered in section 3, this paper's core focus is not on proposals that have been made that apply to just the gas market. These include a cap on the Russian gas price[26] or indeed on all imported gas[27], or the introduction of a price corridor without a fixed cap[28]. These are not electricity market measures. However, price caps on prices paid for international commodity prices look unlikely to be sustainable. Other suggested interventions in wholesale gas pricing include the creation of a new LNG import benchmark price for natural gas to replace the use of the TTF wholesale gas price[29], and the joint purchasing of natural gas at EU level to attempt to reduce prices, via the newly established (2022) EU energy platform[30].

ACER

The Agency for the Cooperation of Energy Regulators published its 'final' assessment on EU wholesale market design in April 2022. A summary of its recommendations is contained in the figure below.

[25] See https://www.energy-uk.org.uk/index.php/media-and-campaigns/press-releases/526-2022/8286-energy-uk-backs-scheme-to-reduce-power-costs.html
[26] See https://www.reuters.com/world/europe/eu-energy-chief-calls-price-cap-russian-gas-2022-09-29/
[27] See https://www.politico.eu/wp-content/uploads/2022/09/28/Gas-Price-Cap.pdf
[28] See https://uk.movies.yahoo.com/eu-try-price-corridor-rein-184335783.html
[29] See https://uk.investing.com/news/commodities-news/eu-wants-new-transaction-based-lng-benchmark-in-bid-to-calm-prices-2766763
[30] See https://www.euractiv.com/section/energy/news/berlin-makes-u-turn-backs-joint-gas-purchasing-at-eu-level/

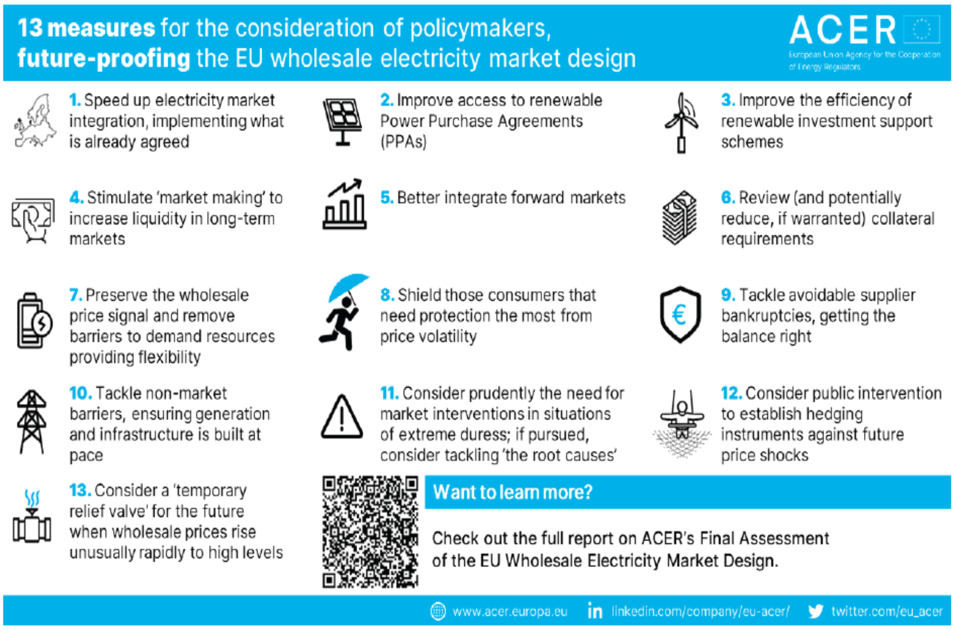

Figure 3: ACER Summary of Future Proofing Measures[31]

ACER's basic starting point is that the single market in electricity is something worth preserving and completing. It makes **13 recommendations** on 'future-proofing' market design. We can group some of the recommendations. For instance, the recommendations to 'speed up electricity market integration' (1), 'stimulate 'market making' to increase liquidity in long-term markets' (4), 'better integrate forward markets' (5) and 'preserve the wholesale price signal and remove barriers to demand resources providing flexibility, are all **objectives of current policy and a part of the current design** (or design intention) of the wholesale electricity market. These are sensible. Completion of the current market is estimated to bring benefits of the order 1-2% of the current wholesale price across Europe (see Newbery et al., 2016), especially if extended to ancillary service markets.

Recommendations on renewable support schemes are not strictly about market design, but about **how renewable support is integrated into the operation of the market**. 'Improve access to renewable Power Purchase Agreements (PPAs)' (2) would allow consumers to lock in lower renewable prices as part of their demand. This happens in some countries where long-term PPAs have been adopted by government renewable support schemes and where, if the strike price of the PPA is below the market price, revenue is recycled to the customer (e.g., Great Britain)[32]. 'Improve the efficiency of renewable investment support schemes' (3) would reduce the long run cost of renewable support. Examples of this would include moving to **auction-based procurement of renewables**, rather than paying fixed prices, or indeed moving to a **European system of renewable support**, where a given country could meet its renewable obligations with renewables in another country. This might give northern European countries access to solar resources in the south and southern countries access to offshore wind resources in the north. The inefficiency of nationally based renewable support schemes was

[31] Source: ACER (2022, p.7)
[32] For more detail on how the UK scheme works, see https://www.lowcarboncontracts.uk/contracts-for-difference

estimated to have cost Europe $100bn by 2014 (WEF, 2015, p.14). Neither of these recommendations is a quick fix for the current crisis but is certainly very sensible at any time.[33]

The nature of competition is addressed by three of the recommendations. Thus 'review (and potentially reduce if warranted) collateral requirements' (6) could improve entry into wholesale and ancillary service markets if small competitors are prevented from entering due to collateral requirements. 'Shield those consumers that need price protection the most from price volatility' (8) and 'Tackle avoidable supplier bankruptcies, getting the balance right' (9) are not strictly about the wholesale market. (8) This is really a **retail question**. For (9), the point is that a competitive wholesale market relies on active competition on the buyer side of the market. None of these recommendations seems likely to influence the price by much, but lower collateral for wholesale market entrants, protecting 'vulnerable' customers and encouraging 'sustainable' competition in the market are **sensible objectives for energy regulators** at any time.

'Tackle non-market barriers, ensuring generation and infrastructure is built at pace' (10) is a good idea, but hardly a measure that will address the crisis in the short-term. However, perhaps now is a good time to get **proposals blocked in planning through the planning system**.

The final three recommendations seek to stabilise the price against future price shocks. 'Consider prudently the need for market interventions in situations of extreme duress, if pursued, consider tackling 'the root causes'' (11) is a call to **make only limited interventions in the wholesale market** itself. If the root cause is high gas prices, then this concentrates on how wholesale electricity prices can be decoupled from high gas prices. It is not clear how this sits with 'Consider public intervention to establish hedging instruments against future price shocks' (12), which is reminiscent of the California power crisis of 2001-2002, where the State of California did eventually enter into long-term contracts for power in order to reduce the price in the wholesale market (see Sweeney, 2002).[34] 'Consider a 'temporary relief valve' for the future when wholesale prices rise unusually rapidly to high levels' (13) suggests that **regulators could step in to cap the price (or suspend trading) when wholesale prices behave in this way**. It is not clear whether this sort of measure can be left to national regulators or the European Commission itself.

Overall, this is a jumble of recommendations, several of which are not really about market design per se. There is nothing particularly concrete or implementable and few are under the control of the EU itself. It is perhaps not surprising that ACER do not recommend any radical departures from a European single electricity market policy that has been decades in the making. It is **worth emphasising the benefits of the single market**, because **a sensible European response relies on maintaining access to the European maximising total generation available and shared demand response**, with the benefits of this being relatively larger for periphery countries. It is also worth observing that, from a

[33] Indeed, if such a scheme had been put in place at the time of the first renewable electricity directive (Directive 2001/77/EC), the cumulative benefits might have been substantial in terms of both lower costs for consumers (across Europe) and higher quantities of renewables in aggregate.

[34] These contracts were heavily criticised at the time and looked high cost once the crisis was over (see Moss, 2002).

global perspective, there does not seem to a reason to quickly abandon the current market design in Europe, given that its desirable properties still indicate that it is a model to be emulated (see Chattopadhyay and Suski, 2022) and that existing market designs (e.g., in New Zealand, Brazil and Colombia) already cope with over 70% renewable electricity (Gimon, 2022).

Great Britain

The Department of Business, Energy and Industrial Strategy in the UK announced a comprehensive **Review of Electricity Market Arrangements (REMA)** in July 2022 (BEIS, 2022). This is summarised in Figure 4.

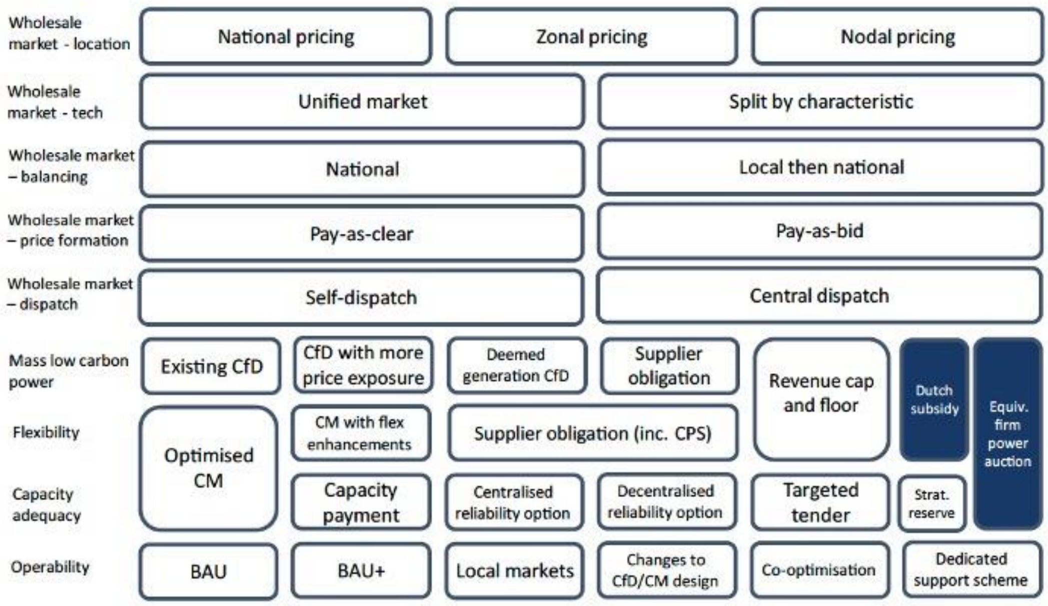

Figure 4 : Review of Electricity Market Arrangements[35]

REMA seeks to address the muted locational investment and operational price signals in the wholesale price, the limited temporal signals for flexibility, low wholesale market liquidity and not making efficient use of all the assets on the system (p.41-42). **REMA will make recommendations based on five criteria: least cost, deliverability, investor confidence, whole system flexibility and adaptability**. The review does this in the context of wanting to keep the cost of capital down to finance the energy transition at reasonable cost. The figure shows the areas being examined by the review.

The **first consideration (Row 1)** is whether the GB wholesale market should provide **locational signals** for investment and operational decisions. This would involve moving away from a single national price and splitting the GB market by zones or nodes, with prices varying by location and according to transmission constrained capacity. The introduction of a **locational wholesale market typically lowers prices in zones or at nodes where there was excess local generation relative to local demand**, in the

[35] Source: BEIS (2022, p.109).

presence of transmission constraint on electricity export; but **higher wholesale prices where local demand was higher than local generation**, in conditions where there was a transmission constraint on electricity import. In GB, this is expected to result in higher wholesale prices in the south than the north and more price volatility between and within regions[36]. The experience from other jurisdiction where price zones exist is that prices can be substantially different (e.g., between North Norway (Zone NO4) and Southern Norway (Zone NO1))[37]. The need for more accurate price signals to support flexibility and more efficient system operation and development has been emphasised by the GB System Operator, NG ESO (2022). This points to problems with rising constraint payments to renewable generators in export-constrained areas of the network, illustrating the need to adequately incentivise demand flexibility and storage[38]. It also notes that current price signals for the efficient use of the existing network infrastructure (in administrative use-of-system charges) are both complicated to understand, forecast and relatively weak. Serious consideration is being given in GB on moving to nodal pricing as part of REMA. We discuss the problems of nodal pricing in a European context in the below box. The introduction of nodal prices (see Box 1) could be seen as a key part of the introduction of the US Standard Market Design for electricity markets (see Wolak, 2021), which would also see the introduction of central dispatch (discussed below).

Box 1: Nodal Pricing

Nodal pricing is a proven market model used in many US markets, to provide short run locational pricing signals representing the marginal value of injections and withdrawals from the electricity network. It can lead to improvements in operational efficiency of the order 2-4% of operational costs.[39] It requires centralised coordination of dispatch, complex bid structures, and advanced optimisation software to clear markets, set prices and allocations taking into account all network and generation constraints. Locational price differences require complex point-to-point transmission rights to hedge bilateral trades. European markets rely on a zonal pricing model where firms self-dispatch, power exchanges are voluntary, and bidding structures and managing congestion risk is often simpler. Nodal pricing is sometimes presented as a zonal model with smaller zones, but this is an oversimplification, as market rules and the responsibilities of actors are very different.

In theory, nodal prices could improve price signals for market operation, generation investment, and provide incentives for network investments.[40] It is often used in systems generally characterised by decentralised political oversight of the electricity sector, weak national regulation and dispersed ownership of transmission assets (e.g., in North and South America where national energy regulation is weak). In its actual operation, **it does NOT operate in practice as theoretically described in electricity textbooks or typical explanations** (e.g., see the diagrams in Singh, 2008).

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[36] See Energy Systems Catapult (2022, p.9).
[37] See https://euenergy.live (Accessed 1 October 2022).
[38] See https://www.nationalgrideso.com/document/266576/download
[39] See Triolo and Wolak (2022) who find the move from zonal to nodal pricing in the Texas market (ERCOT) appears to have reduced operational costs by 3.9% or $323m in the first year of operation. Carbon emissions however increased, potentially offsetting all of this gain at European carbon prices. Wolak (2011) looking at the introduction of nodal pricing in California found a 2.1% or c.$105m annual variable cost benefit in moving from zonal to nodal pricing.
[40] For a spirited defence of nodal pricing, which makes clear its relationship to central dispatch, see Harvey and Hogan (2022).

There is no evidence that nodal pricing helps with getting longer term transmission investments built even in the US (Brown and Butterud, 2021, and Joskow, 2022a). Nodal pricing and efficient redispatch to meet transmission constraints results in the same actual power flows as zonal pricing, but different patterns of payments, as long as redispatch is efficient and includes cross-border flows and consumers (see Singh, 2008). A key payment difference being that in a zonal model, generators facing a transmission export constraint with the right to transmit are compensated, by consumers, for not generating, raising overall payments to generators. This might lead to gaming by producers who engage in an inc-dec game (See Dijk and Willems, 2011).

The nodal price calculated at any node is very sensitive to exact calculation. It is, say, arbitrarily defined as the marginal value of 1 MWh at a particular location. The nodal value could be different if the increment were different. Thus the price might be radically different if the increment were 0.1 MWh or 10 MWh. This difference could be material. A node could be unconstrained at 0.1 MWh and constrained at 1 MWh, or unconstrained at 1 MWh and constrained at 10 MWh. This would significantly alter the nodal price set for all generation and loads at a node. The surprising thing about nodal prices is that even at apparently unconstrained nodes, they could be higher or lower than the average price across the day at unpredictable times. This is a potential consequence of the mathematical arbitrariness of the selected increment. It is also true that if the configuration of the network changed, then nodal prices could change significantly. This would be true if the TSO were to change power flows or to make extra capacity available**. This means that nodal prices are NOT providing useful long-term investable price signals.**

The nodal prices depend not only on network topology, the setting of power switches and transformators, and stochastic security constraints and, due to the non-convexities in the market clearing, the starting values and heurisitcs used, which are unpredictable and outside of the control of the generators**. The nodal pricing model has therefore to be complemented with a system of point-to-point financial transmission rights, forward contracts on the nodal price differences, and a forward energy contract on the hub to provide investments incentives.**

Those financial contracts might be too short in duration to provide full hedging and are not very liquid. In contrast, in a zonal system access rights are explicit. Generators are guaranteed to be able to trade within their zone, and are compensated if that is not possible. (See Petropolous and Willems, 2020). The network operator is, as a result, often incentivised to overinvest to guarantee network capacity. High voltage network costs are usually less than 10% of overall system costs and some overinvestment which improves competition, liquidity and solves bottlenecks might be economically justified.

The short-run monetary benefits of nodal pricing are often calculated by running two market algorithms in parallel under the assumption that market participants do not change bidding or investment strategies, ignoring risk aversion, and hedging strategies, and overlooking the role of financial traders and investors.

The theory that more locational prices which vary in time and place will improve the economic efficiency of the system is based on the theory of the first best. This says that in a first best world, representing all variation in underlying cost would provide the right signals to connectees. Even if this is true, we live in a second best world. This means that there are unpriced elements of costs and inefficiencies. Indeed, nodal pricing is NEVER implemented as per first best. It is always partial, only certain nodes are priced. Not all parties are exposed to nodal prices, usually the demand side is subject to zonal averaging. Thus nodal pricing may lead to a focus on short run solutions rather than long run solutions. Locational signals are powerful and may induce too much response at particular nodes, given what is optimal in the long run, when more investment in the network occurs.

The creation of local markets is an issue for market power and the US has struggled with mitigating local market power (see Monitoring Analytics LLC, 2022, a,b). Some generators receive a must-run status, which means they are basically under regulated contracts. Auction theory (Milgrom, 2017) says that inducing competition between market participants with local monopoly power is possible and involves making bids which may have a local market power compete in a bigger market. While it is true that market power may be exercised by pivotal players behind constraints, in the redispatch market such players do not get to set the price for all players at a constrained node, as competition is maintained for other players. Market power mitigation methods can be equally applied in nodal and redispatch markets. As Graf et al. (2020, p.4) point out, that even though zonal pricing can lead to the exercise of market power, there is – surprisingly – no analysis of whether LMPs actually reduced market power relative to zonal pricing.

Financial Transmission Rights (FTRs) are presented as the solution to the volatility and uncertainty of introduced by LMPs. However, this raises a number of issues. If FTRs significantly reduce volatility and uncertainty by hedging market players, then this inevitably dampens to the price signal effect of nodal pricing. Further, given that LMPs are hedged and also represent only part of the overall price that generators and loads see at a given location, their behavioural response is questionable**. FTRs are lightly traded in illiquid markets and only exist over limited time periods. The evidence is that the FTR market in the US is inefficient.**[41] Analysis of FTR markets suggest that FTRs are substantially underpriced relative to their true value (see Opgrand et al, 2022), exposing customers to extra payment for electricity. The estimate is that financial traders take c. 5% of the value of FTRs out of the market. **The Market Monitor for PJM describes the market design of the FTR market as having 'fundamental flaws'**.[42]

If LMPs do work as intended and signal locational scarcity, then they expose generators (and any loads who are exposed to LMPs) to greater risk. This will raise the cost of capital and reduce

[41] PJM, CAISO and ERCOT all note problems with FTR markets in their annual market review reports. See Monitoring Analytics (2022b, p.680), CAISO (2021, p.212) and Potomac Economics (2022, p.70).

[42] See Monitoring Analytics (2022b, p.680), which describes PJM's FTR market as follows : 'The product, the quantity of the product and the price of the product are all incorrectly defined'. The value of this market inefficiency is large. In 2021 FTR auction revenue was $500m+ less than the realised congestion payments for ERCOT (Potomac Economics (2022, p.71).

investment or skew investment to rapid pay back assets. This issue seems to be ignored in the literature, even though market players in the US do comment on it.

Australia has also been considering nodal pricing. Neoen (2020) for instance suggest it would raise cost of capital by 2% if introduced in the Australian National Electricity Market (NEM). The existence of real time varying nodal prices reflecting network congestion raises the issue of who should be exposed to this risk. **In most networks it is for the network to manage its network congestion, and it does not generally reflect this on its users.** This is what is happening on the distribution system, with the use of local procurement markets by distribution system operators (DSOs) for constraint management.

While five-minute node varying prices would appear to be radically different from a zonal pricing alternative, in practice this is not the case. The existence of FTRs and zonal averaging of LMPs on the demand side and limited nodes at higher voltages means that actual exposure to time and space varying prices is limited**. Theoretical comparisons between zonal and LMP systems exaggerate the real differences between a zonal system with non-firm connection arrangements and implemented LMP systems.**

Evaluations of LMP system benefits raise more questions than they answer. The Energy Systems Catapult (2022) work was improperly presented as being about the benefits of LMPs. It was not. It was about the benefits of zonal pricing. Evaluations often seem to confuse savings on redispatch payments (which arise from the existence of firm connection rights) which are mostly transfers, with underlying operational cost savings. The calculated savings arise from models which assume LMPs are the right answer and give efficient signals. Therefore, it is not possible for a move to LMPs to do anything other than improve efficiency in such a model. For instance, the existence of market power or the potential negative impact on generation or transmission investment is not modelled.

In the end we can come at problem of providing a locational price signal from two ends: either start with complete LMPs and then reduce scope and variance (as happens in the US) to focus on most important net price signals, or start with limited locational signals and increase them incrementally (as we are now doing in UK/Europe). It is by no means obvious which is going to be best, but getting the right long-run signals for location is more important than getting short run signals right. The US system is arguably poor on this. **Nodal pricing rations available transfer capacity by price. The other way to ration by quantity (using capacity allocation rules).** Non-firm connection rights in a zonal market can have a similar effect as nodal pricing in terms of incentivising the value of location. Thus a new load or generator would not get right to unconstrained connection but would have to accept the right to export or import as available. This is an approach which has been trialed at the distribution level and does create incentive on network company to expand network when this is worthwhile, as it gets more units transferred. **The benefits of LMPs in the European context are poorly understood and modelled.** What is required is careful modelling of system costs in line with the indicative planning of the roll-out of renewables. This will signal how costs might evolve and model large scale power flows. This will suggest the size and landing points of offshore wind, for example. Exposure of all parties to LMPs needs to be handled carefully. **Mitigation of market power and use of FTRs requires careful design and the lessons from the US are both unclear and invite further investigation.**

The **second consideration (Row 2)** is whether **the different generation technologies should effectively trade in different markets which could clear at different prices**. A number of **two-market approaches** have been recommended, but one (from Keay and Robinson, 2017) suggests that there could be a **separate market for intermittent power and for dispatchable power**. Thus, wind and solar would be in the intermittent power market and some customers would be happy to buy power from this market (flexible demand customers). Gas turbines would be in the dispatchable power market and available when needed and customers who wanted such power could buy from this market. Under current circumstances the price might be lower in the first market than in the second. Individual customers could buy from both markets to satisfy their demand. There is a related two-markets suggestion that there should be a Green Power Pool (from Grubb and Drummond, 2018) separate from the current power market. In Grubb and Drummond's variant, renewable energy only would face a separate long-term contract market price with demand being directed at bulk industrial sectors, among others. Grubb et al. (2022) further expands on the Green Power Pool concept and makes it clear that there would be two short-term prices for green and conventional power, and that customers (including industrial customers vulnerable to international competition) could be allocated shares of these different types of power.

The **two-markets idea is a confused one because it conflates several different things**: namely long-term contracting for part of demand and short-term market price determination. Thus, while long-term contracting for low carbon generation might yield lower prices and be a sensible hedging strategy, two short-term markets does not make a lot of sense**. This is because two short-term markets is a form of market segmentation** which **arbitrarily separates generators** who in theory provide the same product. Most of the time kWhs from different generators are identical. No rational renewable generator would want a lower price for its product if it could sell in the dispatchable power market at a higher price. A simple way to arbitrage this would be to simply combine renewables with a gas turbine or with a battery within a portfolio and sell dispatchable power. Indeed, Keay and Robinson suggest that a **group of generators could choose which short-term market they were in** (including nuclear, biomass and storage), further ensuring that such arbitrage would take place. To the extent that forcing the system to have two short-term markets and then incentivising costly arbitrage incurs real additional costs to meet market qualification rules and operate two short-term markets. The net result would be to **raise system costs and prices** relative to the current single market price arrangement.

A further fundamental mistake with the two short run markets solution is the idea that the marginal costs of different types of technologies are always different in real time. This is not true, renewables are often constrained off at the margin, meaning their marginal cost of delivery is above the market price. Indeed wind curtailment rose in several European countries between 2009 and 2020 to several percentage points of total wind output (see Yasuda et al., 2022). High market prices incentivise investment in batteries and network capacity by renewable generators. Even nuclear power and large renewables face high marginal costs when coming back from outages early or advancing projects to completion early, not to mention incentives to run equipment hot above its design rating for short periods, at increased risk of wear and tear.

The well-meaning intention of such a suggestion is to use a **two short-term markets solution to capture the resource rent arising from renewables and give it to electricity consumers**. As such, it has the potential to **sacrifice market efficiency to tax resource rents**. The aim of such a redesign is to capture the resource rent of a favourable technology (arising from the availability of free wind or sun at a particular location), without the need to pay the owner of the technology the rent which arises in an efficient market at the market clearing price which is currently set by the price of gas used to generate electricity in a gas turbine.

Another issue with the two short-term markets approach is that while it aims to capture the resource rent that may be present in electricity, an **increase in inefficiency which inadvertently drives up the demand in the gas market creates more resource rent there**. There is in fact a **'two rent' problem**. Given that most gas in most European countries is almost wholly imported, national attempts to capture electricity resource rents may backfire if they increase rents (for foreign owners) on imported gas.

The point is that **we have other ways to do this which maintain market efficiency and limit resource rents.** The most obvious is the **auction for large-scale low carbon generation**, particularly for wind and solar resources, or for nuclear power. These result in government locking in low prices for some part of the total national generation. Any positive surplus arising from selling this at the market price – such as might arise when fossil fuel prices are high – can then be captured by the government and used to reduce electricity bills. This is precisely what happens with the **CfD auctions in the UK**, where the Low Carbon Contracts Company receives the difference between the market price and the CfD strike price and uses this to reduce the levies paid by consumers for low carbon power. Other mechanisms, such as **profits taxes and auctions for the seabed** (and the right to build offshore wind facilities) are additional ways in which resource rent arising from renewables can be taxed.

The Low Carbon Contracts Company is the government entity which acts as the counterparty to CfD contracts between the generality of retail electricity customers and low carbon generators. Originally, the government did consider entirely private contracts between retailers and low carbon generators[43], but abandoned attempts to organise a private group purchasing arrangement due to the legal complexity of doing this (multiple private retailers with continually changing market shares). This experience illustrates the **difficulty of having a private contract between generators and the entirety of the customer base**, which might be useful for individually large generation projects. The additional advantage of the UK arrangement is that non-payment risk is removed from the generators and this reduces the cost of capital relative to private PPAs.

[43] See DECC (2011, Chapter 4).

Auctions for low carbon generation are a good idea if they do reduce the long-term cost of procuring generation capacity that would have been required anyway (via both more competitive procurement and lower financing costs). They are part of what Roques and Finon (2017) identify as the emergence of 'hybrid market regime' where the electricity market combines competition in the market (via conventional power markets) with competition for the market (overseen by the government) in the areas of low carbon generation and reserve capacity. However, it is important to point out that over the long-term the aggregate benefits of this to consumers depend on the correct identification of both the quantity and type of procurement by the government, which historically has been cumulatively poor in some countries, including the UK[44]. An alternative future with investments being left to be guided by longer run market signals could result in less overcapacity and cheaper types of generation. Given that hybrid markets have been developing over the last decade in Europe with the gradual extension of capacity markets and auction-based procurement of renewables, a further move towards hybrid markets is an evolution, not a revolution, in market design (Keppler et al., 2022).

It is important to point out that even long-term contracts mature and that at any point in time only a percentage of electricity generation can be covered by a long-term contract. Thus if all new generation were subject to a 15 year CfD and generation plants lasted on average for 30 years, then it would take 15 years to grow long-term contract cover to 50% of generation (assuming no growth in demand). With permanent growth in demand the long-term contract coverage would be higher but would never reach 100%.

The **third, fourth and fifth rows** refer to **the specifics of market price determination within balancing and energy markets.** Balancing markets could be cleared locally (a form of locational pricing, discussed above) or nationally as now (Row 3). Energy markets could switch from pay as clear to pay as bid (Row 4). Pay as bid is thought to produce slightly lower on average market clearing prices, as bids are shaved lower to increase the probability of being dispatched (Krishna, 2009). However, auction theory says this is less efficient because it might lead to costlier producers being dispatched above cheaper ones (due to bid shaving mistakes), raising overall system costs. A move from **self-dispatch**, as now, to **central dispatch** would see the system operator dispatching plants in price merit order directly based on the short-term market, rather than based on self-declaration of the desire to be dispatched.

Central dispatch is thought to be marginally more efficient because the system operator makes use of all available bid information to dispatch, while under self-dispatch generators must correctly predict their own costs relative to the costs of others and the overall likely market clearly price (and cannot see others' bids), given that profits depend on the actions of others some of which may not be well informed. Analyses of US markets suggests operational cost savings of the other 2-3% of generation operational costs from central dispatch relative to self-dispatch (see Sioshansi et al., 2008), though this is disputable given that such a calculation assumes that system operators know the real time costs of each generator (in particular their real time fuel cost and ramping costs), whereas self-dispatch

[44] See Pryke (1982) on the woeful record of the CEGB.

makes better use of the private information known to a given generator about its own costs of generation in real time. Indeed, in 2016, the Competition and Markets Authority, having looked at central vs self-dispatch in Great Britain, concluded that 'Nor have we found evidence of systematic technical inefficiency arising from self-dispatch' (see CMA, 2016, p.10).

Local energy or balancing markets, cleared at each grid supply point are a possibility (as discussed in Pownall et al., 2021). Local markets are a form of incomplete locational marginal pricing, which effectively does the same thing at a higher-level granularity while also allowing direct competition between generators in the absence of network constraints.

REMA also raises issues to do with **capacity markets or capacity remuneration mechanisms (see Box 2).** Capacity markets are another element of US Standard Market Design (see Fabra, 2018). The UK has a capacity market introduced in 2013. Under this mechanism, the system operator contracts for peak capacity. The main capacity auction is for four years ahead, with a one year ahead auction and capacity contracts that can be 15 years. Capacity markets can be thought of as a part of market design which reduces peak energy prices in return for more certainty around the availability of capacity. **One issue is whether the capacity market should be replaced by reliability options**. A reliability option is a tradeable option whereby generators compensate retailers above a certain wholesale price and hence get paid to be available at times of high prices. They would usually be combined with physical penalties for non-availability at times of high prices. They give very high incentives to be available at times of high prices, not just declared capacity stress events which trigger penalties in a capacity market. Capacity remuneration mechanisms represent an **add-on to the standard European electricity market design** (see Roques, 2021b).

Box 2: Capacity Remuneration Mechanisms

Many European markets and most US markets have organised *capacity remuneration mechanisms* (CRM).[45] In a CRM, the government pays generators for generation capacity in return for a commitment by generators to be available when capacity is scarce. Those commitments often take the form of Reliability Options[46], which are financial call options which are backed-up by generation capacity. Those contracts are procured by the government in an auction often for a period of 1 to 3 years. The payments in the auction, the option price, provide a steady revenue stream to the generator. The strike price of the reliability option limits the payments the generator receives when the spot price is above the strike price, and hedges consumers against price spikes. The reliability options reduce market power abuse in the sport market.[47]

[44] See Hancher et al. (2022) for an overview of the capacity remuneration mechanisms used in different Member States.

[46] Vazquez et al. (2003) is one of first to propose such a scheme for the Dutch electricity market, highlighting already many of the theoretical foundations of the model.

[47] Joskow and Tirole (2007) show that if firms can exercise market power in one state of the world, a price cap and an investment subsidy can restore first-best. Willems (2022) shows that such a subsidy should be technology neutral not to affect the generation mix. Willems (2005, 2006) models a Cournot model with call options and show that might have more pro-competitive effect on spot-market competition than forward contracts.

Why use capacity markets? Not all economists agree on the need of capacity markets. Joskow (2008) looks at the US markets and shows empirically that investors are unable to recoup their investment costs even though capacity is scarce; and highlights several reasons why this might be the case, among others, the existence of price caps in the spot market, monopsony power of the network operator reduce generators' revenues.[48] Cramton and Stoft (2005) indicate that without capacity markets, generation investments depend on the Value-of-Lost Load (VOLL), which is ill-defined without sufficient consumer participation, and would prefer the regulator to set a quantity target. In an oligopoly with entry barriers, a capacity mechanism can bring investments closer to the social optimum (Léautier, 2016). Hogan (2005) argues against capacity markets and prefers that generators and retailers sign bilateral contracts to hedge their positions, and contract away market power.[49]

Compatibility of reliability contracts with other financial contracts such as PPAs

If the strike price of the reliability options is relatively high, then they act as a safety valve on the spot price but leave sufficient room for private parties and / or governments to sign long-term financial contracts. Capacity markets can thus be complementary to other markets. Roques and Finon (2017) call this a modular approach to market regulation and see capacity markets and long-term contracts as two complementary modules.

Lessons of capacity markets design

The design of capacity markets is not straightforward, and many markets see continuous reforms. Those lessons might carry over to new market designs with government-backed long-term contracts.[50] Reliability options are not purely financial contracts, as they are linked to physical assets. This implies that the option price is larger than of a corresponding financial option contract and includes some form of remuneration for investments. Those implicit subsidies affect the generation mix and the distribution of spot prices. It is important to treat intermittent generation and demand side flexibility on an equal footing in the capacity market, as those technologies find it harder to provide a standard reliability contract. Capacity contracts are therefore often adjusted, for instance with a capacity factor.[51] A shift from market power abuse in the spot market to the capacity market might also be an issue , especially if markets are not well-designed, for instance with an inelastic demand for capacity. Cramton and Stoft (2005) suggest that in a nodal market system, capacity markets might reduce locational signals, and location specific capacity markets might need to be developed.

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[48] Note that US markets differ from most European ones as they have obligatory spot markets (pools) and limited retail competition. In Europe generators could decide not to participate in the spot market and instead sell directly to retailers, and avoid some of those problems.

[49] Both groups agree that the prevention of black-outs by the creation of short-term reserve markets is necessary. (Joskow & Tirole (2007) build a micro-founded model on the role of reserves, stressing the lack of demand response and the public good aspects of security. Hogan (2013) stresses that the opportunity costs of using reserves need to be correctly reflected in the spot market prices, in order to obtain efficient market outcomes.

[50] If the goal of new contracts is to de-risk investments, the duration of those contracts will be longer than 1-3 years, and the strike price will be (much) lower, and closer to the fuel price, and maybe even indexed on the fuel price evolution.

[51] Bothwell & Hobbs (2017) demonstrate the use of adjustment factors which depend on the correlation between wind availability and energy scarcity Fabra (2022) suggests instead to use reliability contracts for thermal generation and contracts for differences based on available capacity for intermittent generation. In contrast to Roques & Finon (2017), reliability options and contracts for differences are not two different modules of the market design, but target two different technologies.

In a European context seams issues between capacity remuneration mechanisms matter
These include the relative attractiveness for given capacity to sell into different capacity markets across interconnectors. Higher market prices, arising from a higher VOLL, will attract capacity. Countries might also free-ride on capacity remuneration schemes made in neigbouring countries, or try to restrict export of energy from contracted capacity in case of an emergency.[52] The treatment of interconnectors in capacity mechanisms raises issues of the extent to which two connected systems can contract with the same capacity (given that co-incident peaks might be unlikely and capacity events usually have national origins) and how interconnectors are treated within capacity mechanisms (i.e. what availability might be assigned to an interconnector for capacity derating purposes**)[53].** Bucksteeg et al. (2019) discuss the significant benefits of coordinated capacity market design across Europe[54]. This would seem to leave a role for ACER and for the European Commission to regulate the role of interconnectors in capacity mechanisms.

A striking feature of these suggestions on specifics of market price determination within balancing and energy markets is that they are **small changes to existing market design,** which individually will not make much difference to average energy prices. Indeed, the reason they have not been implemented is because their overall efficiency is questionable at best. They **may however be sensible incremental improvements** to market design on the road to net zero (see Pollitt and Chyong, 2018).

A sixth consideration is around **how renewables should be contracted for and their price regulated**. The current CfD auction scheme involves simply purchasing all of the output of the project at the auction market clearing strike price over a fixed period (usually 15 years). This could be changed to an **equivalent firm power auction** where capacity market and CfD markets are combined on the basis of their equivalent firm power (adjusting for intermittency), or a **deemed output CfD auction** where the strike price is paid on a fixed amount of output, which would encourage locating renewables where subsidies would be paid out more quickly. The revenue of renewable generators could be subject to caps and floors to reduce excess profits in return for guaranteed minimum revenue. A Dutch Subsidy has bidders in low carbon auctions bidding based on their cost of carbon abatement rather than low carbon electricity. This would allow low non-zero carbon sources to compete with zero carbon sources.

[52] Özdemir et al. (2013) study the efefct of a German capacity market on the Northwest Europe.

[53] More research on the cross-border aspects of CRMs is necessary, in particular on the allocation of risks between network operators and the foreign provider of capacity and the physical and financial collatorals provided is necessary. The fact that cross-border participation of capacity is not functioning well can be illustrated in the Benelux. RWE was considering to participate in the Belgian capacity market with its power plant (Clauscentrale) in the Netherlands and wanted to build a 13 kilometer dedicated line to connect to the Belgian network, in parallel to an existing line of the TSO. It withdrew its plans after strong resitance of the Dutch ministry of economic affairs and the regional government. The arguments against this was that the CO2 emissions would be counted as Dutch emissions, while the power would be consumed in Belgium, and the fact that the exporting power would reduce the secuirity of supply in the region (although the power plant was already mothballed).
https://m.limburger.nl/cnt/dmf20220624_94969404# :~ :text=Het%20moet%20een%20totale%20capaciteit,die%20eind%20dit%20jaar%20plaatsvindt

[54] Instead of separate decentralized capacity markets, joint procurement of capacity might be relevent if cross-border capacity is large and price spikes are likely to be temporarily correlated.

None of these approaches seem likely to significantly, if at all, increase overall efficiency in the electricity sector, relative to the current CfD auctions. Equivalent firm power, by combining two currently separately priced attributes in one auction, is unlikely to improve efficiency. Deemed renewables might be useful for guaranteeing the total quantity of money received for a project, but not the time over which it is received, so seems to replace one sort of uncertainty with another. The Dutch subsidy scheme does what a carbon market does and does not focus on what a CfD auction does, which is procure a given amount of low carbon capacity at least cost (and hence promote low carbon technology roll out).

The trade association for the electricity and gas supply industry in the UK, EnergyUK, recently came out in favour of converting nuclear and renewables to voluntary long-term contracts, citing work by the UKERC[55]. This work[56] had calculated the voluntary CfDs for nuclear and renewables could reduce current costs by up to £22.4bn per annum, though this looks like an over-estimate[57]. As UKERC point out this is a high-end figure and seems unlikely to be realised in full, as nuclear plants near the end of their lifetime are unlikely to want to sign such contracts. It also includes biomass, whose price has risen sharply recently. The UK Prime Minister announced in September 2022 that there would be a **move to convert existing low carbon contracts to CfDs**.[58] We discuss the economics of such voluntary long-term contracts below.

Greece

The Greek government presented a non-paper proposal on power market design on 22 July 2022 (Council of the European Union, 2022a). This again proposed a **two short-term markets solution** (similar to Keay and Robinson, 2017). They proposed a segmented market consisting of: (a) CfDs based on total levelised cost for nuclear, renewables and hydro ('when available market') and (b) fossil fuel, peak hydro, demand response and electricity storage ('on demand market') They suggested that high efficiency co-generation should also be included in the 'when available market'. 'When available resources' would submit volume-based bids in a mandatory day-ahead wholesale market and be paid their CfD prices. The day ahead market then clears based on clearing the net load with the on-demand bids. Intra-day and balancing markets are proposed to be unaffected and continue as now. Consumers then pay the weighted sum of the CfDs and the net demand market prices.

This proposal imposes new contracts on existing low carbon sources not currently covered by CfDs or feed in tariffs. It also introduces an **arbitrary distinction between the two short-term markets** and the **ability to arbitrage** through the purchase of storage or through withdrawal from the day-ahead market and selling in the balancing market. Maurier et al. (2022), offer a good critique of the Greek proposal. CfDs, written on behalf of customers alone are what deliver the lower retail prices, so it is not clear why a new and inefficient market design (as we explain above) is needed. They also point

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[55] https://www.energy-uk.org.uk/index.php/media-and-campaigns/press-releases/526-2022/8286-energy-uk-backs-scheme-to-reduce-power-costs.html
[56] Gross et al. (2022).
[57] To get to £22.4bn, the authors have to assume that biomass fuel prices do not adjust in line with fossil fuel prices.
[58] https://www.gov.uk/government/publications/energy-bills-support/energy-bills-support-factsheet-8-september-2022

out that the mandatory inclusion of the when available segment reduces dispatch signals for this segment, ends market-based renewables and raises legality issues with the arbitrary imposition of CfDs. A further suggestion that this blunts demand side incentives is not strictly correct, because that depends on the nature of the retail tariff that they faced.

It is worth noting that, at national level, Greece has introduced a series of measures to finance compensatory payments to consumers. In June, a windfall profits tax was introduced, which taxes extraordinary profits of generators at 90%.[59] The proceeds are credited to the so-called Energy Transition Fund for subsidising consumers' electricity bill. In November, a Retail Market Revenue Return Mechanism was introduced, which in effect confiscates the difference between actual retail market prices and a Reasonable Maximum Retail Price determined by the regulator. Also here, the proceeds are credited to the Energy Transition Fund. The latter measure was introduced in parallel with an Electricity Demand Reduction Service, which obligates electricity consumers, or load-serving entities on their behalf, to reduce demand during peak hours by a quantity set by ministerial decision; compliance comes with a financial compensation (from the Energy Transition Fund), while non-compliance is subject to a penalty.

Spain

In May 2022, the Spanish government adopted a novel direct intervention in the operation of the wholesale power market (see von der Fehr et al., 2022). This **paid gas-fired power plant generators a subsidy** equal to the difference between the day ahead natural gas price in Spain and EUR 40 / MWh (initially). This effectively capped the gas cost at EUR 40 / MWh. By law, generators must use this price in calculating their offers in the European market coupling algorithm. Given limited interconnection with France (and Portugal), this has resulted in **lower wholesale power prices in Spain, though prices are still very high in the wholesale market**.[60] This may be because gas fired power plants in Spain are not setting the marginal price of electricity, possibly more expensive demand response is. For instance, if industrial consumers are deciding to reduce their electricity demand by increasing direct combustion of gas, which they could otherwise sell at the unregulated market price of gas, demand response bids would still reflect wholesale gas prices. Thus the fundamental shortage of gas would still be manifesting itself in electricity prices.

This approach **does not change the existing market design and it is a way of reducing the rent being extracted by low-cost generators**. However, it is **very inefficient**. We describe just how inefficient the Spanish intervention has been in Part 2, Section 1. By subsidising the use of gas in electricity production, it **increases the demand** for gas by encouraging substitution away from coal and biomass and renewables with storage and it also drives up the demand for electricity. Given that it pushes up the demand for gas, it increases the cost of gas to other users, such as industrial users of gas. It **exacerbates Europe's overall supply crunch** and creates a **cross-border trade distortion** due to the fact that the cost of gas for power generation is substantially different in France and Spain. The policy

[59] https://www.reuters.com/article/greece-energy-profit-idUKL5N2X31R2
[60] https://www.surinenglish.com/spain/domestic-electricity-bills-20220823173417-nt.html

is also very **costly**, as the government has picked up the bill for more gas than would otherwise be used at a higher price. As a policy for reducing low carbon rents, this is an **unusually distortionary one and not a model for any other country** (or Europe as a whole) to follow. If this policy were followed across Europe, we would see demand for gas for power surge across Europe at a time when it should be reduced[61]. This intervention, approved by the European Commission, does not make sense for the wider European energy market. It is a political decision to appease an individual member state. If this happened across Europe it **would worsen the gas supply crunch and push up gas prices even further**, distorting relative electricity and gas prices across Europe.

Clearly, **interventions to limit costs to marginal bidders in the electricity market do not make sense in the long-term on the path to net zero**. They do however highlight an important point that **proper oversight of marginal bids in any power market is important**, because it does directly impact on the market price. This was an important lesson from the Californian electricity crisis of 2000-2001 (see Sweeney, 2002), and highlights the **potential role for market monitoring of marginal bids**. One of the disputed elements of market pricing in California was the existence of a soft price cap, which capped wholesale bids up to the cap and then was pay as bid beyond the cap. This can be a way to limit both market power and the negative externality of high marginal bids. The impact of this on market efficiency is negative (see Vossler et al. 2009), but the distributional consequences could be positive.

European Commission

In September 2022 the European Commission proposed 'an emergency intervention to address high energy prices' which is 'time-limited'. A further agreement was reached on September 30, 2022 (see Council of the European Union, 2022b) and a Council Regulation was adopted on 6 October 2022.[62]

This consisted of several important elements:

1. A target **reduction in total electricity demand of 10%**, with a target **5%** reduction in electricity consumption during **peak hours** during the period 1 December 2022 to 31 March 2023 (member states must identify peak hours representing at least 10% of all hours over this period). This is relative to a reference period of the five years beginning November 2017 to March 2018.

2. '**A cap on market revenues from infra-marginal generation technologies'** (p.5). This would include renewables, nuclear and lignite.[63] The proposed cap is 180 Euros / MWh but may be adjusted depending on the generation technology. This cap would be applied to 'realised revenue' and would apply to all revenues whether they occurred under long-term contract or from participation in short run markets.

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[61] For a good discussion of the need to reduce gas consumption across Europe this winter and how to achieve it, see Bachmann et al. (2022).

[62] Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

[63] The full list of technologies included in the cap are: '(a) wind energy; (b) solar energy (solar thermal and solar photovoltaic); (c) geothermal energy; (d) hydropower without reservoir excluding pumped hydropower without reservoir; (e) biomass fuel (solid or gaseous biomass fuels), excluding bio-methane; (f) waste; (g) nuclear energy; (h) lignite; (i) crude oil and other oil petroleum products; (j) peat.'

3. A **temporary solidarity contribution** based on taxable surplus profits made in the fiscal year 2022 and/or 2023). This would be made on crude petroleum, natural gas, coal, and refinery companies. This would contribute to a fund at the European Union level. Only profits more than 20% higher than the level of the four years from 2018 would be subject to additional taxation (p.28). The minimum tax rate would be 33% on these additional profits, though higher tax rates could be applied. The tax rate would be applied to 2022 or 2023 profits.

4. Revenues from the cap and solidarity contributions are required to be **recycled to household and industrial customers**.

While there is agreement that demand reduction is necessary, there is no suggestion about how it is going to be achieved. Pollitt et al. (2022b) advocate the use of **rising block tariffs** to **reflect high marginal prices to customers and help incentivise demand reduction**. It is also unclear what the point of the 5% peak demand reduction target is, when the primary objective should be to reduce total demand for gas. If the 10% average target is achieved, it is likely the peak 5% target would be redundant, given that even bigger off-peak reductions would be required if demand is not reduced by 10% in peak hours. The cap on market revenues is a market design feature. However, it is not a straightforward bid cap, as the cap is on 'realised revenue'. It will not be easy to police and a bid cap would have been a simpler measure, albeit more inefficient. The solidarity contribution is a 'voluntary' temporary tax measure, combined with a requirement to recycle the revenue to consumers.

None of these measures directly impact the design of the wholesale market, and they are **aimed at relieving pressure on household and industrial consumers in retail markets**. However the 'cap' on the revenues of inframarginal generational technologies does raise issues about whether it would in fact be inefficient at the margin and reduce production. In effect, it amounts to a profits tax which is potentially more than 100% on marginal low carbon technologies (and lignite), which is more costly than the cap to produce, but less costly than the full market clearing price. A high profits tax remains a superior approach.

At the request of Member States, the European Commission (2022) produced a non-paper in September, examining the effect of an extension of the Spanish approach to the whole of Europe. It suggested a cap price on gas for power generation of 100-120 Euros / MWh, with member states picking up the difference between the cap and the TTF wholesale gas price. This approach would have all the disadvantages noted earlier of the Spanish approach, with the potential for a much larger distortion in electricity trade – given the size of EU electricity trade with Great Britain and Switzerland - and a bigger impact on the TTF price itself due to the larger demand distortion. The non-paper naively suggests that the UK and Switzerland should be encouraged to adopt similar measures, when this measure is clearly not in the interests of either individual countries or Europe as a whole. The non-paper admits to differential effects which are higher gas costs for Germany, Italy and the Netherlands and lower power import costs for France. It also ignores the potential for alternatives, such as profits taxation or more use of longer term PPAs to redistribute money to consumers without interfering with the efficient operation of short-run electricity and gas wholesale markets.

The European Council has since pressed the Commission to produce a concrete gas price cap proposal At the time of writing, member states were negotiating the Council Regulation proposal for a Market Correction Mechanism tabled by the Commission at the end of November.[64] A cap on gas prices at the TTF is also being discussed.[65] It is important to point out that a high price cap on gas an one European gas hub does not make much sense, for the following reasons. First, it encourages arbitrage between hubs (gas is traded on non-regulated European hubs e.g., NBP in the UK) and times (trading is spread in time but average prices are not reduced). Second, it is likely to be set at a high level and hence not be expected to have much aggregate impact (and so is rather meaningless gesture). Third, if it is actually binding it threatens European gas supply security e.g. at crunch points in the winter), which high prices have so far ensured. Fourth, it sends the wrong global signal that the EU is not serious about encouraged global free trade in energy and invites negative reciprocal action (e.g., from Qatar or the US).

Overall observations on suggested changes to market design

Wholesale fossil fuel prices have provoked renewed interest in market design. Some suggested design changes to the operation of current electricity markets are sensible but even in aggregate they do not offer the likelihood of significant reductions in prices. Indeed, it is unclear as to whether any of them could be implemented quickly. **Continuing with the single electricity market agenda looks just as promising and more important for periphery countries and shared energy security**.

Not surprisingly, the suggested changes to market design, motivated by how far we are currently along the way to net zero and the reality of a gas supply crisis, are not that radical. Fundamental changes to future market design can however be contemplated. For example, **internet style 'rationing' of electricity** in real time to reflect the availability of intermittent renewables and the physics of the system. This would supplement price signals with pre-set algorithmic allocation of electricity to prioritised loads (see Pollitt, 2021). Meanwhile, others (see Gimon, 2022) have – less radically - suggested developing entirely private long-term PPA market in the form of an **organised long-term market** (OLTM) which would allow blocks of low carbon energy to be packaged over longer time frames. This would both allow smaller generators to be aggregated and smaller retailers to buy portfolios of longer term power. By contrast, Finon (2022) suggests an **entirely public central buyer model**, based on long-term government backed PPAs. This is a return to the situation under public monopoly ownership of generation where the state would decide all new generation investment and would essentially purchase all of it under long-term contract from external contractors. Under the modern variant of this model, a single buyer would purchase all low carbon generation under competitively awarded CfDs. The difference between Finon's model and what happens currently in Great Britain with the Low Carbon Contracts Company awarding fixed term CfDs for certain types of

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[64] European Commission Proposal for a Council Regulation establishing a Market Correction Mechanism to protect citizens and the economy against excessively high prices (2022)

[65] Fabra et al. (2022) express support for an imported gas price cap to address strategic behaviour by Russia. They, riskily, assume that this would not result in strategic retaliation in terms of further reductions of exports to Europe from Russia (or other producers).

new generation being one of the likely future extent of the share of power covered by the single buyer (Finon's share of generation purchased by the single buyer would be higher).

Many of the sensible suggestions for reform that we discuss above will only reduce prices in the longer term. There are few market-based design improvements which deliver anything other than marginal changes to average prices. Even the introduction of locational marginal pricing will not reduce average prices by much, even if some locational prices will fall. What remains true is that **extension and deepening of existing markets can increase efficiency and reduce prices**, even if the absolute reduction is only of the order 2-3%. This is sobering in the light of the very large rises in wholesale prices we have seen.

Two surprising observations are that, despite the European Commission's efforts and sensible recent proposals for electricity and gas demand reduction, **more detailed work has not been done at national level across Europe to prioritise actual demand reduction for electricity and gas**, and that **completion of the single market** to protect periphery countries in both electricity and gas is not being further accelerated. A worst-case scenario is that individual countries restrict flows across interconnectors this winter and that we see a breakdown or breakup of the single market in energy. The failure to coordinate a large demand reduction may mean that distorted demand signals will worsen the crisis in certain countries and put unnecessary pressure on the single market.

Markets are largely working as might be predicted given the large underlying rise in the price of gas and market efficiency seems to be being maintained. However, markets do not merely exist to be efficient in many jurisdictions, where they should be seen to achieve wider societal goals, such as perceived fairness. Markets work by raising prices in times of scarcity. This has created revenue streams for some and leaving some market parties exposed to unhedged high prices or some customers unable to pay. This is generally **acceptable if it occurs for short periods, but it clearly cannot continue if large groups of household and industrial consumers cannot afford to pay**. One large energy supplier suggested 50% of all households would struggle with energy bills in the UK this winter.[66] European energy poverty is also expected to increase relative to when it was last measured in 2019.[67]

A **frequently suggested change is for governments to sign longer-term contracts with generators on behalf of customers** (i.e., increase hedging)[68]. This parallels the idea that retailers might agree limit price rises now in return for recovering losses in future years as a form of long run energy pricing. The idea of signing lower price contracts at a time of high short run prices is attractive, but it is less attractive when short run prices come down. The point about this sort of contracting to reduce bills now on existing generation is **whether it is efficient because it effectively borrows money at a high cost of capital from private energy firms**. **Direct government subsidy** (funded by taxpayers or borrowing) to bills would be **more efficient and deliver the same bill reduction** now at a lower long-

[66] https://www.bbc.co.uk/news/business-62643934
[67] See for example: https://edition.cnn.com/2021/09/30/business/europe-energy-poverty/index.html
[68] See for example Batlle et al. (2022).

term financial cost. This is because signing a private PPA with a utility essentially implicitly causes the utility to borrow on private capital markets against its expected future income to smoothe consumer bills, while the government could simply self-finance the smoothing of consumer bills via government bond markets. For instance, at a BBB corporate bond rate for a utility of 5.33% vs. a government bond rate of 3.64%, delivering one year of bill reduction and paying it back over 20 years, it is 32% cheaper for the government to fund it. To put it another way, **the government can reduce the bill by 46% more for the same amount of future repayment, by using government borrowing**. This is relative to the case where the government signs an efficient long run contract.

The **available size of the inframarginal rent from low carbon generation, accruing to generators, is likely much smaller than is being suggested**. Renewable power only makes up 30% of electricity in Europe and much low carbon generation is already sold under lower-price, long-term contracts, from which consumers are benefitting[69]. Meanwhile most retail businesses are integrated with generators and are selling power at below wholesale prices.

There have been **several versions of a 'two-market' solution**, as we discussed above. The UK's REMA explicitly raises it, based on earlier suggestions. The Greek approach also suggests it. Such an approach produces two prices: a marginal price and an infra-marginal one. The central aim of the two-market solution is to price marginal gas-fired power plants at a different price to infra-marginal plants, such as nuclear and renewables. This can be done in the long-term market or in short run markets. In the short run market it could involve a price cap on the bids of low carbon generators. We argue above that **long-term markets already offer a form of a two-market solution, via long-term auctions for renewables**. **Two markets in the short run raises difficult issues whereby market efficiency is likely to be reduced, potentially substantially**. In the short run, the marginal cost of extra low-carbon output from a given facility can be high and this should be priced.

These costs are especially important with respect to cross-border flows within Europe, whereby consumers in importing countries won't distinguish between imports based on low-carbon sources or gas and will see higher prices if lower carbon facilities in exporting countries lower their output due to receiving a lower price. We are already seeing the effect higher prices are having in life-extending existing nuclear facilities (e.g., in Germany).

An issue in suggestions for changes to market design is that they neglect the macroeconomic aspects of energy markets. This crisis is about more than simply what is happening in the energy sector. Indeed, microeconomics and macroeconomics may be in conflict in the energy sector. While high prices are a sensible response to market scarcity, high prices for a basic commodity which contribute to significant inflation mean that prices may need to be capped and some form of rationing put in place to avoid setting off a wage-price spiral which reduces GDP beyond the initial price shock. High prices which are outside the normal range of prices require some **tough political decisions to be taken**

[69]See https://www.ofgem.gov.uk/publications/default-tariff-cap-level-1-october-2022-31-december-2022. This shows a £23 per household credit to consumer bills due to negative CfDs for the consumer price cap latest period.

on how to ration energy, of which rationing by price is one solution (and not the preferred one globally).

Similarly, **suggested changes to market design generally ignore the question of the structure and ownership of the electricity sector**. Under the single market this has been characterised by private ownership (or international ownership outside of home markets) and horizontal and vertical disintegration of utility firms within countries. Changes to current ownership arrangements are being proposed or happening in some jurisdictions (e.g., renationalisation). Nationalisation of electricity generation is one way to capture the resource rents and to make it easier to redistribute back to electricity consumers. However, this if this policy seeks to use a change of ownership to address the problem of redistribution. This can be better addressed by the appropriate use of the tax and benefit system and price regulation. These mechanisms can target profits and electricity prices directly. Nationalisation of energy resources raises its own issues, such as the reduction of incentives to efficiency which motivated the global drive towards privatisation of energy assets in the 1980s and 1990s (Megginson and Netter, 2001).

A final point is that **many of the proposals for changing market design mix up sensible long-term market design for net zero with interventions in the current market design driven by the nature of the war economy**[70]. Sensible long-term design suggestions will take time to have an effect, whereas short run market interventions will not be sensible in the longer term. Being clear about the timeframe of suggested interventions and their likely impacts is important. Doing things quickly in a wartime situation is not necessarily conducive to good longer-run solutions and, perhaps equally, extreme short run measures may make it difficult to get back to policies which are sensible for the longer run. **A more careful consideration of short- and long run perspectives might be helpful.**

In a war economy, as Maynard Keynes pointed out in 1940 (Keynes, 1940), rationing – in the form of suspension of the normal operation of markets – can be necessary to control inflation and maintain post-war purchasing power (as supply improves) to manage the macroeconomy and voter expectations of fairness, which become more, not less, important.

[70] See Pollitt (2022).

SECTION 3: THE ENERGY CRISIS, NET ZERO, AND ELECTRICITY MARKET DESIGN

Section 1 presented the European standard model of electricity markets. It showed that with a uniform pricing model, the inframarginal rents of power plants are essential to pay for the investment costs of generators. In a market without entry barriers, in expectation, infra-marginal rents are equal to the investment costs of the firms and provide a fair return on their capital.

In this section. we look at how **two new elements impact the standard electricity market model**: the **energy crisis** due to the war in Ukraine and the **increased share of renewable energy production** in the generation mix under net zero.

The current energy crisis

The reduction of gas supply in the last year is unprecedented, was political in nature, and was not foreseen by market players.[71] It has given the European energy sector characteristics of a 'war economy': uncertainty in the market has increased,[72] the liquidity of long-term contracting has reduced,[73] and compulsory rationing demand this winter is a real possibility. The high energy prices create hardship for consumers and industries alike and has considerable macro-economic effects. **Considering those circumstances, exceptional temporary measures might be justified**.[74]

The energy crisis has led to higher fossil fuel and ETS prices. This raised electricity prices as illustrated in Figure 3. In a uniform price auction, it is optimal for generators without market power to submit bids which reflect their marginal costs. So, the bid functions in the graph represents the marginal costs of producers. As natural gas is the marginal technology, it sets the wholesale electricity price at p_{crisis} which is higher than the price that would have arisen in a situation without an international crisis, p_{norm}. The market process guarantees short-term efficiency: the electricity price represents the willingness to pay (WTP) of consumers for the marginal unit and all generators with marginal cost (MC) below the spot price are producing. Consequently, the production is produced at the least cost. The **high electricity price provides strong incentives for consumers to reduce demand and for generators to be available**.

The high electricity prices *strongly increase the inframarginal rents* for technologies that do not rely on fossil fuels (nuclear, hydro, wind and solar) if generators would only sell in the spot market. Those short-term profits contribute towards paying for the capital cost of those firms but are likely to be

[71] The price for monthly baseload future contracts for delivery on April 2022, was 43 EUR / MWh in April 2011, while the price settled at ca. 165 EUR / MWh (source: tradingview.com)

[72] On top of geopolitical risk there is also regulatory risk. Market participants are expecting the governments to intervene in wholesale gas and power markets and are therefore reluctant to conclude any new contracts.

[73] Representatives of the German industry report (VEA) that there are very few suppliers in the forward market and municipal utility association TIRANEL indicates that few retailers have contracted energy for 2023. https://www.montelnews.com/news/1348157/german-industry-struggles-to-find-energy-suppliers--lobby

[74] Stiglitz (2022) argues passionately for government intervention during the war in the form of non-linear prices based on historial consumption, and windfall profit taxes.

higher than what an investor might have accounted for even in its most optimistic investment scenario. The green area in Figure 3 represents the additional inframarginal rents on top of the rents that the firms would have collected in a 'standard' market situation.[75] In mid-August 2022, the forward price for German baseload power for delivery in 2023 was around EUR 500 /MWh, which is a magnitude larger than "normal" prices. It could be argued that taking away additional rents in such unexpected and extreme situations does not affect long-term investment incentives, as firms may correctly understand the exceptionality of the current situation. Note that defining 'standard' market rents is not straightforward, as it is a stochastic variable (corresponding to profitable and less profitable years) and requires determining the counterfactual market outcome without major international conflict. [76]

In practice, most generators sell a large fraction of their production on long-term contracts with a fixed price to retailers or large industrial consumers. Hence, for the duration of those contracts, the inframarginal rents do not accrue to the producers but lower in the value chain.

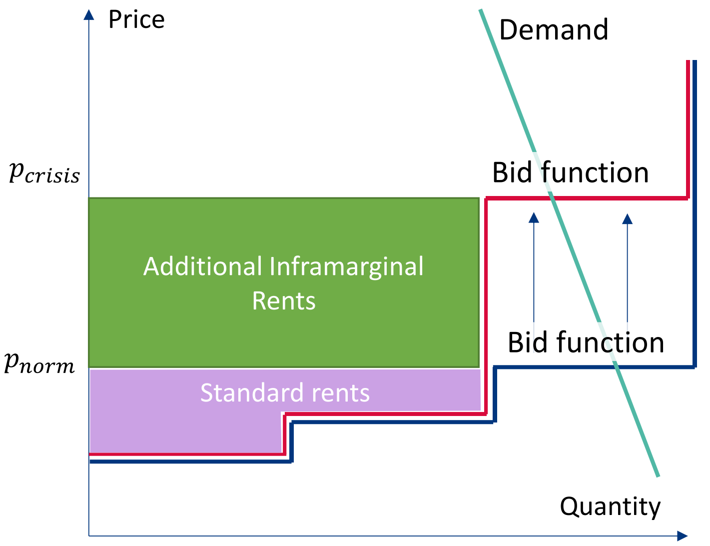

Figure 5: The effect of the energy crisis on wholesale energy prices and inframarginal rents,
The figure applies to a generator that would only sell in the spot market.

Renewable energy sources

The levelised costs of renewable energy sources (RES) have decreased sharply in recent decades. RES have become (almost) cost-competitive with conventional generation technologies. IRENA (2022) reports that in 2021, 73% of newly commissioned utility-scale renewable generation capacity has costs of electricity lower than the cheapest fuel-fired option in the G20. For onshore wind this number is

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[75] Note that the graph is not drawn on scale for clarity reasons.
[76] The IEA (2022) mentions excess profits of up to EUR 200 billion in 2022 in the EU for electricity generation using gas, coal, nuclear, hydropower and other renewables. It is, however, not obvious how those numbers were obtained.

even 96%. RES support schemes are therefore expected to phase out. Hence, new RES will rely solely on market revenue to recoup investment costs. How does this impact the current market model?[77]

Volatility

The phase out of conventional generation and the growing share of RES in the generation mix will make **electricity prices more volatile**. This is because RES production is intermittent with low marginal and high investment cost. In the long run those high investment costs need to be recuperated in a small number of hours with small production levels and high prices. Those more volatile prices provide incentives for storage operators and demand flexibility providers. Indeed, they rely on intertemporal arbitrage opportunities to make money.

The higher volatility also **incentivises market participants to sign more long-term contracts**. The parties to those contracts are typically firms with offsetting or imperfect correlated risk profiles. For instance, generators and retailers, or intermittent producers and storage providers. Consumers will typically sign contracts that hedge against those short-term shocks, make some money providing flexibility themselves, and end up paying an electricity bill corresponding to the long run average system cost.[78] They are likely to remain exposed to medium run energy price movements.[79] Therefore, the introduction of additional renewable energy does not pose a problem for the market design *as such*, although **market outcomes will be different**: **more volatile pricing, larger role for ancillary services markets, and more contracting and hedging**. [80]

Some countries rely on capacity markets to provide more stable investment signals in the medium run. The design of those capacity markets will become more complicated once intermittent generation, storage and demand side management and distribution level generation are taken into account. The Clean Energy Package provides legal guarantees for access, but the capacity markets might need to be reformed to do this effectively.[81]

Hedging and merchant investments

Many current RES investments in Europe rely on government support which provide long-term price guarantees and low risk for investors. Hence banks are often willing to provide debt funding for those

[77] The 2018 CERRE market design report (Pollitt and Chyong, 2018) studies the effect of further integration of renewable energy on the wholesale power markets and the consequences for different types of power plants, and whether market design need to be adjusted. Market based investments in RES are possible from 2025 onwards in a high carbon and high fuel price scenario.

[78] The second part of our report highlights that regulation where consumers can terminate a fixed-price contract early without paying a penalty is detrimental for the development of those fixed-price contracts for households. Blazquez et al. (2020) think that political constraints on extreme price spikes might make a complete transition towards renewable energy difficult in liberalised markets, and indicates that a public monopoly might be better placed to manage the energy transition. Implicit in this conclusion seems to be that demand flexibility, local storage and hedging contracts do not develop and that regulation and integrated resource planning can deal efficiently with those innovations. Gruenspecht et al. (2022) indicate some of the challenges here.

[79] Prices in dry years with low hydro production and cold winters leading to higher demand will be higher. Those prices are likely to be reflected in consumer prices, as contracts are typically limited from 1 to 3 years.

[80] Wolak (2021) argues that the U.S. wholesale market design may not need to be altered with higher percentage of renewables, but may require changes in operational constraints and new ancillary service products.

[81] Gruenspecht et al. (2022) review the challenges of the high penetration of RES in a US context, stressing the important role of storage and demand side participation. They argue in favour of more complex capacity markets or for more reliance on integrated resource planning (IRP).

projects, and capital costs are often very low. As subsidies are being phased out, renewable energy producers must rely more on market-based contracts to manage their risks. Those contracts often take the form of **Power Purchasing Agreements (PPAs).**

A PPA for renewable energy is, in its most basic format, a long-term contract which guarantees a fixed price to a renewable energy producer for its total production. A PPA might be physical (where the energy is taken by the buyer of the contract) or financial (a virtual PPA), where the buyer receives the difference between the spot price and the contract price when it is positive, or pays the difference when it is negative.[82] The buyer of a corporate PPA could be large industrial consumers or a retailer, which would like to hedge their energy prices in the long run and would like to reach their sustainability targets. Sometimes also the government might sign a long-term PPA contract.

The global market for corporate PPAs has been increasing rapidly, especially in the USA. Development in Europe is lower because the volume of subsidised RES remains high, but 8.8 GW deals were signed in 2021 (Stet, 2022 and Bloomberg, 2022). Development of the PPA market was strong in the Nordic countries, Spain, the Netherlands, and Germany. Some of the hurdles for the development of the PPA market in Europe is the **lack of contract standardisation, large price volatility in the short-term, and the important swings** in recent average power prices due to Covid and the Ukraine energy crisis. (Stet, 2022).

Corporate PPAs are leaving **more risk to investors** than the support schemes provided by the government in the past.[83] This **increases the capital cost**, as investors can rely less on bank financing and need to use more equity. However, as markets become more mature, lenders might become more comfortable with rolling-over **shorter duration PPA contracts**, and **innovation is likely to reduce total capital expenditure**, which will reduce total risk exposure (Ryszka, 2020). **Merchant investment** in RES, based on corporate PPAs and project funding can therefore play an important role in the future, but those investments are likely to be complemented with **portfolio-based investments strategies** by larger integrated utilities, who manage most of their risk in-house.

Compared with a standard base-load futures contract, a **corporate PPA-contract is riskier for the buyer of the energy**. The production of RES is intermittent, which creates shaping risk: the buyer needs to balance its consumption profile with the RES production output by buying and selling on the short-term market. RES output is also negatively correlated with the electricity price, which creates price capture risk. PPA prices are therefore often lower than the forward prices. To handle those risks, RES investors might contractually agree to build battery storage as part of their PPA. It could also be that a third party, typically a utility, is involved to managing those additional risks.[84] We expect **this type of risk management to become more important** in the future.

[82] A financial PPA requires a sufficiently liquid spot market. A financial PPA is sometimes also called a Contract for Difference or a fix-for-floating-swap.

[83] Ryszka (2020) identifies several reasons why risks are higher: The demand for long-term contracts is limited. It is 10-15 years for large industrial users, less than 10 years for ICT sectors, and covers less than the full life-time of the investments. Counter party risk for smaller entities with lower credit rating is too large. Contracts cover less than the full capacity to reduce risk exposure.

[84] Those contracts are often called sleeved PPAs. Specific contracting conditions and definitions might differ between utilities.

Scarcity rents

One issue with renewable energy resources is the **scarcity of suitable building locations**.[85] For instance, hydro power plants depend on the availability of water and geographical height differences. Hence, owners of the hydro plants earn scarcity rents based on those natural resources, which the government might want to take away for equity reasons.[86] Those rents could be captured by taxing the owners, by organising a market for the scare resource (auctioning of a building permit for the hydro power plant location), or public ownership of the resource. Figure 6 illustrates the idea of scarcity rents for a hydropower plant. The expected inframarginal rents that companies receive in normal market situations pay for the capital costs of the investments, but cover more than that for hydropower plants, who obtain a scarcity rent. This scarcity rent reflects the economic value of the water in the reservoirs that nature provided for free.

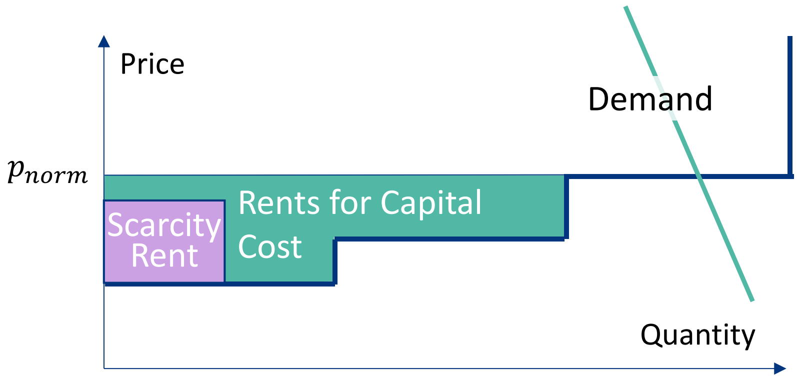

Figure 6: The expected normal inframarginal rents pay for the capital cost of the generators

Those scarcity rents do not only exist for hydro plants, but also for other renewable energy sources. High wind speed sites, close to the transmission network and away from built-up areas are far and between and are a scarce resource. A wind farm at such a site has lower long run average costs than in other sites, as nature provides more freely available energy.

In the current regime, where RES still depend on support schemes, those scarcity rents are taken away by differentiating support based on the characteristics of the resource. For instance, onshore and offshore wind energy receive different levels of support. When support schemes will be phased out, we need a **mechanism similar to that of existing hydropower plants,** to address scarcity rents also for **windfarms and photovoltaics**.

[85] Scarcity rents become more relevant for renewable energy, but they have been studies extensively for fossil fuel extraction and large hydro power plants. Baunsgaard (2001) highlights different fiscal regimes for mineral extraction and design considerations: higher corporate income tax, resource rent tax, royalties, rental fees and bonuses, auctions for exploration right, production sharing and state equity.

[86] Taxing scarcity rents of RES is often motivated by equity concerns, but they can also be motivated as a way to make markets more competitive. By handicapping firms with good sites, competition becomes more intense, and exercise of market power decreases. However, this comes at a cost as not always the firm with the lowest cost that wins the auction.

Taxing the scarcity rents of all RES, will however affect long-term efficiency if the long run supply of good site locations is elastic. In that case, there is a trade-off between extracting rents and investment efficiency.[87] Figure 7 shows the effect of a scarcity tax for onshore, offshore wind and hydro on long-term investments.

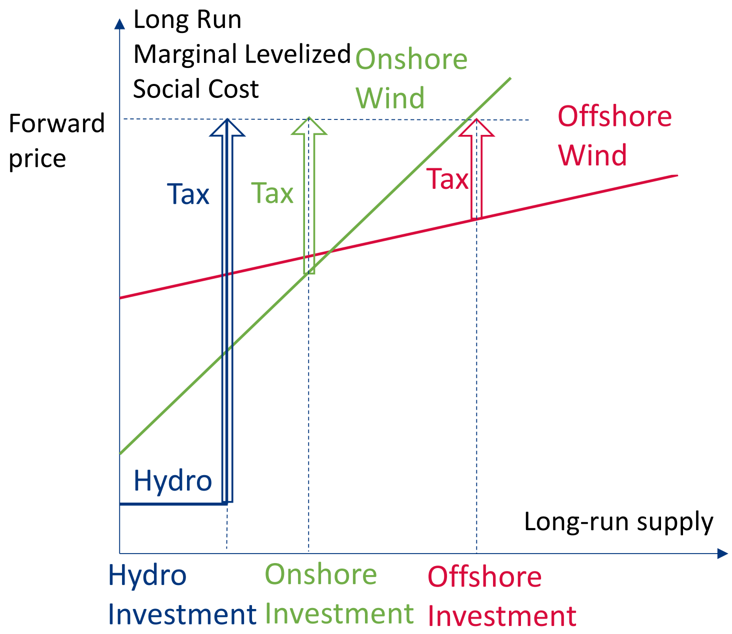

Figure 7: Effect of taxing scarcity rent of onshore and offshore wind energy on long run supply

The curves represent the long run marginal levelised social cost of different technologies as a function of investment levels. Hence the curves include capital cost and the environmental costs. If offshore wind supply is more elastic than onshore, the optimal scarcity tax will be lower for offshore than for onshore wind power.

Note that long-term supply of wind power is likely to be more elastic than of hydro power, and that the optimal scarcity taxes are therefore likely smaller.

Instead of a scarcity tax, we could use *regulated* long-term PPA at prices below the forward price for electricity. See Figure 8: by locking-in a low price for the electricity produced by RES power plants, the scarcity rents can be collected. The scarcity rents then have to be reallocated to the market for instance by auctioning off the PPAs to potential consumers or grandfathering them to energy users proportional to their energy consumption.[88]

[87] The outcome of this trade-off depends on the relative weight the social planner puts on equity and efficiency and the availability of other policy instruments to address equity concerns. Rowland (1980) describes how in the UK the Petroleum Revenue Tax is distortive towards smaller less productive oil fields, and leads to inefficiencies.

[88] We discuss below the potential benefits of government-backed long-term contracts with respect to hedging and the cost of capital and points of attention of implementing such contracts.

Figure 8 also shows that some inframarginal scarcity rents will remain with the RES producers if the PPA price is uniform for all power plants within a given technology class.

The size of the scarcity rents is expected to increase, as capital expenditure is dropping, electricity and carbon prices will increase and the total size of RES market will increase as well, but it is **hard to find reliable estimates**.[89] An indication of the size of scarcity rents are the differences of the Levelised Cost of Electricity (LCOE) across technologies. IRENA (2022) reports LCOE of 0.033 USD/kWh for onshore and 0.075 USD/KWh for offshore wind. If in the current cost structures both technologies would be active without a support schemes, then onshore wind would earn a ca. 130% scarcity premium. IRENA also reports that capacity factors for new onshore wind production in Germany in 2021 is 28% while it is 43% in Spain, so there are significant differences in the quality of onshore locations as well.

If the government did not address the scarcity rents, then those rents could end up with project developers, landowners, or even turbine manufacturer or the network operator, depending on their respective bargaining power. Bargaining power by the landowners would for instance be reflected in higher land prices. **If the government wants to extract the RES scarcity rents, it is important that it commits early whom it wants to "tax"**, the landowner, or the project developer, and **creates well-defined property rights**, so that its policy is correctly reflected in land prices.

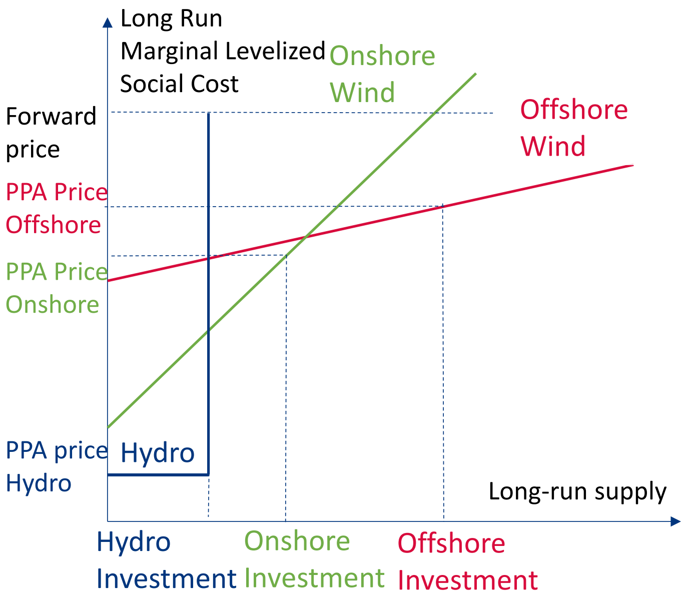

Figure 8: PPA prices below forward prices for electricity to extract scarcity rents of RES producers

[89] Gross et al. (2022) estimate that CfD contracts for wind, solar, biomass and nuclear power could reduce UK energy bills up to £22.4 billion per year. However, this estimate seems to cover not only resource scarcity rents, but also windfall profits due to the energy crisis, and inefficiencies in the ROC pricing.

In **some proposals for new market designs, RES will not be subject to a scarcity tax but instead RES scarcity rents are intended to be extracted through a change *in spot market design***. RES is treated differently than conventional generation and receives a lower payment. We argue below that it **does not make sense to organise the spot market for such a purpose**.

Many RES producers would like the government to keep on providing long-term price security, by signing government backed PPA agreements with them. Those PPAs can also be used to extract the scarcity rents of RES, by setting a PPA price which is lower that the corresponding forward price, but this is not the only way of doing so. It is important to **distinguish those two functions of PPA: hedging and extracting scarcity rents.** A single instrument, a PPA, is used to reach two policy goals: reducing the risk for the investors and extracting the scarcity and technological rents. In public economics and optimal taxation theory, it is often better to use two instruments for two distinct policy goals: one targeting the rents (for instance a tax based on average local wind speed) and another providing price certainty. By separating both roles, one could make the hedging contract technology neutral and allow for more competition between different technologies.[90]

Potential short-term market interventions

In this section, we discuss four proposals for short run market interventions: A **windfall profit tax on inframarginal generation**, a **subsidy for gas-fired power plants combined with a bid cap**, a **price cap on gas imports** and a **switch from a uniform price to a pay-as-bid auction**. The first three measures keep the current market design intact and rely mainly on taxation and subsidies to change market outcomes, while the third one changes the market design.

Those four types of proposals are representative of the policy proposals that are currently being discussed (and which were reviewed in Section 2). For instance, the windfall profit tax targets the inframarginal rents of the RES and nuclear generation, in case those exists, and could be implemented as a tax, cap on auction revenues, or a regulated contract for differences. Those implementations have their benefits and drawbacks, some of which we mention in the text below.

Windfall profit tax

The windfall profit tax proposal is a temporary tax on part of the infra-marginal profits of firms who do not use fossil fuels. In this text we will use the more neutral terminology of a **crisis tax** (See Figure 9). The crisis tax reduces the profits of nuclear, wind and solar producers, but does not affect the electricity price. The **incentives for consumers to reduce energy consumption therefore remain**

[90] If the PPA is used in both roles, the price of the PPA will be lower than the forward price for electricity as shown in Figure 8. Instead of buying a forward contract, which offers a uniform price for a constant output, the government could procure energy with a more complex contract, which insure RES producers against price capture risk (the average spot price the wind farm receives is different from the average baseload price as there is negative correlation between RES production and spot prices), shaping risk (the producer will have to buy extra power when it is short of the contract quantity), ancillary service costs (intermittent wind power is more likely to be in balance), and network congestion costs (RES producer is compensated for local congestion costs). This could also justify a lower PPA price.

intact. This is one of the advantages of a crisis tax. The money that is collected by the crisis tax can be used to compensate vulnerable consumers for the higher electricity price.

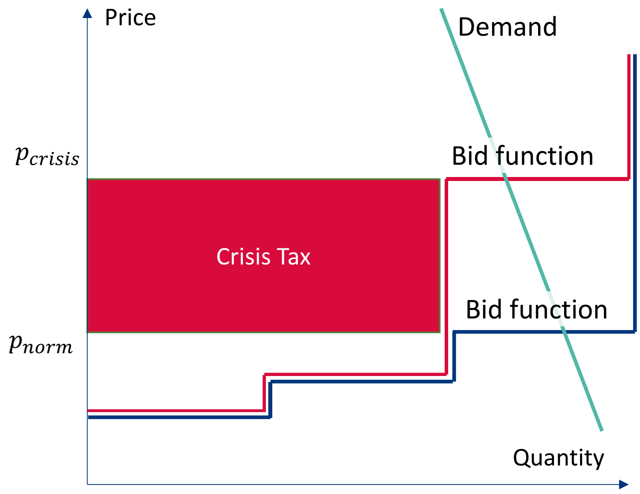

Figure 9: Crisis tax on the extra inframarginal rents of non-fossil fuel-based generation

The **main arguments in favour of a crisis tax are political**. Higher fossil fuel prices have considerable redistributive aspects which increase the profitability of some assets, while reducing those of others. This is seen as a politically undesirable outcome which needs to be corrected.[91]

The **main objection** against taxing the increased value of assets is that it **punishes past actions or investments that are helping us today to reduce the impact of the energy crisis**.[92] It hollows out property rights and lowers incentives for future investments but could possible also hinder short-term emergency investments. Imposing the crisis tax also implies some arbitrariness. Wind turbines and nuclear power plants selling in the spot market are more profitable with higher electricity prices, but other assets, such as rooftop solar and fuel-efficient cars increase in value as well. Based on practical considerations and voter sentiment, policy makers are likely to exclude some assets from a crisis tax (for instance fuel-efficient cars) but to include others (a baseload plant).

To **reduce the impact of a crisis tax on future investment incentives, governments might negotiate long-term deals with energy producers**. In return for paying a crisis tax now, long-term commitments are made that guarantee future income or reduce future risks for producers. For instance, the government could take over some of the risk of nuclear waste or sign long-term contracts under a capacity remuneration mechanism. If those commitments are budget neutral for the firm, the government is in effect taxing firms today, in return for higher profits in the future. Hence, the government is relying on energy firms as an indirect way to borrow funds against the future and relax

[91] A crisis tax will also reduce the burden on the government's budget of social measures to address energy poverty.
[92] Even though extra RES do not have a large effect on electricity prices as long as those are set by marginal gas plants, each unit of RES production translates one-to-one in a reduction of gas imports. It reallocates rents from foreign exporters to domestic producers.

today's budget constraints, instead of going to the capital market. Those **kinds of long-term measures are often untransparent and have a higher implied capital cost than government bonds**.[93]

A second objection against a crisis tax is that is it **not easy to identify who is benefiting from an energy price shock,** as this depends on the long-term contracts that firms have signed. A nuclear power plant who sells energy under a long-term contract for a fixed price to a paper mill does not make extra profit when the day-ahead price for electricity increases. However, as a result of the contract, the paper mill has lower production costs than its competitors and becomes more profitable.[94] Hence, if we follow the logic of taxing unexpected gains due to the war, the crisis tax should be imposed on the paper-mill, and not on the owner of the nuclear power plant. In practice, with complex value chains and many contractual relations, it is **nearly impossible to determine who finally benefits from local production.**

Note that the **largest windfall profits are in upstream gas and oil production** and not in the power market. Therefore, specific measures in the gas market might be necessary, which are not the focus on this report.

A crisis tax can be implemented in many ways. Ideally, it is implemented so that it **does not to distort the short-term incentives of market players**; takes into account **existing contractual relationships**; is **temporary in nature** and specifies under which **conditions** the crisis tax will be automatically abandoned; **leaves sufficient profit to the firm**; and is **not imposed arbitrarily**. Those criteria **might need to be imposed at an EU level**. Note that a crisis tax does not alter the market design or market rules but reallocates revenue streams.

In order for short-term incentives (i.e., operational decisions) to remain intact, the firm should ***on the margin*** **benefit from the high electricity prices**. Increasing production by increasing availability of the power plants or pushing the limits of the power plants should be worth it.

One implementation that satisfied this requirement is to oblige firms to **sell contract for differences (CfDs) for a fixed quantity at a regulatory price**. This regulatory price should reflect some measure of long-term price expectations and still allow the company to recoup its investment costs. This type of mechanism is only necessary if the company did not yet sell its full capacity under a long-term fixed price contract or is subject to a contract for differences.[95] Similarly to the crisis tax, the CfD implementation involves partial appropriation of property rights as lifetime expected profits are affected.

Imposing a **crisis tax ex-post**, based on the historical performance of a firm, does, by design, not alter incentives and could therefore be used retrospectively to finance any crisis intervention.

[93] In order to end the California energy crisis of 2000-2001, the government signed long-term contracts at high prices.
[94] It could also resell electricity on the wholesale market at a premium.
[95] The imposition of the short-term CFDs has been used in Italy to extract windfall profits.

An implementation which **does not** satisfy the requirement of **keeping incentives intact**, is to tax the firm's revenue in the **day-ahead auction**. The firm will no longer receive the price p_{crisis}, but will be paid p_{norm}. The marginal benefit for increasing availability is now p_{norm}, while the social value is equal to p_{crisis}. In most European markets, generators are not obliged to participate in power exchanges and can trade energy in bilateral contracts instead. This mechanism will therefore only work if firms are prohibited from signing long-term contracts.[96] Bids in most power exchanges are not linked to a particular power plant, as nomination only happens after the market clears. So, implementation is not straightforward. Capping the price inframarginal powerplants receive is one of the policy proposals currently put forward by the European Commission[97], which is equivalent to a revenue tax on inframarginal plants.

To determine the tax level, one would need to **determine the profits that the firm would make in a hypothetical situation without an international conflict in Ukraine**. The firms should obtain sufficient short-term profit to fund its capital cost and give it a risk adjusted return for low price periods. Those profit levels cannot be identified from a cost audit or by observing the market bids (which reflect short-term variable costs only).

Price cap on gas power plants

By imposing a price cap on bids of gas power plants, the wholesale electricity prices and the inframarginal rents will be reduced (See Figure 10). As gas-fired power plants will be required to sell below production cost, they **receive a subsidy** so they can buy gas on the international market. This policy reduces wholesale prices for all consumers and reduces the need for providing targeted income support. The budgetary effect for the government will be limited if the fraction of gas producers is small.

A benefit of the system is that it **might be compatible with bilateral long-term contracts**. Prices in the long-term contracts will reflect the lower price in the spot market. Those forward prices become more predictable which could increase the liquidity of the forward markets.

[96] Prohibiting long-term contracts comes at a large cost as it prevents downstream companies to hedge their risk.
[97] Council of the European Union (2022b).

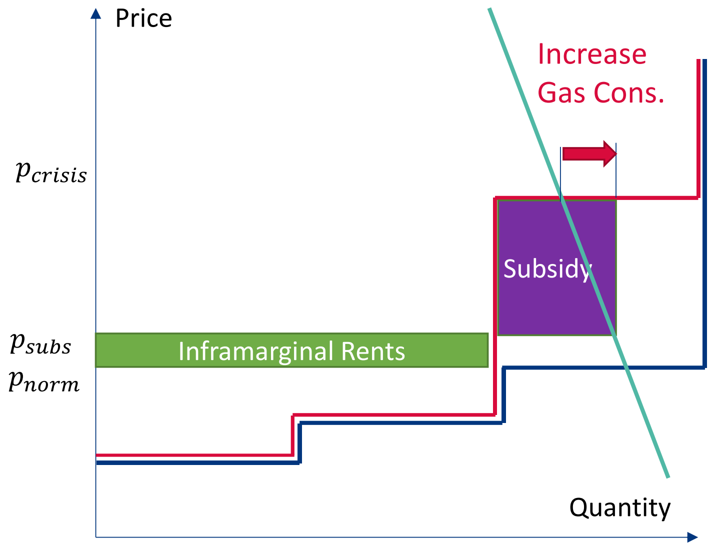

Figure 10: The introduction of a bid cap and a subsidy for natural gas producers lowers electricity prices and increases demand for electricity and gas

A first problem of a price cap is its effect on long-term investment incentives, as it is a form of expropriation. Imposing the bid cap on the wholesale market to drive down energy prices has similar economic effects for the long-term incentives of infra-marginal producers. Although the legal effects on the undermining of property rights might be less obvious, the profits of renewable generation and nuclear energy are reduced. As noted in section 4, it is the generators penalised by this mechanism who may then take legal action. There are signs this is already happening.

A second major problem of a bid cap, and the lower electricity prices, is that it **reduces the short-term incentives for energy conservation by consumers and for being available by generators**. It is therefore required that **additional regulatory measures are taken to reduce energy consumption** across the board.

A third problem with the bid cap is that it **requires a subsidy for gas-fired power plants**. Depending on how the scheme is organised (from government funds or not), this **can constitute state-aid**, which provides an unfair advantage to energy-intensive industries. It also **distorts trade flows** between member states, as electricity prices no longer reflect the true social cost, and might violate the rules or spirit of the internal market and free movement of goods. Member states that subsidise their local electricity price will also try to restrict exports to prevent other member states from benefiting from those subsidies.

A fourth problem is that the **subsidy of natural gas will benefit the gas exporting countries**, and it will **drive up the price of gas for other types of usage**. This is illustrated in Figure 11. If the supply of gas is inelastic, the subsidy in the electricity market will lead to inefficient substitution of gas used for heating and industrial production.

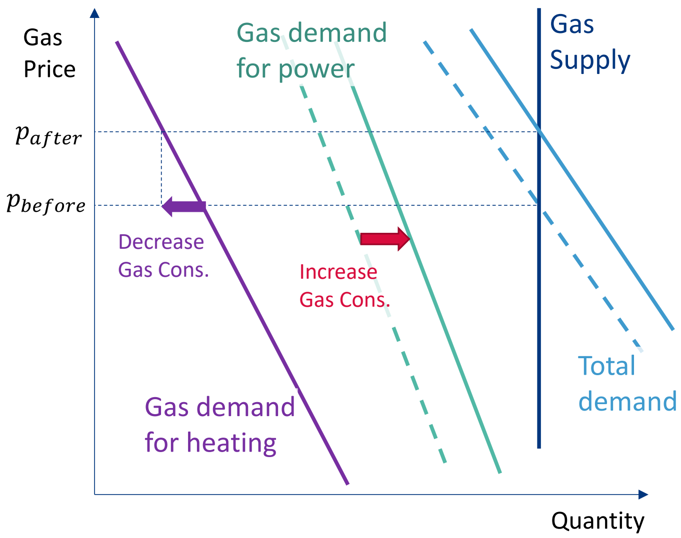

Figure 11: A subsidy for gas-fired producers in the power market

It will shift the demand function for gas. Assuming that the supply of Russian gas is inelastic. This will lead to an equivalent reduction of gas consumption in other sectors and an increase of the gas price.

A fifth problem is that the **measure is not targeted**. Electricity prices are reduced for rich and poor households and industrial consumers. It increases the price of gas for gas consumers, particularly the industry, and if one country does it, it drives up the price of gas for other countries. A more targeted subsidy scheme could **focus on the most vulnerable consumers**, at a lower overall social cost.

Price cap on gas imports and equivalent measures

The policy discussed in the previous section is one where governments subsidise natural gas for electricity production and imposes a cap on the bids of the gas-fired power plants. This led to an *increase* of European gas demand. An alternative remedy is one where the government puts **a cap on import prices for gas.** This will have **opposite effects on the gas market**. It corresponds to a ***decrease* of European gas demand**, **reduces the rents of energy exporters**, and **will increase electricity prices**, but will **create scarcity rents** that can be redistributed to end-users.

One way to implement the price cap for gas imports is the creation of a **single buyer** who **negotiates long-term contracts** with gas exporters. See Figure 12. This single buyer will drive down the price from $\boldsymbol{p_{before}}$ to $\boldsymbol{p_{cap}}$. In response to the lower prices, **exporters will *reduce* supply**. At the price cap, demand for gas within Europe is larger than supply. In order to efficiently allocate the gas imports to users within the EU the single buyer could **organise an auction**.[98] The resulting auction price for gas within Europe will in equilibrium then be equal to $\boldsymbol{p_{after}}$, when demand and supply meet. Hence the

[98] An alternative to auctioning capacity, would be to ration demand and grandfather capacity to existing users based on historical consumption patterns of current importers. However, as gas remains scares, this provide those importers with windfall profits, which would need to be reallocated using additional regulation. This looks very hard to implement.

internal gas price for consumers within Europe will be **higher than before** the intervention, but the single buyer will **collect a rent** which can be used to **compensate consumers**.

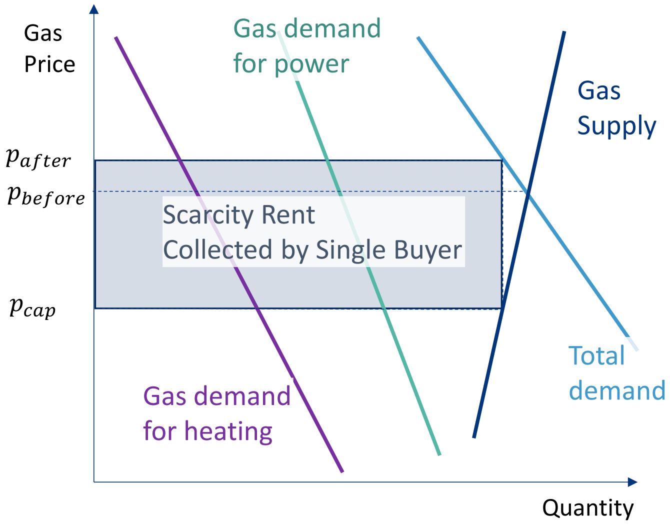

Figure 12: The effect of a price cap on gas markets in a single buyer setting

It reduces the supply of natural gas and the rents for gas exporters, creates a scarcity rent for the single buyer and leads to higher gas prices within Europe for industrial production, heating and electricity production. The scarcity rents can be used to reallocate rents to end-users. Note that if gas supply were perfectly inelastic, prices would remain unchanged.

Instead of a single buyer solution, the EU could also impose an **import tax** which is equal to the difference of the auction price and the price cap, $Tax_{import} = p_{after} - p_{cap}$. The market outcome would be equivalent, but long-term contract commitments would now be made by **individual energy firms**, and not by the single buyer.

Both the single buyer and the import tax solution **might run afoul of international trade rules**. A third equivalent policy measure is to impose a **consumption tax on natural gas**, which is equal to $Tax_{consumption} = p_{after} - p_{cap}$. This is simple to implement at member state level and would allocate the tax benefits to member states. It requires some **coordination between Member States**, in the form of a minimum tax level, so countries do not free ride on each other's effort to lower the import prices.

Moving from uniform price auction to pay-as-bid auction[99]

Most European day-ahead markets use uniform price auctions, where all generators are paid the same price. An alternative would be to use a pay-as-bid-auction, where firms are paid based on the bids they make.

[99] This section is based on recent work by Yu and Willems (2022).

The policy debate on uniform versus pay-as-bid auctions in the electricity sector is not new. It has been discussed during the Californian electricity crisis (FERC, 2000; Sweeney, 2002) and the reform of the England and Wales trading arrangements (OFGEM, 1999). The **economic rationale** for switching to a pay-as-bid auction is **not very strong** and the **policy discussion** is sometimes misguided as it **ignores changes in the bidding** of market participants.

If the bids remained unchanged, the auctioneer collects additional revenue as shown in Figure 13. This revenue could be used to pay to consumers in a lumpsum fashion for instance by a reduction of their network tariffs. Note that in a pay-as-bid auction, generators will not necessarily receive the same price, as prices depend on their own bid.

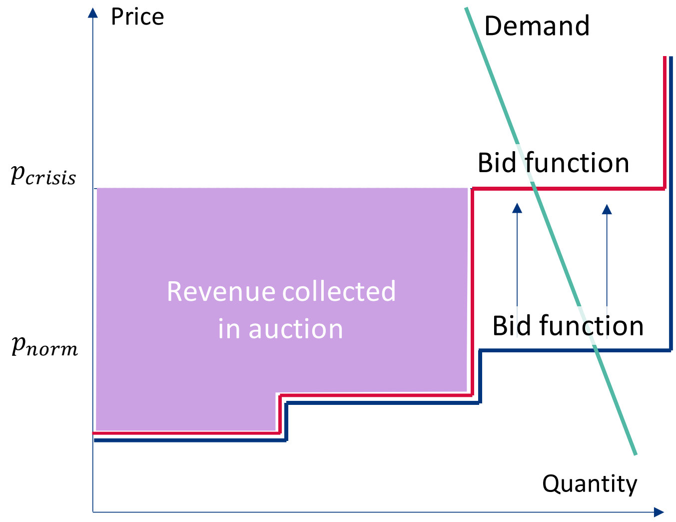

Figure 13: Effect of a change from a uniform price auction to a pay-as-bid auction if bids remain the same (which they will not)

However, Figure 13 is too simplistic, as in a pay-as-bid auction it is no longer optimal for competitive firms to set bids equal to their marginal cost. Firms will maximise their profit by adjusting their bids and include a bid mark-up. This mark-up allows them to make some profit in the short run, which they will use to recoup their investment costs. Hence the effect of going from a uniform price auction to a pay-as-bid auction is not straightforward as firms will **adjust their bidding behaviour**, **short run profits change**, and this **affects long run investment decisions**. It requires long-term models to analyse the overall effect.

If demand is known before firms bid, bidders will adjust their bids, so that their bids reflect the social value of electricity, which is equal to p_{crisis}. The additional revenue collected by the auctioneer will become zero, and the uniform price and the pay-as-bid auction are identical (See Figure 14). Therefore, in this case there is no difference.

However, in the pay-as-bid auction, firms are obliged to make predictions of the equilibrium price p_{crisis} before submitting their bids. If those predictions are wrong, the cheapest technologies might not be selected to produce, and total production efficiency is lower than in the uniform price auction. It may also lead to extra rents for large, better-informed producers,[100] and the cost of making predictions then has to be paid for by end-users (Kahn et al. 2001).

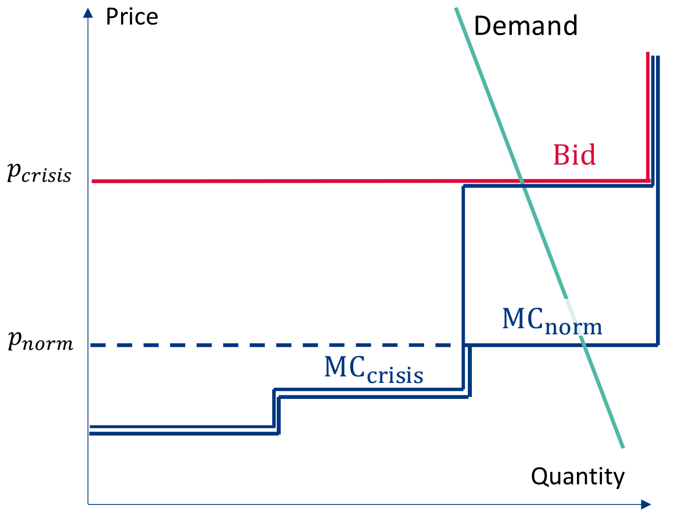

Figure 14: Pay-as-bid auction with perfect foresight on demand

In a pay-as-bid auction with perfect foresight on demand, competitive bidders will increase their bids to the level of the market equilibrium price.

If foresight of future demand is imperfect, generators will still set a bid above their marginal cost, but no longer equal to p_{crisis} as there might be a risk that they will not be called upon to produce. Firms will trade-off higher mark-ups versus the probability of being out the market. The bids will look similar to Figure 14. As bids are below p_{crisis}, the auctioneer will collect some revenue that can be recycled and benefit consumers. In the short run, a pay-as-bid option will therefore **benefit consumers with lower energy bills** and will **hurt producers**.

However, the fact that bids are above the marginal cost leads to **efficiency losses if demand is elastic**. Those efficiency losses are highest during low demand periods, as mark-ups are highest in those periods. Hence, a pay-as-bid auction destroys total surplus and is a rather inefficient way to allocate rents from producers to consumers.[101]

[100] Using agent-based modelling, Bower and Bunn (2001) where bidders develop bidding strategies with an adaptive learning algorithm it is shown that a pay-as-bid auction increases prices. The reason is that firms with a large market share have significant informational advantage.

[101] Several theory papers study the effect of a change towards pay-as-bid auctions. Federico and Rahman (2003), Fabra et al. (2006), and Holmberg (2009) show that in the *short run consumer surplus* increases. Welfare remains constant in Fabra et al. (2006) and Holmberg (2009) as they have inelastic demand and therefore rule out deadweight losses. Welfare decreases in Federico and Rahman (2003) who assume elastic demand.

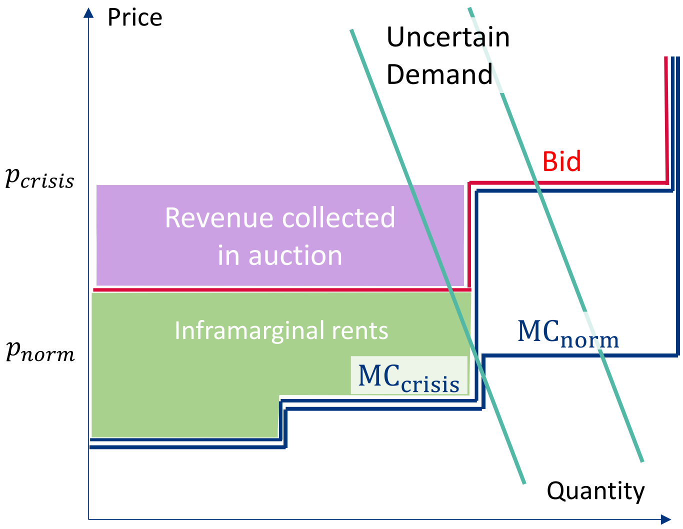

Figure 15: Pay-as-bid auction with uncertain demand.

Generators bid above their marginal cost and obtain some infra-marginal rents. The auctioneer collects some revenue in the auction which can be recycled lower the consumers' energy bills.

In the long run, generators use the inframarginal revenue to recoup their investment costs. As those inframarginal rents are different in the pay-as-bid auction and the uniform price auction, investment decisions will change. The pay-as-bid auction reduces the rents baseload producers collect in the market, and their investment will be reduced. The generation mix will have less baseload capacity and more peak-load capacity, which reduces total surplus. If there are no entry barriers in the market, the long run expected profits of firms are zero, and a reduction of total surplus lowers consumer surplus. Consequently, consumers do not benefit from switching to a pay-as-bid auction in the long run.[102]

Summarising, **pay-as-bid auctions in wholesale spot market are less efficient than uniform price auctions** (price signals distorted for consumers, costly price predictions and scheduling errors). In the **short run they could increase consumer surplus, but in the long run it will hurt consumers**.

In order to address the inefficient short run price signals for consumers under pay-as-bid pricing, some commentators have suggested to use ***pay-as-bid pricing with average bid pricing***, where the consumers pay an energy price that is equal to the average bid submitted by the generators (See Figure 16). As far as we know, this has not been analysed yet, but **first results suggest that it is worse than the "standard"** pay-as-bid pricing.[103]

[102] Fabra et al. (2011), compares investment decisions under pay-as-bid and uniform price auctions with inelastic demand, a single production technology and in a duopoly setting, and finds that consumer surplus increases, total welfare and installed capacity remain constant. Yu and Willems (2022) show that with elastic demand, no entry barriers, and a mixture of generation technologies, total welfare and consumer surplus decrease.

[103] This methodology will lower the price in hours with peak-demand and lead to prices below marginal cost during those periods with high demand. This is inefficient and will lead to extra deadweight losses. During low demand hours, prices are above marginal cost, which is also inefficient, as demand is smaller than economically efficient.

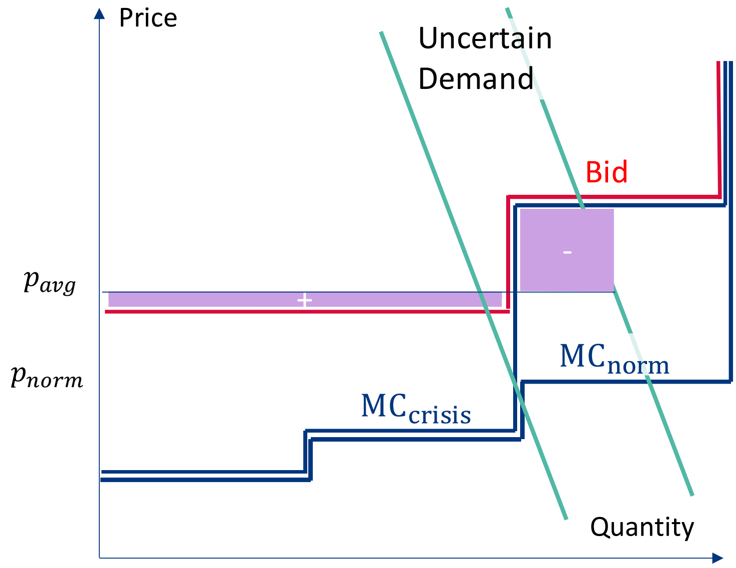

Figure 16. Pay-as-bid pricing with average pricing

Consumers pay the average price $\boldsymbol{p_{avg}}$ which corresponds to the volume-weighted average bids of the suppliers. The two-coloured areas in the graph have the same size.

General discussion

Spot Prices reflect scarcity

In a liberalised market, day-ahead energy prices tend to converge to the social value of supply and demand, independent of the market design. That is where supply meets demand. This price level provides the correct **short-term incentives**; for energy conservation, storage, demand shifting, plant scheduling, plant availability and congestion management.

The market design of the spot market has only limited impact on average price levels as competitive firms will try to exploit all arbitrage opportunities and **shifting towards pay-as-bid auctions is not advisable**. Empirical evidence of the effects of wholesale market design on market outcomes suggests that the impacts are marginal. Market **outcomes are mainly explained by the market fundamentals**: generation mix, fuel prices, demand levels, horizontal market concentration, the number of long-term contracts and vertical integration.[104]

In the **intermediate future, the electricity spot price** will remain to be **driven by the natural gas price** as marginal technology. In the **longer-run net** zero context, it will depend on the **cost of a dispatchable backstop or storage technology and could be driven by international hydrogen prices**. Trying to **decouple the electricity *spot price* from the gas *spot price,* does not improve market efficiency and will only create market distortions**.

[104] Evidence is provided by Evans and Green (2003) for the UK and Bushnell et al. (2008) for USA.

Under the current market design and absent government intervention, future spot prices will reflect, in expectation, the long run average system cost: the long run investment and short run production costs of the portfolio of RES and conventional generation.[105] Hence, forward contracts and PPAs that are based on those spot prices will reflect the long run average system cost and will provide correct investment signals.

The impact of natural gas prices on this average system cost will decrease over time as installed capacity and the capacity factor of gas power plants will reduce. Hence, the **fuel cost becomes a smaller part of the overall system costs and have a smaller impact on forward prices and hence the total energy bill**.[106]

Short-term markets are expected to become **more important in a net zero scenario** as the role of demand flexibility, energy storage, and reserve generation is only going to increase. The phase-out of older support schemes such as Feed-in-Tarrifs, will provide **incentives for RES producers to become more active in the spot and ancillary service market**.

Taxing Scarcity Rents of RES

RES production relies on the availability of natural resources which are unevenly distributed and often scarce. This creates scarcity rents: RES producers in favourable production sites make more money than they need to cover investment costs. **Policymakers might want to take away those scarcity rents. Today, scarcity rents are addressed by differentiating support schemes**: financial support is lower for good RES sites, i.e., sites with higher scarcity rents.

In the future, RES becomes cost competitive and **policy makers might therefore decide to phase out direct support for RES**. **Alternative methods for capturing scarcity rents of good production sites may need to be introduced**. Ideally, rents are captured in a way that does not distort competition and keeps spot price signals intact. **Direct taxation of production assets** (hydro plants) and the **auctioning of permits for using a scarce resource** (oil fields) have been successfully used in the past for this purpose. Those mechanisms might be easily applicable for wind energy, where exogenous parameters like the windspeed are easily observable and auctions for offshore wind sites have been common.

The government does not have full information about the size of the scarcity rents and might instead design markets that incentivise firms to reveal information about the cost of RES production sites. This can be achieved by **creating competition between RES firms in an auction**. Ideally, the auction rules take into account information that the government already obtained before the auction starts and includes additional parameters than price to better screen the cost of RES producers. For those auctions to be of any use in learning about the size of scarcity rents, they **must be organised *before* *firms invest***, as otherwise investments costs are sunk, and screening becomes impossible. The result

[105] In the past, European governments have heavily subsidized RES production, which absent the Ukrainian war would have led to artificially low carbon and electricity prices.
[106] In order for gas power plants to recoup investments costs with lower capacity factors, electricity prices will need to spike more often. Electricity prices will then be determined by bids offering demand flexibility and storage, and not by the price of natural gas.

of the auction could be the level of the yearly permit price that the RES firm pays for using a location, or a commitment to deliver power at a specified price under a virtual PPA setting. Both the yearly permit price and the PPA contract have the advantage of keeping short-term incentives intact. The PPA contract provides additional hedging opportunities for the producer and allows the auctioneer to include additional screening parameters in the auction. PPA Auctions to procure wind and solar have been successful around the world in driving down the cost of renewable energy.[107]

Note that any voluntary scheme where RES producers freely choose whether to participate or not, will not be helpful in extracting scarcity rents, as firms will just avoid the mechanism and sell energy in the spot market or via bilateral contracts instead. Hence, the **government will need to require some form of enforcement, either through taxation or an obligation to participate in an auction in order to receive a production permit**.

Note also that adjusting the spot market design is not helpful for learning more about the size of the scarcity rents, as investment costs already sunk. **Decoupling the electricity *spot price* from the gas *spot price,* by creating a hybrid spot market model will therefore only hamper competition and efficiency** without providing additional information.

Improving the market for long-term contracts

We expect that the use of long-term contracts by private parties will *increase* in the long run net zero scenario, due to the higher price volatility, the phasing out of government price guarantees for RES, and stricter regulation of the retailers' risks.

We also ***expect innovation in energy contracts.*** Long-term contracts will need to go beyond standard forward contracts on the day-ahead market. Specific contracts are needed to **target actors with different risk profiles** (retailers, intermittent RES producers, storage operators, aggregators, conventional generators). Balancing contracting positions might require **multilateral contracting**: For instance, a wind farm, a retailer, and a storage operator together might have a lower risk exposure than any two players together. **The risks that need to be hedged will also change**, not only uncertainty in the day-ahead price will matter, but increasingly also balancing costs, regional price differences and congestion costs. The **market for corporate PPA is likely to mature further, but integrated companies with portfolio investments will remain important**.[108]

There are **good arguments for government intervention in the contracting market** such as: **regulating the risk of retailers**,[109] **standardising contracts** to simplify netting of positions, **improving transparency on contract prices and positions**, **contracting on behalf of consumers** to prevent future

[107] https://www.irena.org/Data/View-data-by-topic/Policy/Renewable-Energy-Auctions

[108] Future market designs should leave sufficient room for innovation in long-term contracts by allowing for instance long-term portfolio contracts, and allowing for different forms of ownership structures, where contracting incomplenteness is solved by allocating propoerty rights, cross-ownership and some joint-liability.

[109] Willems and de Corte (2008) show that regulating the contract positions of retailers and requiring more long-term contracts, does not need to be detrimental for competition.

non-market intervention by the government, overseeing the **contractual terms of energy imports**, and **providing natural counterparties for some contracts** (e.g., transmission prices with Financial Transmission Rights and ETS policy risks by CO2 call options).[110] Some markets may also rely on short-term capacity markets when spot prices do not fully reflect energy scarcity. However, an **important role remains with private parties**.

Government intervention in long-term markets

The existing market has worked well in providing consumers with the option to lock-in prices three to sometimes five years in the future, but consumer demand for those contracts was often limited. While producers might like longer-term contracts to reduce their capital costs, **economists disagree on whether and how we should regulate hedging beyond this period,** especially given the lack of consumer demand for longer term hedging**.** Some economists argue for more government intervention in the long-term contracting market and structural market design changes, as illustrated in the hybrid markets text below (Box 3).

We believe that the s**ubsidiarity principle should apply with respect to the implementation of organised long-term markets** for two reasons: There **is no consensus** among economists or industry participants **on whether we need a large market reform based on long-term contracts**. **Member states have different social contracts** regarding the role of markets versus governments, and have different **risk-appetites across their consumers**.[111]

There are **benefits from using organised long-term markets as they will lower capital costs for investors and hedge consumers againt large price changes**.

Government intervention for long-term contracts may make more sense for base-load producers (e.g., nuclear and renewable energy suppliers) as they have relatively large investment costs, and are less likely to be price setters, and therefore have higher risk exposure if private contracts do not provide sufficient hedging. For gas-fired power plants, the electricity price follows their input cost as they are often marginal, and their price risk is therefore lower.[112]

Flexible energy sources such as storage and demand side management might find it hard to find long-term hedging contracts in organised futures market, but it is **not obvious that targeted government mandated contracts will be very useful** here. Governments might find it hard to quantify the portfolio benefits of different flexibility technologies and **bilateral private contracts are likely to**

[110] Some contractual terms for end-consumers contracts are already harmonised by EU law. This means that the EU already has a legal basis for adopting new provisions if so needed. The situation is a bit different on the wholesale market and PPAs.

[111] Roques (2020) indicates that we already have a form of hybrid markts in Europen as countries are using different styles of support schemes for renewable energy and capacity markets, next to a somewhat more harmonized wholesale market. Some harmonization at EU-level might help in improving the efficiency of those schemes for renewable energy, capactity markets and potentially long-term contracts. Roques and Finon (2017) describe this as a institutional approach of different market modules.

[112] Peakers face volume risk, but little price risk. Baseload plants face mainly price risk, but not volume risk. Roques et al. (2008) shows without private hedging contracts, there will be inefficient investments in nuclear energy in a Monte Carlo simulation in a mean-variance portfolio model of the electricity sector.

be more innovative than standardised government contracts. Moreover, porfolio investors might build a mix of renewable energy and storage facilities and internalise risk offsets within a company.

However, there are also **drawbacks of government-backed long-term contracts**, which might have implications for the internal market, and **for which the European Commission might impose some minimal requirements at the central level**.

(1) The contracted capacity might not fully take part in the short-term markets: day-ahead, balancing and ancillary service market. This could reduce production efficiency.[113]

(2) There might be too little competition for long-term contracts, with insufficient cross-border participation as long-term transmission contracts do not exist and contracts are not sufficiently standardised between member states.[114]

(3) Energy prices might be too low, if a government extracts resource scarcity rents by exercising its monopsony power and signing long-term contracts at below the expected market rates, and passes the lower contract price on to consumers. This could be a form of state-aid.[115]

(4) Particular contract format might suit one technology more than another. So we might obtain an inefficient combination of production technologies. This might be in particularly valid for demand response, storage and other forms of flexibility.[116]

(5) Government-regulated contracts, might crowd-out private PPAs and portfolio investments, because the government could offer better contracting conditions and does not price the risk of different assets correctly. Pfeifenberger et al. (2017) reports that the capacity markets in CAISO and MISO have not been sucesful in attracting merchant investments and large quantities of low-cost capacity supply.

"This is because all supply and investment decisions continue to be made through regulated planning processes, utility programs, and state-directed procurements for preferred resource types several years in advance. New generation is not required to compete with demand response, imports, existing resources, or uprates on a level playing field. By the time the short-term capacity market arrives, all investment decisions are already made and little or no residual decision-making is left to market forces. The result is a bifurcated system between regulated new entry that can be developed at relatively high cost, and all other types of merchant resources earning a very low price in the short-term markets." Pfeifenberger et al. (2017, p. 71).

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[113] Some of the oder schemes to promote RES investment such as Feed-in tariffs have this problem even more pronounced.

[114] Chattopadhyay & Suski, (2022) indicate that long-term PPA contracts may slow down innovation in new technologies, and reduce spot market liquidity and might be less competitive with higher prices. "Many countries […] struggle with low liquidity in the presence of legacy contracts (e.g., 20-30 year long Power Purchase Agreements) that may slow down the pace of decarbonisation.(p.7.) and « Due to a lack of sufficient competition, or the rising prices of fossile fuels, electricity from such contracs might become more expensive than procured from other producers or wholesale markets [] » (p.9)

[115] In Figure 8, the government reduces the amomunt of capacity it procures from a certain technology to reduce the price that it will pay for the energy. It uses its monposony status of a single buyer to depress prices. In theory if long-term supply would be perfectly elastic and there are no entry barriers, this concern dissapears, but this is unlikely to hold in practice. Whether allocating locational scarcity rents to consumers is a form of state-aid, requires more in-depth legal analysis.

[116] Olaya et al., (2016) indicate that the Colombian contract model did not provide enough incentives for inttrmittemt RES. The energy transition will imply large societal changes, which will require innovation in technology, business models, financing and risk allocation and changes for many market participants. Private actors and competition are likely to play an important role here, as regulation is often slow to induce dynamic change.

The EU might try to limit the downsides of those effects by providing some guidelines, but those often increase the risk for investors as well. Examples of such measures are as follows:

- Make the **contracts technology neutral** and **standardised** in order to increase the number of possible bidders. Contracts could focus on **hedging long-term price exposure of consumers** and less on the hedging needs of producers This requires however that scarcity rents are extracted with an alternative policy instrument.[117]
- Use an **auction to determine the contract price**, as this will create more competitive pressure.
- Allow **portfolios of technologies to participate in the market for government contracts**. For instance a RES producer combined with a storage operator can sell a forward contract and manage risk internally. This reduces the need for the auctioneer to rely on availability and portfolio risk factors in the auctioning process, or will allow at least some arbitrage between technology choices. This will require however, **more financial monitoring on the risk exposure of portfolio bidders.**[118]
- **Allow contracts to be traded on secondary markets**, so firms can reallocate contracts. This will allow inefficient generation capacity to exit the market, and retailers can adjust their contracting positions if they gain or lose customers.[119]
- **Turn physical contracts into financial contracts, such a Contract for Differences**, where contract deviations are settled financially. This keeps incentives for availability and participation in the spot market. It requires liquid short-term markets to function well.
- **Fix the contracted quantity ex-ante. Contracts should be based on deemed capacity and not** available capacity. Take-or-pay clauses that are often used for thermal generators eliminate their incentive to participate in spot markets and reduce liquidity. This is also the case for

[117] Wolak (2021) suggests the creation of standardised fixed price forward contracts (SFPFC) to be allocated to retailers in fraction of their demand. This implies that producers of thermal generation will have to hedge the fuel price risk. IRENA and CEM (2005) review of the benefits and drawback of different auction designs and products for renewable energy procurement auctions.

[118] Those types of auctions are called All-source procurements and was popular in the 90s, and are being discussed for California (See section 3.3.3 in Cleary and Ratz 2021).

[119] Secondary markets are important for firms to mothball technology in a timely fashion. For instance, it could be efficient to mothball a wind farm early and build a new farm with more efficient and taller windmills . However, if the wind farm is under a long-term contract with historical favorable contracting conditions, it might not be in the firm's best interest to do so. If the contractual obligations can be transeferred to other assets, this might however be possible. A long-term contract for energy needs to be linked with long-term contract for transmission capacity. This allows a producer in one country to sell a PPA to another country. However, over time the flows over the network might change and more efficient use of network capacity might become available. Without a secondary market for both energy and transmission better outcomes might not be incentivised. See Petropoulos and Willems (2020) for the beneficial effects of secondary markets for transmission rights on investment incentives.

renewable energy production. [120] Hence, the risk for unavailability must be with the seller of the contract.[121]

- If **resource scarcity rents are extracted, this should happen in a transparent way, and state aid concernts need to be addressed**. [122]
- **Allow cross-border participation in the auctions**, as this will increase competition. This will require long-term contracts for transmission capacity.

Taxing Windfall profits

The energy sector currently has some of the **characteristics of a war economy** and skimming the **windfall profits of RES and nuclear generators might be justified for equity reasons**. The best method to skin profits is one that **keeps price incentives on the spot market intact and taxes the inframarginal rents of firms**. Ideally, a crisis tax takes into account existing contractual relationships, is temporary in nature and specifies under which conditions the crisis tax will be automatically abandoned, leaves sufficient profit to the firm, and is not imposed arbitrarily. The revenue collected in a windfall profit scheme is **best used for targeted income support to consumers**. Those criteria might need to be imposed at an EU level. Ex-post taxation of windfall profits can be efficient as it does not distort incentives. Attention should also be given to address **windfall profits in the gas sector**.

Subsidising Demand Reduction

One final, somewhat underexplored, policy to address the energy crisis is **demand management that goes beyond initiatives on energy efficiency**. **Industrial consumers could receive a subsidy to temporary shut down production, or households could receive a bonus for reducing consumption** (as is being trialed in the UK, see below).

This kind of subsidy might be welfare-improving if the wholesale energy price does not reflect the social cost of electricity (for instance because of price caps); when consumers have behavioural biases when choosing consumption levels or buying energy saving equipment; when consumers pay a retail price which does not reflect scarcity at the wholesale level; or when network tariffication and taxation distorts the relative prices of gas and power and self-production versus central generation. There are other market failures in the household sector, such as split incentives between house owners and renters, and financial constraints which hinder investments in new equipment.[123] In the industrial

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[120] Pfeifenberger et al.(2017) report that in the Ontario market the operational decisions of some assets (renewable, hydroelectric, and nuclear) do not respond to market prices, becasuse they are subject to fixed price contracts independent on production levels.

[121] Newbery (2018) argues in favour of subsidies for RES capacity or a fixed, relatively small number of output hours (1) this might be more directly related to the innovation externality and learning-by-doing externalities and (2) because it will not provide extra subsidies for wind farms in high-wind locations.

[122] The current state-aid guidelines might form a starting point; *Guidelines on State aid for climate, environmental protection and energy, 2022*.

[123] A previous CERRE report discusses hurdles to make activate consumers and looks at behavioral nudges, business models, and regulatory changes. It also highlights the importance of aligning incentives. (Giulitetti et al. 2019). Borenstein and Bushnell (2022) show for California that aligning prices for different energy fuels would create significant efficiency gains. Gillingham and Palmer (2014) review the empirical and behavioral literature on whether consumers make the right choices regarding energy savings.

sector, legal limits in the European labour markets might make it hard to furlough personnel and companies might face more than the social cost of a temporary reduction in employment.

Box 3: Hybrid Market Designs

In recent years, several authors have suggested a more fundamental design change in electricity markets, towards so called **hybrid market designs**. Joskow (2022) predicts more government intervention in long-term planning of investments ("integrated resource planning") in carbon-free technologies, more reliance on long-term contracts, more government-mandated competitive procurements of generation resources supported by long-term PPAs, and a partial-return to government planning and vertical integration by contracts rather than ownership. The "hybrid market" would combine "**competition in the market**" for short-term markets and "**competition for the market**" with long-term planning and procurement.

Integrated resource planning (IRP) has kept a more important role in the US, where there are few independent network companies (utilities still own their networks); most households are on regulated tariffs, demand-side flexibility is driven by regulation, and there is little retail competition in buying long-term contracts. Cleary and Ratz (2021) report IRP experiences in California, Colorado and Hawaii, including the governance structure and the type of numerical models used to determine investment needs. They identify the combination of auction-based competitive IRP and centralized optimization-based methods as a potentially interesting avenue for future research.

Keppler et al., (2022) argue that adjusting the existing European market design, by improving ancillary service markets and hedging opportunities, introducing a well-functioning yearly capacity market and direct support schemes for renewable energy, will not be sufficient to reach the policy goals of efficient decarbonised and secure electricity markets. The motivation for hybrid markets is based on (potential) market failures and regulatory failures: social and industrial preferences for the technology mix may not align with market outcomes; carbon prices are too low; the incompleteness of financial markets increases the cost of capital and could lead to inefficient investment porfolios; the different treatment of thermal generation (traded on the spot-market) and RES (under long-term support schemes) might lead to inefficiencies in the long run; RES might not sufficiently participate in spot and ancillary service markets as support schemes eliminate incentives; overcapacicty in generation due to subsidies for RES makes it hard for thermal generation to compete without obtaining some government guarantees as well.

In 2013, Finon & Roques prefer a radical institutional change that would see the implementation of a market-wide capacity mechanism and a reform of the RES policy support, as this would be best from a normative social efficiency perspective. However, they believed in 2013 that this would not be feasible due to a still too small share of RES capacity for the lower effectiveness of market coordination to become visible, and the remaining strong beliefs in market virtues and institutional inertia.

Proponents of the hybrid market model build on the ideas of forward capacity markets, wich are similar to a capacity markets but have a very long contract duration (Ausubel & Cramton, 2010). Those type of contracts have been used in Latin America, for instance in Colombia, Chile and Brazil. They also find inspiration in existing support schemes for renewable energy and nuclear energy, for instance in the UK, which take the form of *long-term Contract for Differences*.[124]

In Colombia (Ausubel & Cramton, 2010) long-term capacity contracts are centrally procured. The ´firm energy contracts´, are financial call options with a relatively high strike prices backed-up by physical capacity. Contracts are procured four years before delivery, so as to allow sufficient time for new investments and locking in energy prices for 20 years in the future. Firm energy contracts are tradable on secondary markets and allow for the reconfiguration of generation portfolios. The cost of the firm contracts are covered in a an additional energy charge to consumers. On top of the firm energy contracts, Colombia has two standardised forward contracts, a take-or-pay load following contract based on expected demand targeting at regulated consumers and a flat forward contracts for the unregulated consumers. The forward market is mandatory for regulated consumers. The last element of the market design is a spot market for electricity. Olaya et al., (2016) argue that the Colombian market model led to a lot of new investment in small-scale hydro, but insufficient investment in intermittent wind-production and argue for additional measures such as Feed-in-Tariffs.

Similar long-term contracts are used in Chile and Brazil (Moreno et al., 2010). In Brazil long-term contracts are procured centrally and allocated proportionally to retailers. In Chile, retailers can design their own long-term contract framework, which are then procured in a centralised auction where all retailers participate and can bid for supplying multiple retailers. Contract standardisation in Brazil has led to more competitive markets. In Chile, the price of the forward contracts are indexed on financial parameters such as fuel prices, inflation and marginal energy prices, which allocate risks to consumers. Reus et al., (2018) highlight that the auctioneer needs to select contracts with low prices, but also needs to consider portfolio effecs. A diverse portfolio reduces overall risk for regulated consumers. This could require a more complicated set of auction rules. However, another option would be to introduce retail competition so consumer could select retail contracts that reflect their risk preferences.

In the UK, Contract for Differences are used to support low-carbon electricity generation. Generators submit a sealed bid in an auction, and if they are selected, receive a contract with a government-owned company. The contract guarantees prices for a 15-year period for the producers, which might differ by project. Cost are recovered by a levy (or a subsidy) on suppliers.[125]

[124] Contracts for Difference - GOV.UK (www.gov.uk) https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference

[125] CfD for nuclear generation were awarded through bilateral negotiation and not through an auction process.

In a World Bank Report Chattopadhyay & Suski (2022) review the literature on the different market models and remain cautious on recommending a new market structure: They state that expert opinions are divided in the academic and industry literature, that there are highly diverging proposals, that no proposal has been supported by empirical evidence, and that there is insufficient evidence that the current systems are not working. They see no reason to rethink yet a complete overhaul of the market design. Also Borenstein & Kellogg, (2021) recognise the challenges of decarbonizing the energy sector, and indicate the *[..] wide disagreement about the best way to operate electricity markets.(p. 252).*

SECTION 4: LEGAL ASPECTS OF WHOLESALE ELECTRICITY MARKET (RE)DESIGN

The EU architecture of wholesale market design legislation

Over time and with the adoption of the different energy legislative packages, the content and manner to elaborate EU energy market legislation has evolved. The EU rules have become more detailed, prescriptive, and technical in nature. The rules are also increasingly reflecting elements of **co-regulation**, with a shift marked in the third energy package with a more **decentralised approach** of lawmaking resulting in the adoption of network codes, guidelines and terms and conditions (TCMs), based on the involvement of notably Transmission System Operators (TSOs), Nominated Electricity Market Operators (NEMOs), National Regulatory Authorities (NRAs) and the Agency for the Cooperation of Energy Regulators (ACER).

The EU architecture of wholesale market design legislation can be described as follows.

In primary law, the legal basis for EU action in the field of energy is **Article 194 of the Treaty on the Functioning of the Energy Union (TFEU)**. Some other legal bases, such as Article 114 and 122 TFEU, have also been used in specific circumstances. While Article 194 TFEU remains the primary legal basis for Union energy policy, the energy **emergency measures enacted at EU level since August 2022 have been based on Article 122 TFEU**.[126] Additional emergency measures for the acceleration of the deployment of renewable energy generation are also expected to be based on Article 122 TFEU.[127] This is a notable legal development that has consequences on the shaping of EU emergency measures. Under Article 122 TFEU, the Council is the one responsible for adopting the EU measures, based on a proposal from the Commission. This leaves the **Council with a large influence** on the choice and the drafting of the EU measures. The European Parliament might possibly be involved in a consultation phase, but this is not required. Article 122 TFEU sets additional requirements for the shaping of the EU measures that must aim to ensure solidarity between the EU Member States (solidarity principle) and be related to a situation of severe difficulties in the supply of certain products, notably within energy.

Moving to EU secondary legislation, the central acts of on electricity market design are the **Electricity Directive**[128] and the **Electricity Regulation**[129]. **Other pieces of secondary legislation** regulate the support to, among others, renewable energy sources,[130] energy efficiency,[131] energy performance in buildings and of appliances, as well as specific trading actors or energy transactions with a focus on

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[126] Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas; Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices

[127] Proposal for a Council Regulation laying down a framework to accelerate the deployment of renewable energy.

[128] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.

[129] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

[130] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources..

[131] Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency.

wholesale market integrity and transparency (notably the REMIT Regulation[132] but also the application of the legislation on market abuse and on financial instruments such as MIFID and MiFIR)[133].

In addition, a third level of legislative acts, increasingly referred to as ´**tertiary legislation**´[134] are adopted in the form of delegated acts, implementing act, or acts adopted using regulatory procedure with scrutiny when this still applies. The most relevant market design rules among this tertiary legislation are the **network codes, guidelines and TCMs** previously mentioned. There are four ´families´ of network codes organised according to their area of focus, i.e., connection, operations, market and cybersecurity. The procedure for the adoption of the network codes, and subsequent guidelines and TCMs, was defined in the 2009 Electricity Regulation and amended in the 2019 Electricity Regulation.

To assist and guide market actors, the European Commission and ACER are also publishing **guidance documents**, of non-binding nature. For example, ACER publishes guidance on the application of Regulation (EU) No 1227/2011 of 25 October 2011 on wholesale energy market integrity and transparency.[135]

As an overall steering mechanism, the different pieces of legislation fall under the wider umbrella of the Governance system of the Energy Union, and the mechanisms defined in Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action (as amended).

The involvement of the different actors in the adoption of wholesale market rules will depend on the nature of the act (e.g., new legislative act or implementing legislation) and its legal basis. The choice of legal basis will influence the voting rules. The adoption of EU measures on energy, internal market, solidarity, taxation policy has different voting procedures and operate under a different share of competence between the EU and Member States. Amending the EU Treaty is not among the options discussed and deemed necessary. **Amending or adopting new secondary legislation will be necessary** to implement certain of the proposed measures at EU and national level and will require the involvement of the Council and the European Parliament, as co-legislators, under notably Article 194 TFEU. Depending on the legal basis for the act, the adoption procedure may give more competence to the Council such as the move towards grounding EU emergency measures in Article 122 TFEU. When necessary, the European Commission will be responsible for adopting approval decisions of national measures, such as state aid approval decisions. This often happens after a phase of pre-consultation between the Member States that will notify the measure, and the European Commission services. The European Commission will also be the one adopting non-binding, guidance documents that will

[132] Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (REMIT).
[133] Regulation (EU) No 596/2014 of 16 April 2014 on market abuse (MAR), Directive 2014/65/EU of 15 May 2014 on markets in financial instruments (MiFID II), and Regulation (EU) No 600/2014 of 15 May 2014 on markets in financial instruments (MiFIR).
[134] The term "tertiary legislation" is not used in the EU Treaties, but it is found in the European Union (Withdrawal) Act 2018 in the UK, following Brexit. See Section 3(2)(a).
[135] https://acer.europa.eu/en/remit/Documents/ACER_Guidance_on_REMIT_application_6th_Edition_Final.pdf

comment on the margin of appreciation left to national governments in the adoption of national measures. Finally, much of the details of wholesale market legislation now involves several actors, as for the elaboration of network codes, guidelines and TCMs. Depending on the level of the measure (national, regional or European), and whether the actors agree or not (risk of escalation to ACER) different actors will be involved. Changing these rules will often be subject to a longer timeline. The measures adopted can also be subject to appeal and judicial review, which will further delay their implementation.

The sequencing of regulatory intervention and legislative changes: short-term, mid-term and long-term processes

A central question to the market design legislation today is **whether it is still fit for purpose for the main part** and just needs the adoption of **supplementary mechanisms** to deal with specific, temporary challenges, or if it requires **a broader revision**. There is therefore a need to distinguish between what should be a future-proof market design under net zero objectives, and the toolbox of temporary measures that can be adopted by governments or market actors in order to respond to short-term disruptions. A main objective of the Clean Energy for All European Package was already to make the European electricity market legislation fit for the clean energy transition.[136] **New actors and services have gained recognition** in the legislation, such as flexibility services, aggregators, energy communities and prosumers, among others. In total volumes at the wholesale level, their **share in the market remains however limited in the short-term**, **but the situation will evolve as more renewables and more flexibility enters the market**. As an additional challenge, a future-proof marked design should take due count of the need to build the resilience of the energy system to respond to more structural risks, such as more extreme weather conditions or cyber threats. This could result, for example, in the insertion of mechanisms that will **valorise energy storage** as a security of supply measure, or **further reward flexibility**.

Therefore, in the context of the current debate on market design, and when assessing the need to revise EU market design legislation, regulatory intervention can be classified according to **short-term (a), mid-term (b) and long-term (c) processes**.

A first reason for looking at the sequencing of the market measures adopted is that it enables to **distinguish between short-term challenges and structural reforms**. Short-term measures aim to address a crisis situation and are adopted within the competences given to the responsible authorities, based on existing legal basis. This is exemplified by the publication of the Commission Communication of 13 October 2021 containing a Toolbox for action and support to tackle rising energy prices.[137] These correspond to the measures adopted during Winter 2021-22, and Spring of 2022. Aware that the energy price and scarcity situation will last and could escalate, governments started assessing possible mid-term measures before the summer of 2022, to address the risks identified in the previous period.

[136] European Commission, Communication, "Launching the public consultation process on a new energy market design", COM(2015) 340 final, 15.7.2015; 2019 Electricity Directive, Recital (6).
[137] European Commission, "Tackling rising energy prices: a toolbox for action and support", COM(2021) 660 final, 13.10.2021.

Therefore, **mid-term measures have primarily related to risk management and adjustment to short-term responses**. They could lead to the adoption of new implementation acts, decrees, or temporary emergency legislation. Such has been the case as part of the Save Gas for a Safe Winter Plan[138] and the adoption of Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas. In the long-term, structural reforms would be needed, to either consolidate and enshrine in law temporary solutions, or revise the existing legal framework, following ordinary-legislative procedures.

A second reason for looking at the sequencing of the adoption of market measures is the **legal consequences that short-term and mid-term measures can have on the internal energy market.** Short-term compensation measures to support a specific sector can potentially create a selective advantage for the beneficiary undertakings, a risk of dominant position on a related market or of cross-subsidisation. Several governments have also considered limiting cross-border trade on electricity or gas interconnectors on the grounds of security of energy supply, with the purpose of limiting exports to first preserve domestic energy supply. Limiting export of electricity is likely to result in quantitative restrictions on exports that are prohibited by Article 35 TFEU, except otherwise justified. As highlighted by the Court in its preliminary ruling of 19 September 2020 in Case C-648/18, an **export restriction** aimed at protecting from high electricity prices **would undermine the very principle of the internal market**.[139] The **(re-)introduction of regulated prices** on gas or electricity would also **undermine some central principles of the current market design legislation**, that is based on market-based signals and liberalisation. This is reiterated in the Electricity Directive that stresses that public service obligations in the form of price setting for supply of electricity constitute ´a fundamental distortive measure´.[140] The **conditions for such price setting intervention should therefore be clearly defined in legislation and its application limited in time** to limit distortive effects. Another impact of regulated prices is that it would also interact negatively with traditional hedging mechanisms; would they be bilateral contracts or through financial instruments. Finally, the pressure put on the European Commission services for a very rapid assessment and approval of state aid measures (short-term intervention measures) could put at risk certain procedural safeguards, as previously illustrated in the Tempus judgment that annulled the state aid approval decision adopted by the European Commission.[141]

A third reason for looking at the sequencing of the measures adopted is the **influence short-term measures will have on ongoing legislative procedures**. Two legislative packages are currently under negotiation, i.e., the Fit for 55 Package of July 2021 and the Hydrogen and Decarbonised Gases

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[138] Communication from the European Commission, "Save gas for a sage winter", COM(2022) 360 final, 20.07.2022.

[139] Case C-648/18, Autoritatea națională de reglementare în domeniul energiei (ANRE) v Societatea de Producere a Energiei Electrice în Hidrocentrale Hidroelectrica SA, 17 September 2020. Para. 43 reads at follows: "Securing the supply of electricity does not mean securing the supply of electricity at the best price. The purely economic and commercial considerations underlying the national legislation at issue in the main proceedings are not grounds of public security within the meaning of Article 36 TFEU, or requirements relating to the public interest which make it possible to justify quantitative restrictions on exports or measures having equivalent effect. If such considerations were able to justify a prohibition on direct export of electricity, the very principle of the internal market would be undermined."

[140] Electricity Directive, Recital (22), (23), Article 5.2 to 5.5.

[141] Judgment of the General Court (Third Chamber, Extended Composition) of 15 November 2018, in Case T-793/14 Tempus Energy Ltd and Tempus Energy Technology Ltd v European Commission.

Package of November 2021. Such interaction has already been taking place with the objective of speeding up the deployment of renewable energy generation capacity. On 18 May 2022, the European Commission adopted a **Recommendation on speeding up permit-grating procedures for renewable energy projects and facilitating PPAs**.[142] Although this is a non-legally binding Recommendation, it relates to topics that are currently under negotiations as part of the revision of the Renewable Energy Directive (Fit for 55 Package) and a proposal for new Council Regulation[143].

A fourth reason for looking at the sequencing of the national and EU measures adopted, is that it could influence future long-term market design reforms. Some temporary mechanisms developed in a period of crisis could transform into permanent solutions. For now, the **temporary measures adopted by Member States or EU harmonised emergency measures all are limited in time**, until early Spring 2023, to avoid further distortion of competition on the internal market.

Finally, most of the short-term measures, and some mid-term measures, have been adopted at the national level. In order to preserve the integrity of the internal market, the European Commission has quickly published **guidelines** aimed at mapping the different measures that Member States could adopt within the existing framework. So far, the European Commission has adopted three communications in that sense: (1) Energy Prices Toolbox, COM(2021) 660 of 13 October 2021; (2) the Additional guidance for Member States, COM(2022) 108 of 23 March 2022; and (3) the Communication on Short Term Energy Market Interventions and Long Term Improvements to the Electricity Market Design, COM(2022) 236 of 18 May 2022. Mid-term harmonisation measures at EU level have quickly been deemed necessary to avoid the possible negative effects of divergent national approaches, in line with the principles of subsidiarity and proportionality (such as the Council Regulation on coordinated demand-reduction measures for gas).

Short-term measures (Toolbox) (crisis management)

Short-term measures to deal with high energy prices have primarily focused on the retail market, with direct support measures in favour of household consumers.[144]

At the wholesale level, a short-term measure considered has been the **use of congestion revenues** to finance different types of market intervention measures, mostly with the objective of reducing the costs of energy for final customers. The Spanish and Portuguese governments have adopted such a support scheme that involves as one of the two sources of financing of the measure, the use of congestion revenues collected by the Spanish TSO on the interconnector to France. Such a measure raises issues under two set of EU rules. First, it has been concluded by the European Commission that the measures constitute state aid in the sense of Article 107(1) TFEU, a conclusion that was not contested by the Spanish and Portuguese governments. In its decision of 8 June 2022, the European

[142] Commission Recommendation of 18.5.2022 on speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements, C(2022) 3219 final, 18.5.2022.

[143] Proposal for a Council Regulation laying down a framework to accelerate the deployment of renewbale energy COM(2022) 591 final, 9.11.2022.

[144] Retail electricity market measures have been the subject of a separate report by CERRE: Von der Fehr et al. (2022).

Commission approved the scheme on the grounds that it is compatible with the internal market pursuant to Article 107(3)(b) TFEU concerning aids aimed "*to remedy a serious disturbance in the economy of a Member State*". The second relevant legal framework when using congestion revenues is Electricity Regulation. The **use of congestion revenues by TSOs is strictly regulated** in Article 19 of the Electricity Regulation in order to avoid any conflict of interests by TSOs. Indeed, there is a risk that TSOs underinvest in interconnection capacity when this additional interconnection capacity would result in decreased congestion income for them.

Another form of wholesale market intervention has been the **support in favour of fossil fuel power plants to cover part of their fuels fuel costs**, with the intention to see them reducing with bid, as they retain the highest influence in setting wholesale electricity prices, due to the marginal pricing method. This approach was also followed by Spain and Portugal in the previously mentioned scheme, that has been approved by the European Commission in June 2022 under EU state aid rules, specifically Article 107(3)(b) TFEU (serious disturbance in the economy of a Member State).

Mid-term measures (risk management, adjustments)

The mid-term measures identified below relate to proposals for action by Member States, the European Commission or even ACER that could challenge internal market rules or secondary legislation, or that would trigger the adoption of harmonised legislation at EU level.

Demand reduction and rationing

In order to prepare for disruption, several governments have started the process of **identifying rationing measures and priority order for curtailment of demand among large energy consumers**. This has been rapidly seconded by supporting measures at EU level, with the adoption of Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas. The Regulation defines a voluntary national gas reduction target of 15% from 1 August 2022 to 31 March 2023).[145] This can be supplemented, in case an ´EU alert´ is activated, by a mandatory demand reduction target.[146] A system similar to the coordinated demand-reduction measures for gas is to be implemented for electricity, building on the same governance structure[147]. In the context of gas, the European Commission has also referred to the possibility of developing rules for "cross-border rationing", but this has not yet been followed by concrete proposals. Adopting **voluntary and possible mandatory demand reduction targets is an approach that resembles other steering mechanisms in EU law,** such as for energy efficiency and the promotion of renewable energy sources. If combined with a market-based approach (e.g., through **tendering of demand reduction**), it also resembles the **system for capacity mechanisms** already in place in several Member States, where demand response can be supported. This would consequently be an approach that Member States are familiar with, requiring monitoring in terms of implementation and enforcement by the Commission. The **implementation of national demand reduction measures** (both for electricity and gas) would raise

[145] Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas, Article 3.
[146] Ibid, Article 5.
[147] Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

questions concerning the possible financial compensation of the undertakings obliged to curtail their demand, which will trigger **state aid rules** as it will result in **subsidising demand rationing**. Developing rules for ´cross-border rationing´ at EU level would be a novel approach (so far only raised in the context of gas) that would elevate at the EU level the question of restriction to exports of energy, as discussed above. It would also raise questions as to the legal basis and scope of the measure.

Solidarity mechanisms between Member States

A parallel approach in the mid-term would be the **implementation of the solidarity mechanisms** defined notably in the Security of Gas Supply Regulation (EU) 2017/1938 and the adoption of the proposed mechanism for voluntary joint procurement of gas strategic stocks (as part of the Gas Directive revision). The **EU Platform** for the common purchase of gas, LNG and hydrogen has had its first meeting already in April 2022, the first regional platforms have been established and an Industry Advisory Group has been set up. The **exact settings of the joint procurement mechanism are yet to be defined and the effects on competition will need careful assessment**. However, it is expected to be part of a longer-term strategy of European cooperation on global energy markets.

New incentives to conclude PPAs

Another path for governments would be to further encourage **large energy consumers to conclude bilateral PPAs**, beyond what is referred to in secondary legislation (Renewable Energy Directive, and its current revision). While Member States can facilitate the adoption of PPAs, it would be an **important shift in regulation to require large consumers to conclude such agreements instead of letting them free to choose** their energy purchasers and form of hedging. It could also have reverse effects, based on the contractual arrangements concluded between each party, a matter that government usually do not interact with.

As explained above, there are different types of PPAs, while the focus on EU legislation in the Clean Energy Package has been on supporting the conclusion of corporate renewable energy PPAs to further enable the uptake of renewable energy sources (Art. 15(8) Renewable Energy Directive 2018/2001). This was based on the fact that there are **still some national barriers to corporate renewable PPAs**. In some countries where legislation does not enable PPAs, the restrictions or constraints on the conclusion of PPAs are primarily related to restrictions on third party ownership of on-site renewable installations, and restrictions on the number of buyers per installation or the number of suppliers per metering point. **By contrast, some other countries have adopted favourable regulatory environments for PPAs**, with the consequence of concentrating the adoption of these PPAs in these countries. Both categories of countries are subject to the same legislation applicable to PPAs, including competition law, internal market, and support schemes to renewables. The **legal barriers faced by some companies in concluding corporate renewable PPAs therefore clearly stem from national legislation.**

A **more mandatory approach to the conclusion of PPAs would be subject to further EU harmonisation**, as previous national practice around PPAs has been subject to in-depth investigation by the European Commission, such as the in-depth investigation opened on long-term PPAs in Poland in 2005. In this case, the Commission considered that the agreements conferred a state aid to the concerned generators and required Poland to amend its proposed legislation in order to plan the end of PPAs and include a compensation system to the generators in line with the Commission's methodology for analysing state aid linked to stranded costs. Finally, the Commission closed the in-depth investigation in 2007 with a positive decision with certain conditions. A similar case arose in Hungary, where the national authorities notified the Commission in 2004 about the existence of long-term PPAs between the state-owned and monopolistic network operator and certain power generators. The PPAs guarantee a return on investment to the generators and a fixed profit margin. The scheme raised similar questions under the state aid framework. Enabling similar forms of PPAs would therefore require an **assessment under state aid rules** and promoting their adoption at EU level would also require **clarification by the European Commission (e.g., in guidelines or in a revision to the state aid guidelines on climate, environmental protection and energy) or the adoption of EU harmonised rules**.

Whether and to what extent Member States provide **long-term, government-backed financial PPAs**, should be left to their discretion, based on the **subsidiarity principle**, and depends therefore on the needs and preferences of individual member states. **Clarifications as to best practices and favoured approach can be provided by the European Commission in the form of soft law guidance**. If so required, **EU harmonised rules should only be proposed as to avoid possible distortions on the internal energy market, but should let member state decide whether or not to introduce government-backed PPAs.**

Monitoring additional support and revenues: state aids and taxation aspects

Member States have adopted different forms of financial support measures that will require to be streamlined on the long-term to avoid distortions on the internal market. **This could require the further revision of temporary crisis framework for measures involving state aids**, with the purpose of **better targeting state aid intervention**.

The **taxation of windfall profits** by government for the purpose of redistributing tax revenues to final consumers is endorsed by the European Commission and Member States. For instance, Greece, Italy, Romania (and the UK outside the EU) have already levied such a tax. A windfall tax is a tax applied to companies that generate a significant increase in their earnings due to circumstances or events for which they are not responsible. The International Energy Agency has estimated that excess profits already amount to EUR 200 billion in 2022.[148] The European Commission has proposed guidance on the introduction of temporary tax measures on windfall profits in its Communication from March 2022[149], followed up by a **proposal for regulation in September, formally adopted by the Council on October 6**.[150] The Commission notably points out that national tax measures on windfall profits would need to be carefully designed to avoid market distortions and to be compatible with state aid rules, while maintaining incentivising additional investment in renewable energy. On its side, the European

[148] https://www.iea.org/reports/a-10-point-plan-to-reduce-the-european-unions-reliance-on-russian-natural-gas

[149] European Commission, "REPowerEU: Joint European Action for more affordable, secure and sustainable energy", 8 March 2022, (COM(2022)010), Annex 2.

[150] Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices, 6 October 2022.

Parliament has called the European Commission and the Member States to coordinate the design of windfall profit taxation schemes.[151] As Member States retain competence on taxation issues, the European Commission has so far **proposed guidance to streamline national approaches on the matter, but a common approach is progressively defined**. Any harmonised measures on the common design of such a tax measure would require the unanimity of the Member States.

Price adjustment mechanisms

Another type of mid-term measures relates to adjustment to existing market rules. A recent example relates to the price spike incidents that occurred in April in France and in August in the Baltics. Both events triggered the need for an automatic increase of the **harmonised maximum clearing price for Single Day-Ahead Coupling (SDAC)**. Indeed, Europe's single day-ahead electricity market has an automatic maximum price adjustment mechanism in case of high prices. According to the Harmonised Maximum and Minimum Clearing Price (HMMCP) methodology,[152] if prices in any zone reach 60% of the maximum price, it triggers an increase in the maximum price limit five weeks later. As price spikes will probably occur more frequently, there is a **need to limit the frequency of increases of the maximum clearing price in the single day-ahead market**. In that way, consumers and market participants could better adapt their behaviour to the scarcity situation on the market. Therefore, on 2 September 2022, ACER urged a review of the rules on the automatic maximum price adjustment mechanism in the day-ahead electricity market.[153] In order to change the methodology, the NEMOs must first propose an amendment to the HMMCP methodology. NEMOs sent their proposals on 15 September, leaving six months to ACER to reach a decision. NEMOs also published an explanatory note for information purposes.[154] In the present case, ACER has indicated that it will complete the procedure within a much shorter framework. In this concrete case, it is the NEMOs that will trigger the start of the revision of the market rules that will be followed-up by ACER and subject to stakeholder consultation. However, stakeholders have expressed scepticism around the procedure for a quick revision of the methodology and its legal basis, pointing out again the difference between emergency measures (with a separate legal basis) and revision of general market design rules (that should follow the regular procedure).[155]

Improving cross-border interconnection capacity

The current energy scarcity situation has had huge influence on energy price and leads to risk of further price spikes. To prevent this to happen, it is **fundamental that enough cross-border**

[151] European Parliament, Resolution of 19 May 2022 on the social and economic consequences for the EU of the Russian war in Ukraine – reinforcing the EU's capacity to act (2022/2653(RSP)), para. 46.

[152] Article 41(1) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation).

[153] ACER urges a review of the rules on the automatic maximum price adjustment mechanism in the day-ahead electricity market | www.acer.europa.eu; ACER reviews the rules on the automatic price adjustment mechanism in the day-ahead and intraday electricity markets | www.acer.europa.eu

[154] Explanatory note to the NEMOs´ proposal of the amendment of the HMMCP methodologies, October 2022. Nemo Committee (nemo-committee.eu)

[155] Eurelectric, Response to ACER's public consultation on the revision of the Harmonized Maximum Minimum Clearing Price (HMMCP) methodology for single day-ahead coupling (SDAC) and for single intraday coupling (SIDC), 7 October 2022. Response to ACER's public consultation on the revision of the Harmonized Maximum Minimum Clearing Price (HMMCP) methodology for single day-ahead coupling (SDAC) and for single intraday coupling (SIDC) - Eurelectric – Powering People

interconnector capacity is made available for trade. Growing congestion in the European transmission system for electricity has been of increasing concern over time and had already triggered a series of amendments to the Electricity Regulation. This supplements the process of market coupling that started earlier. Of particular importance in Regulation (EU) 2019/943 are the new rules on capacity allocation, the requirements for bidding zone (re)configuration and the obligation for TSOs to provide a minimum cross-border trading capacity. For that purpose, TSOs will be under further scrutiny to make the capacity available at the border, and to implement the rules on the use of congestion revenues defined in the Electricity Regulation.[156] Tools on cross-border congestion management are also defined in the market network codes under Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity calculation and congestion management (CACM), Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA) and Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB). Further emphasis can be expected on the implementation of existing mechanisms to ensure that a minimum level of capacity for cross-zonal trade is made available. Pursuant to Article 16 (8)(a) of the Electricity Regulation, this minimum level translates into a 70% rule of the net transmission capacity (NTC) after deduction of contingencies (as determined in the CACM guideline). Where the NTC system has already been replaced by flow-based market coupling, the 70% obligation refers to cross-zonal critical network elements Article 16 (8)(b). To sum up, cross-border congestion management and the implementation of the different existing tools to ensure it will be under scrutiny in the mid-term.

Long-term measures (reform): alternatives for an improved market design

The current discussion on reform of the market design is oriented towards **two main sets of proposals on: price formation and market behaviour**. While the same categorisation applies to measures proposed for the retail market, the analysis below focuses on the wholesale market.

Price formation

In the REPower EU plan, the European Commission is proposing to **strengthen transparency requirements and supervision of transactions in the wholesale market**. This follows previous initiatives and will interact with ongoing processes consisting in: review of the CACM Regulation (CACM 2.0)[157], ACER proposal for new governance for Market Coupling Operation (MCO) functions, monitoring of the implementation of the Regulation. The European Commission is also proposing to **move towards more integrated forward markets**. In addition, the high energy prices and high volatility observed on the wholesale markets has led ACER and NRAs to reinforce their supervision efforts to detect any cases of market abuse, leading to possible sanctions under the REMIT Regulation EU No 1227/2011 on wholesale energy market integrity and transparency.[158] Preserving trust in the

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[156] Article 16 (8) of Electricity Regulation prohibits TSOs from limiting the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their bidding zones.

[157] ACER's proposal for reasoned amendments to Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management.

[158] ACER, "ACER and 3 regulatory authorities reinforce coordination on energy market abuse", 3 November 2022 https://www.acer.europa.eu/events-and-engagement/news/acer-and-3-regulatory-authorities-reinforce-coordination-energy-market-abuse

integrity of the EU wholesale markets will depend on the strict application and enforcement of these rules. Interestingly, national measures (or even public statement calling for change of behaviour) to control hydropower reservoir levels in the view of limiting exports, as investigated in Norway, have already raised questions as to their compatibility with REMIT rules.[159]

The **introduction of locational marginal pricing** is also among the proposals part of the **bidding zone review process**, as documented by the ENTSO-E report from June 2022.[160]

Similarly, a future-proofed market design legislation will need to not only **enable the integration into the market of a higher share of RES**, but also ensure that **market rules function with a higher share of RES**. This applies to both RES produced onshore and offshore. The level of ambition is high. The European Commission has announced a target of at least 60 GW of offshore wind installed capacity by 2030, and 300GW by 2050.[161] In the REPowerEU Plan, the European Commission called upon a further acceleration of RES deployment and an increase of the RES target in general to 45% in final energy supply by 2030. In that context, a major question is to know **which market design model will apply to the new generation capacity added offshore, and notably hybrid assets**. Will the common bidding zone model and general rules on management of congestion income apply to hybrid offshore wind assets? This is at least the approach favoured by TSOs and the industry. Whether the EU can or should push all (or even some part of) RES into the lower price of a two-price system is also an important question.

New added generation offshore could be developed in an isolated manner to shore (**radial connection** with single purpose) to start with, but interconnectors, also called "**hybrid cables**", are seen as a better long-term solution, in particular within sea basins shared by different countries, such as the North Sea or the Baltic Sea. Hybrid solutions could also extend from dual purpose solutions to multipurpose solutions, connecting different energy sectors and consumption points. Moving from radial to hybrid is both more cost efficient and more sustainable, avoiding duplicating infrastructures and optimising generation hubs. Hybrid cables will connect at least two countries or regions, and will also include a point of production or consumption somewhere in between.

Hybrid projects can develop under the current EU legal framework, but market reforms will be needed to better incentivise them and ensure optimal cross-border cooperation and price formation. Notably, the **market design of possible offshore bidding zones will need careful assessment**, as it will influence revenues for the connected offshore wind farms (including congestion management, product design

[159] NordPool, Market Surveillance Quarterly Newsletter, Q2 2022 https://www.nordpoolgroup.com/4a81ca/globalassets/download-center/market-surveillance/market-surveillance-newsletter-q2-2022.pdf

[160] ENTSO-E Report on the Locational Marginal Pricing Study of the Bidding Zone Review Process, June 2022. **https://www.entsoe.eu/news/2022/06/30/entso-e-publishes-its-report-on-locational-marginal-pricing-study-of-bidding-zone-review-process/**

[161] European Commission, An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future, COM(2020) 741 final, 19.11.2020, p.2.

and hedging strategy)[162] and may need to be accompanied by additional instruments such as a revenue stabilisation mechanism.[163] Compatibility with the Electricity Directive, Electricity Regulation, the Renewable Energy Directive (REDII) and the relevant network codes and guidelines (FCA GL, CACM) will also need to be assessed, leading to possible amendments. Common approach to grid connection requirements across sea basins would also be needed.[164]

Finally, the **external dimension of EU regulatory model for market design** should be carefully assessed, when contemplating changes. **Market design solutions should be compatible with cross-border cooperation with non-EU countries, to ensure a broader area of energy cooperation and security of supply around the EU territory.** This also reinforce EU's energy system resilience towards external threats on the energy sector and system, as illustrated by the numerous tensions between Russia and the EU on the application of EU energy law requirements to cross-border infarstructures or lately by the war in Ukraine. This area of external cooperation includes countries part to the European Economic Area Agreement, such as Norway, close European partners like Switzerland and the UK[165], Morocco and Energy Community countries. **The extent to which market design solutions enable cross-border cooperation between EU countries and neighbouring countries is to be taken into account from the start of any market design reform.**

Market behaviour

An important component of future market design reform will be to maintain **regulatory incentives to ensure sufficient investments in renewable generation capacity**, based on the right price signals and with a proportionate return on investment for investors. Therefore, emphasis on **planning, simplification of permitting processes, development of flexibility and new generation** capacity is expected to keep an important place in the legislation, supported by the provisions in the revised **Renewable Energy Directive (RED)**. The **EU regime of PPAs will also probably further evolve, most probably as part of the RED** rather than as an element of market design legislation. The reason for that is that the objective of EU harmonised measures on corporate renewable PPAs is to facilitate their adoption and support the further deployment of RES. **The objective is not to harmonise PPAs or regulate PPAs provision but to encourage their uptake**. The drafting of the corporate PPAs will continue to remain an issue for negotiation between parties to the agreement.

However, some flexibility mechanisms enabling the further integration of renewable energy sources into the energy system and to balance the effect of their integration will probably need to be part of

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[162] European Commission, Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market, August 2022 https://energy.ec.europa.eu/system/files/2022-09/Congestion%20offshore%20BZ.ENGIE%20Impact.FinalReport_topublish.pdf

[163] ENTSO-E Position on Offshore Development – Market and Regulatory Issues, 15 October 2020. https://eepublicdownloads.azureedge.net/clean-documents/Publications/Position%20papers%20and%20reports/2021/entso-e_pp_Offshore_Development_02_Market_Reg_Issues_201014.pdf

[164] European Commission, "An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future" (ORE Strategy), COM 2020(741) final and accompanying document SWD(2020) 273 final, 19.11.2020.

[165] As reflected, as concerns the UK, in the EU-UK Trade and Cooperation Agreement, but also som bilateral agreements with EEA countries implementing energy market design legislation (e.g. Norway).

market design legislation. This applies to both existing mechanisms, such as the capacity remuneration mechanisms, and **new mechanisms such as two-way contracts for differences (CfD).**

The **resilience** of the energy system of the Member States already relies on their integrated energy system. As stated by the European Commission, "*deepening market integration (across all electricity markets) is a no-regret option*".[166] This will continue to be a major element of regulatory intervention, with further regulatory support in favour of coordination of investment decision for the development of smart energy infrastructures and cross-border infrastructures in general. The revision of the TEN-E Regulation already integrates innovation to a larger extent than before in the investment models for elective projects.

Complementary mechanisms to ensure security of supply and investments

Although market design legislation is revised, market failures may remain, which Member States may wish to address by adopting specific measures. These measures would notably focus on further support to renewable energy generation and security of supply. They could take the form of for example **government-based PPAs or two way contract for differences,** and would be subject to the same legal constraints described above, i.e., **compatibility with internal market rules, competition rules, including state aids rules**. Some core elements of their design could also be subject to minimum harmonisation through secondary legislation or soft law guidance by the European Commission. These additional measures would **not be core elements of market design, but would represent additional intervention measures** that Member States could adopt to address specific market failures.

[166] European Commission, "Short-Term Energy Market Interventions and Long-Term Improvements to the Electricity Market Design – a course for action", COM(22)236, 18 May 2022.

SECTION 5: CONCLUDING THOUGHTS ON WHOLESALE ELECTRICITY MARKETS

The current energy crisis has clearly raised questions about the long-term design of the electricity market in situations where unit energy prices will be volatile and high. However, this energy crisis is about much more than market design and clearly about **distributional issues that democratic political systems must address**, guided by national preferences and starting points.

One option is clearly to let the wholesale market continue as now and to help industrial and residential consumers directly through **targeted subsidies** to help with payment of bills. This would have the implication that there would be significant financial incentives to save energy due to being exposed to the impact of high wholesale prices. This approach is not being followed to the same extent by all countries in the European electricity market area, where there are **differing levels of interventions on retail prices directly**, which in turn **increase demand for electricity and raise wholesale electricity** prices. We discuss this in detail in the next part of this report.

Two-market solutions to short run pricing are superficially attractive but **raise serious efficiency issues**. Lowering the price of electricity for some types of generation and not others will lower production of the lower-cost electricity and **raise overall electricity production costs**. It will therefore raise the demand for gas generation and hence the price of gas, causing **backfire by raising rents in the gas sector at the expense of capturing them in the electricity sector**. It may also seriously reduce cross-border trade in electricity. A good example of this in reverse is the recent German decision to extend the life of its nuclear power plants. The economic incentives to take this decision would be substantially reduced in a two-market solution.

A move towards a US Standard Market Design based on central dispatch, capacity markets and locational marginal pricing (LMPs) and financial transmission rights (FTRs) can be considered. However will not address the issues raised by the energy crisis. Capacity markets are an emerging reality across many European countries. **LMPs are theoretically attractive in providing better signals to location, but in reality they raise issues as to whether the potential improvements in short run operating efficiency are worth the disruption and negative impact they might have on long-term investment.** It is also unclear as to the extent to which longer term FTR markets actually work.

Several concluding observations can be made:

First, it is **important not to make changes to market design which are not consistent with good long run operation**, which will be difficult to reverse. The creation of an effective short-term single market in electricity has been a long-running policy objective which has taken two decades to bring about. Net zero modelling tells us clearly that much more, not less, short-term trading of electricity will be necessary to achieve Europe's climate goals while delivering energy security at least cost.

Second, **reducing the demand for gas is key to reducing electricity prices. It is important that gas supplies to Europe are improved, and that European gas demand is reduced**. Policies which indirectly raise gas demand, by subsidising gas consumption (as in Spain) are to be avoided because they worsen the fundamental problem of a shortage of gas and they distort electricity trade towards subsidised electricity production. Encouraging fuel switching away from gas to liquid fuel or alternative gases (such as ammonia) or coal or nuclear is very important.

Third, **reducing electricity demand has a disproportionate effect on prices**. Every 1% reduction in electricity demand, will reduce wholesale electricity prices by of the order of 5-10%[167]. This is because short run electricity demand is relatively inelastic. **National campaigns to encourage electricity demand reduction this winter are essential.** There is a lot of excellent international experience of successful campaigns to reduce electricity demand quickly which individual European countries can draw on.[168] For instance: New Zealand reduced electricity demand by 10% in 6 weeks in 2003, in the face of shortage of hydroelectricity[169]; and Tokyo reduced electricity demand by 18% in the summer of 2011, following the Fukushima disaster in March 2011[170].

Fourth, a **consistent suggestion is that low-carbon generation should be moved to long-term fixed price contracts**. While this might be **sensible for new contracts, it is not clearly true for existing projects**. It is important to point out that if this arrangement is voluntary, it simply **moves payment from today to the future at the private rate of interest demanded by low-carbon generators**. It reduces current bills in return for higher future bills and constitutes a loan from the companies to consumers. It **would be cheaper for the government to do this via the tax system**. The signing of **long-term contracts by the state should be matter of national preference**.

Fifth**, the only way to reduce the net present value of the flow of financial payments to existing low carbon generation over the longer run will likely involve some sort of appropriation of revenue via increased profits taxes.**

This can be done but will come at the potential cost of raising future rates of return demanded by investors on low-carbon generation. This is because there is no agreed definition of "windfall" profits and some inframarginal surplus revenue is required to provide normal returns to individual projects.

Sixth, an **important regulatory question is whether retail prices do reflect wholesale prices. In some countries they apparently do not**. For instance, in the UK, the regulated unit price of electricity for households from 1 October 2022 was only 84% of the forward wholesale price.[171] This could easily have been altered for standard consumption levels by reducing the daily fixed charge and increasing

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[167] Labandeira et al. (2017) estimated the short run price elasticity of demand for electricity between 0.1 and 0.2. The UK has observed a 6.1% reduction in industrial demand between June 2019 and June 2022 and a 44% rise in the real manufacturing electricity price excluding CCL (BEIS Statistics, Table 5.5 and Table 3.3.1, September 2022). This gives a raw elasticity of 0.14.
[168] See IEA (2005) and IEA (2011).
[169] See IEA (2005, p.97).
[170] See Kimura and Nishio (2016).
[171] See Pollitt et al. (2022).

the unit charge to hit the UK government's Energy Price Guarantee on average bill payments. This would also have improved the distributional impact by reducing bills for lower consumption households, who tend to be poorer. It is important here that **bills are reduced while increasing the marginal price of electricity to reflect expected wholesale electricity prices this winter**. This could be done with a **rising block tariff,** where the final block reflects average expected winter prices. Failure to price electricity and gas properly this winter to households (and small businesses), will significantly reduce the **productive capacity of European industry**.

Seventh, **regulatory barriers to additional low-carbon generation should be removed**. It is very welcome to see life extension of nuclear power plants being proposed in Belgium and Germany. Even small increases in the availability of low-carbon generation could significantly reduce the impact of gas-fired generation in setting marginal prices in the wholesale market, via **reducing demand for gas and by pushing gas out of the merit order stack.**

Eighth, **distortionary taxes on marginal electricity production should be removed**. There are examples of extra taxes on the use of gas in electricity production, e.g., the carbon price floor in the UK, which can be removed and would directly reduce the wholesale electricity price in Great Britain.[172]

Ninth, **some of the suggestions for electricity market reform are sensible** – such as the completion of the single market, the use of more locational pricing, the implementation of cross-border congestion management rules and the revision of the HMMCP Methodology – but they will not address the magnitude of the energy crisis in the time frame required. Indeed, these suggestions being implemented could be **thought of as the ongoing development of the single market, however accelerating some of them would bring forward their benefits**. Such changes would have to be looked at in the medium run in the context of the road to 2030 and 2050 climate goals.

Finally, **European electricity market solidarity is important**. All countries need to act together to reduce aggregate market prices and the Commission should pay attention to **policies which help reduce European demand, improve European supply, reduce European prices and call out policies which export bigger problems to other European countries**. The single market in electricity has been great for promoting European energy integration, reducing overall prices and improving European security of electricity supply. Trade in electricity is net beneficial to all countries, though it benefits some through increased returns to national generators and others through lower prices to electricity consumers. It is essential for the achievement of net zero based on wind and solar resources. **If we undermine the single market in electricity, we threaten European energy supply security and the achievement of net zero.** We should not shoot the messenger of the single market in electricity when the fundamental cause of this crisis is an unforeseen (certainly up to April 2021) precipitant reduction in European pipeline gas supply from Russia.

[172] For a discussion of the carbon price floor, see Hirst (2018).

PART B: RETAIL MARKETS UNDER STRESS
INTRODUCTION TO RETAIL MARKET DESIGN

The rise in the cost of energy has put retail markets under considerable stress. The most obvious implication is the increase in consumer bills, but, more fundamentally, retail markets have been shaken in their foundations. Contracts have been broken, suppliers[173] have gone bankrupt and governments have rushed in strong measures to support the market and compensate those who have been adversely affected.

This unprecedented increase in energy prices, caused by external shocks, was difficult to predict. Therefore, it may seem unfair to criticise anyone for being ill-prepared, be it consumers on variable-price contracts, suppliers that had not hedged their exposure to wholesale prices, or regulatory authorities that were unprepared for a market failing to deliver what it was supposed to.

It is now possible to draw conclusions on the need for changes to retail market design. Surely, we will be better prepared when the next shock comes: **more consumers will be on fixed-price contracts, suppliers will**, to a greater extent, **hedge their positions and regulatory authorities** will have devised **better tools for handling market failures and targeting support on vulnerable consumers**.

Although we are still living this crisis and many questions remain open, enough time has passed to draw lessons. The crisis has mobilised European Union (EU) policymakers and national governments since the autumn of 2021. Throughout winter, and with the additional shock of the Ukrainian war, governments stepped in with **various national-level measures aimed at cushioning the short-term impact of the price hike**, and have turned to European institutions to request guidance on how to address the crisis or, at times, to request exemptions to the single market's rules or formulate criticisms of its design and rules. The impact of energy prices on inflation has become a significant concern, even in countries where there was initial reluctance to intervene with energy prices (such as the UK and Germany). This has given way to actual **retail price capping, reductions in VAT or government payment of prices above a certain level** in most countries.[174]

The European Commission first responded with a ´toolbox´ published in October 2021, reminding which types of measures could be taken in line with existing EU legislation. This was followed by an assessment of the EU wholesale electricity market design by the Agency for the Cooperation of Energy Regulators (ACER), two "REPowerEU" communications in March and May, and the Commission's announcement that it would look into possible updates to wholesale market design. In October 2022 EU member states adopted a **Council Regulation affecting the retail market**.[175] This committed member states to: reduce their monthly electricity demand by 10% including by 5% in peak hours by iimplemented corresponded measures; cap market revenues from specific sources of electricity

[173] Although the term "retailer" is often used, throughout we use the term "supplier" for those involved in the supply of retail services. This is consistent with the usage in EU legislation.

[174] For all the countries reported on, there has been direct intervention to reduce the electricity prices that households and many businesses pay. See Sgaravatti et al. (2021) updated.

[175] Council Regulation Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

generation; put additional taxes on petroleum, gas, coal, and refinery sectors and distribute surplus revenues to households and companies to reduce bills; and allow, on a derogative basis, the regulation of small and medium-sized enterprises' (SME) electricity prices. The measures are temporary, and apply from 1 December 2022 to March 2023.

Although energy prices have increased all over Europe, the impact of the price shock and the reaction by the regulators and governments at national level have differed. This can to a large extent be explained by **differences in the design and regulation of the retail markets**. Some retail market elements seem to have worked as intended while others did not. In some markets, the overall design appears consistent, while in others it does not. By comparing experiences across retail markets, we can learn how different designs performed under the test.

This is not to suggest that there exists one ideal retail market design. European countries differ so much – in terms of energy mix, market structure and political priorities – that it is **unlikely that any one design would be ideal for all countries**. Nevertheless, lessons can be learned across countries that may help improve the design of individual markets.

In this part, we present our initial take on these issues. In particular, we aim to cast light on the following questions:

- How well have European retail electricity markets been coping with the current energy crisis? How have governments responded to increasing prices?
- What short-term measures can governments take to soften the impact of high energy prices?
- What long-term measures can governments take to protect consumers from high energy prices?
- What should be role of the EU vs. Member States? What legal constraints are imposed by EU directives and regulations?
- Do we need to regulate the risk exposure of suppliers? What are the options for doing this?

Retailing in energy markets

Energy retailing includes a range of services, including selling energy and offering hedging possibilities, as well as sale of energy equipment, advice on energy efficiency, boiler maintenance and other services.[176] Retailing also includes aggregation.[177] In practice, suppliers represent the interface between final consumers and the energy value chain.

At the core of retailing is the **activity of collecting payments from consumers and transferring them to producers or generators, possibly via wholesale**.

In electricity or gas networks, it is not possible to physically link individual producers and consumers in any meaningful way. Generators are supplying energy at their points of connection and consumers are taking energy at their connection points; it is as if generators are pouring energy into a common pool, and consumers are drawing energy out of it. It is impossible for any specific generator to say which consumers physically took its energy, or for a consumer to say which generators supplied them physically.

This implies that, unlike in most other industries, retailing does not include handling the good being produced and consumed. Electricity and gas flow through the networks from generators to consumers irrespective of how retailing is undertaken, including who is responsible for it and the specificities of retail contracts. In particular, retailing does not encompass the quality of energy supply, such as interruptions, composition of gas and frequency of electricity.

Retailing consists of writing contracts, collecting payments and paying wholesalers or generators, as well as dealing with customers who do not fulfil their contractual obligations, including not paying their bills. Retailing requires matching the payment streams from consumers to the revenue streams of wholesalers or generators, i.e., ensuring that the energy consumption of retail customers is backed by supplies from wholesalers or generators. Retailing therefore necessitates access to metering data on consumption. To the extent that payment streams from retail customers are not perfectly aligned with the streams of payments to wholesalers or generators, retail also needs to handle liquidity, including risk.[178]

Contracts

Retail contracts may differ in a number of dimensions, including whether payments are due before or after consumption takes place, the frequency of payments and what happens in the case of non-

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[176] Directive (EU) 2019/944 of 5 June 2019 on common rules for the internal market for electricity (Electricity Directive) defines supply as "the sale, including the resale, of electricity to customers (Article 2(12)).

[177] Retailing services can also include aggregation. Pursuant to the Electricity Directive, aggregation means "a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market" (Article 2(18), Electricity Directive).

[178] For an early discussion of retailing in electricity markets, see Littlechild (2000) and Joskow (2000).

[178] Directive (EU) 2019/944 of 5 June 2019 on common rules for the internal market for electricity (Electricity Directive) defines supply as "the sale, including the resale, of electricity to customers (Article 2(12)).

[178] Pursuant to the Electricity Directive, aggregation means "a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market".

payment. Perhaps **the most important dimension is the extent to which retail prices vary over time in response to wholesale prices**.

At one end of the spectrum are **´real time´ retail prices** that are directly linked to underlying short-term wholesale prices; an example is so-called "spot-price" contracts, where the retail price equals the spot price at any given time (typically, 15 minute, half-hourly or hourly period), possibly with a mark-up. At the other end of the spectrum are **fixed-price contracts** with durations of one or more years, where the retail price remains fixed over the contract period. Contract prices may also be adjusted at shorter intervals or be linked to average wholesale prices over a certain period, and there may be ceilings (and floors) limiting the extent of price variation over the contract period.

The Electricity Directive provides for harmonised provisions on retailing, notably free choice of supplier, basic contractual rights for final consumers, entitlement to dynamic electricity price contract, supplier of last resort and billing information. As we shall see below, the availability and uptake of different types of contracts vary considerably between countries.

Risk

Retail contracts that involve prices that do not vary as much as the underlying wholesale price provide retail customers with protection against price volatility. More precisely, such contracts **move the price risk from customers to suppliers** (who may choose to transfer it further). In particular, when energy is sourced from a wholesale market where prices vary "continuously" and sold on retail contracts in which prices are adjusted infrequently, suppliers face varying or risky net revenues. This risk may be hedged by entering into wholesale contracts with price developments that match those of the retail contracts; sometimes this is done by the use of financial derivatives.

Energy retailing therefore shares many of the **characteristics of financial intermediation**. In particular, an important part of energy retailing is handling liquidity and risk. This involves managing the maturity mismatch of assets and liabilities, dealing with consumer switching, counter-party risk, predicting risk premia for different contract durations and transmission costs. As will be evident from the country studies below, this is also where some suppliers failed; they had not taken the necessary measures to handle the liquidity and financial risk they were facing. The fact that energy retailing resembles financial services may have implications for how the activity should be regulated.

As part of the possible long-term reforms on the retail markets, one option advanced by the European Commission is to **further regulate the regime for suppliers**. Notably, suppliers could be required to hedge a certain part of their supply. Other requirements may also be set to ensure that suppliers are ´sufficiently robust´ to face new crises and protect final customers. Finally, suppliers could be obliged to offer fixed- priced contracts as part of their portfolio, in the same way that they are already required to offer dynamic contracts.[179]

[179] European Commission, Short-Term Energy Market Interventions and Long-Term Improvements to the Electricity Market Design – a course of action, COM(2022) 236 final, 18.05.2022.

Competition

The economies of scale are not especially large in energy retailing. Many of the costs are fixed, such as those of administration, computer systems and (where relevant) marketing, but these are relatively modest;[180] it does not take very much to set up a retailing business.[181] In the EU, the average number of nationwide suppliers in electricity is above 50 – slightly less so in gas – many of which are relatively small.

As such, retailing is suitable for competition.

Competition can be over multiple dimensions. Most importantly, there may be competition over the mark-up of retail over wholesale prices. Competition could also be over the characteristics of the retailing contracts, such the billing or payment scheme, price determination and amount of hedging.

In practice, competition often takes place over whether energy products are offered in stand-alone contracts or in contracts that bundles different products; in many countries, it is common to offer gas and electricity in a single contract. Energy may also be bundled with other products, such as mobile telephony. Some suppliers offer additional products or services, such as electric appliances or help to reduce energy consumption (such as ´smart´ energy solutions).

A specific phenomenon in the electricity market is the ability of suppliers to market specific ´types´ of energy, notably ´green electricity´ generated from renewable energy sources. What these suppliers do is to bundle electricity as such with contributions or donations to specific forms of generation. As pointed out above, and in the absence of direct line, suppliers have no way of guaranteeing where the energy consumed by their customers is actually generated. Through the use of tracking mechanisms, such as **guarantees of origin (GOs),** it is nevertheless possible to direct payment streams to generators of renewable energy, thereby adding to the revenues of these generators.[182]

The guarantees inform consumers about where their payments will be go (´consumer empowerment´) and help obligated consumers to comply with disclosure obligations, if any.[183] The revenues generated by the sale of guarantees of origin as part of the electricity offer will support generators who have been given the right to sell such guarantees. This is largely done through suppliers, who thereby can give consumers an opportunity to contribute to renewable generation. The guarantees are sold at a premium, with local or domestic generation typically receiving higher premia. While it is not entirely

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[180] Short Term Energy Market Interventions and Long Term Improvements to the Electricity Market Design, COM(2022) 236, 18 May 2022.

[180] The economies of scale in marketing and the building of reputation may in some cases be considerable. Many markets for consumer products (eg. banking and telecom) are dominated by a small number of larger consortia that often operate a number of brands. Notwithstanding the fact that in the energy retail sector there are often many participants, a considerable number of European markets are highly concentrated (ACER, 2021).

[181] The easiness of entry in the retail market depends on the liquidity of the wholesale market, which varies across Europe.

[182] The Renewable Energy Directive (EU) 2018/2001 (REDII) defines a guarantee of origin as "*an electronic document which has the sole function of providing evidence to a final customer that a given share or quantity of energy was produced from renewable sources*." (Art. 2). A guarantee of origin is a so-called Energy Attribute Certificate (EAC). The regime for guarantees of origin has been progressively reinforced in secondary EU legislation, where the Electricity Directive defines an obligation to ('shall') use guarantees of origin to comply with the disclosure obligation when electricity is generated from renewable energy sources, except in a few circumstances (Banet, 2021).

[183] The Electricity Directive (EU) 2019/944 defines the 'electricity disclosure' obligation as part of the billing information. Note that tracking of generation attributes can also apply to gases or heat. However, there is no corresponding disclosure obligation for other energy carriers than electricity in EU law, corresponding to a general 'energy disclosure' requirement.

clear how much the guarantees of origin contribute to development of renewable energy, they have become quite popular in some countries (Mulder and Zomer, 2016; Hulshof, Jepma and Mulder, 2019).[184] Additionally, the reinforced EU requirements concerning disclosure obligation and the use of guarantees of origin in the Renewable Energy Dierctive (REDII) are contributing to harmonised practices on electricity disclosure in billing to consumers.[185]

The **evidence on how well competition has worked in energy retailing is mixed**. In some places, it seems to have worked quite well (see e.g., von der Fehr and Hansen, 2010; Mulders and Willems, 2018), while in other places the experience has been less favourable. Even in markets where it has worked well (such as Great Britain), it has been subject to detailed criticism. A common criticism has been a **lack of market transparency, or difficulties of switching**, with the consequence that consumers are not able to take sufficient advantage of the opportunities that the market has to offer and hence end up with a worse deal than they could have got (Guilietti, Waddams Price and Waterson, 2005; Giulietti, Waterson and Wildenbeest, 2014). According to ACER (2021), the most common reasons for consumers to complain about suppliers are invoicing, billing and debt collection.

The overall importance of competition in retail for consumer costs of energy is limited by the fact that energy bills to a large extent contain items over which suppliers have no influence. According to ACER (2022), in 2021 40% of the final price to European electricity household consumers consisted of the energy component (´contestable charges´), while 60% consisted of non-contestable charges such as network costs, taxes, levies and other charges. For gas, the energy component was somewhat higher at 48%, while other costs amounted to 52%. There are considerable differences across countries, depending on energy supply and national energy and taxation policies; in electricity, the energy component varied from 24% in Denmark to 73% in Malta; in gas, the energy component varied from 29% in the Netherlands to 77% in the Czech Republic.

Although the contestable charges make up a limited part of energy bills, retail mark ups are not insignificant in many countries. ACER (2022) provides information on average annual differences between retail and wholesale prices for household consumers; in over the period 2014-202, this was on average €17/MWh for electricity and €8/MWh for gas (both were negative in 2021). Figure 17 shows the variation across countries; for example, average mark-ups in electricity were above €43/MWh in Great Britain, at €26/MWh in the Netherlands, €24/MWh in Italy, €20 /MWh in France, €17/MWh in Norway and €4/kWh in Spain (the negative mark-ups in some countries are due to regulated prices being set below wholesale energy costs). Mark-ups in gas were generally lower, between €10 and €20/MWh in France, Great Britain; Italy, the Netherlands and Spain.

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[184] The impact on the energy mix would be strong in the case that so many consumers signed up to such contracts that their combined consumption exceeded the available output or capacity of the specific type of energy.
[185] Renewable Energy Directive (EU) 2018/2001 (REDII) Article 19.

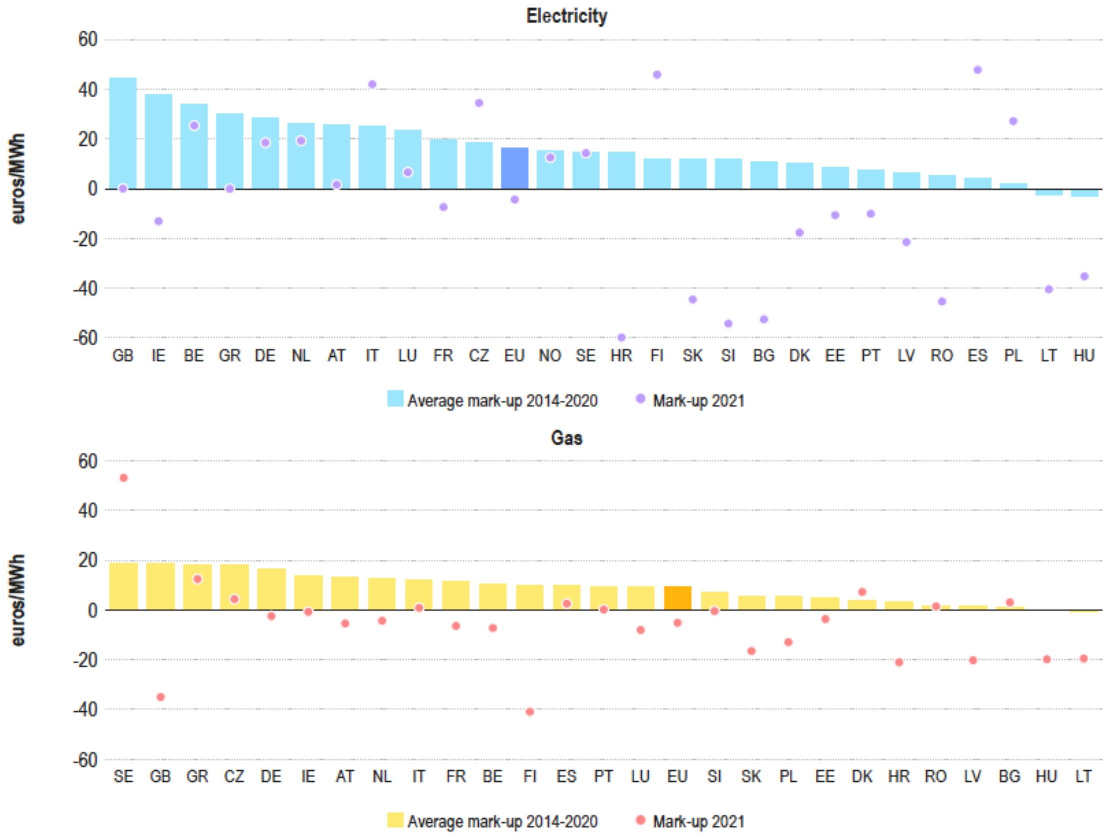

Figure 17: Average annual mark-ups for household consumers, euros/MWh. Source: ACER (2022)

Retail competition is not only about lowering the mark-up between the retail price and the wholesale prices through competition, but also **about innovation in contract types, educating consumers about their energy consumption through marketing, and providing complementary services**. A well-functioning supply market has **positive spill-overs in the wholesale market**; vertically integrated suppliers will compete more fiercely in the wholesale market.[186]

Regulation

Naturally then, much of the regulatory effort in energy retail markets has been directed at free choice of supplier, transparency and consumer protection. The EU and national legislation contain rules on how electricity supply contract should be marketed, what information consumers should be offered, and how suppliers must inform their customers about price changes or other contractual adjustments.[187] This is accompanied by a right to switch supplier and access to comparison tools.[188] Sometimes there are explicit rules on the contractual content (e.g., standardised contractual terms)

[186] The procurement strategies of regulatedRegulated public utilities is often plagued by a lack of long-term hedging. If wholesale prices drop those long-term contracts look like business mistakes *ex -post*.
[187] For harmonised EU rules for electricity supply contracts, see the Electricity Directive, Art. 10 – Basic contractual rights.
[188] Electricity Directive, Art. 12 and 14, respectively.

and invoicing or billing. In some countries, regulatory authorities provide information on available suppliers and their products. EU legislation also requires that effective, independent out-of-court dispute settlement mechanisms for all consumers are in place in case of disagreement. The Electricity Directive encourages moving toward dynamic electricity price contracts – with prices varying in real time in response to market conditions – supported by the development of smart metering systems.[189] Regulation has also been directed at how consumers who find themselves without a regular supplier should be handled. Often this is addressed by the appointment of a `supplier of last resort´, which is obliged to take on consumers in cases when their current supplier has had to leave the market, or when other suppliers refuse to deal with them. The Electricity Directive leaves discretion to Member States as to the adoption of a supplier of last resort requirement in the regime for universal services, as well as how to structure it.[190] In practice, most Members States have a form of supplier of last resort mechanism in place (ACER-CEER, 2018).[191] In some countries, the supplier of last resort are other suppliers; in other countries, it is the local distribution company. If the supplier of last resort happens to be the sales division of a vertically integrated undertaking which also performs distribution functions, the unbundling requirement must be met.[192] The contractual terms of the supplier of last resort, including the retail price, are typically regulated.

Retail market structure is subject to regulation. First, access to the retailing market can be regulated, with rules about who may, and who may not, be involved in energy retailing. Then, the structure of companies involved in retail will be influenced by the unbundling rules that define which activities, between retailing and other energy market activities, that can and cannot be combined. Particular attention is paid to the separation of monopolistic activities, such as transmission and distribution, and competitive activities, such as production and supply. At one extreme, regulation may require that all retailing is done by one designated company, the so-called `single-buyer model´ (this model is no longer present in the EU). All suppliers must be `in balance´ at all times; that is, obligations to supply energy must be backed by access to the warranted resources, through ownership or contract.

Regulation may also encompass the terms on which energy is offered, specifically retail prices. Such regulation may provide limits on how often and by how much prices may be changed, or they may regulate price levels directly. Price regulation may be limited to specific groups of consumers or it may cover the entire market. Sometimes regulation requires that prices depend on the amount of energy consumed, with higher consumption levels being charged at higher prices. In specific circumstances, the EU legislation allows for public intervention in the price setting for supply of electricity.[193]

[189] Electricity Directive, Art. 11 on entitlement to a dynamic electricity price contract.
[190] Electricity Directive, Art. 27.
[191] An exception is Finland, where consumers have to find suppliers themselves; however, suppliers are obliged to serve all customers irrespective of where they live or their financial status.
[192] Electricity Directive, Recital (27).
[193] Electricity Directive, Art. 5.

Both primary and secondary EU legislation set **certain restrictions on the extent to which national governments can intervene in electricity markets, including at the retail level**. In order to guide the action of Member States in their response to high energy prices (emergency measures), the European Commission published a so-called `toolbox´ in October 2021 (EC, 2021). This was supported by two additional communications in March and May 2022 (EC, 2022a; EC, 2022b).

The national measures with regard to the retail market that will be deemed compatible with EU legislation include direct income support to vulnerable end-users, financial support to companies (could involve state aid elements) and targeted tax reductions. These measures are already enabled under current EU legislation (state aid rules, Energy Taxation Directive, retail price regulation in exceptional circumstances).

As a matter of example, Spain and Portugal made use of the existing flexibility left to Member States under the EU state aid rules to develop temporary support measures (until 31 May 2023) to lower the input costs of fossil fuel power stations (EC, 2022c).[194] The aim is to reduce production costs and, ultimately, the price in the wholesale electricity market, to the benefit of consumers.[195] **Such measures do of course carry a number of inefficiencies**, including distortion of competition (internally and externally) and encouraging consumption in a period of scarcity, cf. our discussion of the Spanish case below.

As part of the temporary emergency measures, and by way of derogation to the main rules of the Electricity Directive, Council Regulation (EU) 2022/1854 allows Member States to apply public intervention in price setting for the supply of electricity to SMEs, under certain conditions.[196] The Regulation also allows Member States to set a price for the supply of electricity below cost, under certain conditions and for a limited period of time.[197]

[194] The support takes the form of a payment that operates as a direct grant to electricity producers aimed at financing part of their fuel cost.
[195] The measures were approved by the European Commission on 8 June 2022: State Aid SA. 102454 (2022/N) – Spain and SA.102569 (2022/N) - Portugal – Production cost adjustment mechanism for the reduction of the electricity wholesale price in the Iberian market.
[196] Council Regulation (EU) 2022/1854, Article 12.
[197] Ibid. Article 13.

SECTION 1: COUNTRY CASE STUDIES

Before moving on to the case studies, we provide a brief overview of retail markets in Europe, including levels of consumption, prices, switching rates and extent of government price intervention. The information is drawn from ACER Market Monitoring Reports 2020 and 2021 (ACER, 2021, 2022).
The average household energy consumption across EU Member States was 3, 570 kWh for electricity and 4, 662 kWh for gas in 2019, but with considerable variation, both with respect to overall energy consumption and the relative importance of electricity and gas. Figure 18 shows the average consumption of household consumers of electricity and gas in different countries. Energy consumption is highest in Norway (15,065 kWh), where it consists almost entirely of electricity. At the other end of the spectrum is Latvia, with an average energy consumption of 3,518 kWh, split almost equally between electricity and gas.

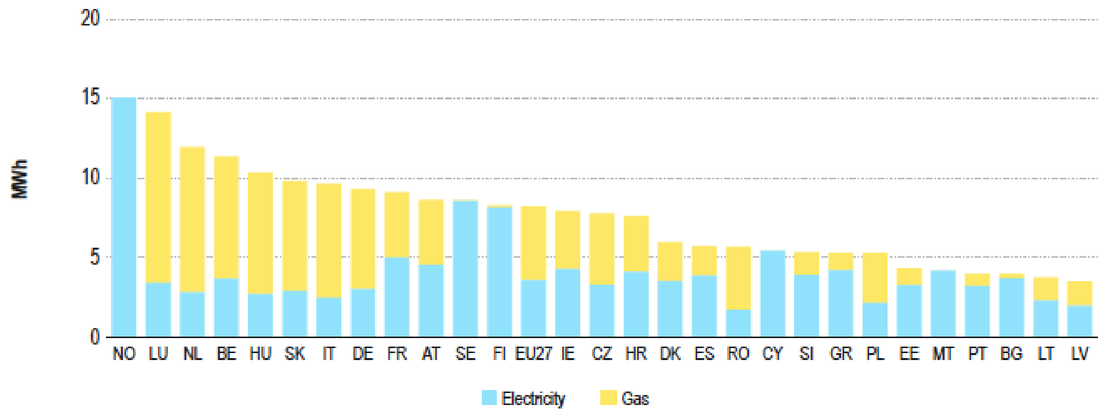

Figure 18: Average electricity and gas consumption, households, 2019. Source: ACER (2021)

Energy prices also vary considerably across Europe. Figure 19 shows final electricity prices and Figure 20 shows final gas prices, for households and industry, respectively. Prices vary considerably across Europe and across types of consumers. For example, household electricity prices in Germany were three times as high as those in Hungary, while industry electricity prices were four times higher in Denmark than in Lithuania. Price differences reflect differences in generation technologies, network costs and taxation levels.

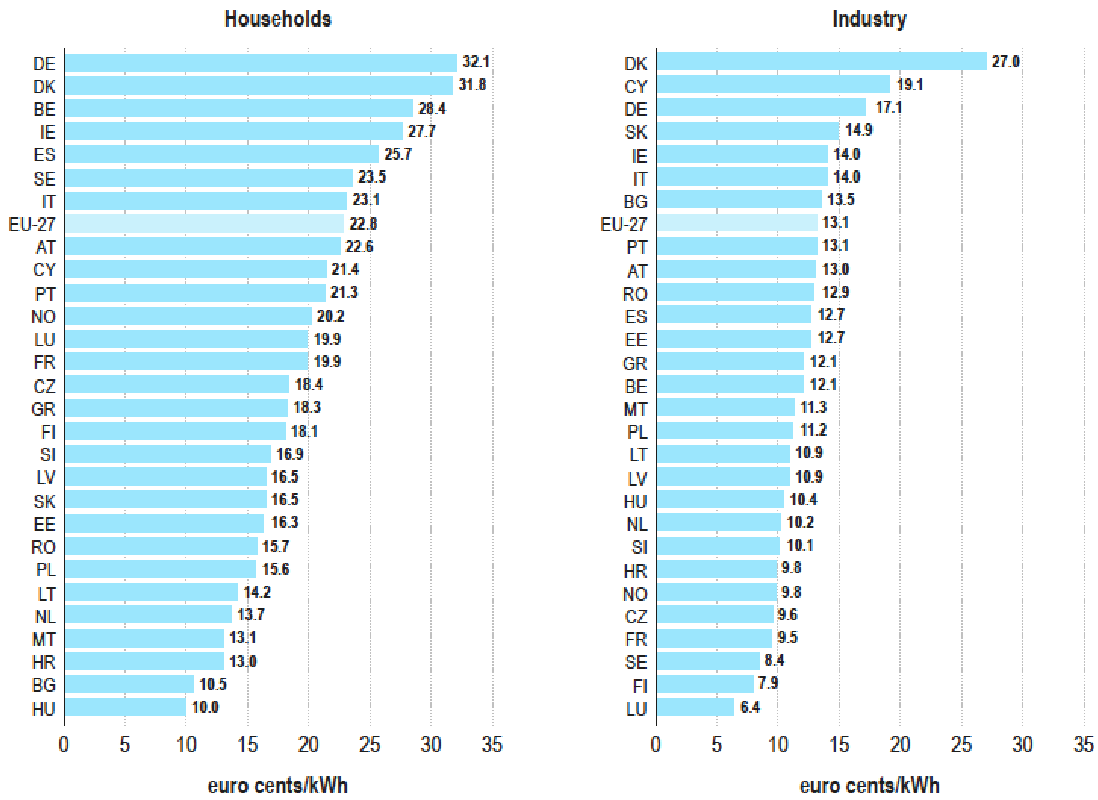

Figure 19: Final electricity price, 2021. Source: ACER (2022)

Prices are generally lower for industry than for household, sometimes by considerable amounts. For example, in France household electricity prices were more than double those of industry, whereas in Italy gas prices to households were more than double those those of industrial customers.

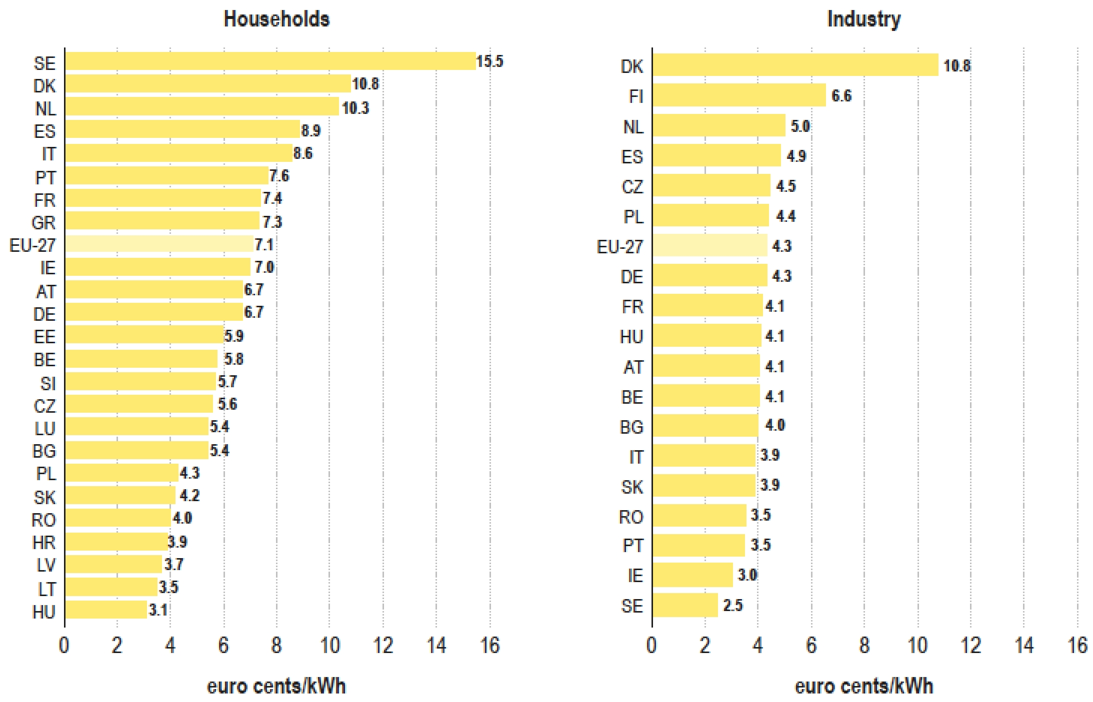

Figure 20: Final gas price, 2021 , including network cost, and all taxes and levies. Source: ACER (2022)

Figure 21 shows rates of household consumers switching from one energy supplier to another, an indication of consumer activity and competition in the retail market. The switching rates were around 20% in and the Netherlands, Belgium and Norway (electricity only). In a number of countries, switching rates were very low or negligible; many of these countries have tightly regulated retail markets.

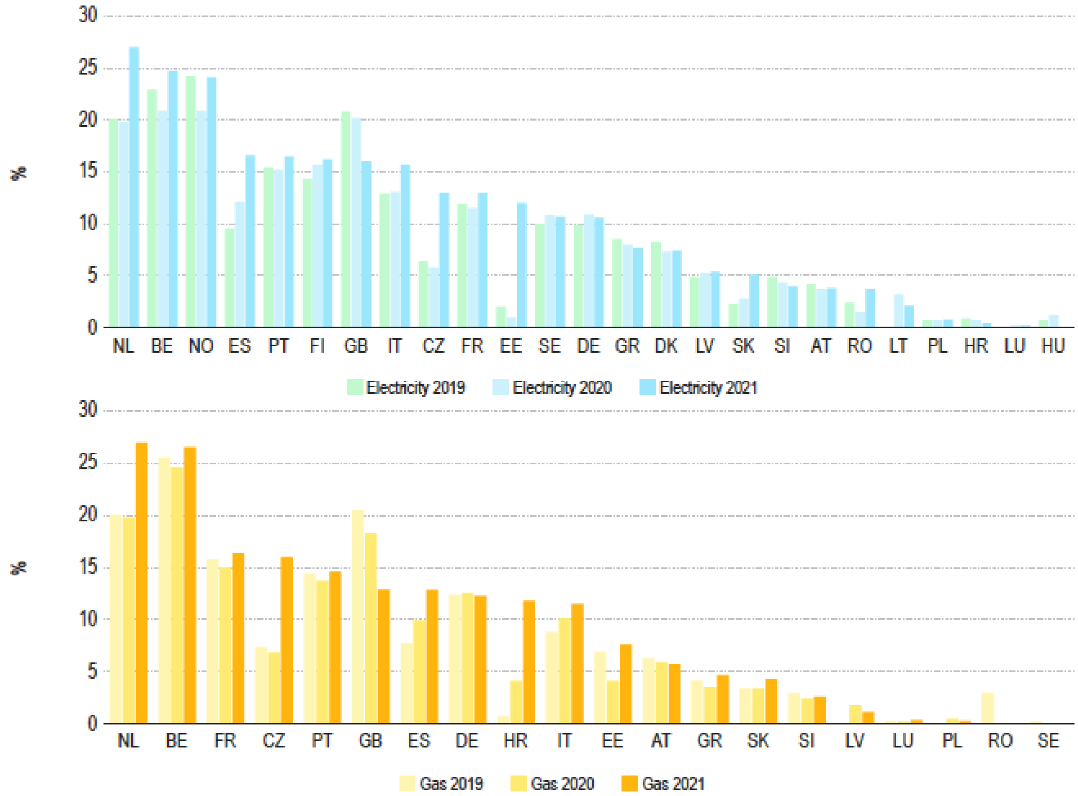

Figure 21: Household switching rates, 2019-2021. Source: ACER (2022)

Figure 22 shows that in 2020, 15 countries had some form of public price intervention to protect household consumers in the electricity market; 14 countries intervened in the gas market. In some of these countries – such as France, Great Britain, Greece, Latvia and Spain for electricity, and France, Great Britain and Lithuania for gas – interventions were restricted to vulnerable consumers. In the non-household market, such interventions are less common, but did exist in nine markets for electricity and four for gas.

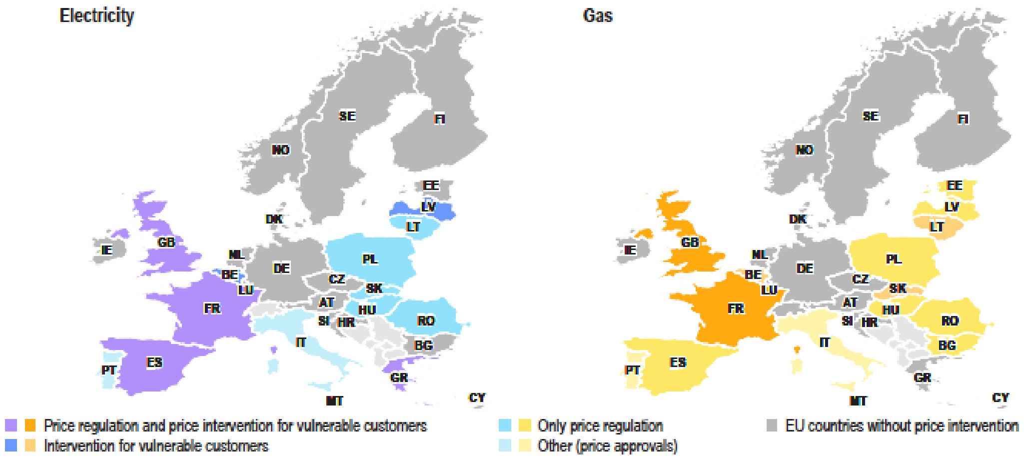

Figure 22: Price intervention, household consumers. Source: ACER (2021)

Of course, this picture is much changed since the energy crisis. According to Bruegel, by November 2022, a majority of European countries had some form of retail price regulation; the exceptions were Croatia, Cyprus, Finland, Greece, Ireland, Italy, Latvia, Malta, Norway, Portugal, Slovenia and Sweden.[198]

[198] https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices

France

A mix of regulation and competition characterises the French retail market. Since the market's complete opening in 2007, the country's main electricity supplier EDF's dominant position is limited. In particular, with the so-called NOME Law enacted in 2011, households can buy electricity from EDF at a regulated price. In addition, a share of EDF's nuclear energy is available to alternative electricity suppliers at a relatively low fixed price. In the current context of rising energy prices, the French government has taken some drastic support measures, setting a low cap on regulated tariffs, and forcing EDF to sell more electricity to its competitors at a below-market price. These measures have reached their primary objective; the increase in regulated electricity tariffs was limited to 4% since February 1st 2022, while the energy regulator, the Commission de régulation de l'énergie (CRE), had predicted a 45% increase. The tariff shield will continue in 2023 with an increase limited to 15% on average in January for gas, and February for electricity.

However, these costly measures are not viable in the long run. Moreover, they may restrict EDF's investment strategy, foreshadowing the inevitable energy price increase due to rising CO_2 costs and a slowdown of the energy transition in France.

The retail electricity market

The historically dominant incumbent EDF competes with more than 80 retail suppliers, known as alternative suppliers (e.g., Total Direct Energie, Engie, and ENI). A hybrid market structure was implemented in 2011 to limit EDF's dominant position. Market players compete for the whole retail market, but small consumers can choose a regulated tariff, and alternative suppliers have access to subsidised electricity capacity.

Residential consumers and non-residential or "professional" consumers with a subscribed power level of less than 36 kVA can choose a regulated price, *Tarif Réglementé de Vente (TRV)*, offered mainly by the incumbent EDF (and the local distribution companies (LDC), which supply 5% of residential consumers). The TRV is set twice a year by the French government and depends, among other things, on electricity transmission and wholesale market prices.

The principle of reversibility makes it possible to switch from the regulated price to market offers and *vice versa* without limitation. Since December 31, 2015, medium and large professional consumers (with a subscribed power level greater than 36 kVA) cannot access the regulated tariffs.

The regulated tariff works as a reference price for the entire market. Most alternative electricity suppliers offer discounts on the regulated electricity tariff (reductions range from 2% to 12%). Other suppliers offer the option of locking in electricity prices (or fixed prices) for a specific duration (from 1 to 4 years). Still, the regulated tariff is used as a base. Like most other European retail markets, all suppliers (incumbent and newcomers) offer these non-regulated price contracts.

As illustrated in Figure 23, at the end of 2021 approximately 72% of consumption was supplied by non-regulated price offers, of which 44% was from alternative suppliers.

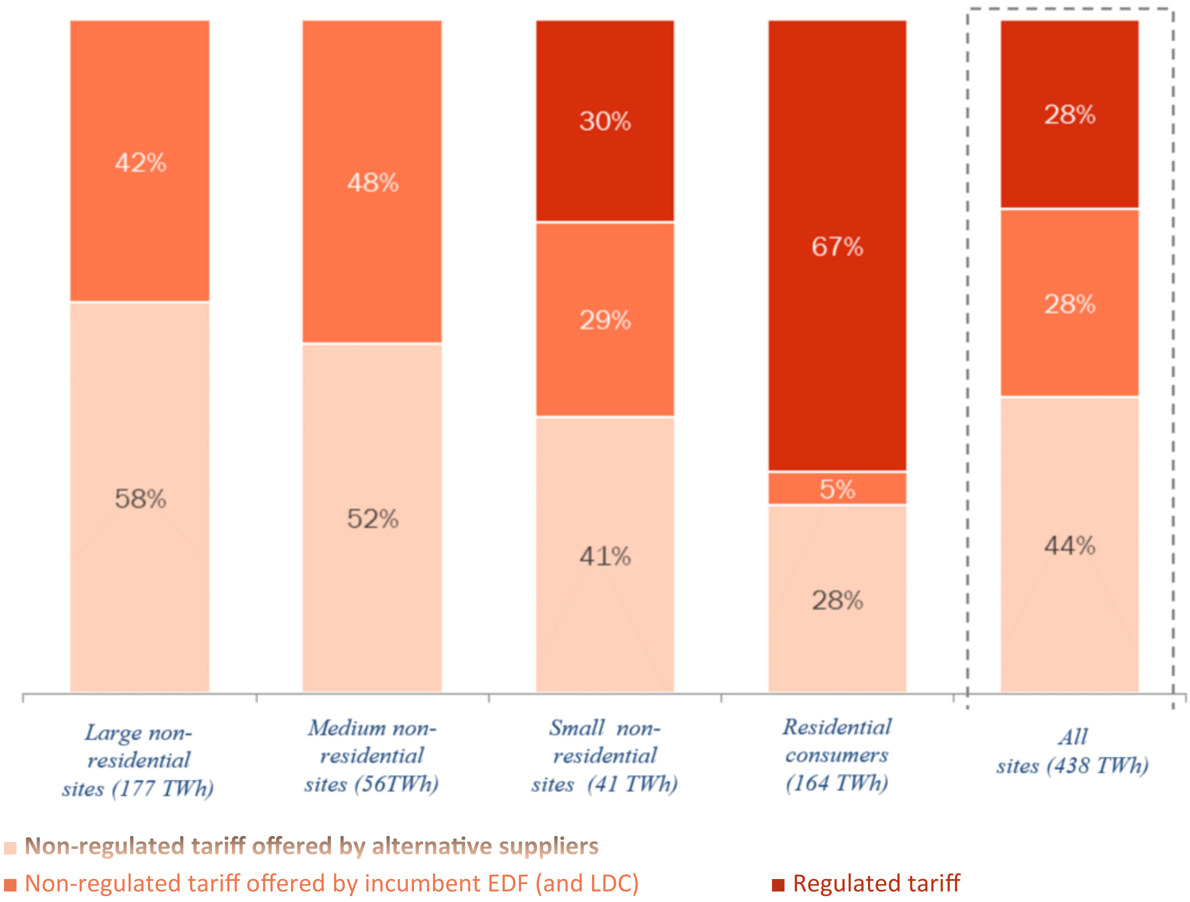

Figure 23: Annual consumption by type of supply as of December 31, 2021. Source: CRE (2021)

To ensure fair competition between asymmetric market players, the regulated access to nuclear electricity allows alternative electricity suppliers to purchase electricity produced by EDF's nuclear power plants at a regulated price for volumes determined according to the consumption of their customer portfolio in France, within the limit of a maximum overall volume. This so-called ARENH (*Accès régulé à l'énergie nucléaire historique* or Regulated Access to Incumbent Nuclear Electricity) mechanism has been in place since July 1, 2011 and will continue until 2026. Until February 2022, the total capacity allocated to the alternative suppliers could not exceed 100 TWh over a year, i.e., approximately 25% of the production of the historical nuclear power plants, and the price cap was 42 euros per MWh.

As illustrated in Figure 24 (which displays requested vs. available ARENH volumes), alternative suppliers did not always ask for the maximum ARENH volume. If the price cap exceeds the wholesale electricity market price, none of the suppliers exercise the ARENH option. This was the case in 2016, when the demand for ARENH was zero. However, since 2019 the total demand of suppliers has exceeded the limit set by the public authorities. In this case, the energy regulator applies a supply reduction coefficient (*taux d'écrêtement*) to each supplier, taking into account the competition in all retail market segments.

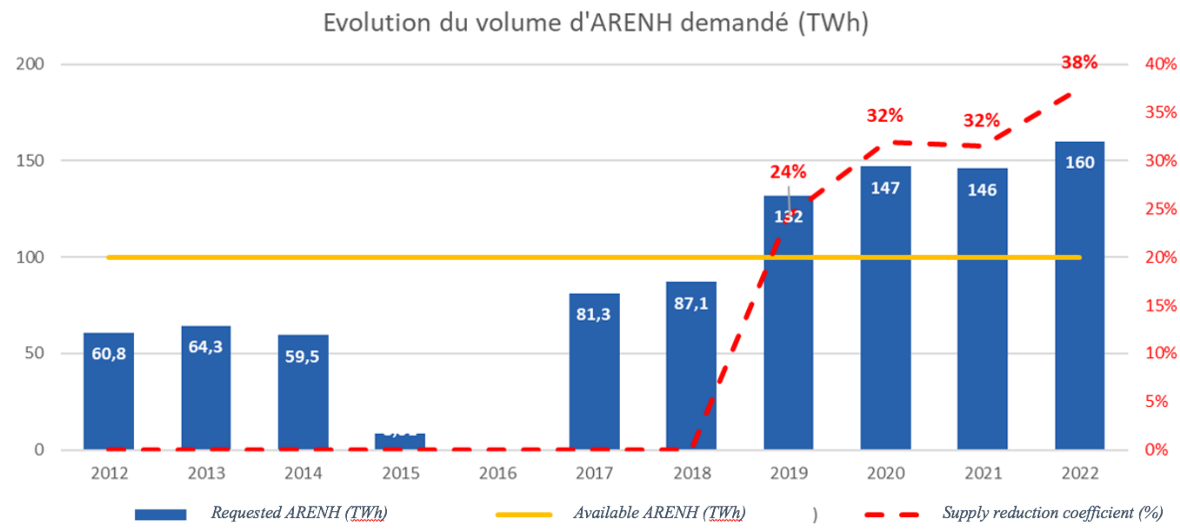

Figure 24: Requested ARENH volume, 2012-2022. Source EnergiesDev (2022)

The ARENH limit was nearly reached in 2017 and 2018, and exceeded in 2019. Since the energy price crisis, the ARENH volume requested by the alternative suppliers was consistently well-above the limit. Since 2017, alternative suppliers (who are not generators) have to buy considerable capacity on the wholesale market at a price above the ARENH price.

However, their market shares kept increasing despite non-incumbent players facing larger supply costs. They covered 15.5% of the residential consumer segment in 2017, 19,5% in 2018, and 23,4% in 2019, while 23 million of French households are still on EDF's 'regulated' tariffs. In addition, alternative suppliers served 39% of the non-residential consumer sector in 2017, 43% in 2018, and 46% in 2019.

The government responded to the rising prices by a so-called `*Bouclier tarifaire*´ (or tariff shield policy), which limited the increase in France's electricity prices to 4% from February 1, 2022, onwards. This limited price increase is completely disconnected from the 45% regulated price (TRV) increase initially forecast by the French energy regulatory commission (CRE, 2021).

Two drastic measures have been implemented to limit the increase in electricity prices. First, EDF's obligation to supply competing suppliers with cheap electricity has been reinforced. By April 1, 2022, the maximum of 100 TWh of electricity produced by EDF's nuclear power plants which is available to alternative suppliers was increased by 20%, obliging EDF to sell 20 TWh more electricity to its competitors.

Second, the government has nearly removed the domestic tax on final electricity consumption, drastically cutting the tax from €22.5 per MWh to €0.5. Half of this decrease is due to a tax cut, and half to a postponement to 2023 of part of the rate increase applicable in 2022.

These two measures led to only a slight increase in household electricity prices (about 5% between 2021 and 2022). This is less than the current inflation rate of 6,2% (in October 2022). The energy-intensive industry has faced a price increase of 38% between 2021 and 2022, as illustrated in the figure below.

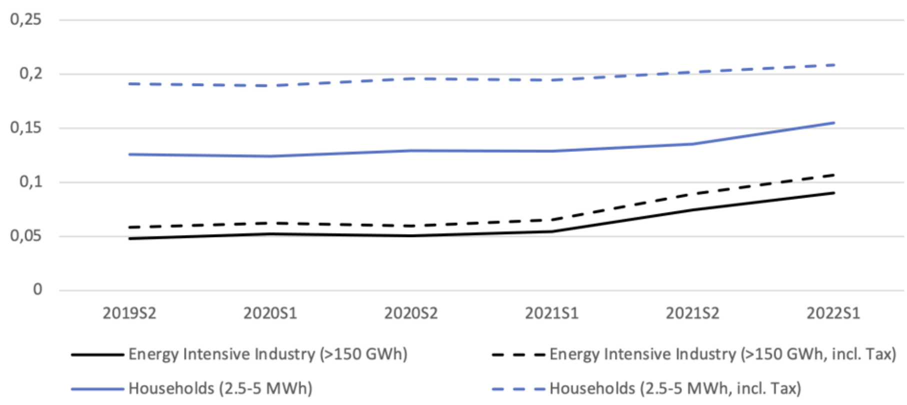

Figure 25: Electricity prices (EUR/MWh) for household and non-household consumers (bi-annual data)

The retail gas market

The situation in the retail gas sector is slightly different. Like the retail electricity market, the incumbent Engie faces alternative suppliers (which account for 22% of the residential customer segment and 65% of the non-residential customer segment). The government has introduced a tariff shield and frozen gas prices. Engie's regulated gas tariffs are blocked since November 1, 2021, (and until December 31, 2022) at the level of the October 2021 tariffs. Contrary to the retail electricity market, government intervention had much less impact. However, without this measure, the average level of regulated sales tariffs on November 1, 2022, would have been 167.5% higher (including VAT) than October 1, 2021’s level (see Figure 26). This price increase is much more significant than in the electricity market.

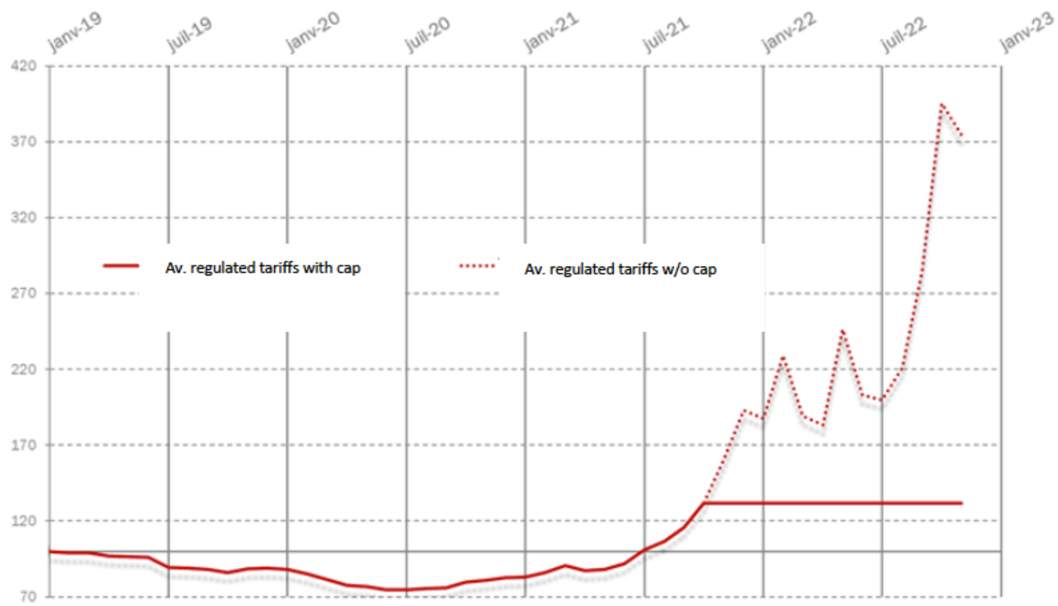

Figure 26: Av. regulated tariffs with and w/o price cap. Source EnergiesDev (2022)

Second, only 28% of residential customers currently benefit from this tariff (i.e., representing only 7.5% of the national gas consumption). Additionally, the regulated tariff will disappear on July 1st 2023, and customers are already encouraged to switch to market price contracts. Finally, half of the customers are on fixed-price contracts, where more than 67% have 3- or 4-year contracts.

The average price of natural gas industrial consumers, excluding VAT, has doubled (+ 103%) between the first half of 2021 and the first half of 2022. The largest consumers have experienced an even moresignificant increase. Companies consuming more than 1 TWh have seen their gas price almost triple in one year and now pay more for their gas than companies consuming less (as illustrated in the Figure below).

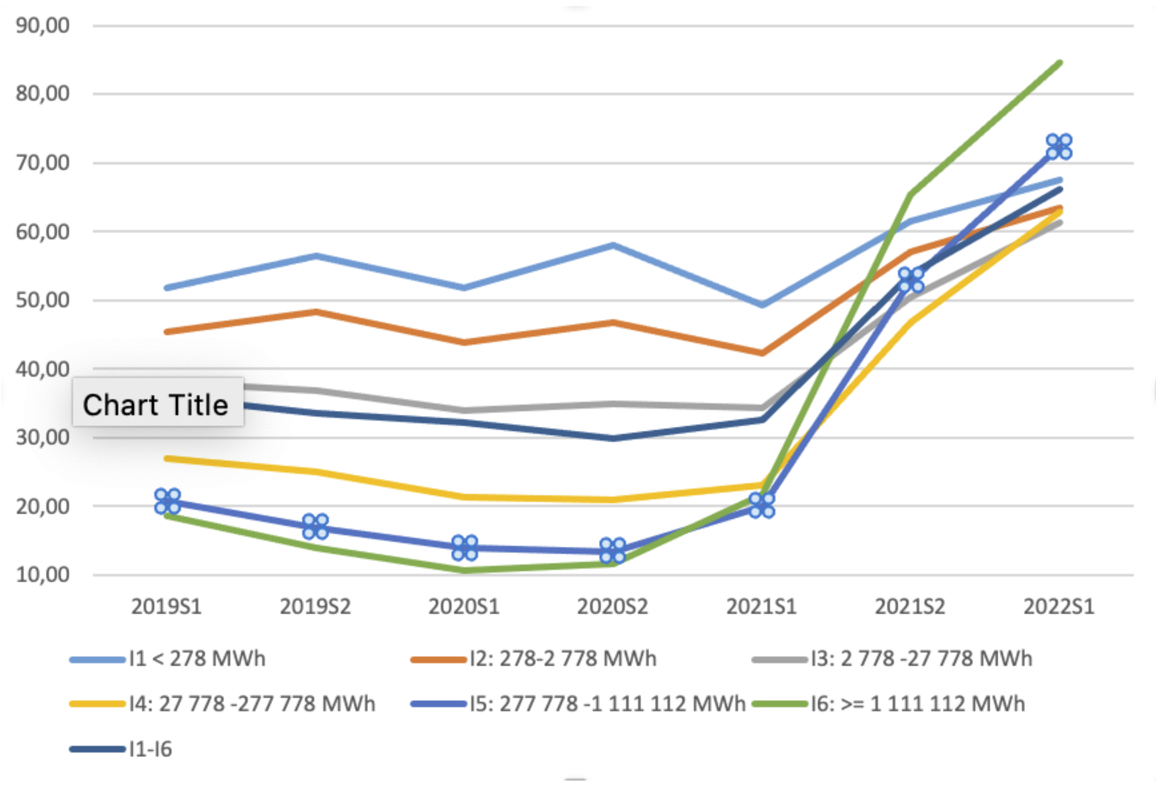

Figure 27: Gas price for industrial consumers

Source: SDES, enquête transparence des prix du gaz et de l'électricité (October 2022)

Compared to the electricity market case discussed above, the benefits and costs of government intervention are lower. A small share of customers is on regulated tariffs and can benefit from the frozen price. Many customers with fixed-price contracts are already protected from market price fluctuations (at least over the contract's duration). The impact of government intervention on purchasing power might be relatively small. However, given the sharp regulated tariff increase, customers on this tariff will experience higher energy bills. Unlike the electricity market, this policy might trigger behavioral consumption changes in the gas market. As for 2023, the tariff shield policy will still be in place in both sectors, with a maximum increase of 15% for the regulated tariffs.

Conclusions

According to the French Ministry of Finance, the tariff shield policy has cost 24 billion euros (with 10.5 billion for the electricity sector and 6 billion for the gas sector) since its deployment in the autumn of 2021. Note that 40% of the poorest households (12 million households) will receive, at the end of December 2022, a one-off energy voucher of €100-€200. This check is in addition to the annual energy voucher (ranging from 48 et 277 €) already sent to 5.8 million households in 2022.

There are obvious trade-offs when discussing government intervention's impacts. It was argued that this policy had enabled a lower inflation rate (5.3% instead of 8.4% in September 2022, INSEE), and the poorest household and pensioners benefited the most from this low rate. According to a recent study (INSEE, 2022), the rising energy prices only contributed to 3.1% inflation points out of a total of 5.3% between the second quarter of 2021 and the second quarter of 2022.

Limiting the increase in energy prices had a direct and immediate effect on the purchasing power of French consumers.

During this period, the energy price increases were severely limited, as illustrated in the table below.

	With tariff shield		Without tariff shield	
	Households	Industrial C^{ers}	Households	Industrial C^{ers}
Electricity	4.7	5.1	36.9	38.6
Gas	37.6	35.3	105	98.4
Av. energy price effect	28.5	20.3	54.2	50.3

Table 1: Energy price increase, between April 2021 and March 2022. Source INSEE (2022)

There were extra benefits in the case of the electricity sector in terms of redistribution and competition. The tax cut applies to all electricity customers (regulated electricity tariff and market offers, regardless of the electricity supplier). Increasing the ARENH volume with a price cap below market price has allowed alternative suppliers who do not operate nuclear power plants to sell electricity at "competitive" prices. Indeed, the number of alternative suppliers was not reduced drastically. Only a few suppliers went bust (e.g., Hydroption, Bulb Energy), left the market (e.g., Cdiscount énergie, GreenYellow), or were bought by competitors (Plüm Energie). Nevertheless, the market is less liquid, with the number of offers reduced by half and almost no contract prices indexed to the regulated gas and electricity tariffs.

The tariff shield policy comes at a cost, especially for the electricity sector. The energy tax cut amounts to a total cost of approximately €8 billion for the government. The price caps limit EDF's revenue; indeed, EDF's lost revenue is estimated at €10 billion and is likely to increase further. The energy regulator (CRE) has recently (June 1, 2022) recommended increasing the maximum volume that EDF has to make available to competitors to 130 TWh at a price no higher than €49.50 per megawatt-hour for the entire volume.

There are concerns that this policy will restrict EDF's nuclear investment strategy and slow down the energy transition. Indeed, the French government decided to fully nationalise EDF in December 2022 as a way to facilitate nuclear energy investments and follow long-term strategy to reduce carbon emissions and `succeed´ in the energy transition[199].

The current energy policy entails uncertainties. The government announced on January 13, 2022, that it would implement a control system to ensure that the additional ARENH volume granted to each supplier is properly reflected in the prices offered to consumers. This system has yet to be implemented, and the extent to which the discounted price will be passed on to consumers remains to be seen.

Some analysts fear that the policy results in a `catch-up effect´ to compensate for current losses, where EDF is compensated through higher electricity prices when/if the market price becomes more stable.

Finally, as with any price control, the price signal is distorted, thereby not providing consumers with an incentive to adapt their electricity consumption up or downward in reaction to market dynamics. In the context of the needed energy transition, this measure might be counterproductive in the long run.

[199] https://www.euractiv.com/section/energy-environment/news/french-move-to-nationalise-edf-reopens-restructuring-debate/

Italy

Characterised by a high concentration since the late nineties the Italian electricity sector was exposed to a series of structural reforms which aimed to introduce competition in generation, supply, and international trading of energy. Italy's primary energy consumption is based on petroleum and natural gas, which are mostly imported. Italy imports 14% of its electricity consumption and more than 90% of its oil and gas consumption. Depending heavily on imports to meet its domestic energy demand, the energy market in Italy tends to have among the highest prices in the EU.

To tackle the steady increase in energy prices, the Italian government has defined a regulatory framework (the National Energy Strategy) which aims to encourage further investments able to guarantee a high level of security in the supply of energy. Even when most of the Italian electricity production is based on fossil fuels, the use of renewable sources, and hydroelectricity in particular, has been heavily incentivized. In 2020 Italy reached the target of 18.2% of of renewables in total energy consumption, ranking Italy as the third amongst European producers of green energy and sixth in the world for the production of energy by using solar panels.[200] However, the exogenous shock represented by the Covid-19 pandemic, along with a lack of coordination between national governments and local agencies, created severe disruptions halting the ongoing expansion in the use of green energy sources.

Following the steadily surge of electricity prices, since 2021 a series of significant measures have been promoted to protect final energy consumers.

The retail market

As part of the EU directive for the creation of an internal energy market, in 1999, with the introduction of the `Bersani Decree´, Italy restructured its domestic energy market. This intervention represented a turning point for the Italian energy market. Indeed, this reform introduced a liberalisation process able to foster competition in generation, imports, and export of electricity. This reform separated the different phases of the energy cycle, which until that moment were vertically integrated under the monopoly of the *Ente Nazionale per l'Energia Elettrica (Enel)*, a state monopoly. To accelerate the liberalisation process of the electricity market, the Italian government introduced a clear separation among responsibilities between the central and the local authorities.[201]

In the most recent years, the level of concentration in the retail market has decreased, both considering the number of consumers served and the market shares. Nevertheless, the Enel group remains the leading energy producer and, jointly with Eni and Edison, accounts for 46% of the electricity retail market (whereas Eni is responsible for 72% of domestic production of gas supply). Distribution is conducted by a few companies, based on government concessions, and once more Enel is the main distribution network operator, being responsible for 86% of the distributed electricity

[200] Full details at https://iea-pvps.org/wp-content/uploads/2021/04/IEA_PVPS_Snapshot_2021-V3.pdf
[201] Full details available at https://www.arera.it/allegati/docs/pareri/020212.pdf

volumes. The management of the national grid is under Terna S.p.A, the exclusive responsible and independent legal entity where the Italian government represents the major stakeholder.[202]

To prevent market foreclosure via a vertically integrated market structure, companies which simultaneously distribute and supply energy and serve at least 100,000 consumers are required by law to separate their activities, transferring their assets and liabilities related to their energy supply to independent companies. The electricity rates applied by the local distribution network operators to household customers are set by the "Autorità di Regolazione per Energia Reti e Ambienti" (ARERA), the independent regulatory authority for all utilities, among which energy, gas, and water. ARERA is supposed to protect the interests of consumers and promote competition and efficiency in the energy market. By law, ARERA is responsible for monitoring the retail markets for electricity and natural gas. To maximize productivity and efficiency of the energy services, along with environmental goals, ARERA sets a price cap which applies to the whole energy market. Recently, this price cap has been under a continuous revision. According to figures provided by the Italian Regulator, in 2019 the average price of electricity (weighted against the sold quantities net of taxes) charged to domestic consumers was c€21.50/kWh in the so-called standard offer service and c€24.21/kWh in the free market.[203] The price difference is the result of different contracts offered in the two markets.

TYPE OF CUSTOMER	VOLUMES (GWh)			DELIVERY POINTS (thousands)		
	2019	2020	VARIATION	2019	2020	VARIATION
Low voltage	88,960	87,752	-1.4%	19,079.00	20,873.00	9.4%
Domestic	29,984	34,107	13.7%	14,536.00	16,173.00	11.3%
Public lighting	3,904	3,745	-4.1%	229.00	236.00	3.1%
Other uses	55,072	49,900	-9.4%	4,314.00	4,463.00	3.5%
Medium voltage	96,492	90,075	-6.7%	102.00	146.00	42.1%
Public lighting	255	257	1.1%	0.76	0.81	6.2%
Other uses	96,238	89,818	-6.7%	102.00	145.00	42.4%
High and very high voltage	26,385	24,609	-6.7%	1.00	1.04	3.7%
Other uses	26,385	24,609	-6.7%	1.00	1.04	3.7%
TOTAL	211,838	202,436	-4.4%	19,183.00	21,020.00	9.6%

Table 2: Electricity consumers in the free market 2019-2020, Source: Annual Survey on Regulated Sectors (2020), ARERA

Residential consumers can choose their energy supplier in three different types of market: (i) the standard offer; (ii) the safeguarded category; and (iii) the free market. The standard offer is a semi-regulated type of service. The final energy price paid by consumers is set on the free market, whereas all terms and conditions of supply are defined by ARERA.[204] For instance, the standard offer service

[202] For more details see https://iea.blob.core.windows.net/assets/e93b7722-cf3b-4fbd-b5bf-c3bce72c7522/EnergiePoliciesofIEACountriesItaly2016Review.pdf
[203] Details at https://www.arera.it/allegati/relaz_ann/20/AnnualReport2020.pdf
[204] Complete details are available at https://www.arera.it/it/consumatori/placet.htm

should always be supplied by a two-tier tariff. Energy supply is provided by companies with less than 100,000 energy consumers which are selected by public tenders. Under the standard offer regime, a Single Buyer (*Acquirente Unico*) is responsible for the supply of electricity on the wholesale market, selling it to standard offer companies at a rate which reflects costs. ARERA sets this rate based on the wholesale market price considering all costs incurred by the companies appointed to provide this service. The safeguarded category market is also a regulated service. The energy price is decided by ARERA which jointly with the Minister of Economic Development compute the fees to cover the costs of supplying wholesale energy, dispatching services and marketing. Compared to the standard offer where the price structure, along with the terms and conditions of the energy supply contract are decided by ARERA, for the safeguarded category both the final price and all contract terms and conditions are set by the energy authority.[205]

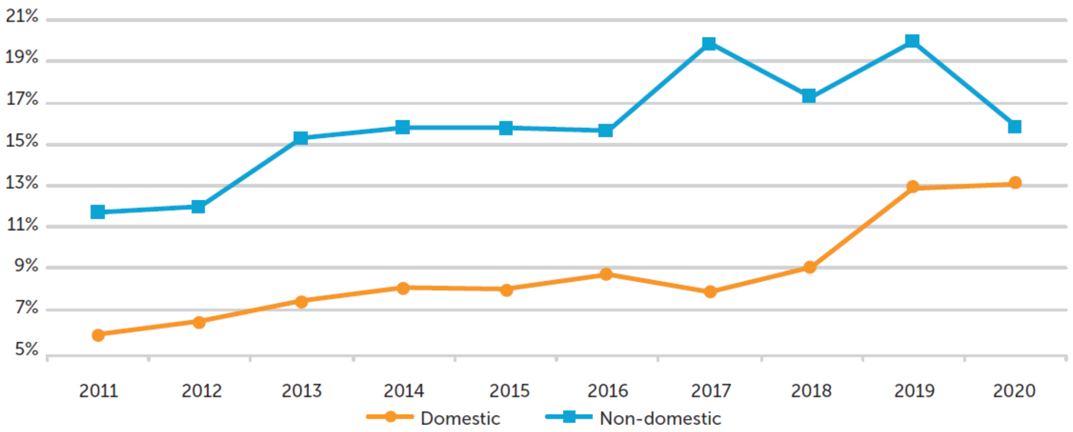

Figure 28: Italian consumer switching behaviour. Source: Annual Survey on Regulated Sectors and Integrated Information System (2020), ARERA

Finally, introduced in 2007, the free market is an unregulated service, where the energy price is set freely by the market, and companies can offer different types of services. To protect consumers, in the free market each supplier must include in its commercial offer two prices defined according to certain conditions, one at a fixed rate and one at a variable rate.[206] ARERA is responsible for the definition of the general supply conditions, except for the price which is set freely by the supplier. The free market has seen entry also of international competitors, such as Axpo Group and E.ON. In 2020, a total volume of 240,960 GWh was supplied across the three different markets, and specifically 35,459 GWh under the standard offer, 3,065 GWh under the safeguarded category, and 202,436 GWh in the free market.

[205] Complete details at https://www.arera.it/it/consumatori/placet.htm
[206] More details on how the price on the free market is defined are available at https://www.arera.it/it/operatori//Monitoraggio_retail2.htm

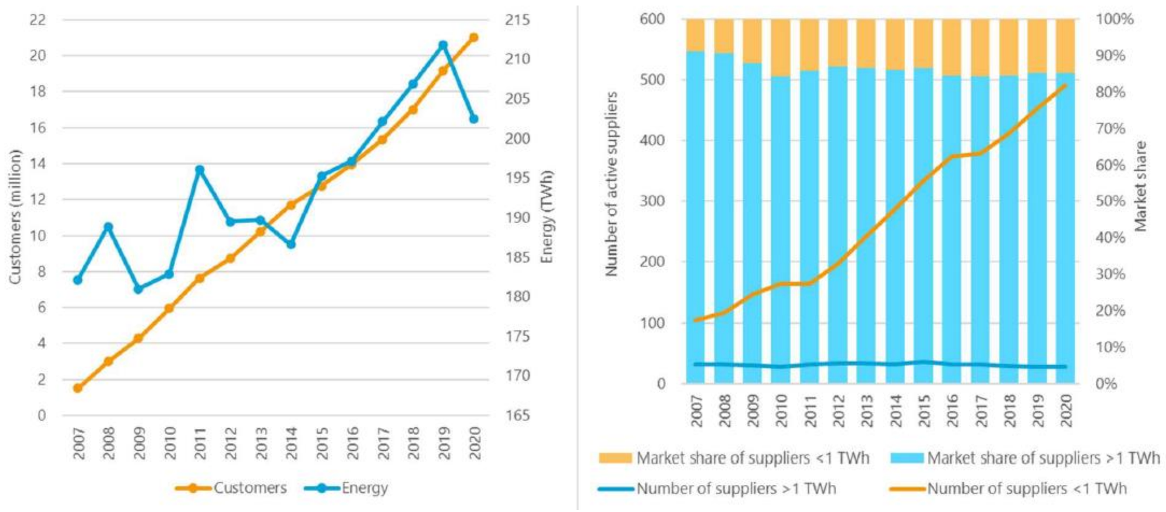

Figure 29: Italian free electricity market evolution. Source: Annual Survey on Regulated Sectors (2020), ARERA

The termination of the standard offer service for households, initially expected for the beginning of July 2020 and later postponed to January 2023, has spurred switching behaviour by consumers, who have shown some levels of interest in free market options. Figure 28 displays the switching behaviour of electricity consumers since 2011, showing that in 2019 and 2020 slightly above 13% of energy consumers switched their electricity and gas supplier at least once during the year. Table 2 shows the total volumes of electricity customers in the free market in 2019 and 2020.

Over time, the number of companies selling electricity in the free market has increased despite its slow development. Indeed, in 2018 a total of 635 companies sold electricity in the free market, increasing to 739 two years after, where most of the companies supply electricity in a restricted number of regions, and only 14% supply electricity across the whole country.[207] Figure 29 shows the development path of energy consumers receiving their supplied electricity from the free market (on the left), and the number of companies with sales above and below 1 TWh (on the right). By contrast, the number of parties choosing the standard offer regime has decreased, mainly because of business activities shutting down. The safeguard service is supplied by only three companies, which also operate in the free market and the standard offer service.

Government response

At the end of 2021, the National Unique Price (*Prezzo Unico Nazionale*), which is the electricity reference price defined on the Italian Power Exchange, was already 65% higher compared to the first semester of the same year and 195% higher than the annual average of the previous year. Due to the rise in the prices of wholesale energy products, at the beginning of 2022, ARERA increased the

[207] More details at https://mercato-libero.it/distributori-energia-elettrica

electricity price by 55% and the gas price by 42%. During the same period, the electricity price applied for the safeguarded category of households with an average yearly consumption of 2.700 kWh was 41,05 c€/kWh net of taxes. Excluding marketing and communication expenditures, the cost of electricity has doubled in size 2021 with final energy price accounting for 80% of this increase.[208]

To reduce the impact of these sustained energy price increases on households and industry, since 2021 a new system which grants an automatic recognition of social electricity, gas and water bonuses has been introduced.[209] Furthermore, in 2022 the Draghi government introduced a series of urgent measures that target both the gas and electricity market.[210] Around thirty million residental and six million non-residental consumers have received financial support from the Italian government in the form of tax cuts and discounts on their energy bills.

More specifically, three different forms of intervention have been introduced to support households. First, starting from 1 March 2022, ARERA has temporarily lifted all fixed costs related to the grid maintenance, and introduced tax deductions to electricity bills to support the green transition. These types of costs account for around 21.8% of electricity bills.[211] This intervention targets all types of consumers (households, firms, and public lighting) regardless of their voltage level but with a consumption below 16,5 kW and excluding electricity-intensive enterprises. By 2022, the government will provide an extra three million euros in funds to the Cassa per i Servizi Energetici e Ambientali, a public institution responsible for both granting subsidies to energy companies facing financial constraints and for the implementation of the green transition.

Second, to limit the effects of price increases in the natural gas sector, the Italian government reduced the VAT for all gas consumption until December 2022 to a rate of 5%.

Third, all households in disadvantaged economic and personal circumstances are eligible to receive a set of specific subsidies. *Bonus Elettrico* represents a subsidy in the form of a discount on electricity and gas bills provided to households that are in financial distress. It varies from a minimum of €238,4 to a maximum of €334,32 per household. The beneficiaries of this type of subsidy are all households: (i) with a yearly income not above €8,265; (ii) with at least 4 dependent children and a cumulative yearly income not above €20,000; and (iii) receiving a state benefit or a pension benefit.[212] Moreover, all households that face personal distress as a result of the electricity price increase are eligible to

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[208] To allow a smooth transition towards the free market, both household consumers and SMEs are allowed to keep their tariffs defined in 2019 within the safeguarded category market until 1 January 2024 and 1 January 2023, respectively. More details at https://www.arera.it/allegati/relaz_ann/22/ra22_sintesi.pdf

[209] Between January and December 2021, more than 4,025,483 bonuses have been granted for energy consumers in economic distress (i.e. 2,487,599 for electricity supplies and 1,537,884 for gas), for a total value of Euro 696.8 million.

[210] Full details about the approved law are available at https://www.gazzettaufficiale.it/eli/id/2022/03/01/22G00026/sg

[211] For more details see at https://www.arera.it/it/elettricita/auc.htm

[212] A pension benefit amounts to 780 Euro per month, whereas a state benefit for a household of two adults and a dependent child above 18 years old, or two adults and two minors amounts up to 1,330 Euro per month. In September 2022 pension benefits have been granted to a total of 120.517 households, whereas state benefits have been granted to 1.038.922 households. For more details see at https://www.inps.it/news/osservatorio-reddito-e-pensione-di-cittadinanza-i-dati-di-settembre#:~:text=Tra%20gennaio%20e%20settembre%202022,Pensione%20di%20Cittadinanza%20sono%20120.517

receive an additional type of subsidy, the Bonus Sociale, which according to the size of the receiving household, regardless their household income, varies from a minimum of €225,8 to a maximum of €556,08 per year.[213] Households with a family member who needs the use of electric devices for their subsistence are privileged in the access to such type of subsidies regardless of their income.[214] Finally, during the same period the government has resumed the use of tax credits in favour of gas and energy-intensive industries, extending it also to all SMEs in financial distress due to their energy bills. All companies with high electricity consumption that have experienced an increase in energy cost of more than 30% relative to that in 2019 will be eligible to receive a tax credit that partially offsets the higher costs. This contribution is equivalent to 20% of the total expenses incurred for the energy services purchased and used in the second quarter of 2022.[215]

Given its strong dependence on imported gas,[216] in the second quarter of 2022 Italy has purchased and stored an amount of natural gas of 115.11 TWh (equivalent to 59.5% of its storage capacity) to guarantee the next winter´s energy demand. The government plan to fill 90% of its gas storage capacity has been achieved but at high costs given the substantial surge in gas price during the summer 2022.

To counterbalance future increases of energy price, in late September 2022 the Draghi government launched a series of extraordinary measures that aim to reduce to 59% the increase in the reference price of electricity for households who are part of the safeguarded category. Following the new method introduced in July 2022 to compute the price of gas for all customers under protection (Resolution 374/2022/R/gas), the price of gas applied to household under the safeguarded category will be updated at the end of each month based on the average actual prices of the Italian wholesale market. This new method should prevent disruptions in the gas supply, minimising the risk that gas suppliers may not be able to guarantee their operations, avoiding households to resort the Last Instance Supply Service (*Servizio di Ultima Istanza)*[217] and electricity providers to activate the default service.[218] These forms of interventions along with the VAT reduction on gas to 5% should alleviate the rise in energy costs for thirty million households and over six million SMEs.

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[213] Details at https://www.arera.it/it/consumatori/bonus_val.htm

[214] In 2021 more than four million households received a subsidy in the form of either *Bonus Elettrico* or *Bonus Sociale*, recording an increment of 196.46% compared to that during 2020. More details at https://www.arera.it/it/dati/cons_4.htm

[215] See at https://www.gazzettaufficiale.it/eli/id/2022/03/01/22G00026/sg

[216] In Italy, natural gas represents the main source of consumption both for the energy distribution sector and for the manufacturing, which in 2019 was 49% and 76% of the total consumption, respectively. More details at https://www.lavoce.info/archives/95816/dal-caro-energia-rischi-per-la-competitivita-dellitalia/

[217] The Last Instance Supply Service is activated by the distributor regionally responsible when an end customer is without a supplier, while remaining connected to the network and can therefore continue to receive gas. Under this scenario, the supply of gas is assigned to a specific supplier, selected by the Single Buyer through an auction led by ARERA, the independent energy authority, https://www.enel.it/it/supporto/avvisi/servizio-fornitura-ultima-istanza#:~:text=Cos'%C3%A8%20il%20Servizio%20di,perci%C3%B2%20continuare%20a%20prelevare%20gas

[218] Since late 2021, a small number of energy suppliers started to activate emergency insolvency procedures. For instance, Green Network an e-commerce platform which supplies both gas and energy in Italy and the UK was placed under receivership, an administration procedure provided by the bankruptcy law for companies that are in a situation of temporary difficulty. Analogously, earlier 2022 Cura Gas & Power has been terminated by Terna and Snam, see https://elyx.energy/i-fornitori-falliti-in-italia/

Conclusions

Italy's net energy import costs are predicted to more than double in 2022. Its dependence on imports jointly with the steadily rise of energy prices have exposed Italy's vulnerability. To contrast the steadily increase of the electricity and gas prices, the Italian government has planned further actions in addition to the initial implemented measures. The government has allocated an additional €102,8 million to ensure the inclusion of households that based on previous income classes were not benefitting from financial aids.

At the time this report is written, the Italian government has just approved an action plan in four steps.[219] Firstly, as it happened during summer 2022 when the lowest allowed temperature of the air conditioning was capped in all public buildings and commercial activities, also for the winter indoor temperatures of public offices and commercial activities will be set to a maximum of 17 °C. Furthermore, to reduce the demand of energy the duration of the heating calendar will be reduced by 15 days. These measures would save around 3.2 billion cubic metres of gas (approximately 5% of the Italian total consumption). Second, the government is going to invest in a wide communications campaign that aims to change consumer behaviour, promoting a more responsible and efficient energy consumption. Despite the difficulties related to the steadily rise of the price for natural gas, Italy has confirmed its original plan to utilise 90% of its gas storage capacity. This target will help to secure a continued supply of energy independently of new negative energy shocks. To reach this goal, Italy has signed bilateral agreements with international partners, among which Algeria and Qatar, for the supply of liquified natural gas. Finally, for a limited period (until March 2023), Italy will resume the use of some of its coal-based plants to produce electricity.

The aforementioned forms of interventions are part of an emergency plan that aims to address the current energy crisis. In the long-term, Italy will have to redefine its energy strategy to become less dependent on energy imports. To facilitate the green transition and make Italy less dependent on energy imports the government would have to implement some strategic structural interventions and reforms of the energy sector. For instance, it could simplify the legal procedures needed to launch new wind and photovoltaic farms. It has been estimated that in 2021 more than four hundred projects have been submitted for approval, and only one project was accepted. Moreover, anticipating the proposal launched by the EU Commission, Italy could invest more in the Nearly Zero-Emission Building project (NZEB), starting with a substantial improvement of the energy efficiency of its public buildings, which already would save a non-negligible amount of energy.

[219] Complete details are available at https://www.mite.gov.it/sites/default/files/archivio/comunicati/Piano%20contenimento%20consumi%20gas_MITE_6set2022.pdf

Great Britain

In Great Britain, the crisis has put retail energy markets under severe strain. Most households have defaulted onto the regulated tariff re-calculated and reset by the energy regulator, Ofgem. The default tariff was introduced in 2017 and was reset every six months. In August 2022, in the face of a very large announced rise on 1 October 2022, the default tariff was replaced by the Energy Price Guarantee, which capped bills below the cost recovery level. Competition to switch customers has largely been suspended (by suppliers, if not formally) with switching websites offering limited, if any, deals to switch to (and recommending staying on default tariffs).

The impact on energy bills of the price rise has been a mainstay of a national debate around a 'cost of living crisis'. It has led to substantial government support packages. Rising energy prices have been a significant contributor to general inflation (CPI), which hit an annual rate of 11.1% in October 2022, its highest rate since 1982.[220] In October 2022, electricity and gas (and other fuels) price rises were contributing 2.59% to the headline inflation rate.

The retail market

In Great Britain, full retail competition (where all consumers can freely switch supplier) for both electricity and gas has been in place since 1999. An initial maximum retail tariff for households was removed in 2002. By 2008, Great Britain was estimated to have a genuinely competitive retail market, with high rates of annual switching (see Pollitt and Brophy Haney, 2014). There then followed a period of intervention in retail markets by Ofgem aimed at further reducing margins and promoting competition. This culminated in a Competition and Markets Authority (CMA) Investigation which was completed in 2016. This advocated further measures for the promotion of retail competition, short of a wide retail price cap (although the CMA introduced a price cap for customers with prepayment meters). The further measures sought to address the behavioural split between a large group of active customers who benefitted from the competitive market and the somewhat larger group of inert customers who did not switch and paid higher tariffs. Continuing controversy and political debate resulted in the imposition of a six-monthly maximum safeguard household tariff calculated by Ofgem. This is calculated on the basis of forward looking wholesale prices for six months and is reset from 1 April and 1 October each year (with updates being announced in February and August). The safeguard tariff protected non-switching households on standard variable tariffs.

Switching actually continued and accelerated following the completion of the CMA Investigation. There has been a significant erosion of market share of incumbent (legacy) suppliers who had inherited the former retail businesses of the 14 regional electricity companies, which had been the monopoly distribution and retail businesses prior to privatisation in 1990. The incumbent suppliers had previously been referred to as 'the big six' and consisted of EDF, RWE, EON, SSE, SP (legacy electricity retail business owners) and British Gas (the former gas monopoly and legacy gas supplier). These firms combined generation and retail and were integrated 'gentailers'. The share of the six large incumbents fell from over 85-90% in Q1 2015 to 55% in Q1 2021 due to some incumbent business

[220] https://www.ons.gov.uk/economy/inflationandpriceindices/bulletins/consumerpriceinflation/september2022#measuring-the-data

sales and rapid growth of new entrants. RWE and EON merged their retail business (into EON) following their corporate merger in 2019. SSE sold their retail business to Ovo Energy in 2020.

A smart meter roll-out is proceeding, but **by the end of June 2022 only around 49% of domestic electricity meters were smart meters operating in smart mode** (i.e., fully enabled).[221] The figure for non-domestic meters was slightly lower. This has limited the offering of innovative smart meter based tariffs.

Monthly electricity switching rose from 2003 to 2008, falling back to a low in 2013, it then increased again until 2018, plateauing until April 2021.[222] Switches were running at 1.7% per month in 2020. Switching significantly reduced in October 2021 (when the default tariff began to be the most competitive tariff) below levels seen at any time since data began in 2003. In July 2022 they were only 0.3% per month.

Around 13% of electricity customers are on pre-payment meters. Most customers pay by direct debit (70%), rather than standard credit (17%) in arrears. By the end of 2020, 40% were on fixed tariffs (e.g. fixed for one year), though this has been falling and was 27% in Q2 2022.[223] Almost none are on real-time tariffs. There are around 4 million on time-of-day tariffs (such as Economy 7 who get cheaper electricity at night for electric heating).

Gas prices have more than quadrupled since 1 April 2021, as shown in Figure 30.

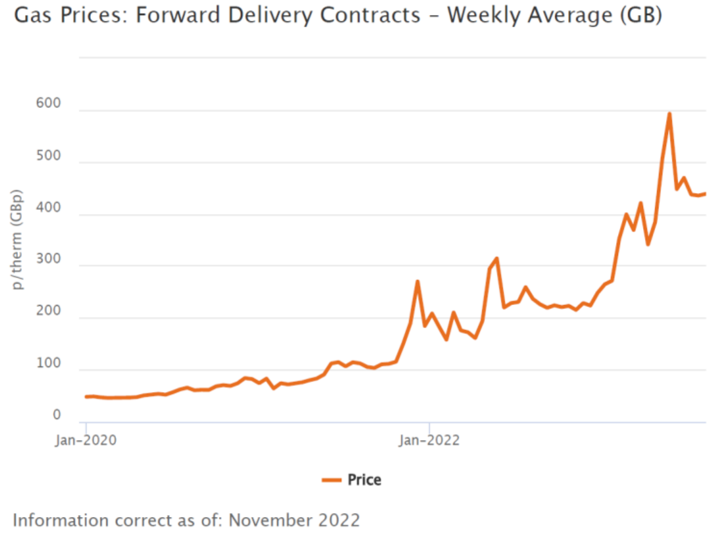

Figure 30: GB wholesale gas prices, forward delivery, weekly average. Source: Ofgem[224]

[221] 14.0 million out of 28.7 million. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1099629/Q2_2022_Smart_Meters_Statistics_Report.pdf

[222] Source: Ofgem.

[223] Source: Quarterly Energy Prices September 2022, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1107499/quarterly_energy_prices_uk_september_2022.pdf

[224] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators

This lies behind wholesale power prices, which have more than tripled since the 1 April 2021, as shown in Figure 31.

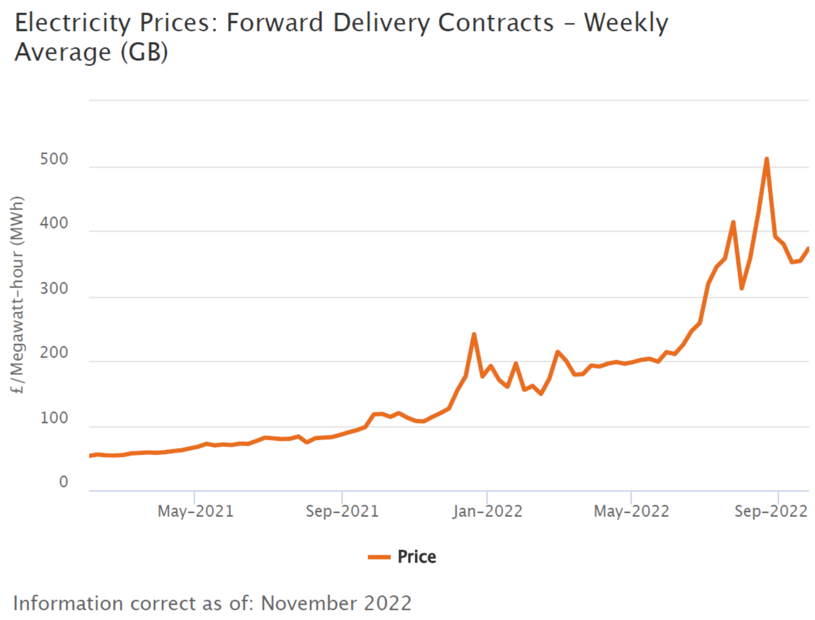

Figure 31: GB wholesale electricity prices, forward delivery, weekly average. Source: Ofgem[225]

The number of active domestic suppliers for electricity and gas peaked at 70 in January 2018, it was still at 52 in December 2020. In May 2022 it had fallen to 23 (NAO, 2022), with 29 supplier failures between July 2021 and May 2022. The market shares of the leading six firms in Q2 2022 were: British Gas 20.3%; EDF 11.4%; EON 17.5%; SP 9.2%; OVO 13.6%; Octopus 10.9%[226]. **Retail supply is not currently a profitable activity**; for instance both OVO and Octopus, being stand-alone supply companies and start-ups, are loss-making according to their latest published accounts.

NAO (2022) reports the transfer of 2.4 million customers to other suppliers and the placing of 1.6 million Bulb customers in a special scheme between July 2021 and June 2022 due to supplier financial failure. There have been losses of around £3.6 billion (around 5% of all electricity and gas annual expenditure[227]) which are in the process of being paid by all retail customers[228]. The exits have been due to the contractual maturity mismatch between typical annual customer contracts and typical monthly wholesale market purchases by the suppliers for electricity and gas.

The **default tariff cap** which lasted until 30 September 2022 meant that all domestic default tariffs are subject to a maximum price that can be charged during a given six-month cap period (currently running from October-March and April-September). The level of the cap was calculated by the

[225] See https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators.
[226] Source: Ofgem website.
[227] Market value of UK inland energy consumption of gas and electricity was c.£61bn in 2020 (DUKES Table 1.4).
[228] NAO (2022), £2.7bn due to the Ofgem supplier of last resort regime and £0.9bn due to Bulb in fiscal year 2021-22, with the prospect of another £1bn in the current fiscal year due to Bulb.

regulator every six-months. The way this is calculated has meant that maximum prices were capped at the time of the initial wholesale price rise and adjusted by only 12% from 1 October 2021 and this then remained in force until 1 April 2022, when combined gas and electricity caps rose by 54%, fully reflecting the underlying rise in wholesale prices. In August Ofgem announced it expected a further 42% rise in the combined price cap on 1 October 2022.[229] Meanwhile Cornwall Insight (a respected energy consulting firm) predicted the rise could be 64%, but their analysis also shows just how volatile the estimated figure is.[230] The government announced in September that the Ofgem calculated price would be capped to achieve a target bill for a dual fuel customer of £2500 from 1 October 2022 under an Energy Price Guarantee.[231] This represented a further 27% rise in combined electricity and gas bills. Initially this Guarantee was to last for 2 years, but it has subsequently been limited to 6 months at £2500, and a further year at £3000.[232]

The **bankruptcy regime** consists of two key elements.[233] The first is the Supplier of Last Resort where Ofgem invites offers from alternative suppliers to take on the customers of a failed firm. While consumers can be switched on to higher tariffs by new suppliers, this was capped by the safeguard tariff. To get suppliers to take customers, Ofgem has had to allow the additional cost of acquiring customers on the safeguard tariff to be socialised across all consumers. The second is a special administration regime which can be used in the case of failure where no alternative supplier is willing to take on the customers of a failed firm. This happened in the case of Bulb Energy. In this case the Treasury places the firm in special administration and the taxpayer funds losses. In each case the credit balances of the customers are protected. The Treasury special administration of Bulb resulted in further losses because of rules[234] limiting the Treasury's freedom to sign longer term generation contracts, exposing it to spot market generation prices, raising total taxpayer costs. A sale of Bulb to Octopus Energy was announced in late October 2022[235].

Ofgem needs to review the default cap calculation and the bankruptcy regime, and this is indeed currently being undertaken.[236] No doubt lessons must be learned. Supplier stress testing and longer forward hedging requirements seem likely, as does allowing a supplier taking on customers of a failed firm to raise prices to a level that allows cost recovery, should that be necessary.

Ofgem has suggested changes to the default price cap calculation (May 2022).[237] The price cap is calculated on the basis one year forward wholesale prices. Ofgem has already announced it will be reviewing the cap every three months and reduce the notice period.

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[229] See https://www.ofgem.gov.uk/publications/letter-jonathan-brearley-chancellor-and-secretary-state-business-energy-and-industrial-strategy-default-tariff-cap.
[230] See https://twitter.com/BernieSpofforth/status/1545455985183031304/photo/1
[231] https://www.gov.uk/government/publications/energy-bills-support/energy-bills-support-factsheet-8-september-2022
[232] https://www.gov.uk/government/speeches/the-autumn-statement-2022-speech
[233] See https://www.ofgem.gov.uk/news-and-views/blog/how-youre-protected-when-energy-firms-collapse.
[234] H M Treasury (2022).
[235] https://www.gov.uk/government/news/uk-government-approves-agreement-between-bulb-and-octopus-energy-providing-certainty-to-15-million-customers
[236] See https://www.ofgem.gov.uk/news-and-views/blog/how-ofgem-responding-energy-crisis
[237] See Ofgem (2022), *Price cap - Statutory consultation on changes to wholesale methodology*, London: Ofgem.

In spite of criticism, there have been limited proposals to change the Supplier of Last Resort (SoLR) or Special Administration Regime which specifies how bankruptcies should be handled and financed, but Ofgem has conducted consultation on the SoLR regime[238], and the National Audit Office has looked into the bankruptcy arrangements and their operation in a recent report.[239]

Government Support Measures

In response to the large rise in bills in February 2022, the government has announced an extension of the Warm Homes Discount for poorer households both in amount and scope (from £140 to £150 and to one third more households, 3m).[240] The Warm Homes Discount is charged to all consumers. In addition, all household customers will receive a one off reduction in the autumn of £200. This will be funded with higher retail bills from 2023-24 for five years. While from April 2022, households in band A-D houses (80% of households) received a one-off Council Tax reduction of £150 – funded from general taxation. These additional measures were intended to address the 54% bill rise in the energy price cap on 1 April 2022, which was around £693 per household with electricity and gas. The government has so far resisted pressure to reduce unit prices by interfering in existing renewable subsidy regimes or to reduce the rate of VAT on electricity and gas.

In May 2022, a further package of measures was announced to provide help with bill payments (valued at £15bn).[241] These replaced the £200 loan with a £400 payment to every household in Autumn 2022 which will not need to be paid back, and included additional measures, listed below.

In addition, 8 million households in receipt of benefits (universal credit, tax credits and pension credit) will receive a one off payment of £650 (payable in two instalments starting in July). 8 million pensioner households will receive an additional £300 on their annual winter fuel payment and disability benefit individuals (6 million) will receive £150.

Local authorities were given a further £500 for the Household Support Fund, bringing total support through this fund to £1.5bn. The Household Support Fund is for vulnerable adults and can provide help with energy bills, as well as other household essentials.

Altogether this means that all households receive a minimum of £400, 80% receive at least £550, with pensioner households getting a minimum of £700, with 80% getting £850. A quarter of households will have received at least £1200 (£550 + £650).

Part of the funding for these payment will be raised through an **Energy Profits Levy**. This will charge an additional 35% on UK oil and gas profits, offset by 80% investment allowance for UK investment in oil and gas (resulting in a net tax saving of 91% of the value of investment). These are expected to raise £14bn in 2023.

[238] See https://www.ofgem.gov.uk/sites/default/files/2022-06/Last%20resort%20levy%20claims%20true-up%20process%20consultation%20%20.pdf
[239] See NAO (2022).
[240] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1052719/Energy_Bills_Rebate_updated_factsheet_v2_.pdf
[241] See Francis-Devine et al. (2022).

It is notable that the UK government has **resisted pressure to cut energy VAT** (which is currently at a low rate[242]) or to remove energy subsidies from within the bill. Both of these would have reduced the price of energy and encouraged more consumption. They are also strictly finite measures which on their own would not have been enough to adequately support the poorest households.

The Resolution Foundation showed that the May 2022 measures in particular were very progressive and mitigated up to 90% of the expected bill rise of £1500 between 30 September 2021 and October 2022 for the poorest households expected at the time of their announcement.[243]

The Energy Price Guarantee imposed on 1 October 2022 limited the bill rise by around £2000 per household, if maintained for a year, at an estimated cost of around £60bn.[244] The unit price is set at around 34p / kWh. This is on top of the support schemes already announced.

A parallel scheme – the Energy Bill Relief Scheme[245] – was put in place for non-domestic electricity and gas customers from 1 October 2022 to 31 March 2023. This is for all customers on fixed price contracts agreed after 1 December 2021, signing new contracts or on variable conracts. This limits prices to £211 per MWh for electricity (and £75 per MWh for gas) on fixed price contracts, with maximum discounts of £345 per MWh for electricity (£91 per MWh for gas).

The EPG results in retailers being paid the difference between Ofgem's calculated price cap and the EPG price. This in theory should maintain incentives to hedge retailer positions which are the same as before the introduction of the EPG. However, it does incentivise all retailers to this customer segment to sign the same set of contracts, rather than diversify relative to their own portfolio or retail offers. The EBRS results in payments based on the discounts actually delivered to customers. The compensating discounts paid to retailers are based on a published average of market prices. This does not encourage retailers to hedge appropriately and will result in higher short run payments by the government.

Conclusions

The impact of the crisis on the Great Britain energy retail market has been profound. Initially, a combination of the **lagging price cap** and rising wholesale energy prices left no room for competition between suppliers on the basis of being able to undercut the safe-guard cap. This raised questions as to how often the price cap should be reset and also the extent to which forward-looking prices should be incorporated the calculation of the price cap. On 1 October 2022, the Energy Price Guarantee, meant that the government was picking up a large share of the energy bill in the UK, ending competition.

The **financial regulation and bankruptcy regime for suppliers has been found to be lacking** (see NAO, 2022). Lax financial regulation of capital adequacy and contract hedging of retail contracts led to

[242] VAT on domestic energy is 5%, which is lower than the standard rate of VAT of 20%. Optimal tax theory suggests there is no good reason why VAT rate would be lower on domestic energy than, for instance, household energy consuming equipment or energy efficiency or production goods (which all carry 20% VAT) (see Mirrlees et al. 2011).

[243] See Bell et al. (2022).

[244] See https://ifs.org.uk/articles/response-energy-price-guarantee

[245] https://www.gov.uk/guidance/energy-bill-relief-scheme-help-for-businesses-and-other-non-domestic-customers

business models which sold long and bought short creating a standard asymmetric risk where shareholders could win on falling wholesale prices and avoid losses on rising wholesale prices, transferring costs to consumers and tax payers. In addition, the safeguard price cap had the effect of capping prices and forcing consumers onto the default tariff at a time of rising underlying costs, restricting the ability of poorly capitalised suppliers to adequately cover costs. This was then compounded by the desire to protect consumers of failing suppliers came at the expense of responsible consumers, who had to finance an excessively generous bankruptcy regime (which almost fully socialised bankruptcy costs for customers who had previously benefitted from lower tariffs).

On the plus side, **initially the government has given generous targeted direct financial support to households for energy bills**. No doubt this will be somewhat crude at the margins as it is not matched to energy consumption. This will give rise to cases where high consumption due to particular family circumstances will be an issue, such as in the case of large families or where there are issues within families of fracture between the benefit recipient and partners (and their children) who actually consume and pay for energy services. However the **support scheme has maintained some strong incentives for energy efficiency and investment in renewables**, by not distorting consumer energy saving incentives or corporate incentives to invest within the electricity and gas supply sectors. It is too early to tell what effect such a large rise in prices might have. Interestingly, monthly domestic demand for electricity in April 2022 after the latest price rises, was 17% lower than April 2021; while total monthly gas output from the transmission system was down 20% between April 2021 and April 2022.[246] It is difficult to believe that a more than doubling of electricity and gas prices over the course of 2022 would not decrease demand substantially. There also appears to have been some strong inducement to enhanced demand response, with the system operator introducing a new 'demand flexibility service' on 3 November 2022 aimed at getting aggregate household and other customers to reduce demand within a half hour period, following a trial involving an innovative retailer, Octopus Energy.[247]

The **Energy Price Guarantee could have been better designed** (see Pollitt et al., 2022b). The Guarantee sets both maximum fixed and variable charge. Even if the government specifies a maximum bill for a customer on standard consumption, it could have made sure that the variable charge reflected underlying wholesale market prices, by reducing the fixed charge. The unit charge actually set (excluding VAT) for electricity was only around 84% of the expected wholesale price. Thus by raising the variable charge and reducing the fixed charge the scheme would have been more progressive (poorer households in general consume less units), delivered more demand reduction and reduced the overall cost to the taxpayer. This is also true of the Energy Bill Relief Scheme where the guaranteed unit price is at an even greater discount to the expected wholesale price at the time it was set (56% of the expected price).[248] With businesses, a better scheme would have given some part of their consumption at the target price and the final part at the expected wholesale price. This would have maintained a stronger incentive to reduce consumption at the margin. This could have best been

[246] Source : Energy Trends, June 2022.
[247] https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility
[248] The regulated price is 21.1 p / kWh, while Ofgem calculated the wholesale cost was 37.4 p / kWh. See Ofgem (2022), Model - Default Tariff Cap Level v.1.13, available at: https://www.ofgem.gov.uk/publications/default-tariff-cap-level-1-october-2022-31-december-2022

done on some baseline consumption, say 80% of a previous year's consumption. This again would have the effect of reducing the expected taxpayer cost.

Stephen Littlechild, one of the architects of the UK electricity reform and an advocate for competitive retail energy markets, recently raised the question of whether the UK will ever return to a competitive retail market for small consumers (Littlechild, 2022). He noted that the price cap was introduced as a temporary measure, but that its operation had effectively ended retail competition and itself had led to a lot of bankruptcies, a view endorsed by the National Audit Office (NAO, 2022). The government is currently still finalising a review of its ***Retail Market Strategy for the 2020s****,* which may bring some more clarity on this issue. [249]

[249] See https://www.gov.uk/government/consultations/future-of-the-energy-retail-market-call-for-evidence. Accessed 13 December 2022.

The Netherlands

The Netherlands has weathered the high energy prices relatively well from a market design point of view. In 2021, it experienced six bankruptcies of smaller suppliers. Those suppliers offered fixed-price contracts and were insufficiently hedged. The **social impact of those bankruptcies was relatively small**, as there were no supply interruptions and it concerned about 2% of households, but it received significant media attention as consumers had to sign new contracts at higher prices. Changes in the regulation of the financial health of suppliers is likely.[250]

The **liquidity of the retail market dried up during the winter months** and several suppliers were no longer accepting new customers. Liquidity has been restored for variable-price contracts, but fixed-price contracts are still hard to come by. This is probably due to **regulation that limits the penalty that consumers pay for terminating their contract early**, making it too risky for suppliers to offer those fixed-price contracts.

The current political debate has shifted towards softening the impact of high consumer prices more generally and restoring the purchasing power of poorer households. There are also some wholesale market issues, such as the potential increase of the production in the Groningen gas field, the increasing cost of congestion management, and a temporary stop of network connections for large energy consumers.

The retail market

In the Netherlands, suppliers require a licence to operate, which is granted by the Authority for Consumers and Markets (ACM), and contains checks on the financial situation of the firms, the internal organisation of the company, the quality of retail contracts offered and organisation of energy procurement (ACE, 2022a). Those checks normally take place each year before the winter months, and the level of scrutiny may be based on complaints received by ACM or in response to structural changes, such as customers from one supplier being taken over by another. Since 2008, suppliers have to be fully unbundled from distribution companies.

There are 54 licenced retail companies (ACM, 2022c), but the market is dominated by brands that are owned by vertically integrated international utilities. These companies are active both in generation and retail. The retail market has become national in scope and most contracts are dual fuel; they cover both gas and electricity. Gas is used for heating and cooking.[251] Switching rates are healthy in comparison to other European countries. About 51% of consumers switched in the last three years. There remains a significant part of the market (23% of consumers) that has never switched since the liberalisation of the market, but the number of `sleepers´ decreases each year. The switching process runs rather smoothly. The new supplier is responsible for cancelling the contract with the previous supplier, and consumers only have a contractual relationship with their own supplier and not with their local distribution company.

[250] Tweede Kamer der Staten-Generaal (2022).

[251] Many new houses no longer have a gas connection and rely on heat pumps or district heating. The government's goal is to stop gas delivery in 2050.

There are two types of price structures for retail contracts: fixed price and variable price. Variable price contracts are subject to price changes by the supplier, and suppliers have to inform consumers before any price changes. Consumers have then the right to switch to alternative suppliers. The price adjustments typically happen every six months. With the fixed-price contracts, the price is fixed for the duration of the contracts. Those contracts are typically signed for 1 to 5 years. At the end of a fixed price contract, consumers are automatically transferred to a variable price contract with the same supplier.

Table 3 shows that 56% of consumers are on fixed price contracts.

Contract types	Share of contracts (January 2021)	Yearly bill, avg cost (May 2021)	Yearly Bill. Δ highest-lowest (May 2021)
Variable price	44%	€1560	€359
Fixed price	56%		
1yr	17%	€1554	€318
3yr	28%	€1565	€244
5yrs	9%	€1635	€96

Table 3: Share of contract types, and typical energy bills, January 2021. Source: ACM (2021)

There is considerable variation between the cheapest and most expensive contracts available on the market, and consumers therefore have to switch or renegotiate contracts with their existing supplier to benefit from the lowest prices. The variance of prices for the fixed-price contracts is smaller than for the variable-price contracts, and the fixed-price contracts are seen as somewhat more competitive.

In addition to competition on prices, there is also competition in other contract dimensions, in particular on the origin of energy. Suppliers offer for instance contracts for Dutch wind, European wind, European hydro, and grey electricity (Mulder and Willems, 2019). About 80% of households buy green energy.

In January 2021, before the energy crisis, the retail component of the household bill was 41% of the final bill, while taxes and network costs counted for 21.3% and 38%, respectively, cf. Table 3.

Contract types	Percentage	Percentage
	January 2021	**January 2022**
Distribution and metering costs (Gas and Electricity)	21.3%	18%
Energy Tax	20.8%	0.4%
VAT	17.4%	17.4%
Electricity	11.4%	26.9%
Gas	29.3%	37.5%

Table 4: Average household cost components, January 2021 and 2022. Source: ACM (2021,2022f)

The Netherlands is rolling out smart meters for gas and electricity on a voluntary basis. Households have the right to a smart meter, but can refuse it. In January 2021, 85% of the households had a smart meter. The smart meters allow network companies to better manage their networks and provide remote meter reading. They also provide a physical and a remote interface for energy consumption managers that can offer services to end-users. Currently there are about 30 companies with apps and/or physical devices of energy consumption management. These can be independent companies or offer their services in cooperation with one of the suppliers.[252]

Regulation of the retail market consists of structural measures (unbundling requirements and licencing), contracting restrictions (limits on the penalties that consumers pay for early contract termination, the prohibition of automatic renewal of contracts, and an obligation to offer at least one standardised contract), a price surveillance process (the so-called safety net) where the regulator checks whether new retail prices are reasonable given wholesale market conditions. The different stakeholders – consumer organizations, suppliers and regulator – have agreed on a number of codes of conduct with respect to information provision (information on bills), and to prevent too aggressive marketing campaigns (e.g., telemarketing); see also Mulder and Willems (2019).

For suppliers that go bankrupt, or lose their licence for other reasons, specific measures are in place. For a period of 20 working days, consumers are not allowed to switch to other suppliers while an administrator (bankruptcy trustee) tries to sell the whole consumer portfolio to another supplier. If no supplier is willing to take over the consumer portfolio, the distribution companies allocate

[252] The Dutch smart meters allow for remote monitoring via the mobile phone network by the network operator of actual and average voltage levels, voltage interruptions and voltage drop and voltage surge. The meter also measures daily electricity and gas consumption, as well as electricity consumption levels every 15 minutes and gas consumption every hour. The amount of data that is read by the network operator depends on permissions that consumers give to the network operator and suppliers. The smart meter is also a physical serial port which provides information on electricity consumption every 10 seconds. It uses a standardized protocol, which can be used by energy consumption managers.

consumers to existing licenced suppliers in proportion to the number of households they have. The reallocated households then receive a new retail contract that conforms with the market conditions of the new supplier (ACM, 2022).

Implications of the price spike

As in all European wholesale energy markets, prices in the Netherlands increased drastically from the second half of 2021 onwards. Wholesale electricity prices (the APX spot market) increased from about €50/MWh in Q1 2021 to around €200/MWh in Q4 2021-Q2 2022. Over the same time period, future prices for gas (TTFs) increased from about €25/ MWh to more than €80/MWh.

With some delay those wholesale price increases were passed on to consumers. Consumers that had signed up for a long-term contract were hedged for the duration of the contract, but would see a price increase when the contract period finished. Consumers on a variable-price contract would see price adjustments on a regular basis, for instance after a six months period. Figure 32 shows the yearly energy cost for an average household with a yearly consumption of 3,500 kWh electricity and 14,500 kWh gas, based on data from the statistical office CBS. The blue line represents the sum of VAT and the energy tax minus an energy related rebate in the income tax. Total energy costs increased from about €2,000 per year to €7,000 per year.

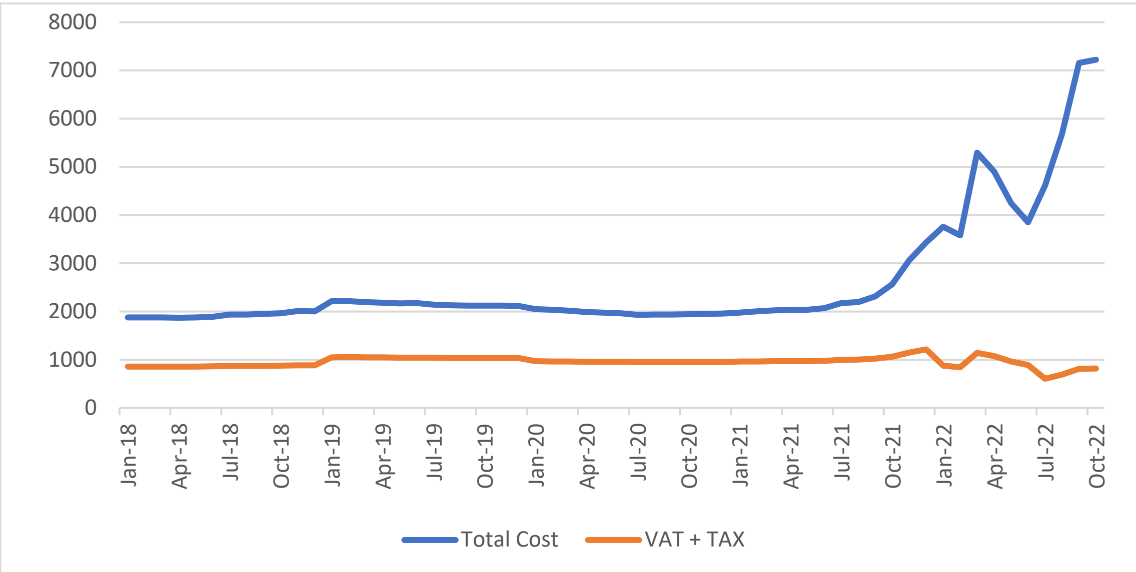

Figure 32: Average energy costs for households EUR/year if monthly prices and tax rates would be in place for the whole year, 2018-2022. Source: CBS own calculations

As a first reaction to high spot prices, some suppliers tried to renege on their obligations under the fixed-price contracts and pass on higher energy prices to end-users or cancel delivery completely. The regulator quickly indicated this was not allowed.

Six suppliers which were not vertically integrated with generation, but bought their energy on the spot market, had to declare bankruptcy before the winter 2021-2022 actually started. Their consumers were reallocated to other suppliers and received a new contract at market rates. None of the consumers experienced a supply interruption, but they often ended up paying considerably more than under their original contracts. This has been considered unfair by some observers. An additional supplier went bankrupt due to a counter-party not-fulfilling its supply obligation.

The **market for fixed-price retail contracts has dried up almost completely**, and only variable-price contracts remain available. One of the reasons is that the regulator has capped the penalty for breaking a contract at €250 to reduce switching costs for households. This has been done in the hope of obtaining a more dynamic retail market with higher switching rates. However, suppliers fear that if they offer a long-term contract, consumers will switch away once wholesale prices drop and cheaper products become available. Hence, suppliers would end up making losses on those fixed-price contracts. The suppliers have argued for an increase of the penalty, while consumer associations have been against. The market for variable-price retail contract also saw a drop in liquidity during the winter months, but supply seem to have restored itself in recent months.

Government response

The government initially responded by reducing the energy tax and the VAT and by introducing cash payments and insulation premiums for low-income households (Ministerie van Algemene Zaken, 2022). The energy tax on electricity was reduced by 6.9 ct/kWh (average benefit €160/yr). A deduction on the income tax for energy tax expenditures was introduced €265/yr for all households.[253] The VAT decreased from 21% to 9% from July 1, 2022 till December 31, 2022. (average benefit €140/6 months). Figure 32 shows the effect of the measures taken on the taxes and VAT . By adjusting tax rates, total tax payments have been kept more or less constant over the last years, but that did not compensate the average household for the higher energy prices. The VAT reduction reduced the energy related taxes that the government collects. Table 4 shows that the change of the composition of the energy bill and compares the situation for January 2021 and January 2022.

Low-income households received a one-off cash payment of €800 from the local municipality, and €300 million was reserved to help them saving energy expenditures for instance by improving insulation. The target group consist of about 800,000 households (about 10% of Dutch households).

In response to the bankruptcy of some suppliers, the ACM decided in February 2022 to conduct **additional checks on the financial positions of suppliers after the winter period**. ACM's concerns were not only the effect of higher wholesale energy prices, but also of decreasing prices, where consumers might break their fixed price contract and switch to alternative suppliers. A supplier could then face the risk that it has to resell what it bought in excess of its customers demand on the wholesale market at a lower price (ACM, 2022b).

ACM also ordered a study to check whether the regulation of the retail markets needed to be adjusted with respect to bankruptcies of suppliers. The regulator had earlier indicated that it could not report

[253] Note that the energy tax on *gas* was not adjusted in response to the high energy prices and increased with 2 ct/m3 (ca. €23/yr). This reflects the fact that the government wants to provide incentives for households to switch from away from natural gas.

or comment on the financial healthiness of individual suppliers, as this could lead to "bank runs" and a self-fulfilling prophecy. Some commentators have argued that additional regulation could be introduced, to prevent consumers from being hurt by retail bankruptcies. This could for instance be in the form of an insurance scheme organized by the sector. In addition, regulation of the suppliers' risk has been proposed.

Lavrijssen and de Vries (2022) indicate that the current licencing procedures of the ACM do not demand specific financial requirements for suppliers regarding solvency, liquidity and capital structure. The rational for this is that the ACM does not see it as one of its tasks to second guess the business models of suppliers, and tries to limit entry barriers for (smaller) suppliers to increase competition. Lavrijssen and de Vries indicate that there is some flexibility within the existing legal framework for ACM to adjust its financial criteria. Since the publication of the study, ACM decided to sharpen the current financial licencing requirements and collaborate with the government to adjust the legal framework in a new Electricity Law (ACM, 2022d).

Lavrijssen and de Vries further note that the ACM and the Ministry of Economic Affairs are against the introduction of a guarantee fund for supplier bankruptcies, as this could lead to moral hazard by consumers and suppliers who would take on too much risk, but the authors indicate that there is a lack of empirical evidence to indicate that this is actually the case.

With the new budget proposals in September 2022, the **government has taken more far-reaching actions to address the increasing cost of living**. The Netherlands has one of the highest levels of inflation in Europe (16.8% in October 2022), which is mainly driven by higher energy prices.[254] The government intends therefore to reduce the impact of high energy prices for low and middle income households.[255]
In October and November 2022, all households received a €190 /month compensation for the higher energy prices, to be paid from the government budget by the retailers.

From January 1 2023 onwards, the Dutch government intends to introduce a temporary retail price cap for households for a period of one year, in the form of a block tariff, to be administered by the suppliers. Once the price cap is introduced, the VAT rates for energy will increase again to 21%.

For the first 11 700 KWh gas, consumers pay €0.145/kWh and for first 2900 kWh electricity, they will pay €0.40/kWh. For consumption above this level, consumers will pay market rates. This means that for a household with an average or above average consumption, at current prices this is saving of

[254] Reference : Eurostat Harmonised index of consumer prices (HICP). The Dutch Statistics office CBS uses a different method and estimates a Consumer Price Index (CPI) inflation rate of 14.1,%, and indicates that 8.1% can be attributed to higher energy and housing prices.

[255] The government also increased rent subsidies, health insruance subsidies, child allowances and the minimal wage, and lowered the tax rate for low-income households.

about €276 per month.[256] Households with a minimum income receive a €1300 additional compensation to be allocated by the local communities.

In order to pay for the price cap the suppliers will receive a subsidy from the government. There is an ongoing discussion between government, supply companies and the regulator about the size of the subsidy. Suppliers would like the subsidy to be calculated as the difference between the unregulated and the regulated retail price. The government would like to adjust the subsidy to prevent windfall profits and would therefore like that it is based on the average wholesale procurement costs plus a reasonable margin. The regulator has indicated that it is unable to calculate the correct compensation, as the current situation is outside the normal market circumstances. Agreement between the retailers and the government are currently being worked out.

Energy-intensive SME will receive a 50% compensation when prices rise above €0.35/kWh for electricity and €0.122/kWh for gas. To be classified as energy-intensive, energy costs needs to be at least 15% of their turnover.[257] The measure will run from November 2022 till December 2023.

The regulator would like to make it easier for consumers to sign long-term fixed-price contracts, and is therefore **proposing new regulation on the penalties for early termination of long-term contracts**. Currently the penalty is capped in an *ad hoc* way by the regulator. For households, the penalty is €50 for one year contracts, €75 for two year contracts and €125 for three year contract.This limits the sustainability of long-term contracts and makes it too risky for suppliers to offer those contracts when the wholesale markets are very volatile.[258]
From January 2023 onwards, the regulator ACM intends to **align the penalty with the direct economic losses of the retailer.** The direct economic losses are defined as the contract price minus the price of the reference product multiplied with the remainder of the consumption volume.[259] If prices increase when consumers switch, they will not receive a compensation. Hence the penalty works as a one-way forward contract. For contracts with variable tariffs, the penalty is zero. Administrative costs and overhead costs are not seen as direct economic losses and are therefore not be included in the penalty.

In October 2022, the government has introduced a **temporary regulation to protect consumers that are unable to pay their energy bills during the winter months**. Retail companies will have to send three payment reminders over a period of six weeks (instead of one reminder), offer debt counseling and inform the local municipality before they are allowed to shut off consumers. This regulation will

[256] Independer Price comparison website: Wat is de invloed van het prijsplafond op je energierekening? - Independer.nl
[257] Kamerbrief regeling Tegemoetkoming Energiekosten (TEK) voor energie intensieve mkb-bedrijven | Kamerstuk | Rijksoverheid.nl
[258] For small companies, penalties are larger. The regulator allows contracting parties to choose one of three contractual options for determining the penaltty: (1) 15% of the consumption level if the company would have stayed a customer, (2) difference between the market price of the contract when the company switched and the expected revenue if the company would have stayed plus a 50 EUR administrative costs, (3) 100 EUR per year of early termination. Richtsnoeren Redelijke Opzegvergoedingen Vergunnigshouders wetten.nl - Regeling - Richtsnoeren Redelijke Opzegvergoedingen Vergunninghouders - BWBR0033394 (overheid.nl),
[259] Concept beleidsregel redelijke opzegvergoedingen vergunninghouders 2022 | ACM.nl

stay in place until April 2023. The regulator ACM is concerned that after April 1, many consumers will loose access to energy and recommends the government to create an emergency supplier that will be responsible to supply those consumers that are unable to pay their bills.[260]

Conclusions

The Dutch retail market has **weathered the rise in wholesale electricity and gas prices relatively well**. Although six suppliers went bankrupt, they supplied only 2% of households and the existing bankruptcy procedures have worked well. There were no supply interruptions, and the affected consumers received new retail contracts, although sometimes at significantly higher prices. We presume that most suppliers had sufficient long-term contracts in place to hedge their exposure to the fixed-price retail contracts that cover 56% of the market.

In response to the bankruptcies the **government intends to change financial requirements for suppliers,** although the goal is not to fully eliminate bankruptcies, as they are seen as part of a competitive market process.

The Dutch situation clearly shows the **regulatory trade-offs in creating competition and innovation on the one hand, and market stability on the other**. By having softer financial requirements for entrants, entry barriers are reduced, competition improves and new business models are introduced, but suppliers might also go bankrupt more often. By limiting the penalties for switching supplier, the retail market becomes more competitive, as consumers find it easier to switch, but it also undermines the opportunity for consumers to sign long-term contracts to hedge future price shocks. It is therefore not evident that the current regulation needs large adjustments.

Rising electricity and gas prices have contributed to wider concerns regarding the purchasing power of poor households, and the relatively high inflation in the Netherlands. The government has initially reacted to those concerns with a reduction of the energy tax (offsetting the increase in the VAT collected due to the higher energy prices) and targeted income support schemes. From 2023 onwards, a temporary price cap will been introduced for households and SMEs. It is instructive that the **price cap tries to keep some incentives for energy savings in place.** The price cap for households takes the form of a block tariff. Households are exposed the the competitive retail rate when they consume more than the threshold value, which is set a bit below the average consumption level. The compensation for SMEs only insures half the price increase above a (lower) price cap; so SMEs remain exposed to price fluctuations.

[260] Honderdduizenden vanaf april zonder energie? ACM pleit voor noodleverancier (nos.nl)

Norway

In Norway, the retail market has been quite resilient to the price spike, in the sense that the market has continued to operate as usual and suppliers have generally not experienced serious financial difficulties.

The main reason for this resilience is that **most consumers are on spot- or variable-price contracts** – i.e., where retail prices are directly or indirectly linked to wholesale prices – and for these customers suppliers bear no real price risk. For consumers who are on fixed-price contracts, or contracts with some sort of price ceiling, suppliers appear to have hedged sufficient parts of their risk, or have been sufficiently solid, to avoid financial difficulties.

As a consequence, the public debate and main political concerns have concentrated on the high consumer prices.

The retail market

In Norway, gas is not used much, there are no networks serving retail consumers, and hence not really a gas retail market. We therefore **concentrate our attention on the electricity market**.

Suppliers need a licence to trade in electricity (`*omsetningskonsesjon*´). If the supplier has a link to a network company, the retailing business must be kept organisationally separate (separate management and accounts); the retailing business must also be run under a different name and logo than the network business, and network companies must not discriminate between their own retailing business and other suppliers. Retailing may be integrated with generation, and often is.

By June 2022, there were 279 companies with a licence to trade in electricity (nve.no). Of these, more than 100 were active in retailing. In March 2022, on average the largest supplier in each distribution area had a market share of 64.9% of household consumers and 60.6% of industrial consumers. The largest supplier is often linked to the local distribution company; hence – 30 years after the market was opened to competition – it seems that the local supplier still has a competitive advantage. The numbers exaggerate the degree of concentration somewhat, as the average is unweighted and concentration tends to be especially high in the smaller of the more than 120 distribution areas. In the Norwegian market overall, the five largest suppliers have a combined market share of 65%.

Meters allowing for a registration frequency of 15 minutes is mandatory for all consumption metering points. Metering values are kept at a data hub (`Elhu´) which is accessible to suppliers on non-discriminatory terms. The format and content of invoices is regulated. In many cases, distributors and suppliers have agreed on a common invoice for network tariffs and energy costs.

Retailing contracts are not regulated, but The Norwegian Consumer Authority (*Forbrukertilsynet*) has, in cooperation with the industry, developed a `*standard*´ contract that is often used. Suppliers are obliged to report their contractual terms, including price per kWh and any fixed payments, to the contract comparison site of the Norwegian Consumer Council (*Forbrukerrådet*) (strompris.no). Suppliers are obliged to inform their consumers directly about changes in contractual terms, including price.

When a consumer signs up with a new supplier, the supplier is responsible for terminating any previous contract on behalf of the consumer and inform the relevant distribution company of the new contract. A new contract is typically made effective within two weeks. In 2021, 24.1% of household consumers and 9.1% of industrial consumers switched supplier.

A consumer who is without a retailing contract will be supplied by the relevant distribution company but at terms so that "the consumer is given an incentive to obtain a regular retailing contract".[261]

There are essentially three categories of contracts – spot price, variable price and fixed price. Spot price is directly linked to the underlying wholesale price, with a fixed and/or variable mark-up set by the supplier.[262] With a variable price the consumer is initially offered a given price that is subject to changes; the supplier has to inform customers about any such changes at least two weeks before they take effect. Fixed price are typically offered with durations of one, two or three years. There also exists hybrid forms of contracts, such as spot price combined with a price ceiling.

Table 5 shows that three quarters of household consumers were on spot-price contracts in the first quarter of 2022; among industrial consumers the share was above 90%. Less than 5% of household consumers had a fixed-price contract; the share was even lower for industrial consumers (energy intensive industries are on very long-term contracts).

Consumer group	Spot price	Variable price	Fixed price
Households	75.9%	18.9%	5.2%
Service industries	91.4%	4.9%	3.7%
Manufacturing industries (excl. energy intensive)	93.5%	3.2%	3.3%

Table 5: Share of contract types in Norway, first quarter 2022. Source: SSB, 2022

Implications of the price spike

While Norwegian electricity prices have tended to be lower than elsewhere in Europe, they have now reached levels that have never before been seen in Norway (as may be seen from Figure 33 below, prices in Norway vary considerably, between seasons and years, to due to changes in temperature and availability of hydro resources). For consumers in the Southern part of Norway, the average

[261] In the first six weeks price should equal the relevant spot market price plus a maximum of five øre/kWh (0.5 euro cent per kWh); thereafter the price should be increased so as to encourage the consumer to find a regular supplier, cf. forskrift om kraftomsetning og nettjenester (Bylaw on power trade and network services) §2-1a.
[262] Since consumers are on hourly meters, this means they have an incentive to move consumption from high- to low-price periods.

energy price (excl. network tariffs and taxes) in December 2021 was almost ten times as high as in December 2020 and about five times as high as the average of prices in December months over the period 2016-2020.

Given that most consumers are on contracts where the price is either directly – as with spot-price contracts – or indirectly – as with variable-price contracts – linked to the wholesale price, **suppliers have generally not been much affected**. Some suppliers have attempted to get out of loss-making contracts in which price could not be adjusted, sometimes by illegally breaking contractual terms. Some suppliers have also experienced substantial losses. But, all in all, it has been business as usual and the retail market has proven quite resilient to the price spike.

Figure 33 shows average daily spot prices in the first quarter of 2022 by price zone, as well as the range of price variation over the period 2000-2020. Prices are given in Norwegian kroner per MWh; the (approximate) corresponding price in euros is found by dividing by ten. The Norwegian spot market is divided into five price zones, where the zones NO1, NO2 and NO5 cover the Southern part of the country where more than three quarters of the population lives. Prices in these three zones have not differed much lately. Prices in the two zones NO3 and NO4, covering the Northern part of the country, have also been very similar. The price difference between North and South is caused by limits on the capacity of the North-South transmission lines.

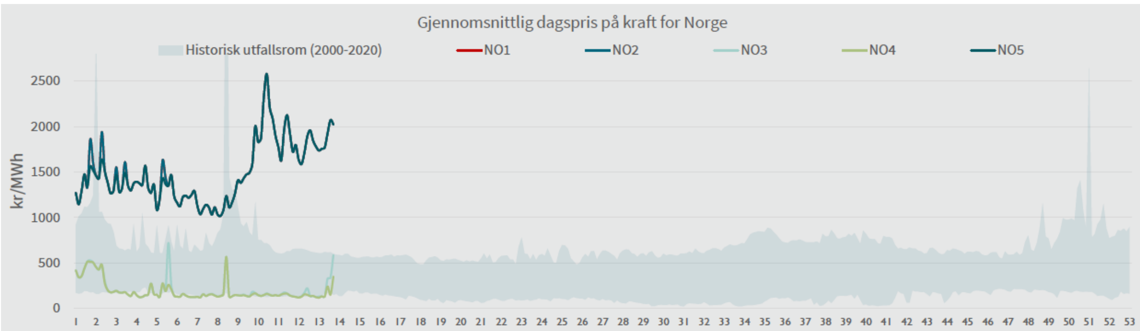

Figure 33: Daily spot prices by Norwegian zones, first quarter 2022. Source: NVE, 2022

Two features stand out from this figure. The first is the unprecedent high prices in the Southern part of the country. The second is the very low prices in the Northern part. Both of these features have been important in shaping the public debate.

In fact, there has been **something of an uproar among the general public.** The anger has mainly been caused by the high prices, but it was further fuelled by the unequal ways in which consumers were affected in different parts of the country and the increase in government revenues. The price differences across the country were essentially caused by **capacity constraints on transmission lines**, although geographical differences in precipitation and filling of hydro reservoirs also contributed. The facts that most Norwegian electricity generation is hydro-based and most hydro facilities are publicly owned, meant that most of the gain has accrued to local and central governments. Some observers have therefore likened the rise in consumer prices to an (unjustified) tax increase.

Government response

The government first responded by **reducing the specific electricity tax and by introducing extraordinary cash payments to groups on various forms of income support**. The electricity tax was halved, from 15.41 øre (1.5 euro cent) per kWh to 8.91 øre (0.9 euro cent) per kWh. Households eligible for housing benefits or on social support were given an extra payment in the winter months of 1,500 kroner (€150) per month from; the scheme was later prolonged with monthly payments of 1,000 kroner (€100) from March to May and October and again 1,500 kroner (€150) for the coming winter months.

These measures were not considered enough and subsequently a rebate to household consumers was put in place. In effect, the government paid 80 of electricity prices in excess of 70 øre (7 euro cent) per kWh for up to 5,000 kWh per month. The basis for calculation is the hourly spot price in the relevant zone. The scheme is administered by the distribution companies and financed by government transfers.

The support scheme has been debated in the Norwegian Parliament on a number of occasions, and it has gradually been made more generous, both with regard to the size of the refund and the coverage of the scheme. The support scheme is now extended to March 2023, with a support share of 90%, rather than 80%, during October to December.

Figure 34 shows the cost of electricity for a typical consumer with an annual consumption of 20,000 kWh[263] in the first quarters of 2020, 2021 and 2022 depending on their type of contract, variable price (*variabelpriskontrakt*), spot price (*spotpriskontrakt*) and one-year fixed price (*fastpris 1-årskontrakt*). Cost is divided into network tariffs (*nettleie*), taxes (*avgifter*), energy cost (*kraftkostnad*) and (the negative) support (*kompensasjon støtteordning*). Energy costs are estimated based on the average of prices in contracts offered during this period.

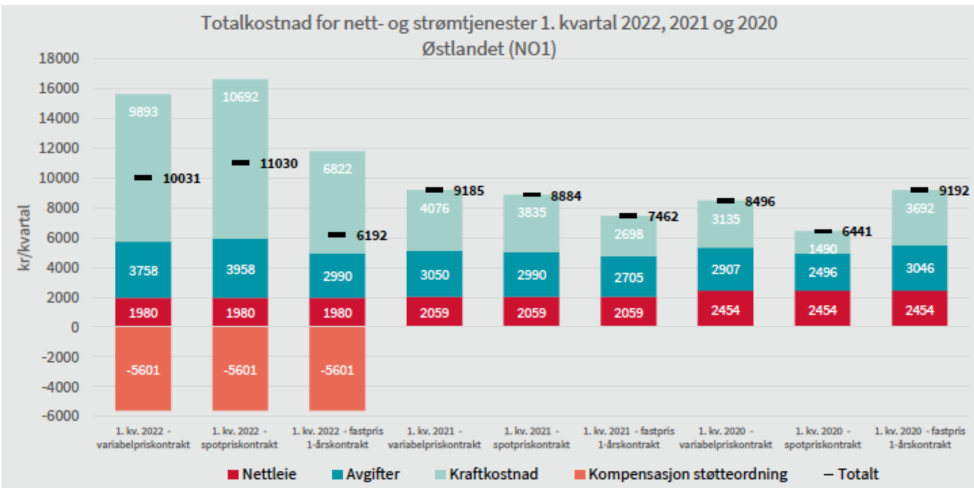

Figure 34: Cost of electricity for households in Southern Norway, Q1 2020-22. Source: NVE (2022)

[263] Since heating is typically by electricity, and the climate is cold, annual consumption of electrricity is high by European standards.

The figure shows that **for all types of contracts, energy costs have increased markedly, although less for fixed-price contracts than for variable-price and (especially) spot-price contracts**. The (regulated) network tariffs have gone somewhat down over the period, while taxes have increased, mainly because of the value-added tax (the specific electricity tax was reduced, as explained above). Without the compensation scheme, electricity costs would have increased from the first quarter of 2021 to the first quarter of 2022 by (approx.) 70% for consumers on variable-price contracts, 90% for consumers on spot-price contracts, and 60% for consumers on fixed-price contracts. Due to the support scheme, actual increases were instead 10%, 24% and -17%, respectively.

The fact that consumers on fixed-price contracts actually had their electricity bills reduced, is due to the fact that the support scheme does not depend on the actual energy price that the consumer is paying, but on the spot price; hence support is the same for all contract types, at 5 601 kroner (EUR 560) over the three first months of the year. While having the virtue of being administratively simple, the support scheme has produced some odd results; some consumers have experienced negative energy bills due to a combination of a favourable contract price and high spot prices.

In September 2022, the government introduced a series of measures aimed at reducing the cost of electricity for industy. The main component is a change to the tax of energy companies, that will make it more profitable for them to offer fixed-price contracts; this will take effect as of January 1, 2023. Until then, firms for which electricity accounts for more than 3% of total costs may apply for economic support, based on a model similar to that for household consumers, but with a lower rebate; the government will cover 25% of prices above 70 øre/kWh, or 45% if firms undertake energy-saving invests.

Conclusions

The unprecedented rise in wholesale electricity prices – which, due to the fact that Norwegian consumers are mostly on retail contracts with prices linked to wholesale prices, hit consumers directly – forced the government to take measures to reduce the cost of electricity. This was done, not by intervening in the electricity market as such, but by **offering economic support linked to wholesale prices and financed by general taxation.**

While the support scheme provided relief from the main concern of high energy costs for households, a **more general debate about the organisation and design of the electricity market, both at the retail and wholesale level**, has continued.

The fact that most consumers are on spot-based contracts is not for the lack of choice nor for the experience of varying prices (cf. Figure 34). As explained above, other types of contracts, including fixed-priced contracts for up to three years, are widely available, but have not been very popular (since the price spike hit, the supply of fixed-price contracts has essentially dried up in Southern Norway, cf. nve.no). Some observers have argued that consumers have been misled by `experts´, including the Norwegian Consumer Council, who have advised that spot-based contracts have been cheaper than other types of contracts. While not contesting the fact that over time spot-based contracts have been cheaper, the critics argue that when concentrating on average prices, one may forget the benefit from being insured from high prices. Some political parties on the left have suggested getting rid of the retail market altogether and instead offer electricity at fixed prices on government-backed contracts; this idea does not seem to have wide support.

Much attention has been directed at the **role of interconnectors to neighbouring countries and integration with the wider European market.** Two new interconnectors – to Germany and the UK, respectively – have been widely blamed for the high prices and many have argued for a moratorium on further cables, as well as restrictions on the use of existing ones. Of course, this argument overlooks the benefits from interconnection, including gains from trade and the opportunity to import in periods of insufficient availability of national hydro resources.

In addition, many have questioned the fact that, due to limits on internal transmission capacity, only the Southern part of Norway experienced high prices and did not benefit from the abundance of energy supplies in the North. For some, this also represents an unfortunate – and unfair – consequence of how the market is organised and operated, especially the use of internal price zones. Others have pointed out that transmission capacity is costly, and that the current market set up contributes to efficient use of available resources on either side of the constraints.

An interesting observation is that even though the support scheme effectively capped the rise in electricity prices for household consumers – as demonstrated above, the percentage increase in electricity bills was actually quite modest – **consumption of electricity has gone down quite considerably.** According to a study from Statistics Norway, middle income households may on average have reduced their electricity consumption by as much as 20% during the winter months of 2021/2022.

Spain

The retail market

The Spanish retail energy markets deliver electricity to approximately 28 million households and natural gas to approximately 9 million households. Customers are free to choose and contract with suppliers, but they also can also opt for regulated price contracts in electricity and gas[264]. At the end of 2021, slightly less than 40% of residential customers were under regulated electricity contracts while 20% used the regulated tariff for natural gas.

Electricity retailing has experienced very dynamic entry of new participants in the last decade. Starting with 104 suppliers in 2011, there are now more than 350 suppliers serving residential customers in 2020. Despite this, the market share – for non-regulated contracts– of the three largest historical incumbents (Iberdrola, Endesa and Naturgy) has fallen only moderately and remains very high (it stood at 73% in 2020 versus 83% in 2016). A similar evolution has been observed in gas retailing: the total number of suppliers has increased from 37 in 2012 to 120 in 2020, but the market share of the dominant player (Naturgy) remains high at 47% and the three incumbents retain a combined share above 80% (CNMC 2022).

Spain's current design for the regulated electricity contract was introduced in 2013, as part of a broader package of reforms aimed at restoring the transparency and financial sustainability of the electricity system. The `**Voluntary Price for Small Consumers**´ *(Precio Voluntario para el Pequeño Consumidor*) offers customers the option to pay a pre-tax price which is set as the sum of three components: 1) the hourly wholesale market price for electricity; 2) the regulated network and policy charges[265]; 3) a regulated overhead margin to cover suppliers' administrative costs. The **successful rollout of smart meters in Spain (99.2% of customers already have a functioning smart meter) allows real time pricing to be implemented at hourly resolution**, delivering full transmission of the wholesale price signal to customers. Importantly, the regulated price reflects the real time cost of delivering electricity to the household fully, there is no subsidy element in the price and there is no hedging of volatility nor any option to smooth out payments[266]. Eight `dominant´ suppliers[267] have the obligation to provide customers with access to the regulated contract, and they are prohibited from attaching any other service or cross-selling other products to consumers using it.

The Voluntary Price for Small Consumers is, as mentioned, optional: consumers can contract any other contract with their preferred supplier. Despite this, the **Voluntary Price for Small Consumers plays a role as a yardstick**, helping improve transparency for customers. By providing a widely available

[264] Regulated prices are available for consumers with contracted power below 10kW (electricity) or annual gas consumption below 50.000 kWh, which in practice is almost the totality of the residential market.

[265] Policy charges in Spain cover mainly the cost of support for renewables, the subsidies required to equalize the price of electricity in Spain's islands with that paid in the mainland and the recovery of past debts incurred with utilities during the 2000s.

[266] A `fixed price´ version of the regulated price is mandated in Spain's regulation, but its utilisation has been marginal. This issue is discussed later in this section.

[267] These were initially chosen among suppliers with more than 100.000 customers and the regulation allows updating the list to reflect changes in retailing market structure.

reference for the minimal price of unhedged electricity costs, customers can better evaluate whether the additional services provided by alternative contracts are worth the additional costs that they entail. Spain's National Markets and Competition Commission *(Comisión Nacional de los Mercados y la Competencia*, CNMC henceforth) regularly publishes historical and real-time analysis of the comparative costs of different contracts available in the market and their comparison with the Voluntary (i.e., regulated) Price.

Suppliers have historically concentrated their marketing on attracting customers out of the Voluntary Price into the unregulated market and more than 1.1 million customers (9% of the total number of regulated contracts, and 4% of all residential customers) made this switch in 2019 and 2020. Time of use contracts are not frequent in the unregulated market. The most common pricing structure is a fixed price[268] which is updated annually with general inflation, but which also allows suppliers to alter the economic conditions of the contract[269]. In aggregate, around 60% of all residential customers are on fixed-price tariffs and 40% on real time tariffs, the proportions given by the share of unregulated and regulated contracts in the market.

The regulated gas tariff is updated quarterly using a pre-established formula that computes an average basket for the price of natural gas in international markets plus the corresponding regulatory charges. An important difference with electricity is that this formula automatically smoothes out the variation in prices, as it is based on relatively long moving averages of international prices of energy commodities. Four dominant suppliers have the obligation to provide the regulated gas contract. Unregulated contracts for natural gas are signed under a wider variety of pricing options, but most of them have fixed prices, with some indexation (to the regulated price or to general inflation) and/or the possibility of annual revisions.

Measures to alleviate energy poverty exist in the Spanish system both for electricity and gas. Under the `Bono Social´ program, customers below certain income thresholds have the right to a 25% discount over the regulated contract price in electricity, and households with the lowest incomes can see this discount increase to 40%. Both types of households can also get a cheque to help pay for their heating needs, which is determined by their income and geographic area[270]. Utilities have recurrently challenged in courts their obligation to finance these discounts, so that in practice their costs have been recovered in the past through the regulated charges applied in energy bills[271]. Suppliers are prohibited from automatically interrupting energy services to certain categories of particularly vulnerable customers who fail to make their payments.

[268] Many of these contracts include some differentiation of the unit price of energy for peak and valley hours of the day, but the unit price is fixed for the duration of the contract in between revisions.

[269] , Page 55.

[270] Using gas is not an explicit requisite of this cheque, but the larger amounts are received in regions where gas heating is more common. The cheque is financed with fiscal transfers from the general budget.

[271] The most recent version of this regulation distributes the costs among all participants in the electricity sector (generation, transmission, distribution and supply) and, as of this writing, it is being applied.

Implications of the price spike

Day-ahead wholesale prices for electricity in Spain experienced sharp increases in the last quarter of 2021 and the first months of 2022. Prices went from around €40-60/MWh at the beginning of the year to above €200/MWh in late 2021 and the first months of 2022. The magnitude and causes of these movements were broadly in line with those observed in other European markets.

The **direct implications of the evolution of wholesale prices have been very different for customers with regulated real-time price contracts and those on unregulated fixed-price contracts**. For the former group, CNMC estimates that the average bill in 2021 has been approximately €229 (+45%) higher than in 2020. Sensing a commercial opportunity, suppliers have accelerated their efforts to attract customers away from the regulated contract and, partially as a result of these efforts, 1.2 million customers (more than one in ten customers) switched to unregulated contracts in 2021 alone, doubling the rate observed in previous years.

For unregulated prices, updated information about recent trends is limited[272]. Anecdotal reports suggest suppliers are already increasing their prices to residential customers in unregulated contracts. The pace at which these revisions occur may be tempered by two factors. First, unregulated contracts had historically benefitted from widening profit margins in the last decade (most likely as a consequence of inflation indexing and the cross-sale of additional services beyond electricity supply), implying there is scope to absorb some of the short-term cost increases in order to gain or defend market share (Figure 35). A second factor, and one that the crisis has clearly brought to prominence, is related to the interaction between generation and retailing in the face of fuel price shocks and given the market structure of both markets in Spain. The largest incumbents are all vertically integrated companies with their own generation assets and, as a legacy of their historical position, own most of the installed generation assets in non-intermittent technologies not directly affected by fossil fuel prices: they jointly own approximately 87% of total hydro capacity and more than 98% of all nuclear capacity. Thanks to this, it has been common for the largest incumbents to sign long-term fixed-price contracts with their integrated suppliers, a practice which has, in turn, allowed them to maintain stable prices to their retail customers.

[272] CNMC publishes real time comparisons of all available new offers in the market and regular statistics on switching rates. However, there is no updated information on the price changes that suppliers apply to existing contracts. This is clearly an area where more transparency would be needed.

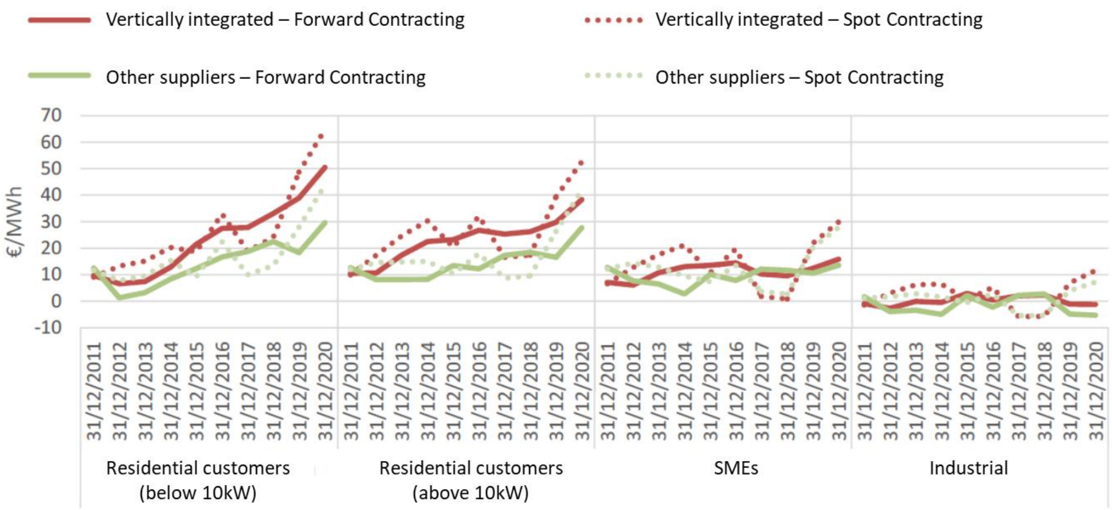

Figure 35. Electricity suppliers' estimated gross margins (average). Source: adapted from (CNMC 2022)

For non-vertically integrated suppliers, the spike in short-term prices has created tensions, but the number of failed suppliers and affected customers has remained low. There are several reasons for this. Most of the second-tier suppliers (those with market shares around 1%) are part of larger corporate groups, with diversified investments in fossil fuels, infrastructure, and other assets. `True´independent suppliers who do not benefit for their parent firm's solvency have been very active in signing renewable PPAs and, according to the limited information available, using financial hedges for their commitments. Some of the most active new competitors have decided to stop customer growth[273], highlighting the potential negative implications of the price situation on effective competition. According to CNMC registries, 44 electricity suppliers ceased their activity in 2021, but only 9 of them did so on account of regulatory breaches, and only 34,000 customers were affected. Spanishs law allows the Ministry of Energy to transfer the clients of failed suppliers to the regulated contracts automatically. So far, these transfers have occurred smoothly because the number of clients involved has been low and because the regulated contract is a `cost plus margin´ contract, implying that the suppliers who accept the new customers are not forced to accept losses on them[274]. As in other European markets, **CNMC has adopted several measures (most recently in September 2022) to reduce the guarantees that need to be deposited by electricity suppliers in order to operate in the market**, which had increased as a consequence of higher prices.

[273] For an example, see page 39 of https://www.holaluz.com/downloads/investors/20220429-investors-day.pdf

[274] Suppliers have historically argued that the regulated margin is too low and does not cover their costs, but its validity has been upheld several times by the CNMC and Spanish courts.

Government response

The Government's policy response to the price spike has focused on three areas: **targeted support for vulnerable households, changes in energy taxation and direct intervention in energy markets**[275]. Support measures for vulnerable households had already been enhanced as part of the response to the COVID pandemic. In October 2021, the Government further increased the discounts in the price of electricity available to poorer households, the `Bono Social´ mentioned above, from 25% to 60% (and from 40% to 70% for those on the lowest incomes). The combined effect of these measures and tax changes (described below) imply that eligible households could see their bills for 2022 increasing by 10-20%¨ compared to 2019[276] (depending on their electricity consumption and the trajectory of prices for the remainder of the year), whereas non-eligible households are likely to see their bills increase by at least 120%.

Prior to the spike, electricity was taxed using the general VAT rate (which in Spain is 21%) and a special tax, whose rate was 5.11% of the total bill amount. In June 2021, the Government reduced the VAT rate for electricity from 21% to 10% for residential customers. In June 2022 it was further reduced to 5%. In September 2021, the rate of the special tax was also reduced to 0.5%. Both measures were initially considered as temporary solutions but, as the evolution of prices worsened in later stages, both have been renewed and it seems likely that they will remain in place for much longer than initially envisaged[277].

Market intervention was part of the policy response even in the earlier phases of the price crisis, probably because the **issue of market reform was already part of the political agenda in Spain**. The coalition Government agreement of 2019 – signed before any of the events leading to today's situation – explicitly included commitments to *"[…] reform the electricity market, so that electricity prices reflect cost reductions in renewable energy technologies*" and to "*[…] approve the necessary legal changes to end the excessive retribution in wholesale markets (otherwise known as "windfall profits") of certain technologies installed before liberalisation of the sector that have already recovered their investment costs"*[278].

In September 2021, the Government approved a **reform whereby non-emitting generation plants would have the value of their sales of electricity reduced in proportion to the impact of natural gas prices[279] on the cleared wholesale electricity price.** By itself, this measure did not alter the market clearing price or the merit order, and its likely effects would have been similar to a tax on the profits

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[275] The description here is not exhaustive, due to lack of space.

[276] We use 2019 as a reference year, since wholesale electricity prices (hence, the regulated price of electricity) were abnormally depressed in 2020 due to the Covid pandemic. Author's calculation using CNMC's bill simulator, for a representative household with 3,000 kWh annual consumption.

[277] The Government announced in July 2022 a windfall profit tax on energy companies. At the time of writing, not enough details about this measure are known to evaluate its potential impacts.

[278] https://www.psoe.es/media-content/2019/12/30122019-Coalici%C3%B3n-progresista.pdf (in Spanish)

[279] In August 2021, the Government launched a similar proposal aimed at mitigating the impact of the price of ETS prices, which is still in the process of being approved in Parliament.

of certain inframarginal and renewable generator plants. The implementation of this measure was complex, as many generators had negotiated long-term contracts and their market sales were hedged with these positions. The consequent adjustments to the initial design have led most analysts to conclude that its final impact has been relatively limited.

After an intense period of negotiation with European authorities and other Member States, in **May 2022 the Government approved a new mechanism aimed at limiting the impact of natural gas prices on wholesale electricity prices**. This new mechanism is in essence a direct subsidy to the price of natural gas used for electricity generation. Natural gas plants (mostly combined cycles in Spain[280]) will receive the difference between the day ahead price of natural gas in the Spanish market (MIBGAS) and a **fixed price, initially set at €40/MWh**. Generators are required by law to submit their offers factoring in this fixed price of €40/MWh and their `subsidised´ offers are used in the European coupling algorithm, implying that – once the interconnection with France is saturated – they should result in a lower equilibrium price for Iberian buyers. The exact impact cannot be easily forecasted, however, given the interaction of different technologies setting the marginal price in Spain. The costs of the price subsidy for natural gas power plants are charged to demand, implying the total cost per MWh for accepted demand bids will be given by the clearing price and the prorated cost of the subsidy[281]. The initial results of the "Iberian mechanism" have allowed a significant reduction of the total cost of electricity for buyers, with the Government estimating savings of around €250 million in only fifteen days[282]. According to Government estimates, the clearing price was 45% lower. The reduction in the final demand price (i.e., once the subsidy cost is factored) was more moderate, at 14%[283]. Importantly, retail customers in the regulated tariff benefit directly from the reduction in the wholesale cost of energy. However, the initial indications suggests that the **distortion of the marginal price signal has also meant that electricity consumption and the share of natural gas generation have been higher than what would have occurred if the full price pass-through had been allowed.**

In gas retail markets, the reference formula for the regulated gas contract should already have reflected the exceptional increase in the international price of natural gas, but – as part of the crisis response – the Government limited the maximum quarter on quarter increase in the reference cost of gas to 15%, with the cumulative difference between the capped and the uncapped variation being recovered in subsequent quarters. Because of this, the price in regulated gas tariffs is currently much lower than in unregulated contracts. Surprisingly, this pricing differential has not attracted new customers to the regulated tariff, which in fact has continued losing market share to unregulated alternatives (a trend that suggests residential customers are not sufficiently aware of energy prices and/or that the costs of switching gas contracts are high).

280 Coal plants can also receive this payment, and it is calculated exactly as if they used natural gas and had the thermal efficiency of a CCGT plant.

281 Long-term bilateral contracts signed before April 2022 are exempt from paying the cost of the subsidy. These are mostly held by the incumbents owning hydro and nuclear plants.

282 The subsidy started functioning on June 15th, after definitive approval by the European Commission.

283 https://www.miteco.gob.es/es/prensa/20220701_informemecanismoiberico15-30junio_tcm30-542306.pdf

A detailed analysis of the trends in energy consumption in Spain suggests these **interventions have created significant distortions which, overall, have resulted in higher energy demand.** Total electricity generation in the peninsular system has been growing strongly since the `Iberian mechanism´ entered into force. Total generation between May and October 2022 was 15% higher than for the corresponding period of 2021, whereas in the first four months of 2022 (prior to the Iberian mechanism) growth had been of 3%. A significant factor in this growth has been the **very significant shift in export patterns: exports to France and Morocco had grown dramatically after the market intervention.** Exports to France for the period from May to October 2022 grew 1,164% (they were growing at around 15% before the intervention). The corresponding figures for Morocco are 314% (vs. 171%). As could be expected, exports to Portugal (who participates in the Iberian mechanisms as the market clearing is common for both countries) have not experienced any similar trend and in fact have decelerated during the application of the market intervention (to 26%, coming from 62% before the mechanism was approved).

Similar distortions can be observed in final electricity demand from Spanish consumers. Total demand is slightly down between May and October 2022 compared to the same period in 2021, falling by 0.9%. However, the **reduction was more acute before the Iberian mechanism was applied** (-2.5%), implying that the overall trend is towards a smaller adjustment of national demand. Unfortunately, disaggregated data for different categories of electricity users is only available with a significant lag. Taking the last month available (May 2022), CNMC reports point to large industrial users adjusting significantly their demand (with falls ranging from -11% to -26% for customers in this segment), whereas middle size firms, SMEs and residential customers were experiencing much more modest reductions or even increases (-3% for residential and +2.7% for mid-size firms).

Importantly, the distortions are also apparent in the demand for natural gas. Residential and SMEs demand is down by 5.9% in the year, whereas industrial demand is falling by 21,5%. However, the reduction in conventional demand is more than offset by the substantial increase in natural gas for electricity generation (+77,8% in the year). The **share of natural gas in electricity generation has gone from an average of 17% before the Iberian mechanism to 30% on average since May**, matching the highest levels observed in the last decade. As a consequence, total gas demand grew by 2,9% during the first 10 months of 2022.

Given the continuation of significant tensions in European energy markets, the Spanish government will continue adopting further measures, both as part of wider European efforts led by the Commission and on its own. The coordination of national and EU level remains, as has been the case throughout the crisis, a contentious issue. Spain has initiated the legislative process to approve a tax on energy companies, set as 1.2% of their total revenue. This proposal is substantially different from the extraordinary windfall levy which the EU has recommended, which would be set at 33% of excess profits made as a consequence of the war. Conceptually, taxing excess profits would seem to be a more logical approach, as energy companies are not totally shielded from the repercussions of higher international commodity prices in their costs. The Spanish government has so far resisted calls for adapting its tax to the European proposal.

Conclusions

It is safe to assume that the price crisis of 2021 will have **long lasting consequences on Spain's energy markets.** As in other countries in Europe, the crisis has highlighted the **limits of customers' (and policymakers') tolerance for high energy bills.** The emerging lesson here is that full transmission to households of the volatility that is likely to occur in wholesale energy markets is unlikely to be socially and politically sustainable. This realisation is closely related with the `rediscovered´ value of geopolitical security of energy supplies, which wholesale markets and policymakers had failed to fully acknowledge until now. The challenge seems to be to strike a balance between the attractive features of current market designs and their powerful incentives, while delivering economic and geopolitical stability for European energy.

In Spain, **long-term contracting of the production of generators (renewables and inframarginal technologies)** which are not affected by variations in the price of fossil commodities and CO_2 has emerged clearly as a **critical tool to foster the stability of consumer costs**. Long-term contracting of these sources does not alter the short-term merit order or the marginal incentives to save/use energy, but it stabilises the final-user cost.

In this regard, the fact that Spain has **been among the most active markets for merchant PPAs for renewable technologies in recent years**[284] is an important strength, suggesting that future steps to facilitate this type of contracting could pay off. The coordination of corporate PPAs with retailer PPAs and with centralised purchases in the official renewable auctions is an area that could create policy challenges in the future and affect the effective capacity of risk hedging by different players in the sector.

A more complex issue arises with the long-term contracting of nuclear and hydro power resources. While the large incumbents can justifiably claim that it has helped smooth the prices paid by their customers, this raises the question of whether this is an unfair competitive advantage against other suppliers. Given that new build at scale of any of these technologies seems impossible in the Spanish market, the **potential for using long-term contracts to foreclose competition could be relevant** and the fact that some independent suppliers have decided to stop customer growth could be seen as preliminary evidence for this. This is a topic that should probably be of interest to Spain's competition authorities.

The **role of regulated prices in Spain will also probably need to evolve** as a consequence of the experience of the crisis. A regulated contract with fully cost-reflective real-time prices remains a useful

[284] https://pexapark.com/european-ppa-market/

instrument as a yardstick for contract transparency and a valuable option for customers. The challenge is to offer a fixed-price version that provides a `fair´ hedge. In this regard, the liquidity of Spain's future markets appears insufficient to use their prices as a reference, and it could be preferable to use a basket composed of futures and the long-term contracts signed by integrated and independent suppliers. This option would serve to ensure that customers on the regulated contract obtain access to renewable and inframarginal power plants on similar grounds as vertically integrated companies, while also allowing unregulated suppliers that are able to contract on better terms than the average to offer more competitive long-term prices.

A **policy debate around the options for better protecting vulnerable consumers is also overdue**. The social discount is an imperfect instrument, both from an energy policy perspective (because it distorts energy saving incentives) and from a social policy perspective (as it is disconnected from the social safety network of Spain social policy). Using income transfers to partially offset the effects of higher electricity prices on vulnerable households is a better option, and given recent innovations in Spain's minimum income support, its application should now be feasible.

Bankruptcy procedures in Spain have functioned satisfactorily and affected customers have been assigned to new suppliers with limited costs or social repercussion. To a large extent, this is simply a reflection of the low number of households involved, but a potential lesson is that using a contract with a `real-time cost plus margin´ structure provides a transparent tool for transferring customers automatically, avoiding protracted negotiations and uncertainty. The potential application of this system with larger numbers of affected customers could, however, raise other issues, such as its effect on competition or the social acceptability of transferring customers from older but cheaper contracts to higher cost regulated contracts without any transition period or support. It would be also **worth considering CNMC's proposals to improve the procedures used for handling these transfers so that early action can be taken before completion of the full administrative process**.

Regarding market design, the **idea of disconnecting aggregate electricity costs from the short run marginal cost of fuel fossil power plants has gained momentum during the crisis**. Even admitting that Spain's subsidy to natural gas does achieve this objective, at least partially, it is **difficult to see it as a desirable or stable solution for any future market design**. The operation of the system has shown that it distorts energy use decisions dramatically: at a time when energy priorities should be focused on the efficient conservation of natural gas and other energy resources, both economic theory and the initial data suggest Spain's subsidy is doing the opposite: incentivising excessive use of these commodities. There **may be merit in designing tools that partially stabilize the volatility of energy markets, but they are unlikely to deliver value to customers over the long-term if they create incentives that are contrary to basic economic principles**.

Summary

Before going on to discuss lessons learned from the case studies, we summarise some of the differences between the six different countries studied in this chapter in the table below.

Elements	France	Italy	Great Britain	Netherlands	Norway	Spain
			Retail market			
Market structure	Dominant historic incumbent + 80 alternative suppliers	>700 (most very small), 3 largest 46%	22 by June 2022, 6 largest 80%+ share of market	>50, 5 largest 80% share of market	> 100, 5 largest 65% share of market	>100, 3 largest 73% market share
Share of consumers on flexible rate	72%	26%	small	56% fixed price 44% 6 months intervals 0% real time	> 95%	40%
			Government Response			
Clear Intervention in price formation	Yes, only 4% increase for regulated tariffs	Yes, reducing to 59% the increase in the reference price of electricity for households part of the safeguarded category.	Energy Price Guarantee and Energy Bill Relief Scheme	No	No	Yes, through intervention in wholesale elec. market
Regulatory tools	1. EDF obliged to sell more electricity to its competitors at below-market price 2. Domestic tax on final electricity consumption removed	1. Reduction in grid charges. 2. Reduction in VAT. 3. Support to vulnerable consumers. 4. Tax credits to businesses.	Calculated energy price cap suspended. Discounts to all households. Additional discounts to vulnerable households.	1. Reduction in VAT and energy tax 2. Targeted support schemes poor households 3. Compensation income tax (tax credit)	1. Reduction in electricity consumption tax 2. Refund scheme to household consumers	1. Increase in discounts for poor households 2. Reduction in VAT and electricity tax 3. Subsidy to gas used in electricity generation
			Consequences			
Retail bankruptcy	Little	Little	29 failures (July 2021-May 2022)	6 firms, 2% of households affected	None	9 in 2021, less than 1% of market
Market liquidity/Number of offers	Less liquid (fewer offers)	Reduced number of offers	Less liquid.	Strong reduction in availability of fixed price contracts	Strong reduction in availability of fixed price contracts	Reduction in avail. offers (particularly from independent suppliers)

Table 6: Summary of lessons learnt from country case studies

SECTION 2: DEMAND RESPONSE AND GOVERNMENT ACTIONS

It is often assumed, and it is clear from many market design choices, that the supply side, as opposed to the demand side, constitutes the main source of adjustment in electricity markets. In particular, to guarantee balance in the power system, the logic has been to adjust production planning in response to consumption forecasts. This organisation of electricity appears, however, to be increasingly fragile. Many power plants are not flexible and cannot quickly adapt to changes in demand. Due to outages or maintenance, power plants may not produce at full capacity. Moreover, demand is predicted to grow. For example, the demand for electrically charged vehicles (ECV) increased during the first quarter of 2022 by 19%.[285] Against this background, and following a major negative supply shock such as the one triggered by the war between Russia and Ukraine, there is a significant risk that available production capacity is insufficient compared to the need. In such a situation, supply-side adjustment may not be sufficient to balance the system and avoid disruptions. Adjustment from the demand side may be necessary.

This section explores the extent to which the demand side has responded to the current scarcity by analysing the timing of government interventions, price trends, load variation and the role of industrial consumers. It concentrates on the countries (with the exception of Great Britain due to unavailable data on the ENTSO-e platform) discussed in our case studies section and using the load variable from the ENTSO-E dataset as a proxy for electricity consumption. The section concludes on the potential drivers behind demand response, comparing load variation and policy measures across the five countries.

No obvious relation between load and price variation

The first series of graphs (Figure 36) shows the evolution of daily load in selected European countries between January 2021 and October 2022. The green vertical lines indicate major government interventions (up to September 2022). The red lines indicate the start of the war in Ukraine.

[285] https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/quarterly_report_on_european_electricity_markets_q1_2022.pdf

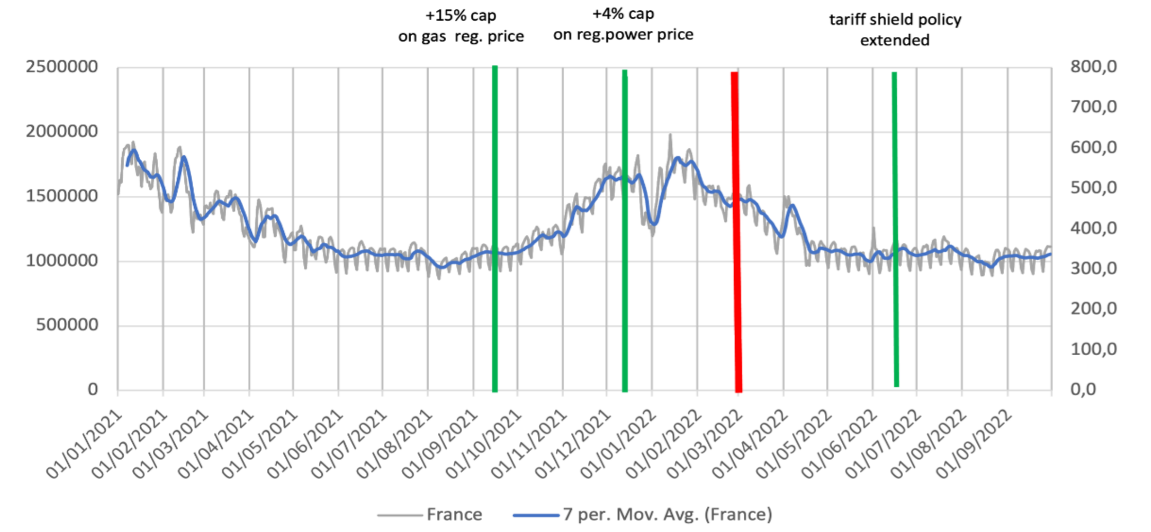

Figure 36.a France_Weekly Load and Government actions (Jan 2021 -Oct 2022)

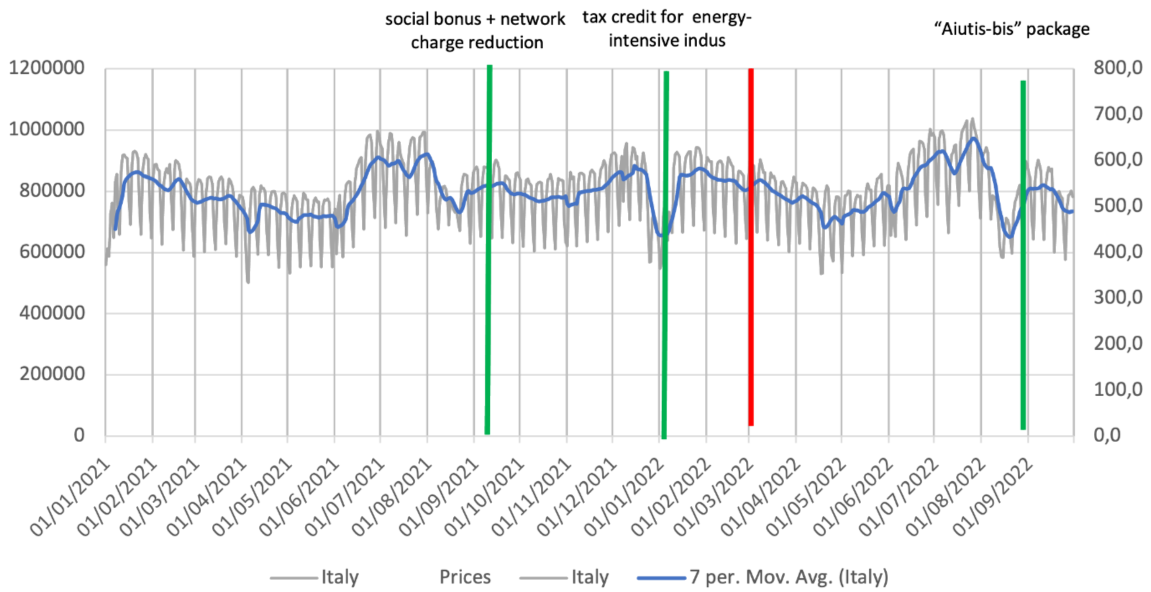

Figure 36.b Italy_Weekly Load and Government actions (Jan 2021 -Oct 2022)

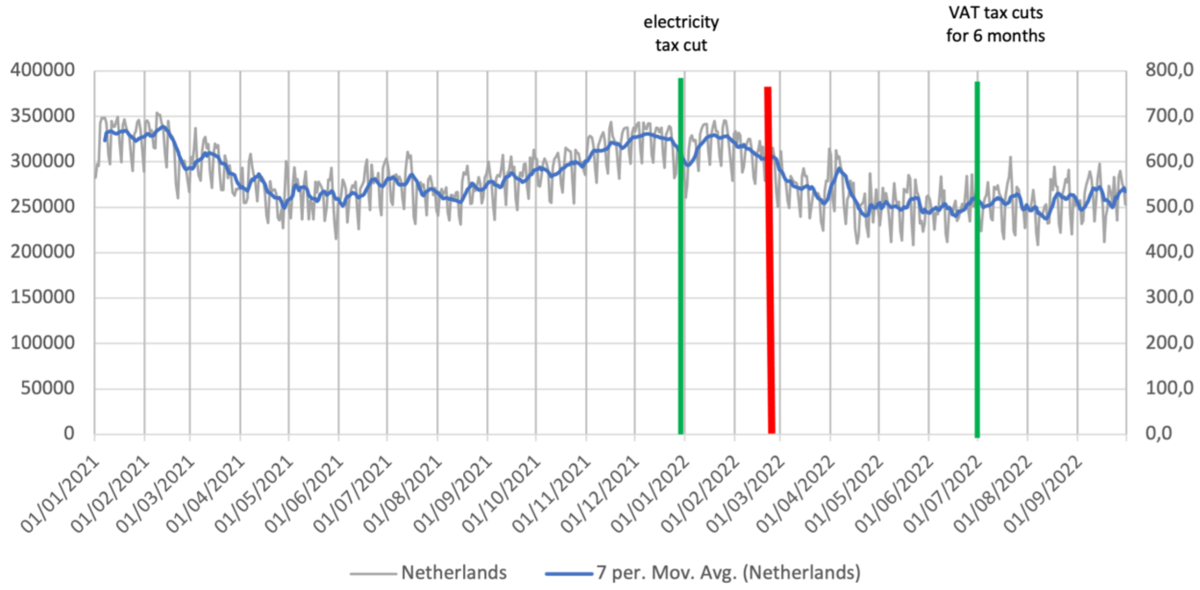

Figure 36.c The Netherlands_Weekly Load and Government actions (Jan 2021 -Oct 2022)

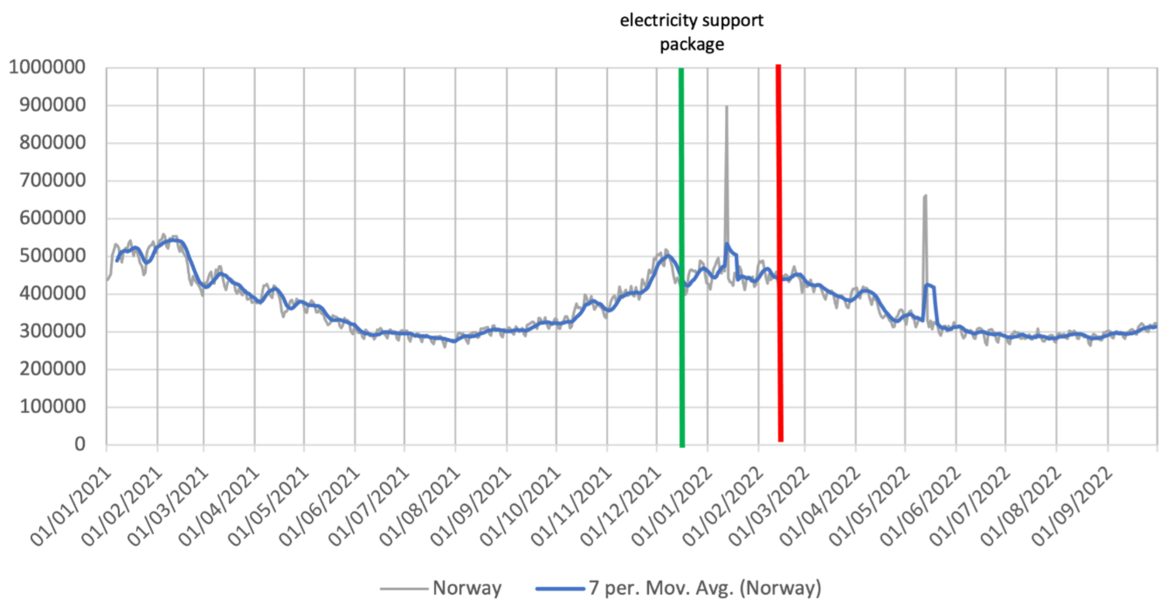

Figure 36.d Norway_Weekly Load and Government actions (Jan 2021 -Oct 2022)

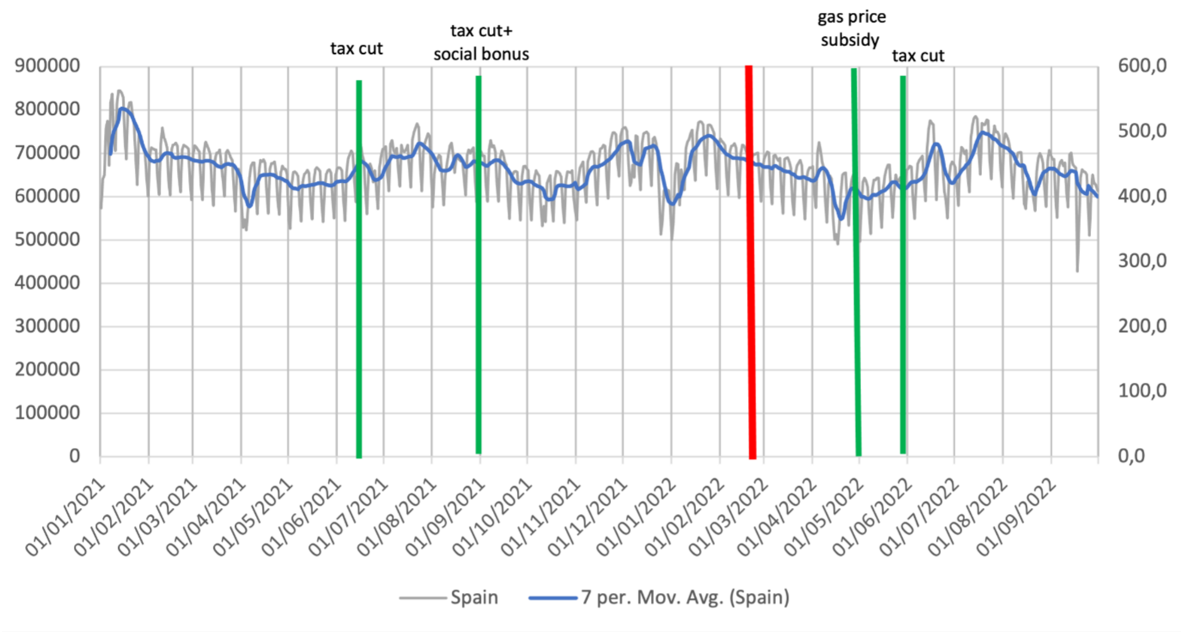

Figure 36.e Spain_Weekly Load and Government actions (Jan 2021 -Oct 2022)

Source: Own graphs with Entso-E data

The wholesale market price level and wholesale price variability started to increase drastically in all countries from the fall of 2021 and remained historically high. In France, Netherlands, and Norway, the load seems to follow a seasonal pattern, with high consumption in the winter and low consumption in the summer. In particular, this seasonal pattern appears to not have been affected much by the historically high increase in prices. Interestingly, this is the case even in Norway, where most consumers are on spot- or variable-price contracts, and demand response might be most likely. As is apparent in the graphs, the type and the timing of the government response differ across countries.

Even without an obvious impact of exceptional wholesale price levels on consumption, looking at the difference in load over the years might be more fruitful, especially given that announcements of policy changes may not co-incide with their implementation. In particular, to compare consumption in 2022 with consumption levels before the Covid-19 period.

Load variation over the years

The second series of graphs (Figure 37) displays the data for the first 36 weeks of 2022. Each graph shows the weekly load for the years 2022, 2021 and an average load for 2018/2019. The second y axis shows the difference between 2022 and 2018/2019. Price change refers to the difference between the average wholesale price in 2018/2019 and 2022. Note that the “price tag” is a percentage change, which represents the electricity price change between 2018/2019 and 2022.

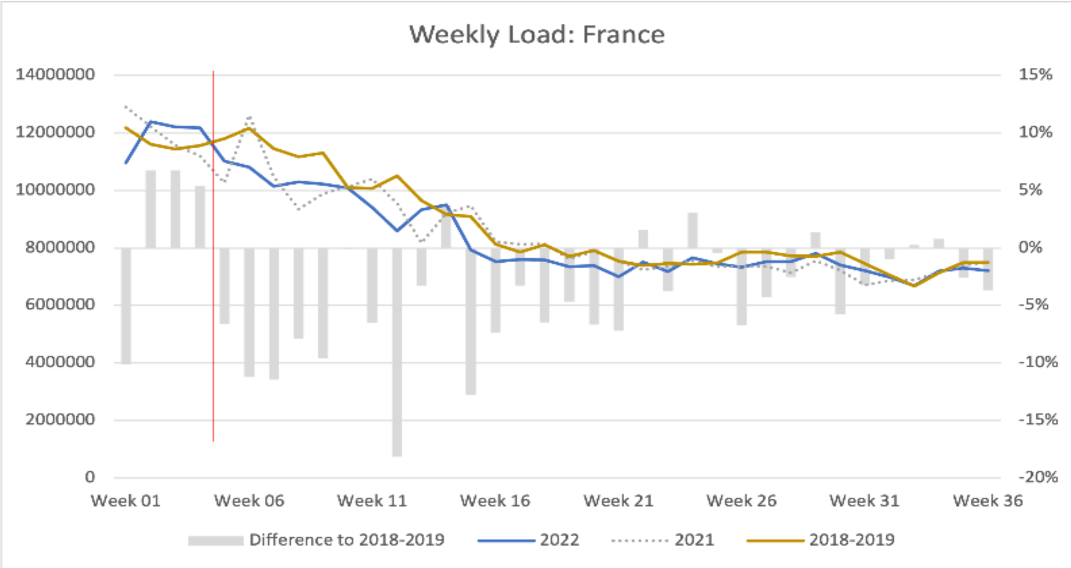

Figure 37a_France: Weekly Loads (2022 vs. 2018/19)

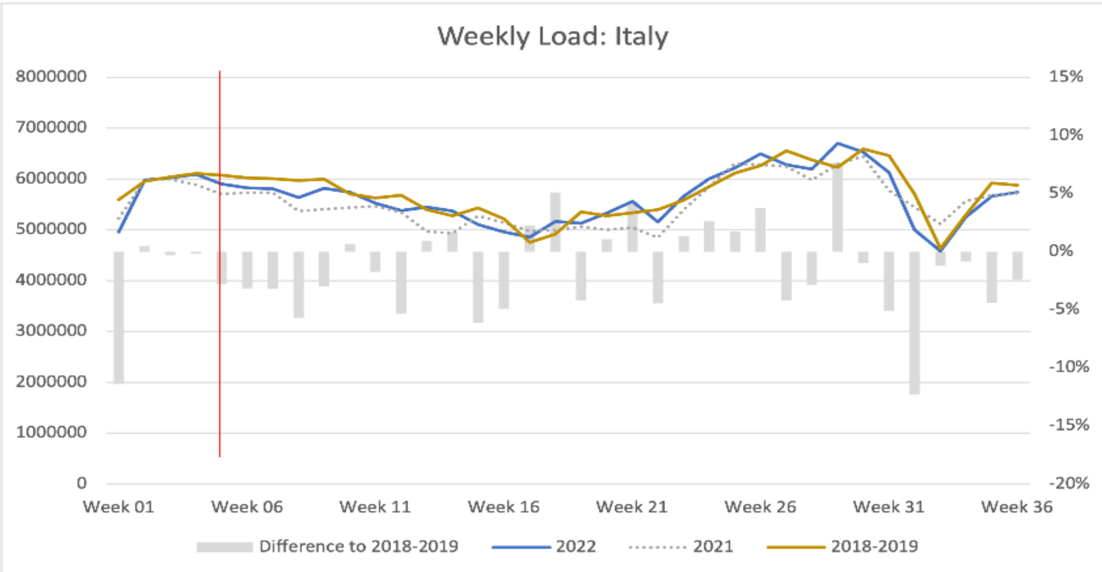

Figure 37b_Italy: Weekly Loads (2022 vs. 2018/19)

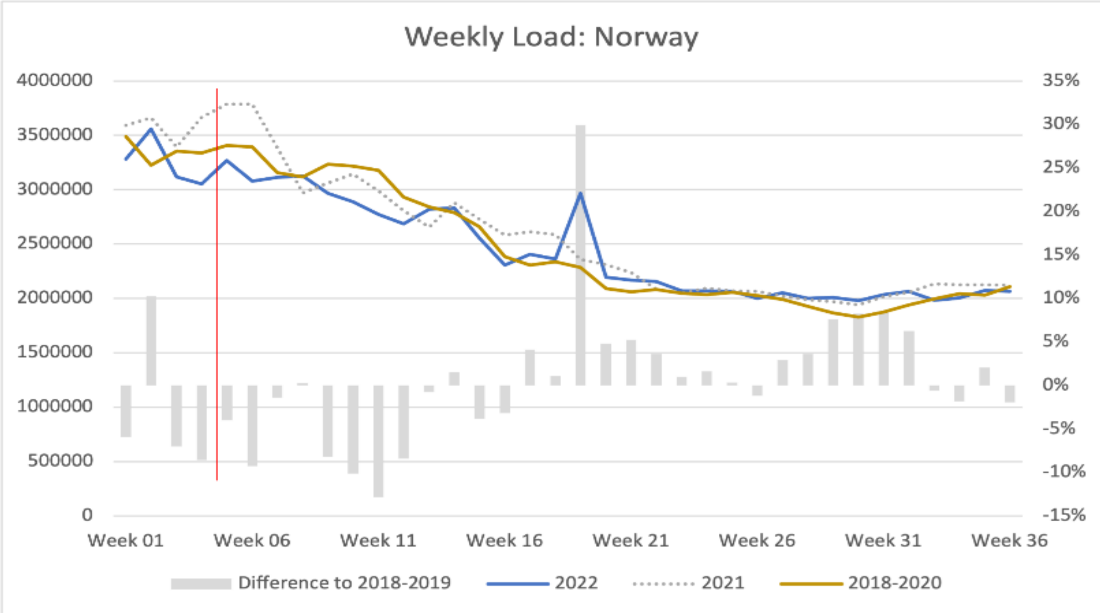

Figure 37c_Norway: Weekly Loads (2022 vs. 2018/19)

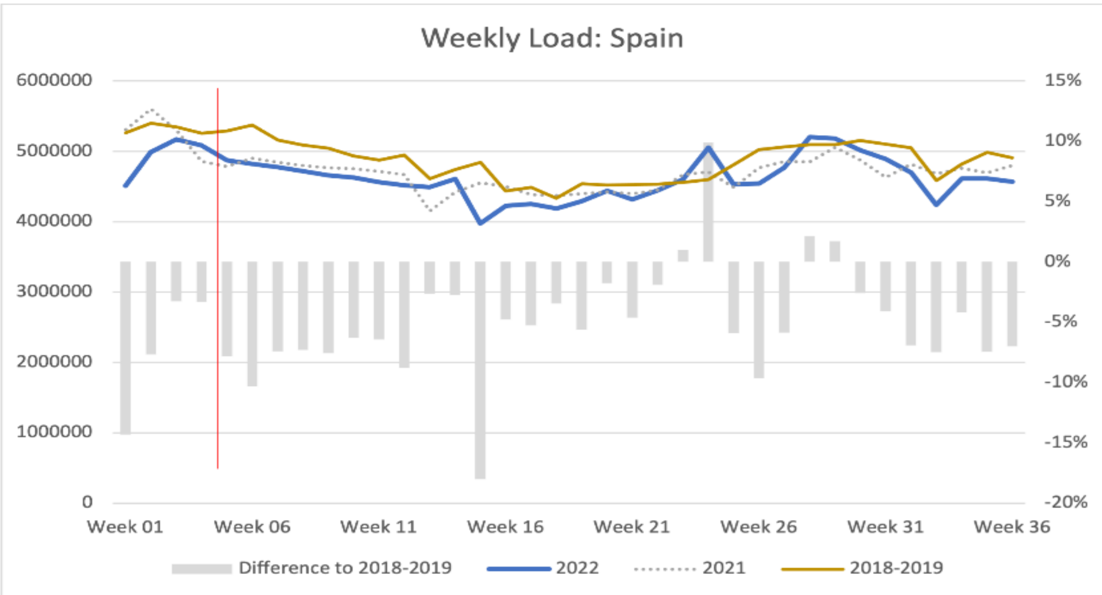

Figure 37d_Spain: Weekly Loads (2022 vs. 2018/19)

Source: Own graphs with Entso-E data.

It appears that the weekly load has decreased in 2022, at least in some countries most notably in the Netherlands and Spain and to lesser extent in France. But this pattern is not obviously true for Norway and Italy.

Additionally, the war between Ukraine and Russia may have even reduced consumption in the short run. According to Figure 37, the reduction in load in 2022 relative to 2019 (except for Norway) strengthened in the weeks following the Russia's invasion. Interestingly this reduction may come about through a price mechanism as prices temporally increased drastically after this event.

Analysis of energy demand data from individual countries

France

In France, electricity and gas prices for end customers have increased significantly in the first half of 2022. Because of the tariff shields put in place and the inertia of contracts, the price increase is significant but more moderate for households: +7% for electricity and +22% for gas between the first half of 2021 and the first half of 2022. The average prices for businesses have increased by 31% for electricity and 103% for gas.

As expected, the most energy-intensive companies have experienced even more significant changes. This electricity increase is even greater for the largest consumers, with an 87% increase for companies consuming between 70 and 150 GWh. Companies consuming more than 1 TWh have thus seen the gas price almost triple in one year and now pay more for their gas than companies consuming less.

The demand response on both markets allowed a 17.2% cumulative savings (gas and electricity) since 1 August 2022, compared to the same period in 2018 (Minsitère de la Transition énergétique)[286]. Gas consumption has fallen 14% in France since August, compared to the average of the last five years. This number is significantly larger than the reduction rate for electricity consumption. One reason is that a smaller share of gas consumers (compared to electricity consumers) benefit from the shield tariffs. This percentage is, however, likely to be overestimated as the consumption of power stations that run on gas is not included in the calculation.

The electricity consumption adjusted for temperature has remained close to the levels before the crisis (just lower by around 1 to 2% for the first half of 2022). This is mostly due to the "tariff shield" introduced in 2021, which largely protects consumers from price changes. The weak demand response is likely to continue in 2023, as the 15% increase announced on 14 September remains much lower than the increase in electricity market prices. It is worth noting that the fall 2022 has witnessed a electricity demand reduction of 4% for the month of September 2022 and 8% for November 2022. According to the French electricity transmission network this downward trend is however primarily due to large industrial sites stopping or moderating their activity.

Italy

At the end of 2021, the National Unique Price (*Prezzo Unico Nazionale*), which is the electricity reference price defined on the Italian Power Exchange, was, in real terms, already 65% higher

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[286] https://www.ecologie.gouv.fr/suivi-hebdomadaire-consommation-energetique-france

compared to the first semester of the same year, and 195% higher than the annual average of the previous year.[287] Due to the rise in the prices of wholesale energy products, at the beginning of 2022, ARERA increased the electricity price by 55% and the gas price by 42%. In August 2022, according to *Terna*, the system operator that manages the Italian transmission grid, Italy consumed a total of 25.9 billion kWh of electricity, registering a drop of 2.6% compared to the same period in 2021, and around 13% compared to 2019 levels (pre-COVID period).[288] This reduction in consumption most likely has been triggered by the higher energy price, but also by government's large campaign to promote energy savings.

Great Britain

The price rises in the UK for electricity and gas have been substantial, however discerning the underlying price effect is difficult given the impact of Brexit, COVID and temperature. On top this the government is giving cash handouts and bill credits to help with energy bills, which might affect price responsiveness. Brexit has continued to reduce GDP growth and limit industrial output, while COVID produced both a very deep recession and an almost equally sharp recovery. The latest available data for both price and quantity is Q2 2022. For this quarter, industrial electricity demand is down 8.2% relative to Q2 2019[289], against a real price rise of 45%. Residential gas demand was down 18% relative to Q2 2019 on a real price rise of 43.0%[290] (most households receive a monthly bill for both gas and electricity). Household electricity demand continues to be affected by working from home (which also attracted additional tax credits) and new household formation, however electricity Q2 2022 demand was 6.2% below Q2 2019, on a real price rise of 36.1%. These figures are before an even larger bill rise in October 2022, since when further large reductions in electricity and gas demand have reportedly been observed, of a further 10%.[291]

The Netherlands

The Dutch government has focused its intervention on (targeted) income support, a reduction of VAT and the energy tax, but did not intervene in the retail energy prices themselves until January 2023. Many consumers were therefore exposed to high energy prices and the Dutch rate of inflation has been one of the highest in Europe.

When comparing the period March 2019-September 2019 (before Covid) with March 2022-September 2022, total gas and electricity demand decreased with 27% and 3% respectively. In comparison to 2019, there are large reductions of gas consumption in the crude oil industry (more than 50%), chemical industry (50 %), and basic materials (growing response up to 30% in second half of 2022). [292] Based on a simple forecasting model that includes temperature and macro-economic situation in the

[287] https://www.arera.it/allegati/relaz_ann/22/ra22_sintesi.pdf
[288] https://www.terna.it/it/sistema-elettrico/statistiche/pubblicazioni-statistiche
[289] Industrial Electricty Price (BEIS Table 3.3.1); Industrial and Domestic Sales (BEIS Table 5.5); RPI All Items; RPI Electricity DOBX.
[290] Domestic Gas Sales (BEIS Table 4.1); RPI All Items; RPI Gas DOBY.
[291] https://www.theguardian.com/money/2022/nov/27/uk-households-have-cut-energy-consumption-by-10-say-suppliers
[292] https://www.cbs.nl/nl-nl/visualisaties/indicatoren-aardgasgebruik-van-de-industrie

Netherlands, The Rabobank shows a gas demand reduction of about 15% for the first half of 2022 compared to forecasts. The rest of the reduction can be attributed to warm weather and macro-economic effects.[293] The demand for electricity did not reduce much. This could be due to fuel switching (away from gas towards electricity), the extra rollout of EVs, and the introduction of heat-pumps, but this needs to be studied in more detail.

Comparing prices over the same time periods, average wholesale prices increased 600% for electricity (APX price from 38 to 271 EUR/MWh), and 1200% for gas (TTF price from 12 to 143 EUR/MWh). The relative price increase for households was smaller. The Dutch energy bills consist of a monthly fixed component for network access and an energy component which is proportional to consumption. The energy price component increased by 150% for electricity (from 221 to 557 EUR/MWh) and 340% for natural gas (99 to 438 EUR/MWh). It is unclear whether households adjust consumption based on energy prices, as theory predicts, or just look at their total energy bill, which combines gas and electricity prices and network tariffs. Part of the price increases have been compensated lump-sum through income subsidies, which might also affect consumers' demand for energy.

Norway

The support scheme aimed at household consumers has effectively capped the rise in electricity prices for these consumers. Nevertheless, consumer bills have increased, depending on the type of contracts that consumers have. As explained above, nominal electricity costs increased from the first quarter of 2021 to the first quarter of 2022 by (approx.) 10% for consumers on variable-price contracts and 24% for consumers on spot-price contracts, and decreased by -17% for consumers on fixed-price contracts (the latter effect is due to the fact that the compensation is not based on consumer specific, but on market-wide wholesale prices).

Interestingly, even though the rise in prices for household consumers has been quite modest, their consumption of electricity has gone down quite considerably**.** As refered to above, a study from Statistics Norway, shows that middle income households may on average have reduced their electricity consumption by as much as 20% during the winter months of 2021/2022.

The energy intensive industry is almost entirely covered by fixed-price contracts of very long duration, and hence has not been affected by the price rise (mostly these contracts do not allow for resale of contracted quantities); its electricity consumption has been more or less flat over the last three years (ssb.no).

Load variation, government intervention and industrial consumers

We move next to exploring the potential effect of government interventions on load. The Netherlands stands out as the least interventionist country, relying more on income support mechanisms and less on measures that change the energy price, implementing only an energy tax reduction in January 2022 and a VAT tax cut in July 2022. Thus, Dutch consumers appear to be the most exposed to price

[293] https://www.rabobank.nl/kennis/d011300043-gascrisis-in-nederland-hoe-staan-we-er-voor-in-aanloop-naar-de-winter

increases, which may explain the significant reduction in load (see Figure 36). If so, government interventions in other countries may be considered to have reached their objective of protecting end-consumers interests. Still, in other countries like France, there has also been load reduction, although not to the same extent. Therefore, it is possible that this load reduction was partly driven by consumers who were not protected by such government measures.

Indeed, electricity-intensive and gas-intensive industries have been exposed to soaring prices, as most government interventions did not target protection towards these industries at the beginning of the energy crisis. Stiewe et al. (2022) argue that this adjustment has been severe for the steel and aluminum industries (with high electricity consumption) and ammonia, paper, and brick industries (with high gas consumption). It is the case that some sectors were forced to innovate and improve energy efficiency in their supply chain.

However, if demand response corresponds to an industrial activity reduction, this may have long-term economic consequences (e.g., delocalisation or increseased unemployment). There is also anecdotal evidence that energy-intensive companies were forced to cut production. For example, the chemical giant BASF has recently announced that its operations will be permanently downsized in Europe due to the high energy price (see FT, Oct 19, 2022).

Concluding observations on demand response

Our analysis suggests that government interventions on retail prices have reduced the demand impact, that might otherwise have resulted from a pass through of wholesale prices. However some falls in demand are observed. For instance, the decrease in load observed in Figure 37 could result from many factors beyond high energy prices and government intervention. It is possible that increased energy efficiency, media attention on the energy crisis, but also “ethical reactions to Russia’s invasion of Ukraine” may also have mattered (Ruhnau et al. 2022).

Thus, this section does not claim causality. The purpose is solely to illustrate some trends and offer reflections about potential interactions between high prices, government interventions, and demand response by different types of consumers.

To conclude, the energy equation is complex. One would need more careful analysis and better and more detailed data to pin down and disentangle the impact of government measures from the other factors affecting demand. What is clear is that national government interventions to protect most consumers from wholesale price rises, or to limit their effects, have substantially dampened the demand effects we would expect to see.

SECTION 3: LESSONS LEARNT

There is no doubt that **many consumers were ill-prepared for the rise in energy prices, in the sense that they were on retail contracts that provided little or no hedge**. What is less clear is whether they had taken a calculated risk or were misled into being excessively exposed to price rises. For example, Norwegian consumers, who mostly rely on spot-based contracts, are not unaccustomed to fluctuations in prices, across seasons and between years, driven by the availability of hydro resources. They also have easy access to other types of contracts, including fixed-priced contracts for up to three years. Nevertheless, almost all of them chose to expose themselves to the risk of high prices. In any case, their bet paid off: they were rescued by their government.

What consumers certainly would have had difficulty foreseeing was any **lack of preparedness of their suppliers**. Suppliers often rely on sourcing energy on short-term wholesale contracts, thereby exposing themselves to margin risk. This is a problem for companies whose gross margins (on all wholesale and network costs) are very small.[294] When the wholesale market turned up, some of them paid the price, in the form of bankruptcy. Unfortunately, their (lack of) hedging strategies also had consequences for others; in the Netherlands, it was the customers of the failing suppliers that bore the cost of having to enter into new and less favourable contracts; in Great Britain, much of the cost of failing suppliers was socialised on energy consumers as a whole. Suppliers with a closer maturity match between their retail and wholesale contracts, or which, through vertical integration, had access to their own energy resources, have fared better; Spain provides a case in point. Customers (and their regulator) are generally hedged from supplier failure because continuity of supply is guaranteed.

Ofgem, in Great Britain, seem to have been unaware of the implications of having large wholesale price rises, interacting with the price cap, for supplier financial sustainability. The regulator and the government had encouraged consumers to switch to new and cheaper suppliers, hailing the loss of market share of traditional suppliers as a success; notwithstanding the fact the new suppliers had created a competitive pressure that benefited consumers, more could have been done to stress test retail business models and warn consumers about the risk they were taking when signing up to suppliers with very risky business strategies (it did not help that consumers were effectively protected against bankruptcy through the socialisation of their losses). The situation was similar in the Netherlands. The Dutch regulator did test the risk exposure of retailers, but the test could have been more stringent, even within the existing regulatory framework. The effect for Dutch customers was exacerbated by the lack of any financial compensation for customers that saw their suppliers disappear. In Norway, government authorities had been more concerned about what consumers pay on average than what risks they are exposed to.

The crisis has also demonstrated how **well-intentioned regulatory measures to improve market performance in general, and competition in particular, may undermine the workings of the market**. In Great Britain, the price cap intended to avoid excessive prices and exploitation of consumers

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[294] Ofgem in GB set the retail profit margin in the default tariff at 1.9% of the total bill. See https://www.theguardian.com/money/2022/apr/19/how-are-uk-gas-and-electricity-bills-calculated

became generally binding, driving margins to levels where suppliers no longer want to actively compete for customers. In the Netherlands, the cap on the penalty for customers breaching their contract has meant that suppliers are unwilling to offer long-term contracts, hence leaving consumers with no means to hedge against volatile wholesale prices.

The French model has shielded both suppliers and their customers more or less completely from the increase in energy prices. A consequence of the **muted price signal is that there will be little or no consumer response to what is effectively a scarcity in the availability and supply of energy**. Moreover, by letting generators such as EDF cover much of the cost, the incentive and ability to fund new investment is undermined. The Spanish solution, to intervene at the wholesale level, has admittedly reduce retail prices but has also fuelled energy consumption and created huge costs not born by the energy consumers themselves. The Norwegian tax reductions and rebate to consumers also have the effect of limiting the incentive to save on energy, but here the price to generators was not distorted. In Great Britain, the default cap meant a temporary, but not a permanent, delay in the increase in retail prices, and the measures for relieving the impact of higher energy bills have been implemented outside of the market. The same is true in Italy, where prices have mostly been allowed to rise, and where compensation has been in the form of tax reductions and direct economic support. In the Netherlands, the reduction in the energy tax was modest. The tax was reduced in percentage terms but remained about the same in absolute levels. Part of the tax reduction was given through a reduction of the income tax, which does not affect incentives to save energy. Part of the energy tax is used to provide subsidies for renewable energy. During periods with high energy prices, those subsidies are no longer needed as the energy price is already high enough. So a reduction in the energy tax might be economically justified.

The energy crises, in combination with the wider implications of a "wartime" economy, has contributed to a general awareness that saving energy is important and probably has had an impact on demand. This effect has been further strengthened by deliberate **efforts by governments to encourage energy efficiency and saving**. In Italy, for example, as part of its "action plan", the government has introduced regulations on indoor temperature (to reduce cooling in summer and heating in winter) and will run campaigns to encourage awareness of how indviduals and companies can contribute to more responsible and efficient energy consumption. One should not underestimate the potential effect of such efforts in the current situation in Europe.

At the time of writing, measures to keep retail prices from rising in line with the rise in the cost of energy, have **created deficits that need to be financed in some way**. In Norway, the deficit is wholly financed by general taxation on an ongoing basis. In Great Britain, part of the deficit will be covered by the sector itself, in the form of additional levies on energy prices and (windfall) profit taxes on gas and oil companies, though most of the latest price guarantees will be financed from general taxation. This is true also in Spain, where a windfall profits tax is in place for renewable generation. Italy has similar plans, although much of the cost would seem to be born by the tax payer. In France, much of the burden has been put on generation, especially on EDF, with the likely effect of requiring higher energy prices in the future. The consequence of not covering the additional costs of energy immediately is that it must be covered later, sometimes by those who were protected from the costs in the first place.

SECTION 4: CHALLENGES AND OPPORTUNITIES

We are in an **energy war** with an enemy that is using interruption to energy supplies as a weapon against Europe. This means we should distinguish between interventions that would be appropriate for the short run, until the war is won, and those that are sensible in the longer run. Pollitt (2022) discusses what it means to put the economy on a 'war footing' in this energy war. This may involve elements such as a **significant programme of electricity and gas demand reduction**; a 'dig for victory' programme in energy aimed at increasing in domestic energy production and demand side interventions'; fair pricing of energy, which both incentivises reductions in demand while protecting the vulnerable; and a temporary set of profits tax to reduce war time profits of energy firms.[295]

In October 2022, a German energy expert group outlined a scheme for reducing German gas consumption using **rising block tariffs** which both addressed high energy costs and incentivised deep reductions in domestic gas demand.[296] Under this scheme, from January 2023, 80% of September consumption for a household would be at €c0.12/kWh, with the rest at the unsubsidised price (in addition to a month free in December 2022). Industry would receive 70% of its 2021 consumption at €c7/kWh, with the rest unsubsidised. This effectively gives strong incentives for households to cut consumption by 20% and industry by 30%. A similar scheme for electricity would make a lot of sense.

The **post-war longer-term issues are somewhat different.**

The recent unexpected higher energy prices have highlighted the challenges of designing well-performing retail markets. On the one hand, one would like consumers to have access to energy at prices that reflect underlying costs and that provide a hedge against undesired risk. On the other hand, one would like consumers to respond to varying electricity prices when the availability and supply of energy is limited. More specifically, one would want to **facilitate behavioural change in energy consumption that increases energy efficiency and supports the energy transition.**

This is a balancing act. It is difficult to keep retail prices low and stable while encouraging flexibility and energy saving. It is also not possible to induce a change in behaviour without exposing consumers to the costs of their actions and, to raise the revenues that will be necessary to fund the energy transition, prices have to reflect the actual costs of renewable energy. A good retail market design must balance these different considerations, where the balance may well depend on the specificities of individual countries.

It is **possible to encourage demand flexibility by exposing consumers to short-term price variations while at the same time locking in a significant part of their energy costs at fixed prices**. It is also possible to **protect vulnerable consumers through the general tax and support system, rather than through interventions in the energy market**. And it is possible to ensure that suppliers take full

[295] Stigliz (2022) makes some of the same suggestions for short-term interventions while the war continues.
[296] https://www.euractiv.com/section/energy/news/german-experts-release-e91-billion-plan-to-curb-gas-prices/; the full report is ExpertInnen-Kommission Gas und Warme (2022).

responsibility for costly or risky strategic choices and develop stronger hedging strategies, rather than passing the cost of their mistakes on to their customers, or to others for that matter.

In spite of this a number of important issues can be identified.

A first issue is **ensuring that suppliers are prepared and can handle the risk they face**. One could argue that, as long as customers have the opportunity to choose a new supplier at competitive prices, suppliers who cannot handle their risk should simply pay the price and go bankrupt. However, there are real costs involved in any bankruptcy, especially if suppliers hold a large portfolio of customers, and so some safeguards would likely be desired. Since energy retailing is essentially a financial service, there are lessons to learn from financial sector regulation. Stricter requirements on the financial position of suppliers are likely warranted, including supplier stress-testing and extending forward hedging requirements.

In addition, there may be **room for improving the methods for dealing with consumers who find their supplier going bankrupt or leaving the market for other reasons**. Consumers must, to some extent, be held responsible for their choice of supplier – otherwise the door would be wide open to offers that are "too good to be true" – but they must also have ways of entering into a new contract on reasonable terms when warranted.

There is a possible trade-off here; on the one hand, **ensuring that suppliers do not fail reduces the need for customer protection**; on the other hand, a **sound system for customer protection makes financial regulation of suppliers less important.** Given that both financial regulation and customer protection come at a cost, **finding the right trade-off should be a priority**.

A second issue is **how financial support for consumers should be delivered.** According to the theory of optimal taxation, **consumer support is best administered through the regular tax and welfare system**. The current crisis has shown that this system did not respond adequately – or, at least, it was not seen to do so – and various *ad hoc* schemes (e.g., capping price hikes) were introduced. These schemes clearly provided some relief for vulnerable consumers. However, they also had several unintended consequences, partly by providing support where none was called for, and partly by encouraging consumption in a time of scarcity. **Where the impact on inflation is significant, support schemes need to be implemented in a way that actually reduces measured inflation**, e.g., directly via reductions in fixed energy costs where the inflation impact of energy prices is calculated on average costs.[297] If they are instead paid as cash payments this risks stoking the price-wage spiral by letting measured energy prices rise while actually providing financial support for paying them. **Careful thinking about the design of consumer support schemes is clearly necessary**. This becomes all the more important in a situation where costs of living moves on to the top of the political agenda.

Financial support for consumers requires funding. **Funds may be raised from general taxation or taxing of the energy industry itself**. In some countries, new measures are introduced to raise funds from the energy industry. In the United Kingdom, an Energy Profits Levy taxes the oil and gas industry.

297 See Pollitt et al. (2022) on the calculation of energy price inflation in the UK.

Greece has introduced a series of measures on both generators and suppliers whereby revenues above certain thresholds are withheld in favour of the Energy Transition Fund, which is used to discount electricity bills for eligible consumers. In Norway, the government has introduced a `high price contribution´, which taxes revenues earned at prices above €70 per MWh at 23 per cent. **However, adding new taxes to the energy industry, or increasing existing ones, may put energy companies under stress and will negatively affect incentives to invest in new capacity**; investment incentives may be negatively affected not only by the taxes themselves, but also by undermining trust in the stability of the regulatory framework.

A third issue concerns **how consumers can be allowed to hedge market risk while encouraging demand flexibility and energy conservation**. Fixing retail prices – whether trough regulation or contracts – provide some hedge, but at the cost of little or no demand response to changes in the availability of energy. Full cost pass-through provides strong signals, but also exposes consumers to the full risk of changes in energy prices. The default price cap in Great Britain provided an intermediate solution, but turned out to delay rather than remove the rise in prices. An alternative is to **encourage (or mandate) the development of retail contracts that locks in part of the energy consumption at fixed prices while retaining price variation on the margin**. One way to do that would be to **combine real-time pricing with financial difference payments for a fixed quantity of energy.**[298]

Another important trade-off in the retail market is **balancing competition and innovation versus stability.** Measures that increase switching regulates and lower the requirements for new suppliers, but might increase aggregate market risk. Regulation of contractual terms must however be carefully considered, given that the availability of contractual types and the terms on which they may be offered are closely related. In the Netherlands, the cap on penalties that consumers pay for early contract termination seems to have undermined the market for long-term contracts. Similarly, the opportunity for French (and Spanish) consumers to switch back and forth between a regulated price and market offers may limit the incentive of suppliers to offer innovative contracts, especially of longer duration. **Regulation of contractual terms must therefore balance consumer protection and incentives of suppliers.**

The considerable diversity in retail market design, as well as the ways in which governments have responded, and will want to respond, to the supply crisis and potential future shocks, raises the **question of the implications of the subsidiarity principle in retail markets: what are the limits to what member states can do?** Should these limits be reconsidered? Indeed, to what extent should retail markets be a concern for the European Commission rather than individual Member States? While the final after tax price of energy for households can be allowed to vary across Europe (and did vary substantially before the crisis), the impact on aggregate European demand for electricity of highly subsidised marginal prices of electricity consumption in one country does produce negative externalities for the citizens of other European countries. **Price interventions which have large detrimental effects outside of the countries in which they were implemented should be prevented.**

[298] This could be organised within a single contract with a retailer or, if permitted by national legislation, by two different contracts: the retailer who offers a fixed price hedging contract, and an aggregator that sells flexibility on top of that.

It is therefore to be welcomed that the EU has recently implemented regulation to reduce electricity demand across Europe, as this will encourage Member States to look carefully at their marginal consumer electricity prices. Meanwhile, **interventions which differentially impact Member States commercial and industrial prices have competitive effects which raise standard state aid concerns**. This is because differential national levels of support for retail electricity and gas prices for non-households translate into differential prices of goods and services and distort competition between European countries.

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