# The political economy of wholesale power market reform and renewable energy integration: a comparison of Britain, Italy, and California

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## Abstract

The need to integrate growing shares of variable renewables, like solar and wind, into the power system has sparked a new wave of wholesale electricity market reforms. Their objectives are often multifaceted: not only do emerging market designs need to leverage substantial low-carbon investments, but they must also secure the scale of short-term operational flexibility and long-term capacity needed to uphold grid reliability amid increased supply variability. While extensively explored from a techno-economic perspective, the political economy drivers and implications of these changes are frequently overlooked. Yet, power system evolution is not merely shaped by logics of techno-economic optimisation, it is also an inherently political process, rooted in specific liberalisation histories, political and institutional settings.

This thesis contributes to the literature by conducting a comparative political economy analysis of recent wholesale electricity market reforms in Britain, Italy, and California. It explores how the unique technical and political economy contexts of these jurisdictions influenced their approach to reforming their power market designs between 2013 and 2021. This encompasses short-term energy markets, balancing and ancillary services, long-term capacity and low-carbon investment mechanisms. Conclusions draw on the analysis of over 300 policy documents and 53 in-depth interviews with key power system stakeholders including senior sector experts, policymakers and private sector representatives.

Evidence shows that all jurisdictions introduced significant modifications in their wholesale market designs in response to changing system conditions. Notably, the energy transition is bringing a reconfiguration of the political economy of the power sector involving increased state involvement in markets, even in traditionally liberal countries. Nevertheless, variation exists in terms of the scope of reform, chosen mechanism designs, policy trade-offs, and technological outcomes. These differences stem from specific physical system realities, as well as a set of key political economy conditions, including national political priorities, historical state-market relations, national and multi-level governance arrangements, legacy market structures and key stakeholders' interests. This has important implications for power sector governance, as discussed in this thesis.


## Impact statement

The novelty of this work lies in the application of a comparative political economy perspective to the study of wholesale power market reforms for the integration of renewable energy sources. Existing literature tends to focus on the techno-economic aspects of these changes – i.e. how to reform market rules to achieve cost-effective renewable integration – overlooking the question of why countries adopt different approaches based on their unique political economy settings. This thesis underscores the real-word complexities of power market design evolution, which cannot be reduced to a mere techno-economic process; instead, it is heavily shaped by the political, institutional and economic context within which is embedded.

Through an in-depth analysis of three case studies, this thesis makes an important empirical and theoretical contribution. By establishing a constant dialogue between theory and data, the chosen abductive analytical approach proved extremely valuable for studying a fast-evolving, understudied policy area, enabling flexibility and the emergence of novel insights. Further, this allowed to develop a workable conceptual framework, which could be employed in future political economy studies to deepen our understanding of power sector evolution. Avenues for further research have been identified and discussed in the concluding chapter.

Beyond academic significance, this thesis holds direct relevance for energy policy practitioners, consultants, and industry stakeholders, by offering a systematic account of the policy strategies and institutional reforms implemented by three global leaders in renewable adoption and integration. The author has developed a set of policy implications, identifying potential options for market design

reform appreciative of local economic and institutional contexts. Specific market design features have been discussed extensively, including key aspects to consider when designing the various mechanisms, the main trade-offs involved, and potential unintended consequences.

By highlighting the real-world political economy dynamics of power market change, this thesis sheds light on the implications of diverse institutional designs and governance arrangements for power sector decarbonisation. This understanding is critical for crafting coherent and legitimate governance and market design strategies, which can be sustained in the long-term and which strike an appropriate balance between coordination and market-based mechanisms, leveraging the value of different energy resources. These decisions will influence the pace at which states will be able to achieve wider electrification of the economy and the retirement of fossil fuel generation, and the resulting trade-offs in terms of decarbonisation, system security and costs.

Cross-learnings have already been generated through the sharing of this work with participants, who represent the top experts in power market design in their respective jurisdictions across the public and private sector. However, findings also yield important lessons for all other countries undergoing the energy transition. To maximise impact, the author has disseminated findings through different channels. These include a publication on the Energy Research & Social Science journal, and the presentation of key findings at the 2023 'British Institute of Energy Economics conference' at the University of Oxford, and the 2023 'Society for the Advancement of Socio-economics conference' at the Federal University of Rio de Janeiro.

## Declarations

*"I, Giulia Ragosa confirm that the work presented in my thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the thesis."*

Part of this work is currently being published in an academic journal, as follows:

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# List of acronyms

| | |
|---|---|
| **ACER** | Agency for the Cooperation of Energy Regulators |
| **AIGET** | Associazione Italiana di Grossisti di Energia e Trader |
| **ARERA** | Autorità di Regolazione per Energia Reti e Ambiente |
| **BEIS** | Department for Business, Energy and Industrial Strategy |
| **BETTA** | British Electricity Trading and Transmission Arrangements |
| **CAISO** | California Independent System Operator |
| **CALWEA** | California Wind Energy Association |
| **CCA** | Community choice aggregator |
| **CCC** | Climate Change Committee |
| **CCGT** | Combined cycle gas turbine |
| **CEC** | California Energy Commission |
| **CEGB** | Central Electricity Generating Board |
| **CfD** | Contract-for-difference |
| **CNR** | Consiglio Nazionale delle Ricerche |
| **CPUC** | California Public Utilities Commission |
| **CRM** | Capacity remuneration mechanism |
| **DECC** | Department of Energy and Climate Change |
| **DER** | Distributed energy resources |
| **DG** | Distributed generation |
| **DNO** | Distribution network operators |
| **DSO** | Distribution system operator |
| **DSR** | Demand-side response |
| **DWR** | Department of Water Resources |
| **EBSCR** | Elecricity Balancing Significant Code Review |
| **EC** | European Commission |
| **EIM** | Energy Imbalance Market |
| **ELCC** | Effective Load Carrying Capability |
| **EMR** | Electricity Market Reform |
| **ENEA** | Ente per le nuove tecnologie, l'energia e l'ambiente |
| **ENEL** | Ente Nazionale per l'Energia Elettrica |
| **ENI** | Ente Nazionale Idrocarburi |
| **ENTSO-E** | European Network of Transmission System Operators for Electricity |

| | |
|---|---|
| **EPEX** | European Power Exchange |
| **ESDER** | Energy Storage and Distributed Energy Resources initiative |
| **FERC** | Federal Energy Regulatory Commission |
| **FFR** | Fast frequency response |
| **FiT** | Feed-in-tariff |
| **FSO** | Future System Operator |
| **GME** | Gestore dei Mercati Energetici |
| **GSE** | Gestore Servizi Energetici |
| **IEA** | International Energy Agency |
| **IEM** | Internal Energy Market |
| **IOU** | Investor-owned utility |
| **IPEX** | Italian power exchange |
| **IPP** | Independent power producer |
| **IRENA** | International Renewable Energy Agency |
| **IRP** | Integrated Resource Planning |
| **ISO** | Independent system operator |
| **LMP** | Locational marginal pricing |
| **LSE** | Load serving entity |
| **MB** | Mercato del bilanciamento |
| **MGP** | Mercato del giorno prima |
| **MI** | Mercato infragiornaliero |
| **MISE** | Ministero dello Sviluppo Economico |
| **MSD** | Mercato dei servizi di dispacciamento |
| **MTE** | Mercato a termine |
| **NETA** | New Electricity Trading Arrangements |
| **NGESO** | National Grid Electricity System Operator |
| **NIMBY** | Not in my backyard |
| **NOA** | Network Options Assessment |
| **OECD** | Organization for Economic Cooperation and Development |
| **OFFER** | Office of Electricity Regulation |
| **OFGEM** | Office of Gas and Electricity Markets |
| **PE** | Political economy |
| **PIRP** | Participating Intermittent Resource Program |
| **PJM** | Pennsylvania-New Jersey-Maryland Interconnection |
| **PNIEC** | Piano Nazionale Integrato Energia e Clima |
| **POU** | Publicly owned utility |
| **PPA** | Power purchase agreement |
| **PURPA** | Public Utility Regulatory Policies Act |
| **REMA** | Review of Electricity Market Arrangements |
| **RES** | Renewable energy source |
| **RIIO** | Revenue = Incentives + Innovation + Outputs |
| **ROC** | Renewable obligation certificate |
| **RPS** | Renewable Portfolio Standard |
| **RSE** | Ricerca sul Sistema Energetico |
| **RTO** | Regional Transmission Organization |
| **SCAD** | Single Dayahead Coupling |
| **SCE** | Southern California Edison |
| **SDG&E** | San Diego Gas & Electric Company |
| **SO** | System operator |
| **STOR** | Short-term operating reserve |
| **TIDE** | Testo Integrato del Dispacciamento |
| **TSO** | Transmission system operator |
| **UKIP** | UK Independence Party |
| **UVAC** | Unità virtuali abilitate di consumo |
| **UVAM** | Unità virtuali abilitate miste |
| **UVAP** | Unità virtuali abilitate di produzione |
| **VOLL** | Value of lost load |
| **VRE** | Variable renewable energy |
| **XBID** | CrossBorder Intraday |

# 1 Introduction

Decarbonising the electricity supply is a fundamental step towards meeting climate change targets. Not only does power generation directly contribute to a significant share of global emissions (roughly 40%), but it is also a key enabler of the wider decarbonisation of the economy. Thanks to targeted policy support, some jurisdictions achieved significant levels of variable renewable energy (VRE) adoption, particularly solar and wind generation. While this is a great success story, their experiences reveal that integrating large shares of these resources into the power system comes with a set of challenges that call into question legacy electricity sector arrangements, originally designed around fossil fuel resources (Pollit 2021; Newbery et al. 2018; Joskow 2019).

As VREs become more prevalent, we tend to higher need for system flexibility, the ability of the system to manage uncertainty and variability in the supply-demand balance across different timescales (IEA 2018; Ela et al. 2019). Flexibility needs have been traditionally met through dispatchable plants and the transmission grid, but other solutions are emerging like new storage technologies, demand-side resources, flexible renewable operation and smart grid technologies (Ländner et al. 2019). Wholesale market rules thus need to account for the specific characteristics of these technologies to leverage value from a wide as possible pool of assets (Green 2021; Roques 2021; Wolak 2021). This not only involves maximising operational flexibility in short-term markets, but also leveraging adequate long-term investment in flexible and peak capacity capable of fulfilling future operational requirements (ibid). Moreover, the unique cost structures of VREs affect short-term market dynamics, exacerbating existing concerns about the effectiveness of investment signals for ensuring long-term resource adequacy, or the ability of the system to adequately serve demand in the long-term (Green 2021; Wolak 2021; Bulbitz et al. 2019; Roques 2021). In parallel, market design also needs to sustain the scale of low-carbon investment needed to deliver on decarbonisation objectives (ibid).

Against this background, thirty years after reforms were first initiated to liberalise the electricity industry, many countries have embarked on a new wave of reforms to make their wholesale power market designs fit-for-a-low-carbon-system (Pollit and Anaya 2015; Hobbs and Oren 2019). This includes rewriting the rules for short-term markets (i.e. day-ahead, real-time and balancing) as well as redesigning long-term investment mechanisms (i.e. low-carbon investment subsidies and resource adequacy capacity procurement) (Ela et al. 2021). Beyond the techno-economic challenges discussed above, transitioning to a greener power mix calls into question legacy institutional structures, governance models, the roles of incumbent market players and traditional ideas on the roles of state and markets (Schmalensee 2021; Pollit 2021). Yet, most literature in this area is technical or economics oriented, focusing on the question of how market rules should be reformed to achieve cost-effective VRE integration, while overlooking the question of why countries adopt different approaches based on specific political economy contexts.

This thesis fills an important gap in the literature by examining recent electricity market reforms from a comparative, interdisciplinary perspective that considers the interplay of techno-economic, political, and institutional factors. Using a comparative political economy approach, it analyses the evolution of wholesale power market design in Britain, Italy and California between 2013 and 2021. The aim is to determine how differences in the techno-economic and political economy contexts of these jurisdictions affected their approaches to reforming power markets to enable wider integration of VREs. In fact, while all of them achieved significant renewable penetration levels in recent years, they exhibit some economic and institutional differences that make them particularly interesting to compare. Conclusions rely on the analysis of over 300 policy documents and in-depth interviews with 53 key power system stakeholders comprising of academics, sector experts, policymakers, market operators, representatives of different energy companies and consumer groups.

Findings show that all three jurisdictions introduced important modifications in their wholesale market design in response to changing system conditions and growing renewable shares. As they transitioned to a greener power mix, they faced a set of techno-economic challenges that acted as a major catalyst of change. Notably, the energy transition is bringing a reconfiguration of the political economy of the power sector involving increased state involvement in markets, even in traditionally liberal countries. Nevertheless, variation exists across case studies in terms of the scope of reform, chosen mechanism designs, policy trade-offs, and technological outcomes. These differences stem from specific physical system realities, as well as a set of key political economy conditions, including national governments, legacy state-market relations, national and multi-level governance arrangements, market structures and the interests of key power sector stakeholders. This demonstrates that power system evolution is not merely shaped by logics of techno-economic optimisation, but it is also an inherently political process.

Beyond collecting empirical evidence within an understudied area of research, this study also directly contributes to policy practice by providing a systematic account of the policy strategies and reforms adopted by three global leaders in renewable adoption and integration, thus highlighting precious lessons for countries undergoing the energy transition. Further, by unpacking real-world policy dynamics this thesis also shed light on the key institutional and political conditions shaping change in this area. This is important in terms of building a coherent governance framework for managing the transition to a high-VRE system: "Opening up the black box of policy processes may assist in developing policy recommendations that are better informed about the politics of policymaking and implementation and therefore potentially stand a better chance at being adopted and sustained" (Kern and Rogge 2018:2). This thesis also addresses a set of fundamental questions around the role of electricity markets in the context of the low-carbon transition.

This thesis is structured as follows: Chapter 2 presents a critical summary of existing theory and research in this field; Chapter 3 outlines the research questions and the adopted conceptual framework; Chapter 4 details the methodology employed; Chapter 5 provides the contextual background for the cases, focusing on their techno-economic and institutional environments; Chapters 6 and 7 analyse change in short-term energy[1] and balancing markets, respectively; Chapter 8 delves into the evolution of resource adequacy, while Chapter 9 explores low-carbon investment policy. Chapter 10 presents a more comprehensive summary and discussion of the results, answering the research questions, unpacking key policy implications, addressing limitations and identifying potential avenues for further research.

[1] The term 'short-term energy markets' is used throughout this thesis to refer to all those markets in which electricity is traded in the day-ahead and intraday timeframes. While the term 'wholesale power (or electricity) market' is used to refer to the overall market model including short-term markets and long-term investment mechanisms.

# 2 Literature review

## 2.1 Techno-economic literature

There is well-established strand of literature in energy economics that has been studying (and often actively shaping) the evolution of power market design from the years preceding liberalisation reforms that swept the world from the end of the 20th century. One of its core premises is that electricity is not like any other product exchanged in a market – i.e. electricity is difficult to store, generation must always equal demand on the system, electricity delivery is subject to availability of network capacity, power plants have complex technical characteristics like non-convexities, electricity demand tends to be inelastic, and the sector is characterised by important economies of scale (Wolak 2021; Pollit 2021). An additional layer of complexity resides in the fact that electricity is an essential service underpinning most economic activity (ibid).

Wholesale electricity market design refers to the overall structure, rules, and mechanisms that govern the buying and selling of electricity at the wholesale level (EC 2015). In principle, wholesale market design should maximise short-term operational efficiency and long-run efficient investment in new capacity as illustrated in Figure 1 (Cramton 2017; ESC 2019). The theory underpinning liberalised markets is based on the fundamental principles of the peak-load pricing approach (Boiteux 1949). Market participants bid their short-run marginal costs, and fixed costs are recovered through: (1) inframarginal rents as technologies with higher marginal costs clear the market and set the power price; and (2) scarcity rents when the market is tight, and prices go beyond the marginal cost of the technology clearing the market (Roques 2021). This is illustrated in Figure 2.

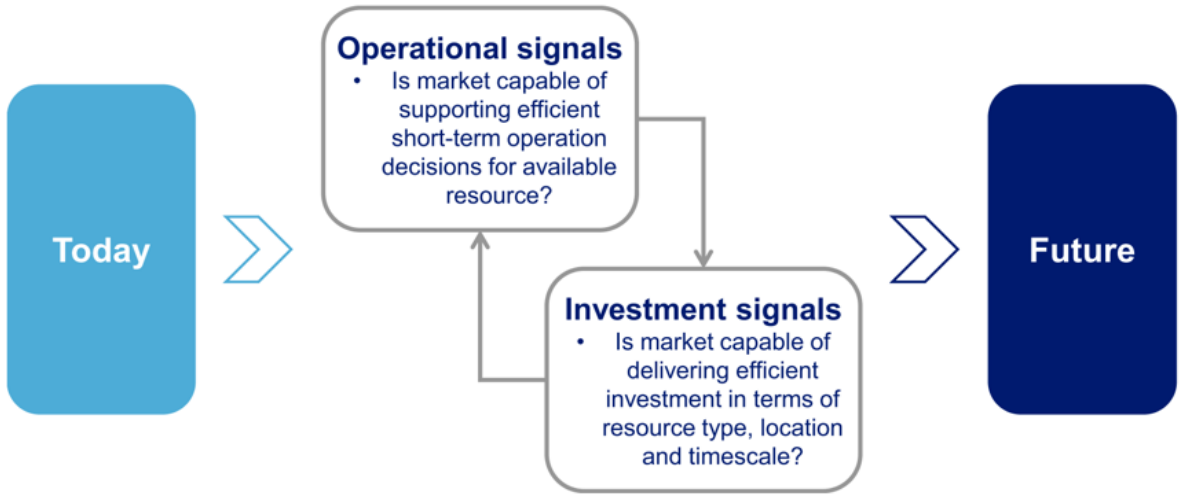


***Figure 1** - Signals needed for delivering electricity (ESC 2019)*

Beyond achieving short- and long-term efficiencies, power market design often also needs to deliver on other key policy goals such as de-risking low-carbon investment, maintaining resource adequacy and system reliability, addressing distributional issues, fostering innovation and industrial competitiveness (Cramton 2017; Pollit 2021; Newbery et al. 2018). Coupled with the constraints discussed at the beginning of this section, this means that in practice the market design process takes place "through explicit regulatory actions that set the rules for how market participants connect to the network and how they are paid for the electricity they inject and how they pay for the electricity they withdraw, rather than through the unilateral actions of producers and consumers of electricity" (Wolak 2021).

There exists a variety of market mechanisms, policy instruments and regulatory interventions employed to achieve power system objectives. Existing research often distinguishes between four key

areas: 1) short-term operation; 2) long-term resource adequacy; 3) low-carbon support mechanisms and 4) grid infrastructure. For example, Table 1 illustrates the taxonomy proposed by the IEA (2016).

***Table 1** - Overview of the key dimensions of market frameworks for decarbonisation (adapted from IEA 2016)*

| Objective | Policy | Regulation and market mechanisms |
|---|---|---|
| **Low-carbon investment** | Carbon pricing | - Carbon regulation<br>- Carbon prices |
| | Policy support | - Design of low-carbon long-term contracts |
| **Operational efficiency, reliability, and adequacy** | Short-term energy markets | - Energy market rules and cost-reflectivity<br>- Ancillary services design and cost-reflectivity<br>- Reliability standards |
| | Capacity mechanisms | - Capacity requirements<br>- Capacity prices |
| **Network efficiency** | Regulation | - Regional planning<br>- Network cost allocation |
| **Consumption** | Retail pricing | - Tariff structures<br>- Retail prices |

There is a vast literature in energy economics studying the effects of increasing VRE generation on power market dynamics. First, solar and wind generators are non-dispatchable, meaning their maximum output is intermittent/variable subject to weather conditions (Green 2021; Schmalensee 2021). Once a power system contains a significant proportion of these generators, the supply curve will be shifting as well as the demand curve (ibid). This in turn creates the need for more operational flexibility and availability of peaking capacity (Ela et al. 2019). Second, VREs have high capital cost and low short-run marginal cost compared to traditional dispatchable fossil fuel plants (Schmalensee 2021). As noted by Roques (2021), "whilst in theory, marginal cost pricing can still work with a part of the generation mix having very low marginal cost, prices become more volatile as the share of renewables increases. Because their marginal costs are very low, wind and solar output will tend to displace the output from higher-cost plants, depressing prices in the hours when they are available." Illustrated in Figure 2, this dynamic often leads to the emergence of negative or zero power prices in some periods, triggering a debate on the need for market reform (Roques 2021; Green 2021).

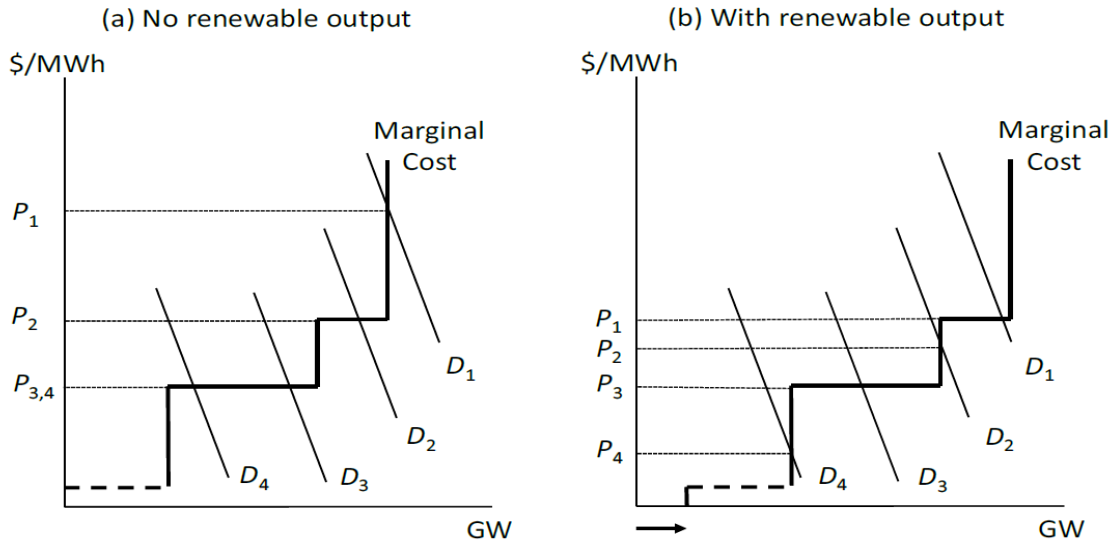


***Figure 2** - Supply and demand in a simple power market: a) no renewable output; b) with renewable output (Green 2021)*

Beyond diagnosing the implications of large-scale VRE entry, the economic literature also offers a plethora of market design solutions to deal with emerging challenges. Their coverage is wide: some discuss spot markets (Green and Leautier 2015), ancillary services (Pollit and Anaya 2021), or capacity markets (Fang et al. 2018). They also vary in geographical scope with numerous papers focusing on European power markets (Newbery et al. 2018; Kong et al. 2019; Roques 2021), US markets (Joskow 2019; Ela et al. 2019) or conducting comparisons (Botterud and Auer 2018; Burtaw et al. 2019). In fact, market design evolution is heavily dependent upon the legacy market frameworks in place. Broadly, electricity markets can be organised in two main ways: the EU Target Model for electricity markets and the US Independent System Operator (ISO) model. These are discussed extensively in relation to the three case-studies in Chapters 5, 6 and 7.

### 2.1.1 Implications of VREs for the design of short-term energy markets

As discussed above, VREs boost flexibility needs. Hence, the techno-economic literature often stresses the importance of cost-reflective and granular price signals in enabling the cost-effective integration of growing shares of VREs (Wolak 2021; Pollit 2021). As noted by Pollit (2021), "it is quite fashionable to suggest that the future of the electricity market involves more use of time-of-day and locational price signals than we see today. This is because the nature of intermittent renewables and flexible demand will mean that there is more value in signalling underlying system costs more clearly." From this perspective, short-term energy market rules should be reformed as to incentivise flexible operation in the hours prior to dispatch by a wide as possible pool of resources (IEA 2016; Roques 2021; Botterud and Auer 2018). This in turn should enable the most efficient use of both supply and demand assets including renewables, storage technologies, demand response and cross-border resources[2] (Newbery et al. 2018; Botterud and Auer 2018; IEA 2018; Ländner et al. 2019).

A key design feature to consider in the design of short-term energy markets is the extent to which energy prices reflect the real value of energy during times of under- or over-supply (Ela et al. 2019). Scarcity prices occur when there is insufficient generation to meet demand while negative prices signal oversupply (Stoft 2002; Hogan 2013). Price spikes have been identified in the literature as enablers of VREs integration in view of their potential to boost flexible resources' financial viability including investment signals for battery storage and demand response (Roques 2021; Botterud and Auer 2018; Hu et al. 2018). From this perspective, wholesale price caps should be set at the value of lost load (VOLL), representing the average consumer willingness to pay to avoid the involuntary curtailment of electricity consumption. In fact, this should incentivise market participants to produce (or consume) when most valuable while allowing generators to recoup the fixed costs of capacity that is otherwise seldom utilised (ibid). However, real-world implementation mostly diverges from theory and price caps are often set below the value of lost load (Schmalensee 2021). This is partly related to difficulties in distinguishing market power from genuine price spikes (Pollit 2021), as well as political reasons discussed more extensively in sub-section 2.4.

The literature suggests that larger presence of intermittent generation might require changing some key parameters in the design of day-ahead and intraday[3] markets. It is often argued that improving the granularity of price signals should enable market participants, especially VREs operators, to respond to increasingly fast-changing system conditions and adjust their positions before gate closure (IEA 2018; Hu et el. 2018; Fox et al. 2021). Specifically, increasing the time granularity of electricity products (settlement and dispatch period) should result into a better market representation of the system's physical realities as illustrated in Figure 3 (Ela et al. 2019). As such, more granular market timeframes are often identified as an important way to improve these markets and reduce demand for balancing services and associated costs (Schittekatte et al. 2020).

[2] This refers to interconnection or generation capacity beyond the borders of a given jurisdiction/system.
[3] Real-time markets in the US.

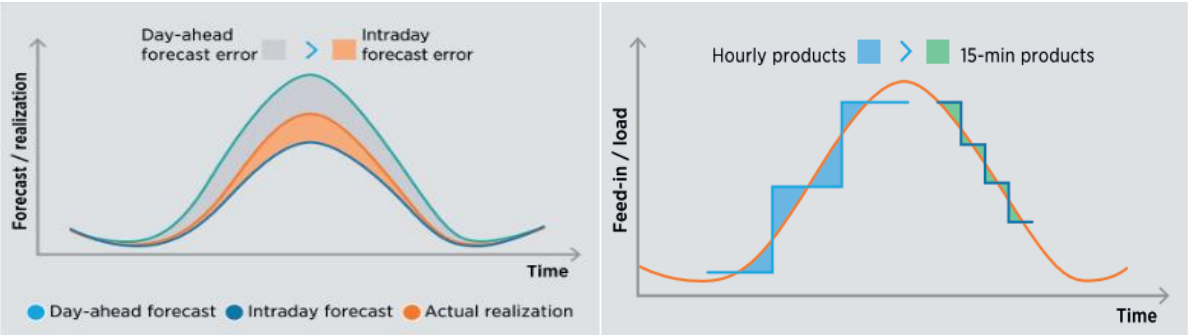


***Figure 3** - Approximation of realised load and forecast errors in intraday markets (IRENA 2017)*

VREs growth also stimulated discussions over adequate gate closure time, which marks the end of the bidding process for any given trading period (IEA 2018). As VREs are more difficult to forecast than traditional generators, some argue that "moving all markets towards real-time is important for the short-run management of the system" (Pollit 2021). This raises important questions around the definition of boundaries between market activities and system operation. In fact, modifying gate closure time involves modifications in other key, complementary market parameters (e.g. bidding formats, clearing or pricing rules). If taken together, these characterise the operational logic of the system: centralised versus de-centralised dispatch (IRENA 2017; Hu et al. 2018). Decisions on the operational logic involve important trade-offs across different power market design objectives. For example, Wolak (2021) argues that, while maximising the use of market close to delivery clearly yields benefits, "the total cost of committing and dispatching the generation units that arises from a centralized unit commitment process is likely to be less than the total commitment and dispatch costs that result from a self-commitment market provided generation unit owners submit start-up, no-load and energy offer curves that are representative of their actual costs" (Wolak 2021).

High VREs penetration often leads to a more constrained transmission network. As such, the way congestion costs are reflected in energy pricing has emerged as a key market design issue in the context of VREs integration (Green 2021; Hu et al. 2018; Wolak 2021). There are different approaches to pricing transmission availability ranging from the very granular locational marginal pricing (LMP), producing a different price for each node on the transmission network, to a single national price zone. According to some economists, with increasing VREs penetration, the efficiency gains of more granular locational pricing become more prominent due to its ability to accurately reflect changing system conditions and encourage efficient use of the network (ibid). However, there is no absolute consensus on which paradigm is superior as the implementation of any approach involves important trade-offs – e.g., efficiency gains, computational complexity and implementation costs, liquidity effects, and distributional impacts on consumers/producers (Newbery et al. 2018).

Finally, further integration of neighbouring power systems and markets is widely identified in the economic literature as an important enabler of further VREs growth (Pollit 2019; Roques 2021; Castagneto Gissey et al. 2019). More interconnection across different geographies allows cross-border transfers of power that can help meet reliability needs during times of scarcity or excess generation made more frequent by a growing VREs fleet, while further market integration across different timescales (day-ahead, real-time) enables the optimal allocation of cross-border resources resulting in the dispatch of the most economically efficient plants and, hence, lower average prices (Newbery et al. 2016;2018).

### 2.1.2 Implications of VREs for the design of balancing and ancillary services

Larger VRE diffusion has direct consequences for real-time power system operation. High shares of intermittent generation lead to much higher degrees of variability and uncertainty, lower system inertia, more frequent and prolonged events of excess demand/generation, and higher congestion and curtailment rates (Green 2021; Joos and Staffell 2018). Hence, the need for balancing and ancillary

services relative to electricity generation increases substantially with larger fluctuations in frequency and higher reserve requirements (Pollit and Anaya 2021). As such, the question of how procurement of these services and related market rules should be reformed has become extremely relevant (Ela et al. 2017). According to experts, adjustments to these mechanisms should lead to better incentives for the full range of resources able to provide system flexibility services (Roques 2021; IRENA 2017; IEA 2018).

First, the rules defining how balancing services are priced and dispatched are a fundamental aspect to consider as they shape the operational behaviour and investment incentives of different resources participating in the market. Potential elements to reform identified in the literature include settlement mechanisms, cap and floor pricing, imbalance pricing rules, scarcity pricing mechanisms, single versus dual pricing and imbalance settlement periods (Schittekatte et al. 2020; Hu et al. 2018; Brijs et al. 2017; Hirth and Ziegenhagen 2015). Broadly, the literature suggests that these should be made as cost-reflective as possible to incentivise system-compatible operation (ibid). It is often argued that this also involves creating a better interface (some form of co-optimisation) between energy and balancing markets (Baldick et al. 2021; Roques 2021).

Pollitt and Anaya (2019) discuss the impact of rising amounts of VREs on the demand for non-energy ancillary services. They note that “current market designs are often quite sophisticated with respect to energy, but often much less so with respect to non-energy ancillary services. Frequency regulation, voltage control, constraint management and reserves could become much more important parts of the wholesale energy markets and hence will need to become more sophisticated market arrangements, which are co-optimised with energy and network investments.” As such, the economic literature often encourages policymakers to work on better defining old and new ancillary service products rewarding flexibility and fast ramp rates to meet emerging system inertia and frequency control needs (Green 2021; Pollit 2021; Ela et al. 2019; Fox et al. 2021).

Further, the literature consistently points to the need to optimise the use of traditional assets as well as unlocking flexible value from new balancing service providers (Green 2021; Pollit and Anaya 2021; Ela et al. 2019). Diversifying the procurement of balancing and ancillary services from a variety of resources can in fact help in dealing with uncertainty. For example, market access can be improved for new business models and technologies, such as aggregations of distributed energy resources (DERs), demand side response (DSR), battery storage assets and flexible renewable generators (Pollit 2021). In turn, this makes system operation less reliant on traditional fossil fuel generators.

Finally, the growth in intermittent generation connected to the low-voltage grid might pose new challenges for local networks, which were designed around unidirectional and predictable power flows (MIT 2016). New business models might be developed for the procurement of balancing services from DERs at the local level (i.e. behind-the-meter battery storage, demand-side response and electric vehicles) (Pollit et al. 2018; Pereira et al. 2018; Roques 2021). This might entail a new role for distribution system operators as neutral market facilitators procuring local grid services (Pollit 2021). Local flexibility markets might also take different forms such as local energy communities, transactive energy models and microgrids, each involving different power system architectures and relationships across the system operator (SO), distribution network operators (DNOs) and final consumers. This more decentralised scenario is illustrated in Figure 4 and discussed more extensively in Chapter 7.

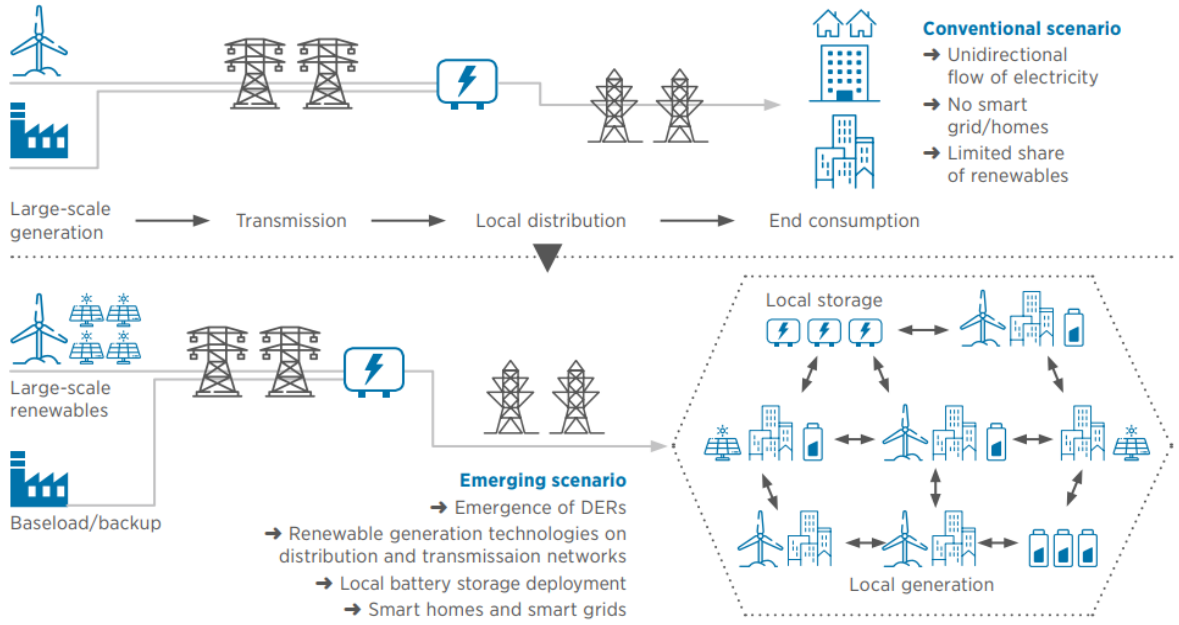


***Figure 4** - Conventional scenario versus decentralised energy system (IRENA 2019)*

### 2.1.3 Implications of VREs for the design of long-term capacity mechanisms

A key objective of power market designers is to ensure system resource adequacy, or the ability of the system to serve demand in the long-term (Creti and Fontini 2019). According to economic theory, signals for long-term investment should be conveyed through short-term market prices, which should allow investors to recoup their costs, while forward contracts and over-the-counter markets should help managing risk (Bublitz et al. 2019). In line with this principle, energy-only markets are purely reliant on markets for ensuring generation adequacy (ibid).

However, economists point to a set of 'market failures' traditionally plaguing the electricity sector that often prevent market-driven capacity investment from happening. The 'missing money' problem refers to the inability of investors to recover investment costs from price spikes in spot markets due the existence of low-price caps unreflective of the value of lost load (Newbery 2016; Hogan 2017). Even more relevant, low liquidity in long-term markets often means that investors face high risk and high cost of capital, undermining the case for investment – the so-called 'missing markets' problem (ibid).

These issues are further exacerbated by VREs, which alter the economic dynamics of legacy power markets as discussed in sub-section 2.1 (Milligan et al. 2016; Green and Léautier 2015). In fact, renewables with low marginal cost can have a depressing effect on wholesale prices, the so-called 'merit-order effect' (see Figure 2) (Newbery et al. 2018). Implications are twofold: a reduction in conventional plants' load factors and revenues, which in turn reduces the incentives for investment in future capacity. At the same time larger, VREs boost flexible and peaking capacity needs, which is however expected to generate for relatively short periods (Green 2021).

Thus, the ability of future power systems to cope with substantial VRE growth depends on appropriate incentives for flexible operation and investment being conveyed to a wide-as-possible pool of resources – i.e. rectifying missing market problems (Newbery et al. 2018). System operators procure system flexibility services and maintain reliability in real-time but longer-term contracts might be needed to secure long-term capacity investment (ibid). Capacity remuneration mechanisms (CRMs) refer to policies explicitly remunerating capacity (or load) to provide the proper level of resource adequacy (Creti and Fontini 2019; Bulbitz et al. 2019). Table 2 offers an overview of different CRM options.

***Table 2** - Typical characteristics of different CRMs (adapted from Creti and Fontini 2019; Bulbitz et al. 2019)*

| CRM | Description | Procurement model | Examples |
|---|---|---|---|
| **Strategic reserve** | A certain amount of additional capacity is contracted and held in reserve outside the energy market. The reserve capacity is only operated if specific conditions are met – e.g., a shortage of capacity in the spot market. | • Centralised<br>• Volume-based<br>• Targeted | Germany, Sweden, Belgium |
| **Capacity payment** | A central body sets a fixed price paid only to eligible capacity – e.g., selected technology types or newly built capacity. | • Centralised<br>• Price-based<br>• Targeted | Spain |
| **Capacity market** | The total amount of required capacity is set by a central body and procured through a central bidding process (auctions) determining the price. Two common variants of the central buyer mechanism include a simple capacity market and a reliability options design. | • Centralised<br>• Volume-based<br>• Market-wide | Britain, Italy, PJM, NYISO, Ireland |
| **Capacity obligation** | An obligation is placed on load-serving entities to individually secure the total capacity they need to meet their consumers' demand. Individual contracts between electricity suppliers and capacity providers are negotiated. | • Decentralised<br>• Volume-based<br>• Market-wide | CAISO, France, Australia |

* Both Italy and Britain only recently transitioned to a capacity market, as analysed in this study.

### 2.1.4 Implications of VREs for the design of low-carbon support schemes

There is a vast literature investigating the need for out-of-market mechanisms to promote low-carbon investment (e.g. Roques and Finon 2013). There are three main takeaways: 1) renewables have high capital costs but low running cost; 2) renewables' main cost is thus the financing cost; 3) the more predictable the costs and revenues at the time of investment, the lower the financing cost (Newbery 2021). Hence, traditionally, renewable support schemes have focused on shielding investors from risk as much as possible thus lowering the financing cost. For example, traditional feed-in-tariffs (FiTs), historically widely used in Europe, remunerate RES generators on a per-kilowatt-hour basis for they production for a fixed number of years independent of actual demand, effectively fully shielding investors from market risk (IRENA 2017; Hu et al. 2018; Newbery et al. 2018).

As RES technologies have now become more mature, economists tell us that support schemes can be adjusted to achieve more cost-efficient and market-compatible outcomes (Roques 2021; Newbery et al. 2018; Hu et al. 2018; IEA 2018). Ideally, an adequate RES support scheme would account for the revenue streams collected by RES across different markets and top this up with an incentive that makes investment attractive while minimising unnecessary spending and market distortions (ibid). By fully shielding investors from market signals, traditional support schemes discourage the adoption of system-friendly behaviour, technologies and arrangements (Newbery 2021). For example, FiTs allow VRE producers to generate electricity at extremely low or negative spot prices (ibid).

As such, some economists suggest that it is not sufficient to achieve system integration of VREs, instead, the long-term aim should be to achieve their 'market integration', which involves progressively increasing the market exposure of VRES. Hu et al. (2018) define market integration as "a dynamic transition of letting the investment and production of VRE be increasingly driven by market price signals via a well-functioning electricity market in order to minimize integration costs, which must be safeguarded by increased policy efforts to establish a level playing field, improve the electricity market design and adjust support schemes field, to minimize distortions." For example, an alternative approach to traditional FiTs involves tying the subsidy payment to the energy market through a so-called feed-in premium, whereby generators sell their output on the wholesale market and receive a premium on top of the market price, exposing their operating decisions to market forces (Newbery et al. 2018; Roques 2021). Further, auction mechanisms can be introduced to determine the level of

renumeration needed to top up market revenues enabling the discovery of the most competitive technologies.

In addition, some argue that RES contracts should be designed so to provide signals both in terms of time and location, mitigating existing incentives for over-bidding during times of negative prices and encouraging RES operators to take grid congestions into account in investment decisions (Newbery 2021). As put by Newbery (2021): "least system cost requires that new VRE is the right design (able to offer some balancing services), locates in the right place and is dispatched optimally." It is important to note that there exists a verity of instruments currently used to incentivise utility-scale RES investment across different jurisdictions. For example, these range from FiTs to renewable portfolio standards, tax credits and tradeable energy certificates. As such, the specific design features that need to be adjusted to render RES support mechanisms more market-compatible will vary from system to system depending on legacy policy frameworks.

Beyond reforming support schemes for utility-scale renewables, the process of RES market integration might also involve important modifications in the policy and charging regimes of small-scale distributed generation (DG). As noted by Newbery et al. (2018), "domestic PV subsidies often have been generous in absolute terms and disproportionately taken up by richer households while higher electricity prices affect poorer households relatively more strongly. […] Consequently, the appointment of charges between fixed, per kW peak and per Kw use of system charges needs to be changed to be more cost reflective."

Finally, several techno-economic analyses point to the importance of coordination and planning mechanisms in ensuring the efficient expansion of renewables. For example, they point to the advantages of more integrated resource planning processes to deal with some of the coordination and planning issues associated with VRE growth (Roques 2021; Schmalensee 2021).

### 2.1.5 Limitations of techno-economic approaches

In conclusion, the techno-economic literature has gone a long way in diagnosing the techno-economic implications of VRE entry in power markets, highlighting a range of solutions to re-designing different market segments to enable cost-effectives VRE integration. Some have taken a step further by proposing entire overhauls of legacy market designs, highlighting a variety of new combinations of policies, regulatory and market design options that could be adopted to integrate high shares of VREs – for a review of potential new market design options see for example Pownall et al. (2021), Peng and Poundineh (2017) or Edwards (2020). It is important to note that liberalised power markets were not identified as the only pathway to deliver on these objectives, and some available options entail a complete move-away from market-based coordination and a return to centralised government coordination across the supply chain (ibid; Schmalensee 2021; Pollit 2021).

However, techno-economic studies often fail explain why real-world markets are seldom organised according to prescriptions of economic textbooks and why countries adopt different approaches to market design reforms. As observed by Leautier (2018:364): "policymakers never fully embrace economists' prescriptions […] policymakers incorporate legitimate political concerns in electricity markets design." Political and institutional conditions also need to be considered as they can help to explain this gap between theory and reality but are often treated as a residual category. Hence, it is argued that economic theory alone does not offer a suitable analytical framework for fulfilling the objectives of this study and that electricity markets cannot be studied in isolation from their institutional context. Instead, the aim of explaining recent power market reforms for the integration of VRES requires expanding the theoretical lenses beyond economic theory into political economy institutionalism and socio-technical energy transition theories.

## 2.2 Political economy institutionalism

The focus of political economy (PE) institutionalism is on the links between economics and politics within capitalist systems, in other words, on understanding and interpreting the evolution of state and market relations (Clift 2014). The key themes PE seeks to address are hence the nature and role of the state, and the political struggles that arise around the distribution of resources across society and decisions on how to manage capitalism, how the latter are affected by the legacy institutional environment (ibid).

These very questions motivated the work of the fathers of PE thinking such as Adam Smith, Karl Marx, Polanyi, Weber and Hayek at the turn of the 19th and 20th centuries. In fact, PE scholarship arose out of the need to explore and make sense of the profound social and political transformations occurring alongside the deep economic changes brought by the expansion of the market economy and the industrial revolution (ibid). These scholars laid the foundations of PE theory and its basic assumptions, which can be synthesised into four core insights. These are discussed in Sub-section 2.2.1 in relation to the seminal contributions of classical thinkers and the history of power markets, while sub-section 2.2.2 defines the core concept of 'institutions' discussing how various streams in recent literature emphasise different aspects of institutional formation, function and change.

### 2.2.1 The key assumptions of political economy

The first key assumption of political economy is that state and markets are mutually constituted (Clift 2014). This is in contrast with a tendency by economic scholars to understand these entities as 'analytically separate realms each with its autonomous logic', an approach that has been referred to as 'state-economy dualism' (Block and Evans 2005:512). Classical PE scholars largely avoided this dichotomous conceptualisation. For example, Adam Smith saw capitalist markets as taking place within a social order characterised by state interventions with multiple aims ranging from ensuring law and order, protecting private property and contracts, shielding citizens from oppression and injustice, to providing a variety of 'publick goods' and 'publick works' (Smith 1993[1776]).

Similarly, Polanyi stressed the role of the state in providing the frameworks and rules within which market exchanges occur (Polanyi 2001[1994]). Without some form of public governance, he argued, markets could not persist. In his seminal contribution *The Great Transformation,* he illustrated how "regulation and markets, in effect, grew up together' and that 'no market economy separated from the political sphere is possible" (ibid:71). Finally, the heirs of Marxist thinking, contemporary historical materialist PE scholars, refuse to "fetishize either the market or the state' and reject 'those frameworks which insist on regarding states and markets as fundamentally opposed forms of social organisation' (Burnham 2001:106). From their perspective, the state is a 'nodal point' within a circuit of capital and; as such, markets and state cannot be separated nor empirically nor analytically (Ibid).

The idea that state and markets are co-constituted has been found to hold also in the context of power markets evolution. Following a comprehensive historical analysis of electricity sector restructuring in the US, Isser (2015:2) concludes: "Federalism, ideology, and happenstance were as important in determining outcomes as the visible hand of politics and the invisible hand of the market. Regulatory choices determined market outcomes, since the set of rules and incentives that shaped the markets were the products of legislation and regulatory decisions. Market outcomes in turn influenced legislation and regulatory decisions, as economic actors invested resources into obtaining favourable decisions in the political and regulatory arenas."

Directly following from the first assumption, the second pillar of PE analysis further explores the nature of state intervention in markets. The latter are conceived not as a naturally occurring phenomena, but as politically constructed and maintained (Clift 2014; Mazzucato 2019). In other words, markets need to be made and designed in what is a profoundly political process, which can have different manifestations depending on the societal context. In his seminal *National System of Political Economy,* List (1856[1841]) argued that international economic relations occur against the background of an

ongoing power struggle amongst nations. This in turn means that capitalist markets will never be exempted from political intervention. List criticised British liberal capitalism of the 19th century, not on the basis that a free trade regime is undesirable, but in view of what he saw as a hypocritical economic strategy that professed free trade when, in fact, was deeply protectionist (ibid).

It can be argued that the capitalist markets celebrated by Adam Smith and other liberals came into being thanks market-making interventions of mercantilist statesmen widely criticised in his *Wealth of Nations* (Swedberg 2005; Mazzucato 2019). The goal of mercantilism had in fact been to give birth to a unified national market for commodities (Clift 2014). Similarly, Polanyi also pointed to the seeming liberal character of 19th-century British capitalism as misleading: "there was nothing natural about laissez-faire; free markets could never have come into being merely by allowing things to take their course […] Laissez-faire was planned" (2001[1944]:146).

In line with conclusions by classical PE thinkers, power markets have been referred to as 'designed markets' as they did not emerge from an unorganised marketplace, but rather, out of an externally imposed regulatory process (Cramton 2017). Electricity was initially provided by regional monopoly utilities single-handedly operating generation, transmission and distribution, typically regulated under a rate-of-return model (Figure 5). From the 1980s, this model was increasingly criticised as leading to inefficiencies and over-investment (ibid). The first step towards markets was the creation of power pools whereby competition was established across regions and, subsequently, independent power production was permitted whereby new market players participated in competitive bidding to obtain power purchase agreements with the incumbent utility (Cramton 2017; Peng and Poundineh 2017). The final step was the creation of a wholesale market, which allows real-time energy trading by competing generators, and the retail market, where service providers compete for retail customers (Perez-Arriaga 2013). To introduce competition in the power sector, governments forced divestures, unbundling and restructuring on incumbent utilities (ibid).

Even in the context of contemporary liberalised power markets, governments often intervene in pursuit of specific policy objectives. An interesting theoretical development seeking to explain this is the 'hybrid markets' perspective (Roques and Finon 2017). Its core argument is that, although many electricity systems have undergone liberalisation and we often refer to 'power markets', in practice, they are 'hybrid regimes' relying on a combination of market signals, regulatory interventions, planning, long-term risk sharing mechanisms (ibid).

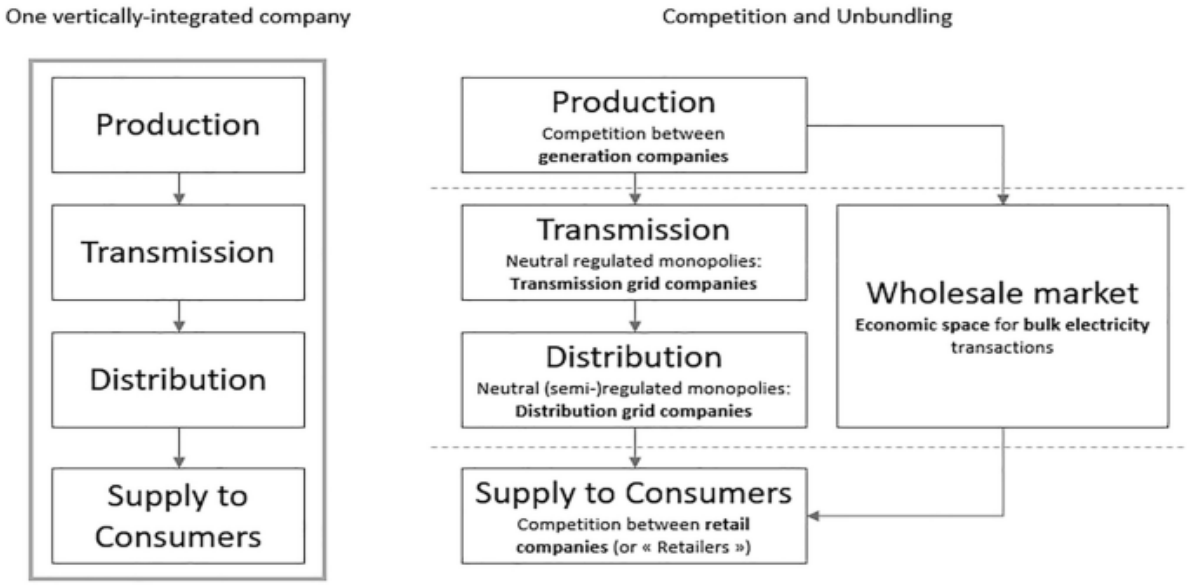


***Figure 5** - Power sector structure before and after deregulation (Vassilopoulos et Lahmar 2022)*

The third core assumption of PE theory is in direct opposition to some ideas found in economic literature around the relationship between the social, the economic and the political. Specifically, PE as understood here rejects 'all other things equal' assumption of neoclassical economists, instead, it appreciates the interrelatedness and co-evolution of these different dimensions (Clift 2014). The economic analysis by Smith, Ricardo and Marx was rooted in the broader historical, social and political context of their time accounting for what Marx labelled as 'social relations of production' (Marx 1974; Smith 1993[1776]). Classical PE scholars all analysed society "in class-based systems, identifying categories of land, labour and capital as sources of a stratified social order" (Clift 2014:36). Following this legacy, more recent critical PE scholars refer to 'state/society complexes' (Cox 1981), while economic sociologists to 'embeddedness' to illustrate this interrelatedness and co-evolving relationships (Granovetter 1985; Block and Evans 2005). Once again, this assumption has been found to be highly relevant in the context of power sector evolution (e.g. Correlje and de Vries 2008).

Finally, the fourth PE assumption challenges the 'ceteris paribus' assumptions at the core of static equilibrium models in economic analysis (Isser 2015). In fact, PE is concerned with how political economic systems evolve over time and the dynamic interactions of economic, social and political forces (ibid). This idea of PE as a diachronic phenomenon that is 'learned and perfected over time, through a long process of institutional adaptation' (Woo-Cumings 1999:15) was appreciated by List (1856[1841]) who argued that, in order to obtain power, nations give up present advantages to pursue benefits that will materialise in the future. This idea is captured by the notion of 'dynamic efficiency', which is presented in opposition to that of 'static efficiency' of neoclassical economics (Chang 1999). Dynamic efficiency proposes a vision whereby decisions are made to address long-term economic objectives, which 'cannot adequately dealt with by blindly following current price signals' (ibid).

Marx's historical materialist perspective also sees capitalism as dynamic and ever evolving. Change can occur at critical junctures or be underpinned by smaller incremental changes that, cumulatively, become transformative (Mahoney and Thelen 2010). This conception of change is further elaborated by Isser (2015:7): "When an institution, or technology, legal regime, or behavioural norm has become deeply embedded in numerous activities throughout the economy, an exogenous shock may be required to disrupt the status quo. In other cases, changes in technology and social attitudes over time may erode the stability of the current equilibrium to the extent that incremental change may move society and the economy to a more efficient equilibrium." From this perspective, the economy is embedded within society, which is in turn shaped by its history (Bennett and Elman 2006), and path dependencies are treated as dynamic concepts. As Campbell (2010:108) notes, "institutional reproduction and change are flip sides of the same coin." Previous analysis has found that this conception of change is relevant to the electricity sector, whose evolution has been shaped by exogenous shocks, path dependencies, and adaptive incrementalism at different times (Isser 2015).

### 2.2.2 Institutions and institutionalism

To understand political economy thinking and how its core assumptions are reflected in specific theoretical formulations, it is paramount to define the ever-featuring concept of institutions. In fact, as noted by Correlje and de Vries (2008), "the behaviour of market actors, as regards to pricing, production, resource allocation, investment, strategies of horizontal and vertical integration, and so on, is assumed to be influenced by a market-specific body of rules and conventions: institutional arrangements."

North (1990:3), one of the fathers of institutional theory, defines institutions as "the rules of the game in a society or, more formally are the humanly devised constraints that shape human interaction." The institutionalist scholarly tradition is not a unified body of thought, on the contrary, it is composed by a variety of approaches exhibiting different understandings of institutions and assumptions about the dynamics of change. Four main approaches are identified here, which draw from different disciplinary fields:

- *Rational choice institutionalism* emphasises economic gains in terms of social efficiency. As such, institutions are enablers of collective action of self-interested actors through lowering transaction costs (see for example, North 1990; Williamson 1996; Glachant and Finon 2000; Roques and Finon 2017).
- *Sociological institutionalism* sees behaviour of political actors as culturally determined and institutions are understood in the context of the transmission of cultural knowledge (Hall and Taylor 1996).
- *Historical institutionalism* focuses on the general features of the prevailing political and economic system and sees state institutions as non-neutral brokers structuring the outcomes of group conflicts (Hall and Taylor 1996; Lockwood et al. 2017).
- *Discursive institutionalism* gives a central role to ideas about politics and policy and their articulation through discourses. Institutional change is understood as political struggle that results in the establishment of new ideational paradigms (Campbell 2010).

These traditions emphasise different aspects of institutional formation, function and change ranging from material or political interests, symbolism or ideas, strategic behaviour to the constraints of existing institutions (Kuzemko et al. 2016). Nevertheless, as noted by Hall and Taylor (1996:955), they "share a great deal of common analytical ground", and in certain combinations they can complement one another."

It is evident from the discussion above that political economy institutionalism provides relevant theoretical insights to study change in power markets. However, it suffers from one important limitation, that is, it under-conceptualises and overlooks the role played by technological systems in shaping societal outcomes (Cherp et al. 2018). In fact, while PE theory stresses the co-evolution of the political, the economic and the social, there is a tendency to omit how these interrelate with material factors. This could be seen as problematic given the relevance of technology and physical infrastructure in the context of power sectors' evolution.

## 2.3 Energy transition theories

Socio-technical literature has attempted to address the limitations of economic and political approaches by developing energy transitions theories that explain patterns of technological evolution and change accounting for both social and physical elements (ibid). For example, Jacobsson's and Jonsson's (2000) *Technological Innovation Systems,* Geels' (2002) *Multi-level Perspective* or Grubb's (2014) *Domains of Transition* have in common that they combine different categories of factors that shape energy transitions (e.g. technologies, economic dynamics and institutions) in co-evolutionary frameworks. Cherp et al. (2018) identify three broad co-evolving domains at the core of these theories also represented in Figure 6:

- *Techno-economic systems* defined by energy flows associated with energy extraction, conversion and use processes involved in energy production and consumption as coordinated by energy markets;
- *Socio-technical systems* delineated by knowledge, practices and networks associated with energy technologies; and
- *Systems of political actions* influencing energy-related policies.

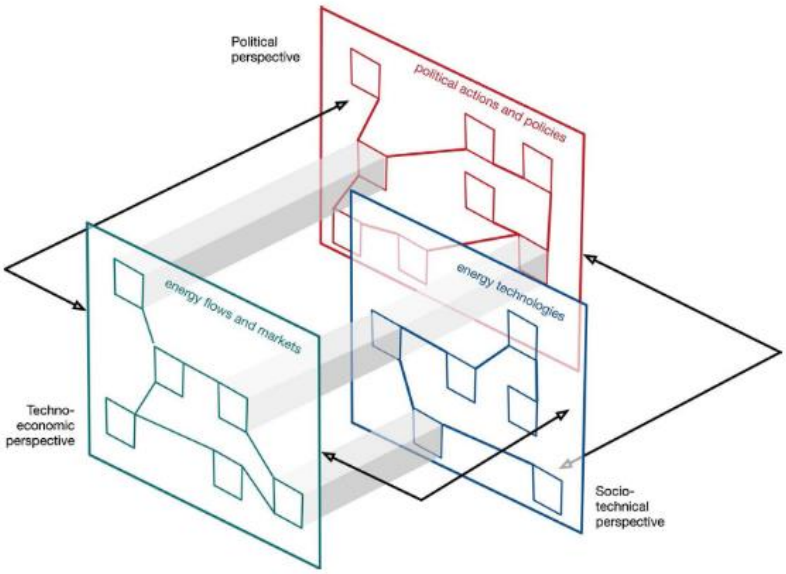


***Figure 6*** *- Co-evolving systems in and perspectives on national energy transitions (Cherp et al. 2018)*

Socio-technical transitions theories have offered compelling analyses of how co-evolutionary processes unfold in the context of different technological systems. Nevertheless, they themselves suffer from a set of important limitations. First, they largely focus on "changes involving significant novelty […] overlooking changes in deployment of already existing technologies requiring only incremental innovation or no innovation at all" (Cherp et al. 2018:81). Second, these theories often offer an insufficient conceptualisation of political factors and dynamics (ibid). The latter are seen as existing and unfolding as part of a 'seamless web' within socio-technical systems where a priori distinctions across analytical categories can become blurred, and political conflict is often characterised as the oversimplified opposition between 'incumbents' and 'newcomers' (Cherp et al. 2018; Meadowcroft 2011).

## 2.4 Existing political economy and socio-technical research: scope and key findings

Existing socio-technical and PE institutionalist research focused on different aspects of institutions and change within the power sector and the wider energy transition arena, adopting a variety of conceptual and methodological approaches and covering different geographical areas. Overall, these studies found that political institutional factors such as market structures, the nature of interest groups, governance processes and ideologies can significantly impact decision-making processes, determining the nature, the scope and speed of policy change. The sub-sections below discuss their key findings in relation to the policy area they investigate.

### 2.4.1 Energy transitions and environmental policy

A substantial part of the literature has explored the institutional underpinnings of broader energy transitions (Haas 2019; Guarnieri 2020) or has applied political economy lenses to specific policy developments such as green strategies (Craig 2020), climate policy (Karapin 2016), or renewable support mechanisms (e.g. see Stenzel and Frenzel 2008 and Mauleon and Garcia 2020). Findings suggest that a set of key factors shape change in this area ranging from economic conditions, institutional characteristics of governments to the power of various interest groups to influence policymaking. Different configurations of these conditions not only affect how advanced jurisdictions are in tackling environmental issues but also the nature of policy strategies adopted to achieve system change.

In a comparative study of climate policy development in California and New York, Karapin (2016) identifies a set of structural economic conditions contributing to positive environmental performance. These include high income and education levels, relative lack of heavy industry, dependence on fossil fuel imports and the potential of renewable energy. Beyond economics, the author also highlights the importance of some institutional factors, particularly, the level of administrative capacity. He argues that centralised, well-funded and professionalised bureaucracies are more likely to result in successful climate strategies due to their ability to gather information, develop and implement policy. The level of institutional capacity and coordination in government have also been found relevant in the context of green strategies' development in Britain (Craig 2020).

Another factor identified as significant in this literature is the nature of government-business relations (i.e. pluralist versus neo-corporatist). While neo-corporatism is characterised by formal consultations and negotiations between government and a small group of well-organised broad groups and a high degree of cooperation, pluralism by adversarial relations between government and multiple competing groups (Karapin 2016). Cross-national studies show a correlation between neo-corporatism and environmental outcomes with Nordic European countries scoring relatively high on both. In the US, it has been argued, pluralist systems have often allowed anti-regulatory business interests to hamper environmental policy (ibid).

Larger corporations and incumbent utilities have been identified as particularly well positioned to influence policymaking due to their small numbers and large resources, upon which decision-makers structurally depend for investment, economic growth and employment (Kuzemko et al. 2016; Geels 2014). Existing studies suggest that incumbents employ a variety of strategies to obtain preferential treatment. For example, electric utilities in the US have increasingly sought favourable legislative and regulatory outcomes in the context of changing power sector economics and diminished revenues, by engaging in lobbying and leveraging their exclusive links with policymakers (Berry and Ormond 2015; Stokes 2020; Harrison 2020). Harrison (2020:16) notes that the "battle for the US electricity future seems set to play out behind closed doors and obscured by the legal minutiae of federal and state utility regulators."

Using a multi-level perspective framework to analyse the Italian energy transition, Guarnieri (2020) also finds that incumbent utilities used their power to actively resist change, especially during the 2008 financial crisis. However, he notes that this resistance decreased with improved economic conditions and that companies progressively became more supportive of the energy transition. Evidence in fact suggests that incumbents might resist or embrace change if the political economic context is conductive, and that different renewable resources are more or less prone to alter the political economy of energy systems. Through a comparative analysis of wind diffusion in Germany, UK and Spain, Stenzel and Frenzel (2008) demonstrated that although most incumbents engaged in political activities to hamper renewable diffusion, some proactively drove their diffusion. More recent econometric analysis of various EU countries by Mauleon and Garcia (2020) found that no renewable technology apart from PV has a consistently negative impact utilities' performance and that wind's effect is, instead, frequently positive.

Literature investigating energy transitions and environmental policy also highlights the deep links between the energy and the financial sector. This strand of literature has investigated the question of how financialization is related to low carbon transitions and how financial capital can aid to transferring investment from high- to low-carbon assets (Castree and Christophers 2015). It found that the financial industry ca act both as a force for continuity and change. In the former case, financial partners backed incumbents and their political champions in the attempt to discredit environmental policies and avoid losses related to sunk costs (Harrison 2020). On the other hand, the financial industry actively promoted renewable energy diffusion and financed other disruptive technologies (ibid).

Another group of actors identified as key in the literature in shaping energy transitions is civil society. For example, in their study of wind power diffusion in Colorado, Doblinger and Sopper (2013) found that environmental groups were pivotal in educating citizens on the advantages of this technology, in deploying strategies leading to policy and regulatory action, and in directly assisting utilities with wind deployment. Similarly, Haas (2019) partly explains differences in the Spanish and German renewable energy transitions in terms of the role played by the civil society: while one was elite-driven, the other was driven by civil society groups through bottom-up action. However, civil society actors might also oppose environmental policy if misaligned with their objectives. For example, trade-unions representing workers in countries with large fossil fuel industries might lobby against renewable energy policies that would lead to significant job losses (Karapin 2016).

### 2.4.2 Power sector liberalisation

Relevant to the evolution of power markets, existing studies drawing from the political economy tradition have offered compelling analyses of the process of liberalisation reforms, explaining variation in outcomes across different jurisdictions in terms of political, economic, and historical factors. For example, Correljie and De Vries (2008) offer a compelling comparative qualitative analysis of how PE conditions shaped liberalisation processes and market design outcomes across a variety of countries worldwide. They find that these are shaped by the path-dependent interaction of policy goals, market conditions at the outset of restructuring and a variety of exogenous factors driving the choices and strategies of actors. Similarly, in his comprehensive historical analysis of power system restructuring in the US, Isser (2015) identifies four key factors shaping liberalisation processes: ideology, technology, economics and interest groups.

Like those of energy transitions, studies of liberalisation have highlighted the importance of economic factors. For example, following an econometric analysis of panel data from multiple countries and US states respectively, Erdogdu (2013) and Guerriero (2016) find that liberalisation is more likely to occur in jurisdictions with smaller industry sectors and where the marginal fossil fuel costs and inefficiencies in fuel usage was lowest. Equally, they demonstrate the importance of institutional characteristics such as institutional quality and stability (ibid), and the power of central government, whose scope for action and capacity for coordination were found to be key ingredients in shaping the outcomes of liberalisation reforms (Glachant and Finon 2000; Correlje and de Vries 2008). Isser (2015) finds that lack of power centralisation led to a historical failure by the US government to impose a homogenous pattern of liberalisation as states were able to veto reforms perceived as undermining their own authority over energy decisions. The importance of government authority, specifically the availability of state ownership and regulatory power, has also been found to determine the success of industrial strategies for the internationalisation of national utilities in Italy and Spain (Bulfone 2020).

In line with findings from the energy transitions literature, studies of power sector nationalisation and liberalisation reveal strong ties between the power system and the financial sector. For example, it was noted that the initial development of the Italian power system in the early 20$^{th}$ century "followed the logics dictated mainly by financial partners and the banking world" (Cringoli 2019:15). The elite governing the early days of the power sector was a collaboration between the industrial bourgeois, Italian banks and foreign capitalists, which managed to exercise a strong pressure on the state to maintain their oligopolistic advantages. Only following the crash of Wall Street in 1929, the Italian state was able to progressively increase its control over the sector (ibid).

More recent analysis has explored how the state-infrastructure-finance nexus has been evolving under neoliberalism and increasing financialization of the world economy (Hall 2011). In line with this broader trend, the power sector also saw "shareholder value" emerging as the main performance parameter of generators and driver of firms' decisions (O'Neill 2001). The introduction of markets "reconfigured the interactions between the electricity sector and the financial industry […] through the introduction of new types of risk and roles for financial capital" (Harrison 2020:3). Revenues became more volatile with the possibility for large losses and windfall profits (ibid). As a result, Isser

(2015) notes how financial entities with larger risk appetites have entered the sector with early merchant power producers in the US financed through joint ventures of independent power producers (IPPs), investment banks and private equity firms. The specific ways in which the wider process of financialization translated across different jurisdictions has led to differences in the relative influence of the financial industry over power sector policy and, specifically, market design. For example, Cramton (2017) argues that the European preference for an exchange-based model, instead of the integrated model adopted in the US, was partly determined by the presence of traders with higher structural power than their US counterparts.

Further, existing research has found that the history of the power system is deeply intertwined of that of the industrial sector. This is well illustrated by the process that led to the nationalisation of the Italian power industry in the early 1960s (Cringoli 2019). In the years preceding this shift in the political economy of the country, industrial consumers, who had been suffering from high electricity tariffs, openly waged a mediatic war against monopolistic power providers. The conflict caused the latter to leave the country's main industrial interest group Confindustria to create their own association, Finelettrica. Backed by the rise of socialist ideology and the desire by the centre-right government to achieve a comprehensive industrial strategy, the interests of industrial groups prevailed over those of electricity oligopolies (ibid).

A similar struggle between power companies and industrial consumers underpinned the events that led to power sector liberalisation in some US states (Isser 2015). The high prices caused by the oil embargo in the 1970s led to growing pressure on utilities from manufacturing plants (ibid). Eventually, "a small group of energy intensive large industrial companies focused on reducing electricity costs would begin to erode the traditional regulated electricity model" by pressuring "FERC[4] and the Congress to permit entry into existing markets by new companies" (Isser 2015:42). Cross-national studies on liberalisation also found that differences in reforms' outcomes can be explained by the relative strength of industrial consumers (Erdogdu 2014). On average, the size of the industry sector seems to be negatively correlated with market liberalisation internationally (ibid). However, this largely depends on the specific context within which the process unfolded. In fact, while in some jurisdictions industries set to benefit from liberalisation in the form of lower prices and improved service, in others, industrial electricity prices are highly subsidised and liberalisation is hence perceived as a threat (ibid).

Distributional and affordability issues have also been found to be high on the agenda of residential and commercial consumers in the liberalisation process. For example, Erdogdu (2014) finds that, as urban consumers tend to benefit most from liberalisation, this is most likely to occur in countries with high levels of urbanisation, while Guerriero (2016) finds that deregulation is more likely to be implemented where politicians were the most pro-consumer. The strength of the civil society has also been found to be a significant determinant. Specifically, past research found a negative correlation between the level of civil liberties and the progress of liberalisation reforms, which might suggest that the scope for reform is limited within jurisdictions with powerful civil society institutions such as trade unions that see change as detrimental to their interests and goals (Erdogdu 2013).

Finally, studies on the PE of liberalisation highlight the importance of economic and political ideas in shaping reforms. Leautier (2018) notes how the 1980s saw a shift in the ideological paradigm towards neoliberalism driven by scholars from the University of Chicago such as Friedman and von Hayek, which motivated the transition from the vertically integrated utility to liberalised markets in many countries. Coorelje and de Vries (2008) note how EU countries vary greatly in their degree of faith in markets and competition. While the UK and the Nordic countries exhibit a strong commitment to liberal market forces, Belgium and France have shown historically a negative attitude towards competition and were reluctant to implement liberal market reforms, which were externally imposed

[4] Federal Energy Regulatory Commission

by the EU (Ibid). Finally, Edorgdu (2014) observes a decrease in vertical integration during the terms of parties with 'right' or 'left' ideologies in OECD countries.

Some studies have investigated the relationship between ideas and some specific design choices for power markets. Blumsack et al. (2005) seek to explain why the EU opted for an exchange-based market structure, in which energy companies trade day-ahead and throughout the day at prices that clear the market without central optimisation, while US opted for an integrated market structure, in which system operator centrally optimises the scheduling and dispatch of resources. They find that the choice against an integrated model by the EU reflects an ideological commitment to avoid concentration of power in the hands of the market operator and the desire to drive transparency. Interestingly, the transparency argument was used in favour of integrated markets in the US (ibid). Leautier (2018) analyses the differences between the US and EU electricity market designs in terms of the adoption of locational pricing and conclude that policymakers in most of Europe objected to spatial differentiation of electricity prices as they felt it threatened hard-won national unity.

### 2.4.3 Recent changes in power market design

Studies of more recent change in power market design have tended to focus on specific market segments. For example, a stream of the literature has investigated the political economic conditions shaping capacity mechanisms (Lockwood et al. 2019; Breaslau 2013). Institutionalist theoretical lenses are rarely applied to the issue of reforming the entirety of wholesale electricity markets for the integration of VREs, albeit with important exceptions.

For example, Roques and Finon (2017) offer a compelling account of the recent evolution of market design arrangements in the context of increased VRE penetration using a rational choice institutionalist perspective. Based on their international review, they conclude that typical changes include the introduction of long-term risk sharing and coordination mechanisms as well as improvements in short-term price signals through the reform of intra-day, real-time and reserve markets. This supports their 'hybrid markets' argument, positing that the power sector effectively constitutes a hybrid of market and state-led mechanisms. However, this study adopts a functionalist approach to explaining recent developments in relation to notions of social efficiency, leaving scope for a more nuanced analysis of the political dynamics underpinning change in this area.

Pollit et al. (2015) compare the strategies adopted to 'cope' with increasing renewable shares in Britain, Germany and the US state of New York. They find that the three jurisdictions exhibit important differences in terms of their vision for the future of electricity markets. Specifically, Germany has adopted a 'just do it' approach whereby as more renewables are added to the system, the market design was adjusted incrementally to respond to integration challenges often at significant cost. On the other hand, Britain's emphasis has been on decarbonisation rather than the promotion of renewables and on the use of competitive mechanisms to contain costs. Finally, New York's strategy was driven by the ambition to promote distributed energy resources to respond to arising integration challenges. The authors concluded that "the three cases illustrate very different jurisdictional trade-offs between security of supply, the environment and affordability" (Pollit et al. 2015:23). Though this study offers important insights on how different countries are responding to integration challenges in relation to different contexts, this relationship is not investigated systematically through a political economic framework.

Gawel at al. (2017) use the German power market case to explore the political economy of security of supply and VRES integration. Through using a form of process tracing, analysis of documents and interviews with key power system stakeholders, the authors map the constellation of different interests held by key power system actors and how these became intermediated by institutions and translated into policy outcomes – i.e. the introduction of a capacity mechanism, the reform of renewable energy subsidies and the lack of implementation of locational marginal pricing. While this

study offers important insights on the PE of recent market reforms, these remain largely unexplored in other contexts from a comparative perspective.

The first key insight gained through PE analysis of recent changes power market design is around the role played by public entities' self-interest in shaping policy debates. In line with Bureaucracy theory literature (Niskanen 1971), evidence suggests that decision-makers do not act as completely neutral 'transfer brokers' balancing the interests of different stakeholders, instead, public agencies and governmental actors are also motivated by their own self-interest to maximise their power and public support. For example, Gawel et al. (2017) argue that the German regulator BNetzA supported the introduction of capacity markets regulated by BNetzaA itself, as this would grow its scope, power and budget. Further, vote-maximizing, risk-adverse politicians have been found to prioritise security of supply over other policy objectives, given the high political cost of blackouts (ibid).

Supporting findings from the energy transitions and power sector liberalisation literature, studies of recent power market design evolution also found that incumbents have a prominent role in the policy process. In fact, large generators with significant degree of structural power have been found to lobby the government and deploy ideas strategically to achieve favourable outcomes. This has been demonstrated in policy discussions around the introduction of capacity mechanisms both in Britain (Lockwood et al. 2019) and Germany (Gawel et al. 2017). In both cases, incumbent suppliers implicitly threatened to withhold crucial investment and deployed ideas such as that of 'missing money' or a 'looming capacity shortage' targeting policymakers and public media. In both cases this resulted in the introduction of a capacity mechanisms, and a generous 'pension scheme' for old lignite power plants in Germany (ibid). The two cases also demonstrate how decision-making in this sphere is often characterised by information asymmetries between large companies and policymakers, who might not be able to distinguish actual system needs from strategic behaviour. Both in Britain and Germany, it was extremely hard for them to assess the actual threat posed by under-investment as they lacked full access to pivotal information and companies publicly signalled an imminent capacity shortage (Gawel et al. 2017; Lockwood et al. 2019).

Existing research also demonstrates the dynamic and heterogeneous nature of interest groups. For instance, British incumbents were not a completely unified front in terms of their preferences for the introduction of a capacity market, instead, a few favoured strengthening the energy-only market given the nature of their new assets and investments (Lockwood et al. 2019). This dynamic character is particularly evident in the case of renewable energy providers who, once new market entrants, now often retain significant market shares and are increasingly able to exert substantial influence over policymaking (Kuzemko et al. 2016). This is demonstrated by the development of RES support schemes in Germany, which was characterised by intense lobbying by the RES industry to obtain technology-differentiated instruments (Gawel et al. 2017).

Next, this research stream also highlights the importance of consumer interest groups. For example, discussing issues of cost-allocation for RES subsidies in Germany, Gawel et al. (2017) note how " due to the comparatively high degree of organization of industrial interests, industry consumers successfully dodged the largest part of the financing burden at the expense of private electricity consumers". Further, more spatial and temporal differentiation in electricity pricing, which is seen by many as the cornerstone of adjusting power market design for VRES integration, is often seen as politically unfeasible due to potential distributional impacts on consumers (Leautier 2018). As such, price caps are widely adopted in electricity spot markets, while nodal pricing has been largely avoided by EU policymakers (ibid).

Finally, ideological factors have also been found to contribute to explaining how countries deal with security of supply issues. Breslau (2013) analyses the role of economic ideas in the politics of the formation of capacity markets in the United States and demonstrates that economic framings were key in shaping the politics of market design by establishing specific terms for the legitimate conduct of

the struggle over the definition of market rules. Lockwood et al (2019:5) note how distinctive corporate cultures across British major supply companies have played a role in shaping their diverging positions around the development of capacity mechanisms, and some of them, although set to benefit from capacity payments, remained committed to the idea of "making energy markets work without intervention."

### 2.4.4 New market entrants

Another stream of literature has focused on how institutional factors affect the development of policy frameworks for new market entrants. These are here understood as players that seek to gain market share and that could potentially challenge the dominance of incumbent energy companies. For example, this role was initially taken up by renewable energy producers when they first entered power markets. More recently, a relevant set of new market entrants is constituted by DERs, DSR, storage and aggregators, which can compete with incumbents in the provision of energy products and power system services.

Existing research has shown that there is a set of particularly contentious issues leading to conflict between new service providers and incumbents mainly revolving around the terms of access and participation across various markets (e.g. spot, capacity and balancing) (Gawel et al. 2017:20; see also Vandezande et al. 2010; Hirth and Ziegenhagen 2015). Specifically, barriers to participation can arise from rules around minimum bid sizes, symmetry requirements for products (i.e., whether both positive and negative reserve needs can be offered), long tender periods or costly registration processes (ibid). Similarly, in their analysis of contestations in storage policy debates, Winfield et al. (2018) find that these mainly revolve around technical barriers to market participation, ability to offer multiple services across markets, rules for aggregation of DERs, and the meaning of 'technological neutrality'.

A key set of conditions found to affect the outcomes of these contestations in this area are pre-existing market structures and rules. For example, studies on the political economy of smart grids highlighted that industry structures, regulatory context, and the power of energy policy were key in determining whether new system configurations were able to emerge across different contexts (Eid et al. 2016 and Rohde and Hielscher 2021). As such, the expansion of distributed resources and their relative influence over decision-making does vary across regions. Winfield et al. (2018) focus on the development of storage policy across a variety of North American and European jurisdictions and find that more progress has been made in the context of liberalized or semi-liberalized markets and in jurisdictions that expressed strong commitment to pursue significant low-carbon system reconfigurations. Hess and Lee (2020) explore the developments in community solar and choice aggregation in California and New York states (Hess and Lee 2020). Evidence suggests that differences in the adoption of these models and in the intensity of political conflict experienced in the two states can be attributed to differences in retail competition rules and the ability of utilities to own distributed generation.

New market entrants tend to have less well-organised interest groups, which might result in less capacity to influence policy outputs. For example, this has been demonstrated in the context of the policy process that led to the introduction of the British capacity market (Lockwood et al. 2020). At the time when these discussions were taking place, most DSR aggregators were relatively new and small, which meant that they were unable to gather and process the same amount of information and modelling of established generators. Further, despite the counter-lobbying by the DSR industry and NGOs, existing institutional configurations granted major producers with favourable terms of access, causing the issue of DSR participation in the capacity market to slide down the political agenda (ibid). Further, the very limited experience of policymakers with DSR may have made them particularly receptive to ideas around the uncertain performance of these technologies fostered by incumbents (ibid).

Literature on the dynamics of new actor's entry in power markets has highlighted that both incumbents and newcomers engage in different forms of institutional work to advance their interests

and ideas. For example, analysis of the evolution of smart grid policy in Germany by Rohde and Hielscher (2021) has pointed to five core strategies, namely, pooling, playing up, standardising, advocating and gap filling. Challenger market entrants might also use more adversarial strategies to advance their visions like leveraging the legal system or multi-level governance arrangements. This is once again demonstrated by the study by Lockwood et al. (2020) on DSR participation in the British capacity market. On the other end of the spectrum, research has also shown that new market entrants, instead of opting for confrontational strategies, might cooperate with incumbents to advance their position in the power system. In their analysis of DSRs entry in power markets in Finland, Kangas et al. (2021) find that institutional conditions led new entrant DER firms to cooperate with incumbents to establish new markets, which benefitted them by increasing their customer base and resource-use efficiency.

Finally, existing studies point to the importance of interactions across new market entrants and civil society actors in shaping policy and market outcomes. For example, Hess and Lee (2020) find that the degree of influence exerted by the civil society over policymaking contributed to the development of different models of community choice in New York and California, while Lockwood et al. (2020) note how initial interest in DSR in the development of the British capacity market was partially the result of lobbying by organisations such as E3G, Friends of the Earth, Green Alliance and WWF.

### 2.4.5 Regulatory, technical and multi-level governance arrangements

Another key factor identified in the literature shaping energy policymaking are the institutional arrangements for energy regulators, whose powers and capacities can differ greatly across jurisdictions. For example, in an analysis of the development of independent energy regulators across EU countries, Thatcher (2011) finds that in continental Europe these remain more under direct parliamentary control and tend to have a more limited role as compared to Britain. Lockwood et al. (2017) note that a similar trend can be observed in the US, where more direct control over regulators, especially through appointments of regulatory boards, has been the norm.

Cross-jurisdictional variation can be observed also in terms of the relationship between the regulator and private companies. It has been argued that EU countries where regulators have a weak position in relation to captive electricity lobbies tend to have highly concentrated markets and have been less able to foster competition (Correlje and de Vries 2008). Lockwood et al. (2017) note that, compared to GB, regulators in the US have maintained more control over utilities' investment decisions. As such, they argue, some US power systems are well-positioned to support the growth of a flexible electricity system with high VRES shares (Ibid).

Other studies focused on system operators' governance processes. For example, stakeholder consultation processes for system operator PJM[5] have been analysed through both decision-making modelling (Yoo and Blumsack 2018) and a methodical review (Simeone 2021). Findings suggest that the process is characterised by strong influential coalitions, low member diversity and participation rates, structural administrative bias and lack of transparency. Similarly, Welton (2021) criticises the NE-ISO[6] and PJM markets as "private membership clubs in which incumbent industry members make the rules for electricity markets … through private mini-democracies – with voting privileges reserved for RTO[7] members."

As varying institutional contexts provide market and network operators with different functions, incentives and levels of structural influence, the reform process is affected in multiple, sometimes unpredictable, ways. For example, system operators have opposed spatially differentiated pricing in Germany (Gawel et al. 2017). Further, the fact that system operators (SOs) might or might not own the

[5] Pennsylvania-New Jersey- Mayland Interconnection.
[6] New England Independent System Operator.
[7] Regional transmission organisation.

grid or directly procure products has large implications for the evolution of power market design as conflicts of interest might arise (Strbac et al. 2014). Within the context of the energy transition, important choices in terms of system architecture and power market design must be made by decision-makers, some of which might entail a complete re-arrangement of current roles including those of market and network operators. For example, DERs integration in the power system can be achieved through an SO-centric model whereby distribution system operators and third-party aggregators take part in the wholesale market or, alternatively, through a DSO[8]-centric approach whereby the system operator has limited coordination functions and DSOs take a leading role through local market platforms (IRENA 2017). Jurisdictions are already making different choices: while California and PJM have been broadening the scope of SOs to cope with growing shares of VRES and DERs, New York state has proposed a vision with an increased role for DSOs, customer choice and DERs participation (Hobbs and Oren 2019). This is likely to reflect, at least partially, differences in institutional arrangements for system and market operators.

Also significant are the arrangements for the governance of power market codes and rules as they largely "determine who can participate in wholesale, ancillary services and capacity markets […] and define a set of common rules for the electricity trade, including how to incorporate technical restrictions on the formation of prices" (IEA 2019). Despite their importance system codes have been largely overlooked in political analysis with a few exceptions. For example, Lockwood et al. (2017a) analyse GB code governance and conclude that this is characterised by 'double delegation' (from the government to the regulator and from the latter to the industry itself), which they argue raises legitimacy concerns. Further, they note how private consumers tend to be much less well represented in panels governing network codes as compared to industry players (ibid). Other arrangements exist in other jurisdictions: in most US markets the governance of codes is conducted under boards of ISOs but must receive final approval by the federal regulator and assumes a quasi-judicial character when complex issues arise, in Denmark this is overseen by a state-owned TSO[9] directly reporting to the ministry, while in Australia this is directly overseen by the regulator with any stakeholder able to suggest rule modifications (Brattle Group/Simmons and Simmons 2008).

Finally, existing research has highlighted the importance of multi-level governance arrangements in shaping the evolution of power markets. For example, while the European Commission (EC) has managed to progressively steer member states towards a fairly harmonised model for power market design and governance, the situation is quite different in the US (Hobbs and Oren 2019). Following the introduction of the Third and Clean Energy Packages, increasingly detailed European Network Codes have been dictating the technical rules for the EU electricity market, the so-called 'European Target Model' (Schittekatte et al. 2020). On the other hand, US electricity systems are governed through a patchy combination of federal, state, and local agencies with differing objectives and interests (Harrison 2020). Hobbs and Oren (2019) note how, following a failure to impose a standard market design on liberalised power markets, FERC only managed to promote a 'voluntary' wholesale market platform. Nevertheless, it is important to note that, even in Europe, large variation exists in the way governments approach issues of power market reform. In fact, "EU member states have been found to strategically interpret and implement the directives and guidelines of the EU, their main concern being their own position within the emerging EU market" (Correlje and de Vries 2008).

Previous research has also investigated the political and governance challenges related to cross-border interconnections and market integration. For example, Lenhart et al. (2016) analyses the governance characteristics of the Western Energy Imbalance Market, which allows California and neighbouring jurisdictions to trade imbalances. They find that the Californian system operator CAISO must strike a delicate balance between the interests of domestic utilities, transmission owners and decision-makers,

[8] Distribution system operator.
[9] Transmission system operator.

and those of stakeholders in the wider region. The policy goals and interests of these two categories of stakeholders are often not aligned often contributing to political tensions and inaction. Similarly, Dutton and Lockwood (2017) found that it was challenging for Irish and British decision-makers to define their interests and achieve coordinated action in the context of the interconnection project linking the two systems due to informational complexities and unintended consequences.

## 2.5 Summary of literature and research gaps

To sum up, important trade-offs exist across economics, PE institutionalism and socio-technical theory in terms of their potential to realistically explain power sector change. Table 3 below summarises the key characteristics of these approaches and related limitations.

***Table 3*** *- Three perspectives on national energy transitions (adapted from Cherp et al. 2018)*

| | **Economics** | **Socio-technical** | **Politics** |
|---|---|---|---|
| **Disciplinary roots** | Economic history, neoclassical economics, energy system analysis | Sociology of technology, socio-technical transitions, evolutionary economics | Political science, political economy, policy studies, governance studies |
| **System focus** | Energy flows and markets | Energy technologies within socio-technical systems | Political actions and energy policies |
| **Research focus** | Economic effects of VREs entry in different power market segments and potential solutions | Energy transitions in OECD countries, environmental, climate and RES policies | Climate policy, power sector liberalization, governance of recent changes in specific power markets areas |
| **Limitations** | Overlooks political and institutional factors | Under-conceptualises political dynamics | Overlooks techno-economic factors |
| **Examples** | Green and Leautier 2015; Pollit and Anaya 2021; Fang et al. 2018; Newbery et al. 2018; Joskow 2019; Botterud and Auer 2018 | Jacobsson and Jonsson 2000; Geels 2002; Guarnieri 2020; Cherp et al. 2018 | Karapin 2016; Erdogdu 2013; Isser 2015; Breslau 2013; Lockwood et al. 2020; Winfield et al. 2018; Yoo and Blumsack 2018 |

Economic theory has gone a long way diagnosing and explaining the current issues arising from integrating renewables into the power system. However, functionalist accounts alone are not able to explain the real-world implementation of power market reforms as they do not account for contextual political and institutional factors. The PE and socio-technical literatures have offered compelling accounts of power system liberalisation and generated important insights on the institutional underpinnings of change across various policy areas, power market segments, geographies and power system institutions. Nevertheless, to the author's knowledge, there is a scarcity of studies exploring the political economy of the power market design in the context of increased VRE penetration. Research in this field has tended to focus on one element at the time (e.g. capacity markets) rather than approaching market design wholistically. Further, recent reforms have hardly been studied from a comparative perspective. This study proposes to fill this gap through providing a systematic account of how different techno-economic and institutional conditions shaped recent power sector reforms.

# 3 Research questions and conceptual framework

## 3.1 Research aim, questions, and objectives

This study uses a comparative political economy perspective to systematically unpack recent changes in wholesale power market design for enabling the integration of VREs in Britain, Italy and California. The aim is to determine how differences in the technical and political economy contexts of these jurisdictions shaped their approaches to power sector reform, drawing some lessons for power market design and governance in the context of a high-VREs future. The objectives are as follows:

- To identify the key reforms in wholesale power market design implemented in Italy, California and Britain between 2013 and 2021 to enable the integration of VREs.
- To determine and analyse the key techno-economic and political economy conditions that shaped the reform processes within each of the cases.
- To conduct a comparative analysis of these dynamics across the three jurisdictions, drawing both theoretical and policy-related insights.

Hence, this study seeks to answer the following research questions:

1. What are the key wholesale power market design reforms implemented in Britain, Italy and California between 2013 and 2021 to integrate growing shares of VREs on the electricity system?
2. How did differences in the political economy contexts of these jurisdictions affect their approach to reforming power market design to enable wider integration of VREs?
3. What are the implications for the design and governance of power markets in these jurisdictions and beyond?

## 3.2 Conceptual framework

This thesis is concerned with the power market reform policy process. It is useful to think about the policy process as made of three components: 1) the inputs – structures and agency influencing decision-making; 2) the outputs – policies and regimes adopted; 3) the outcomes – consequences of policy changes (Figure 7). The focus here is on how policy inputs (political economy conditions) have affected policy outputs (changes in market design rules) and outcomes (power market evolution). Sub-section 3.2.1 operationalises power market design reforms, while sub-section 3.2.2 operationalises the key political economy inputs expected to influence them.

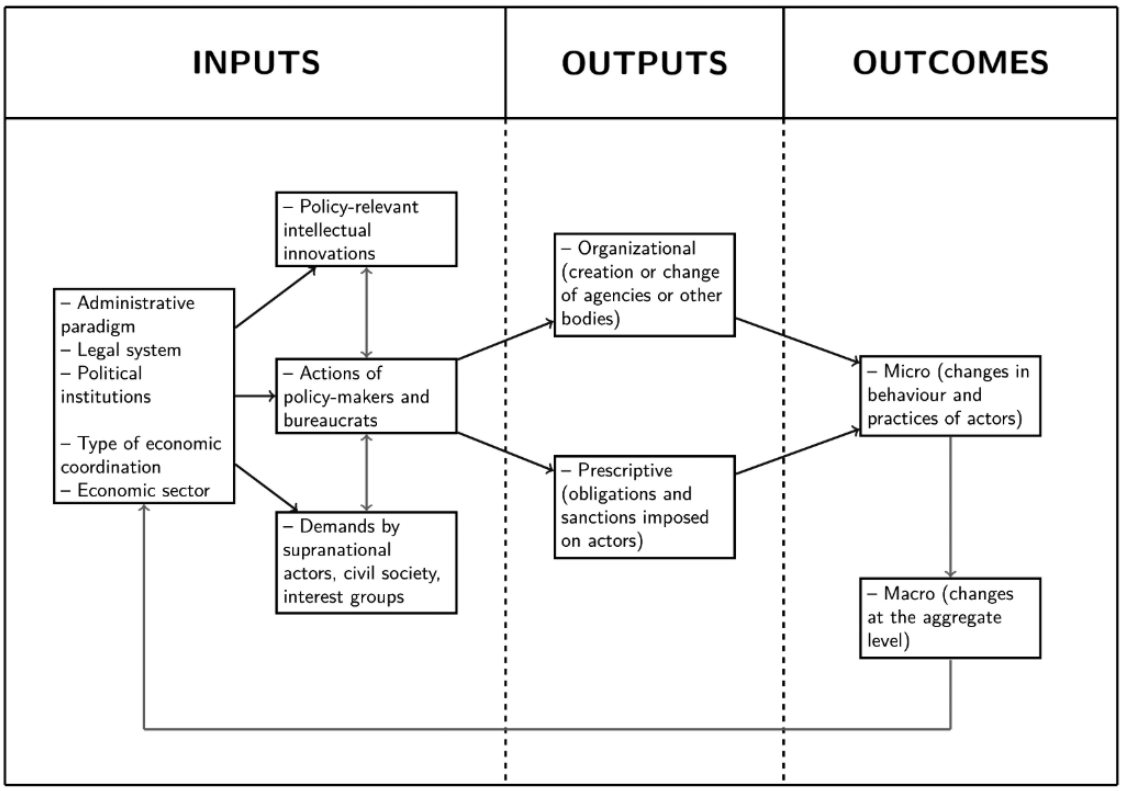


***Figure 7 –*** *Representation of the policy process (Guidi et al. 2020)*

### 3.2.1 Operationalising policy outputs and outcomes

To operationalise the main output of interest, power market design reform, this thesis draws from the modularity frameworks developed by Roques and Finon (2017) and Peng and Poundineh (2017). This allows to distinguish between the different components of the power market and analyse their interactions. Figure 8 offers a graphical representation of this approach: the white boxes represent traditional power market modules comprising of regulated network monopolies, wholesale, balancing and retail markets; while the blue boxes represent additional out-of-market mechanisms often introduced to leverage long-term investment in resource adequacy and low-carbon capacity.

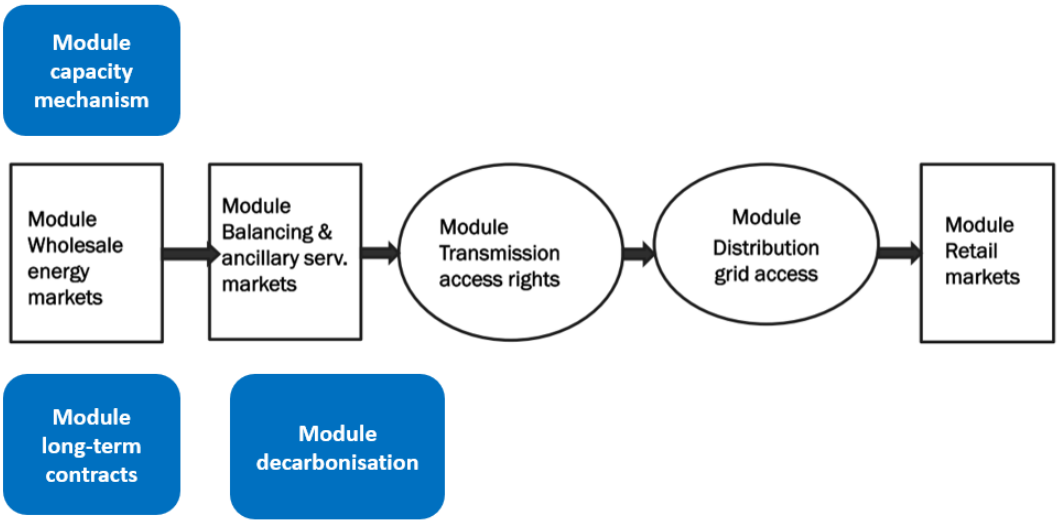


***Figure 8 -*** *Modularity framework of the power market (Roques and Finon 2017)*

Among the power market modules illustrated above, this study focuses only on those at the wholesale level including wholesale energy markets, balancing and ancillary services, low-carbon investment mechanisms and long-term capacity contracts. These were defined based on a comprehensive review of the techno-economic literature (see Section 2.1) and are illustrated in Figure 9. The wholesale market is in fact the cornerstone of electricity delivery and has been the focus of many reforms to integrate VREs so far. Additionally, time and resource constraints did not allow for the exploration of other market modules, including transmission, retail and distribution. These also play a crucial role in VRE-integration and deeply interact with the modules analysed as part of this research. While it was not possible to treat these aspects comprehensively, they are briefly addressed where most relevant.

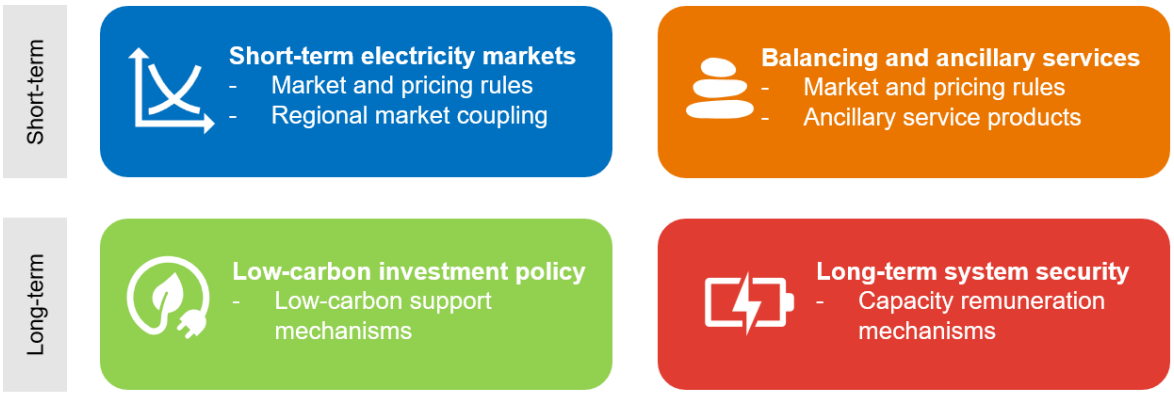


***Figure 9 -*** *Market design modules analysed in this study*

Power market design can be enacted through different means and, depending on the jurisdiction, this process is overseen by specific decision-making institutions. Typical governance tools and related institutions are summarised below (IEA 2019):

- *Energy strategies (ministry)* - set overall change direction, medium- to long-term policy priorities and objectives acting as a reference point for all other interventions.
- *Legal frameworks (mixed)* - define power sector roles and responsibilities (e.g., unbundling and privatisation, legal definitions of participants and assets), high-level objectives or specific targets.
- *Policies and programmes (legislative)* - typically used to achieve of specific objectives in energy strategies (e.g. incentives programmes)
- *Regulatory frameworks and decisions (independent regulator)* - determine allocation of costs and risks, regulatory conditions around certain activities (e.g. tariffs, access, licencing), legal requirements and targets, or ex-post monitoring.
- *Power market codes and rules (system and market operator, regulator or technical body)* – determine who can participate in markets and the technical rules for electricity trading and price formation.

Finally, policy outputs and outcomes were analysed based on their key characteristics along some key dimensions including their stated objectives, scope of change, modifications in key design parameters, resulting policy trade-offs and technological choices (Kuzemko et al.2016; Correlje and De Vries 2008).

### 3.2.2 Operationalising policy inputs

To explain the evolution of recent reforms and operationalise the drivers of change (policy inputs), this thesis used an abductive approach. First, a set of key general ontological and theoretical assumptions were developed drawing from political economy and socio-technical theory. This allowed to define the key assumptions about human behaviour, core conceptual constructs and theoretical relationships expected to determine power system change. Second, to facilitate the analysis, these dynamics were operationalised in a set of categories of key political economy conditions, developed based on existing studies of power system change. The analysis then proceeded abductively through a constant dialogue between theory and data. As more data was analysed, these categories were adjusted and refined until a final list of political conditions was developed (see Section 4.3 for a full explanation of the analytical process).

In terms of ontology, the chosen approach exhibits a hybrid theoretical emphasis positing that energy decisions and policies take place across the categories of structure, agency and discourse and that human behaviour is both shaped by the self-interest of actors, their values and belief systems (Sovacool et al. 2018; Mahoney and Goertz 2006). Accordingly, key conceptual constructs drawn from political economy literature include: 1) institutions – relatively stable structures of rules and conditions constraining behaviour of political actors; 2) ideas – mental constructs that influence people's perceptions and priorities; and 3) interests – self-interested motivations of actors (in)directly participating in decision-making (Kuzemko et al. 2016).

Drawing from economic and socio-technical theories, it is posited that power system change is also shaped by techno-economic conditions – 'hard' constraints that make up the physical and economic characteristics of the power system (Cherp et al. 2018). It follows the main theoretical assumption underlying this analysis: market design evolution is the result of co-evolutionary interactions between a power system's key techno-economic conditions, the underlying institutional environment, the ideas and interests of the main actors involved in the decision-making process. Figure 10 illustrates these theoretical relationships, constituting an expansion of the theoretical frameworks developed by Kuzemko et al. (2016) and Correlje and de Vries (2008). Box 1 discusses each layer of the framework in more detail in relation to existing literature.

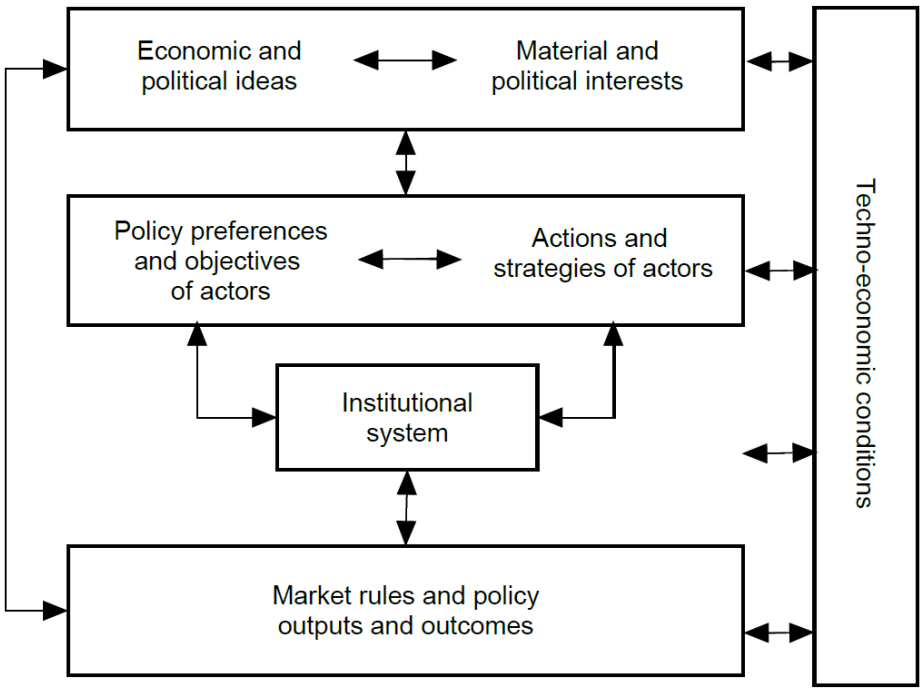


***Figure 10** - Theoretical framework*

**Box 1 – Key theoretical assumptions and relationships**

1. The power sector is characterised by interactions across **multiple actors** – e.g. government, regulators, system and market operators, incumbents, new market entrants, financial investors, residential and industrial consumers, energy sector workers and civil society (Correlje and de Vries 2008; Gawel et al. 2017; Lockwood et al. 2019). Based on institutional incentives, ideational environment and techno-economic context, these actors develop specific **economic and political ideas** about how the system/market works and the policy priorities to pursue, as well as specific **material and political interests** (Kuzemko et al. 2016).
2. The combination of these interests and ideas results in a specific configuration of **policy preferences** and **objectives**. To enact these visions and steer change in their preferred direction, actors engage in a set of **actions and strategies** (Lockwood et al. 2020; Galwel et al. 2017; Geels 2014). These can be material, whereby material resources are used to influence change, or discursive, whereby ideas and narratives are deployed to shape debates (ibid). Specific mechanisms of influence include activities like networking, publishing of sponsored research, lobbying, and more confrontational legal challenges (Lockwood et al. 2019; Gawel et al. 2017).
3. Strategies are constrained by the **institutional system**, which determines the extent to which actors can influence policy debates and outputs (Correlje and de Vries 2008). Formal institutions include structural power, resources availability, the organisation of interest groups, relational networks with decision-makers, policy change processes, power delegation across governance scales and the quality of public institutions (Karapin 2016; Erdogdu 2013; Lockwood et al. 2019; Isser 2015). Informal institutions delimit the discursive environment where policy change occurs restricting the range of policies considered acceptable or viable (i.e. the prevalent policy paradigm) (Haas 2019; Hall et al. 1993; Breslau 2013).
4. The strategies deployed by actors in pursuit of specific policy preferences are hence filtered through the institutional system in a process of intermediation, often resulting in a political struggle where the interests and ideas most aligned with existing institutions gain more traction and become translated into favourable **policy outputs** (Kuzemko et al. 2016).
5. Policy outputs in turn lead to specific **policy outcomes** altering existing **techno-economic conditions,** which are in a co-evolutionary relationship with the policy process (Cherp et al. 2018). These in fact determine the techno-economic solutions available to decision-makers to deal with VRES integration, the incentives and resources available to various actors (Karapin 2016). Key techno-economic factors include, for example, indigenous energy resources, fuel prices, electricity demand size and growth, system size, VREs integration phase, grid development and interconnections, technology cost, power plants flexibility and electricity demand composition (Correlje and de Vries 2008; Karapin 2016; IEA 2018; Erdogdu 2013).

The theoretical relationships outlined in Box1 were then operationalised in a list of simpler, clearer key political economy conditions to simplify the analysis and comparison of the case-studies. This list underwent several reiterations during the abductive analysis process, as theory and emerging data were cross analysed (see Section 4.3). Table 4 below illustrates the final list of political economy conditions identified through the analysis mapped onto existing literature.

***Table 4** - Political economy conditions identified through the abductive analysis and existing literature*

| Categories | Specific conditions | Examples |
|---|---|---|
| **National politics and government** | • Political ideologies, priorities and cycles<br>• Political acceptability of technologies and mechanisms<br>• Government incentives, structure, effectiveness, and openness | Karapin (2016), Correlje and de Vries (2008); Guerriero (2016); Leautier (2018); Gawel et al. (2017); Pollit (2021); Erdogdu (2013) |
| **State-market relations** | • Legacy political economy paradigm<br>• Dominant ideas on the role of markets<br>• Degree of unbundling and privatisation (liberalisation) | Leautier (2018), Karapin (2016); Correlje and de Vries (2008); Lockwood et al. (2019) |
| **Sector-specific institutions** | • Legacy power market model and operational philosophies<br>• Dominant ideas on technologies and mechanisms<br>• Institutional cultures, incentives and interests<br>• Capacity, independence, and policy influence | Gawel et al. (2017), Correlje and de Vries (2008); Lenhart et al. (2016); Leautier (2018); Breslau (2013); Lockwood et al. (2019) |
| **Multi-level governance** | • Regional political homogeneity and relations<br>• Capacity, coordination and trust in multi-level institutions<br>• Dominant cultures and ideas in multi-level institutions<br>• Institutional independence and balance of power among members | Lockwood et al. (2020); Lenhart et al. (2016); Harrison (2020) |
| **Market structures and interests** | • Market structures and ownership of key assets<br>• Economic composition of electricity demand<br>• Turnover and employment in energy sector<br>• Variety and organisation of interest groups<br>• Policy access and influence | Kuzemko et al. (2016), Lockwood et al. (2019-2020); Gawel et al. (2017); Geels (2014); Karapin (2016); Guerriero (2016); Harrison (2020), Isser (2015), Erdogdu (2013) |

# 4 Methodology

## 4.1 Comparative case study analysis

This thesis uses qualitative comparative case study analysis to examine the evolution of power market design across different contexts. This approach to cross-case comparison is particularly suitable for advancing in-depth understanding of political economic processes and for refining theory in the context of understudied research domains (Collier and Collier 1991; Mahoney and Goertz 2006; Ragin 2004). Further, qualitative analysis is also suitable for the chosen multi-layered conceptual framework as it enables complex causal relationships characterised by configurative interactions of multiple, intertwined variables (Ragin 2004; Smelser 1976).

The logic underpinning qualitative case-study analysis is rooted in Mill's method of comparison and Boolean logic (Bennet 2020). The underlying core idea is that "the extent to which the similarities and differences across systems are more or less systematic can tell us more about the plausibility of a theoretical relationship under review" (Keman and Pennings 2017:51). The qualitative research process often takes the form of a continuous dialogue between theory and evidence (Ragin 2004) and analysis is conducted based on necessary and sufficient causes (Mahoney and Goertz 2006; Bennet 2020). In other words, certain observations are vested with particular importance due to their revealing nature, amounting to 'smoking guns' tests able to corroborate or challenge certain theoretical notions (Brady and Collier 2004:252).

It is important to note that conducting comparative research in real-world contexts presents a particular set of challenges. This is mainly because researchers cannot manipulate the environment in which events occur like in a lab setting (Kellstedt & Whitten 2013). Instead, they can only rely on the observation of reality. As pointed out by Keman and Pennings (2017:51), "since we cannot control for all possible causes of Y, there is always a chance that some third (confounding) variable is causing Y." This problem can be mitigated through thorough data collection and analysis, and careful consideration of alternative explanations (ibid). Bold causal claims and firm conclusions should be avoided, and findings should be presented in a tentative way (Clift 2014).

Further, this type of analysis raises risks in terms of the so-called 'too many variables' problem (Smelser 1976). In other words, there exists a trade-off between parsimonious, simplistic explanations with few factors, and too complex explanations that consider multiple factors but offer little scope to draw generalisable insights. To mitigate this potential risk and select the appropriate amount of factors, it is necessary to establish a strong dialogue between theory and evidence. By considering existing literature, it is possible to 'judiciously restrict' the analysis to the most significant factors, ignoring those of negligible importance (Lijphart 1971; Smelser 1976; Ragin 2004).

Finally, in terms of epistemology, the author distances herself from a positivist approach arguing that social science research does not lend itself to dispassionate scientific inquiry unbiased from *a priori* assumptions (Hall 2003, Mahoney and Goertz 2006, Pierson 2004). This perspective challenges the possibility that political phenomena can be entirely observed, measured and quantified (Clift 2014). Nevertheless, this study seeks to provide a systematic and rigorous medium-range explanation, appreciative of contextual conditions but still conductive of some cautious generalisable insights (ibid).

### 4.1.1 Case studies selection

The case selection process in comparative case study research involves three key decisions: 1) the number of cases, 2) the temporal scope and 3) the underlying logic of comparison of the analysis. In terms of the number of cases, there exists a trade-off between studying numerous cases with few variables or a limited number of cases considering multiple variables, while the temporal dimension of the investigation can range from a single interval to multiple points in time. Figure 11 illustrates how different research design options are positioned along these continuums.

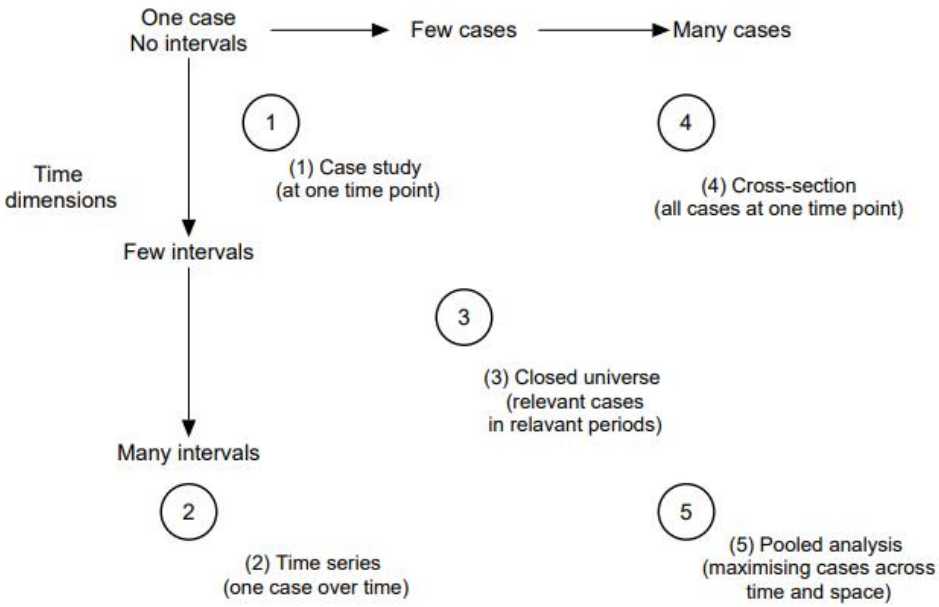


***Figure 11** - Types of research design (adapted from Keman and Pennings 2017)*

At one end of the spectrum, one could investigate many cases at one point in time (option 4), while at the other end, one could focus just one case over multiple time intervals (option 2). Considering that aim of this research is to acquire in-depth knowledge but nevertheless to derive some parsimonious theoretical insights within resource and time constraints, option 3 (the 'closed universe') is deemed the most appropriate research design. This strategy consists of focusing on a limited number of key cases across particularly relevant intervals of time, identified based on significant events (or critical junctures) (Keman and Pennings 2017). This is considered a particularly robust approach to derive conclusions in qualitative research as compared to other methods (see Figure 12 below).

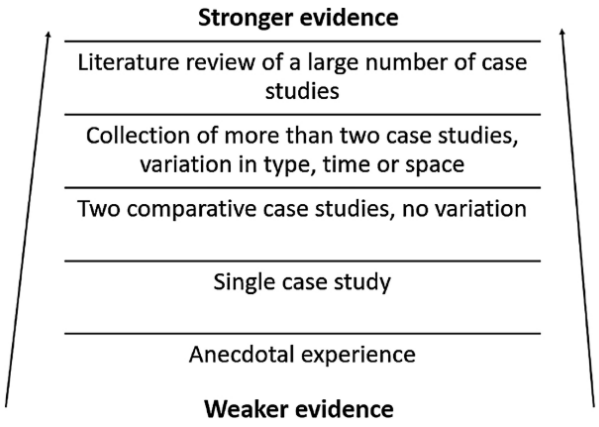


***Figure 12** - Hierarchy of evidence for qualitative case studies (Sovacool et al. 2018)*

The focus of the analysis is on reforms implemented between 2013 and 2021 (in the last 9 years). This decision is based on the identification of critical junctures across the three cases consisting of key policy developments and a VRES penetration level of about 10%. In fact, various sources (IEA 2016, Sijm 2014) indicate that with at this share, system costs can rise significantly, and operational challenges tend to emerge. Further, in 2013 Britain saw the introduction of the Electricity Market Reform that led to major changes in the electricity market design, Italy introduced the National Energy Strategy that provided a comprehensive energy policy plan focusing on the issue of VREs system

integration, and California ramped up its renewable portfolio standards to 50% by 2030 (see Chapter 9).

Finally, the selection of the three case studies was informed by the seminal work of Mill, specifically, the most similar system design, which compares cases with the most similar characteristics but that differ in some key respects expected to explain differences in outcomes (Mill 1949[1843]). This has been widely used in the context of comparative political economy analysis of OECD states (Clift 2014) and is relevant to the aim of this study, which is concerned with the extent to which differences in the political economy of liberalised power markets are reflected in differences in market design choices. Key differences and similarities across the selected case-studies are briefly reported below and discussed more comprehensively in Chapter 5.

The three systems are highly reliant on gas and experienced significant growth in renewable generation, however, they differ in the relative importance of nuclear, hydro, wind and solar generation. In 2016, the IEA (2019) positioned all three of them in the 'third system integration phase', whereby VRES determine the operation pattern of the system boosting flexibility needs (Figure 13). Additionally, while the three jurisdictions recently implemented important changes to their legacy market designs, there is often a divergence in their approach and, hence, in this study's outcome of interest.

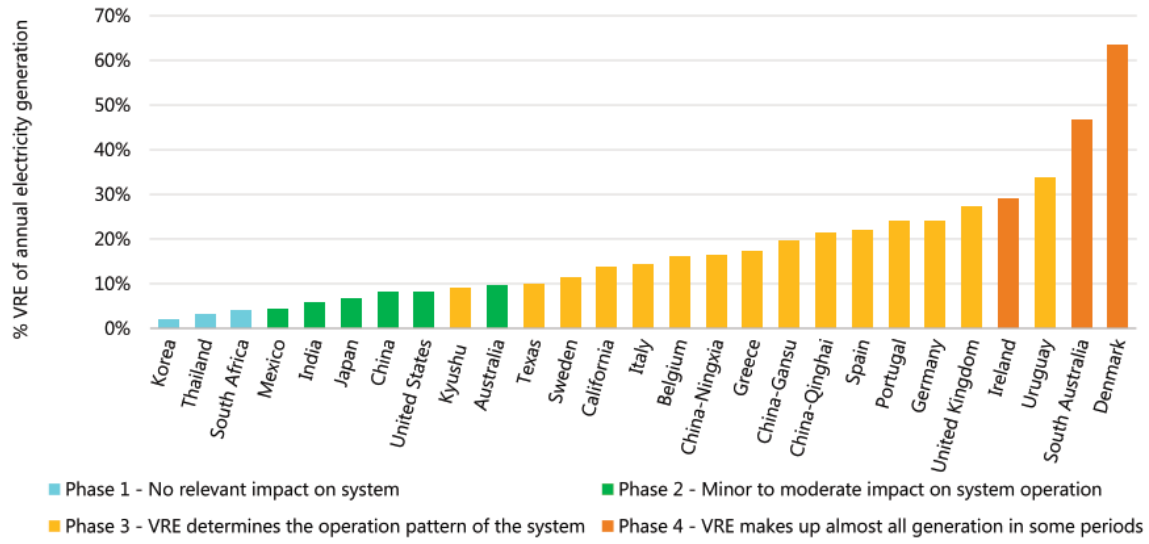


***Figure 13 -*** *Annual VRE share and corresponding system integration phase in selected countries in 2016 (IEA 2019)*

The three cases exhibit similar economic development levels, market sizes and all have liberalised markets (Table 5). Yet, variation is observed in terms of liberalisation outcomes, legacy operational philosophies and power market design models (Hobbs and Oren 2019; BEIS 2020; Iacovone 2019; Burtraw et al. 2019). There are also differences in legacy market structures, including the ownership and financing of key power system assets, and portfolios of key companies (BEIS 2020a; Terna 2021; Ofgem 2021; ARERA 2019; CEC 2021; Statista 2018). Further, variation exists in terms of the composition of electricity demand, turnovers and employment across energy and industrial sectors (OECD 2017; World Bank 2021; EIA 2021).

***Table 5 –*** *General characteristics of case studies*

| | Britain | Italy | California |
|---|---|---|---|
| **GDP (USD/capita)** | 48711 | 44140 | 66661 |
| **Population (million)** | 66.4 | 60.4 | 39.5 |
| **Electricity demand (TWh)** | 326.9 | 315.8 | 284.4 |
| **VRE generation in 2014 (%)** | 10.7 | 13.5 | 12 |

*Databases: OECD; IEA; Energy Information Administration; California Energy Commission; Our World in Data.*

While they all have large government capacities, they exhibit varying levels of government effectiveness, governance centralisation and different political cultures (Karapin 2016; Loeffler & Bovaird 2018; Cepiku 2018). Divergence can also be found in sector-specific institutional arrangements including regulators, system and market operators (OECD 2019; CPUC 2021; Montella et al. 2018; NGESO 2021; Terna 2021a; GME 2021; Lenhart et al. 2016). Finally, they differ in terms of legacy multi-level and cross-national governance arrangements (Schittekatte et al. 2020; Geske et al. 2019; Iacovone 2019; Lenhart et al. 2016; Hobbs and Oren 2019).

## 4.2 Data collection

The triangulation of statistical, document and interview data were used to increase findings' reliability and cross-check information to mitigate bias (Halperin and Heath 2012; Sovacool et al. 2018). The focus was on evidence offering insights into recent technical, market and policy developments, as well as the interests, motivations, interactions of key stakeholders, the underlying institutional environment and key implications of policy change.

First, information was selectively extracted from a variety of quantitative databases, which helped to shed light on the evolution of power mixes, revenue streams and turnouts of different organisations, market shares and ownership of key assets, power sector employment and various institutional characteristics. These included both international databases (e.g. OECD, IEA, World Bank, EU) and national statistics (e.g. BEIS, EIA, CEC, GME, Terna). Over 300 documents were also analysed, which were used to extract different types of information as summarised in Table 6.

***Table 6 -*** *Collected documents and uses*

| Source type | Information extracted | GB | IT | CA |
|---|---|---|---|---|
| **Key organisations' webpages** | Missions and interests, history of organisation, activities, institutional structures and governance processes, rules and policy changes, policy/political priorities and techno-economic ideas | 6 | 10 | 10 |
| **Official policy and consultation documents** | Policy/political objectives and priorities, rules and policy changes, drivers of reform, policy processes, techno-economic ideas, policy trade-offs and implications, technological choices | 27 | 28 | 37 |
| **Media publications and statements** | Rules and policy changes, drivers of reform, key debates, interests and preferences of key stakeholders, policy trade-offs and implications, technological choices, power relations and policy influence | 5 | 8 | 14 |
| **Industry publications and consultation responses** | Interests and preferences of key stakeholders, key debates, techno-economic ideas, policy trade-offs and implications, technological choices, power relations and policy influence | 6 | 8 | 10 |
| **Technical reports by key institutions** | Evolution in key techno-economic conditions, rules and policy changes, drivers of reform, implications of policy change | 31 | 24 | 20 |
| **Grey and academic literature** | Evolution in key techno-economic conditions, rules and policy changes, drivers of reform, policy processes, institutional structures, policy/political priorities and techno-economic ideas, policy trade-offs and implications, technological choices, interests and preferences of key stakeholders, key debates, power relations and policy influence | 26 | 22 | 25 |

| | | | |
|---|---|---|---|
| **Total** | 101 | 100 | 116 |

Between October 2021 and June 2022, 53 interviews were conducted with key power system stakeholders (Table 8). The interviews' target population consisted of power system elites and experts who "are especially useful for revealing the motivations and actions behind policy formation and adoption" (Sovacool et al. 2018). In other words, anonymous interviews with stakeholders directly involved in policymaking are the best route to gaining insights into political processes, which often occur 'behind closed doors' and are impossible to capture from official policy documents.

Interviews were used in two main ways: 1) as a source of evidence for identifying the most important recent technical, market, institutional and policy developments; 2) to understand the motivations, interests, ideas and interactions of key stakeholders. One-to-one fully anonymous interviews were chosen over other interviewing techniques such as focus groups to enable participants to fully express their views without any peer pressure or fear to be recognised by other industry stakeholders.

A sample size range between 45 and 60 was partially pre-determined based on a review of best practices in the literature to ensure that variation would be appropriately captured in the analysis (Sovacool et al. 2018; Baker and Edwards 2012). The sampling strategy was 'purposive' in that participants were selected based on theory (Robinson 2014). Specifically, the sample was stratified according to relevant conceptual categories, which were pre-assigned a specific participants' number across all cases (Table 7). Overall, the goal was to achieve the highest variation in views across different types of stakeholders whilst maximising the validity of conclusions drawn from a specific category of participants (Baker and Edwards 2012). As such, organisations with a range of characteristics and participants with varied expertise and roles were considered for each category.

***Table 7 -*** *Expected interviews and actual sample*

| **Participants** | **Number*cases (expected)** | **Total achieved** | **GB** | **IT** | **CA** |
|---|---|---|---|---|---|
| Academics and experts | 3*3 = 9 | 16 | 5 | 7 | 4 |
| Consultants involved in policy process | 2*3 = 6 | 5 | 1 | 2 | 2 |
| Policymakers and officials at regulators | 3*3 = 9 | 7 | 4 | 1 | 2 |
| System operator representatives | 1*3 = 3 | 3 | 1 | 1 | 1 |
| Representatives of incumbent utilities and producers | 3*3 = 9 | 10 | 3 | 5 | 2 |
| Representatives of renewable energy producers | 1*3 = 3 | 4 | 2 | 1 | 1 |
| Representatives of new flexibility providers and decentralised energy solutions | 2*3 = 6 | 4 | 2 | 0 | 2 |
| Representatives of consumer groups | 1*3 = 3 | 1 | 0 | 1 | 0 |
| Financial investors | 1*3 = 3 | 2 | 1 | 0 | 1 |
| Other | | 1 | 0 | 1 | 0 |
| **Total:** | 51 | 53 | 19 | 19 | 15 |

Collected interviews slightly differ from this pre-determined sample, and the final sample that is not perfectly balanced across stakeholder categories and cases (see Table 7 for a comparison). This is partially related to issues of access, as it was not always possible to secure an interview with the sought expert. However, this does not undermine the validity or replicability of the results. In fact, it is standard practice in qualitative research to collect data based on the quality of information (instead of quantity) until the so-called point of saturation, whereby new evidence does not yield additional information (Mason 2010). In fact, it was often the case that new interviews simply did not yield new information. Secondly, many experts covered multiple roles over time and academics were often directly involved in policy processes thus offering the needed information across a wide range of topics, limiting the need for additional interviews. Further, the interview sample also depends on the availability of information from document sources. For example, the author conducted less interviews

for the Californian case as she had access to particularly abundant and insightful document data including consultations and media publications.

Hence, while it is possible that some bias exists in the results related to the interview sample (e.g. in terms of theemphasis different stakeholders put on specific factors or policy changes), it is argued that the overall political dynamics captured in this research would stay unvaried if this study was to be replicated. The researcher has mitigated bias risks through triangulation, by constantly cross-checking information with existing theory to assess whether emerging relationships are likely and reasonable, as well as by peer-reviewing results with colleagues and industry experts.

***Table 8** - List of participants interviewed for each case*

| N. | Participant role at the time of reform | Case |
|---|---|---|
| **1** | Energy economist | Britain |
| **2** | Energy economist | Britain |
| **3** | British energy policy expert | Britain |
| **4** | British energy politics expert | Britain |
| **5** | British electricity market design expert | Britain |
| **6** | Electricity market design consultant | Britain |
| **7** | Senior government policymaker | Britain |
| **8** | Senior government policymaker | Britain |
| **9** | Senior government policymaker | Britain |
| **10** | Senior official at regulator | Britain |
| **11** | Senior market expert at system operator | Britain |
| **12** | Representative of major incumbent generator | Britain |
| **13** | Representative of major incumbent generator | Britain |
| **14** | Representative of renewable energy industry | Britain |
| **15** | Representative of Scottish renewable energy industry | Britain |
| **16** | Electricity storage asset management expert | Britain |
| **17** | Energy trader at medium-sized operator | Britain |
| **18** | Representative of decentralised energy industry | Britain |
| **19** | Representative of non-traditional flex provider | Britain |
| **20** | Energy economist | Italy |
| **21** | Energy economist | Italy |
| **22** | Energy economist | Italy |
| **23** | Resource adequacy expert | Italy |
| **24** | Technical expert in power system technologies | Italy |
| **25** | Italian energy policy expert | Italy |
| **26** | Power sector journalist | Italy |
| **27** | Senior official at regulator | Italy |
| **28** | Senior market expert at system operator | Italy |
| **29** | Government consultant | Italy |
| **30** | Government consultant | Italy |
| **31** | Representative of major incumbent generator | Italy |
| **32** | Representative of major incumbent generator | Italy |
| **33** | Representative of major incumbent generator | Italy |
| **34** | Representative of gas generator | Italy |
| **35** | Representative of major RES generator | Italy |
| **36** | Representative of power sector industry | Italy |
| **37** | Representative of medium-sized generators | Italy |
| **38** | Representative of industrial consumers | Italy |
| **39** | California energy policy expert | California |
| **40** | Energy economist | California |
| **41** | Energy politics expert | California |
| **42** | Electricity market design expert | California |
| **43** | Energy regulation consultant | California |
| **44** | Senior representative of system operator | California |
| **45** | Senior official at energy regulator | California |
| **46** | Senior policymaker | California |
| **47** | Government consultant | California |
| **48** | Representative of large independent power producer | California |

| | | |
|---|---|---|
| **49** | Representative of large wind generators | California |
| **50** | Electricity investment banker | California |
| **51** | Representative of distributed PV generators | California |
| **52** | Advocate of local energy systems | California |
| **53** | Representative of local utility | California |

The interviews were semi-structured and in-depth with extensive use of open-ended questions and follow-ups to allow new topics to emerge (Baker and Edwards 2012). Participants were asked to discuss recent developments in electricity markets and relevant reforms, drivers and dynamics of policy and power system change, the role of key institutions and organisations, and opinions on future developments. This semi-structured interviewing techniques are particularly suitable in the context of this research, which aims to unpack decision-making processes, actor perspectives, discourses and meanings, and complex interactions across different political economy dynamics which could not be extensively captured through a survey or a questionnaire. Further, the explorative nature of the research questions calls for a flexible approach in terms of allowing participants to touch on themes that might not have been foreseen by the researcher.

Participants were identified ex-ante based on internet sources, publications by the various organisations, meetings and conferences and based on the researcher's and her supervisors' networks. Some snowballing sampling also took place when participants made relevant recommendations (Robinson 2014). Participants were contacted via email and all those asked to participate received an information sheet and were asked to sign a consent form in which they were given the option to be recorded. Data collected hence included basic identifiers such as names, contact information and organization of the participants, while the bulk of the data consisted in audio recordings of interviews, transcripts of interviews, and field notes containing reflections of the researcher.

## 4.3 Data analysis

Collected data (all interviews and the most relevant documents) was thematically analysed through Nvivo. Alternative approaches to the analysis were considered. For example, more quantitative approaches involving text scanning, multi-criteria analysis or comparative qualitative analysis (CQA) could have provided a pathway to quantifying and ranking political economy determinants. However, not only this would have involved limiting the scope of the analysis, but it would have also failed to fulfil the objectives of this research. In fact, the aim is not about ranking or quantifying these dynamics but understanding the complex interactions across forces that shape power market reforms and the discourses/meanings that underpin them, which are all deeply qualitative factors in nature.

Another alternative approach extremely relevant to the research aim is process tracing. This would have enabled the researcher to trace deep causal links across qualitative data and develop a more detailed representation of political economy processes. However, this strategy is extremely time-consuming, and its use would have had to be restricted to a single policy development or a single case study. This is not aligned with the broad aim of this research, that is, painting a full picture of power market design change across market modules, considering the full range of actors involved in decision-making across three different systems.

Figure 14 illustrates the code-to-theory process underpinning qualitative research elaborated by Saldana (2021). First, codes are developed capturing essential information in the data. Second, they are clustered together according to patterns reflecting regularities, which are synthesized into broader analytical categories or themes. Finally, in the last stage the researcher uses focusing strategies to develop theoretical insights from patterns, categories and themes.

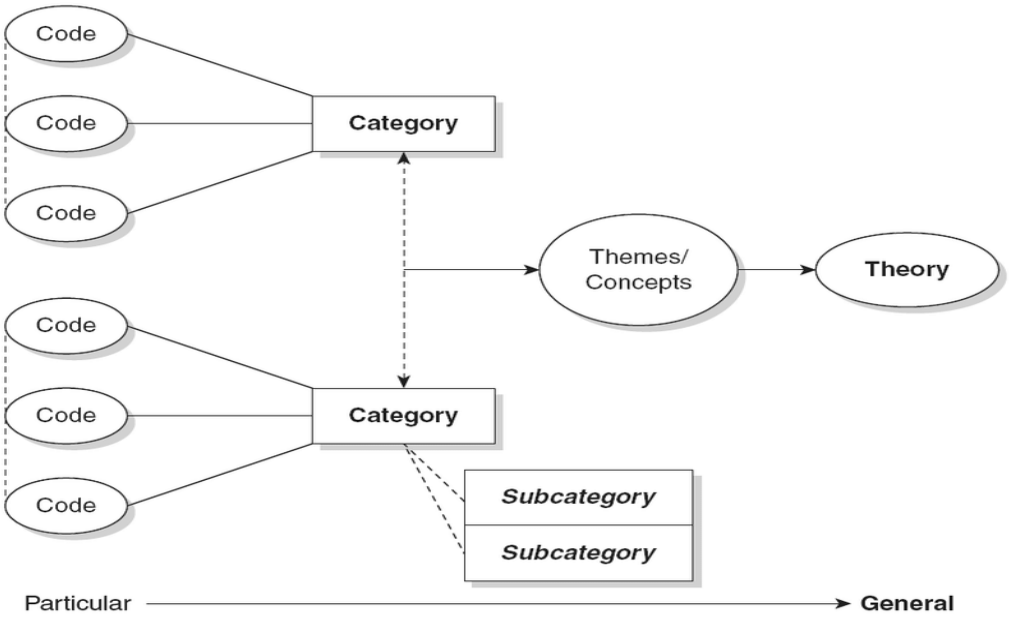


***Figure 14 -*** *A streamlined code-to-theory model for qualitative inquiry (Saldana 2021)*

The chosen approach was abductive in nature in that it combined a provisional list of codes developed beforehand (to align coding with the conceptual framework) with data-driven coding to enable flexibility (Fereday and Muir-Cochrane 2006). Table 9 at the end of this section illustrates the provisional codebook used by the researcher.

As more data was coded, provisional categories were adjusted using an eclectic coding strategy and by clustering codes according to commonalities, regularities and variation to generate a smaller and more focused set of themes. *Pattern coding* refers to the development of 'meta codes' – category/conceptual labels that identifies similarly coded data (ibid). Examples of possible coding patterns used at this stage include similarity, difference, frequency, sequence, correspondence, causation and hierarchy. This tool was particularly relevant to the focus and objectives of this study. In fact, Miles et al. (2020:79) argue that pattern coding is suitable for compressing a substantial amount of data into a few analytic units (categories, themes, concepts), identifying causal links in the data, studying human relationships, developing theoretical constructs and processes, generating common themes in cross-case analysis.

Finally, the last stage of the analysis involved drawing theoretical insights from the concepts and patterns identified in the data and reporting findings in a well-structured way. This process involved an intense dialogue between theory and evidence, and hence, between the conceptual framework developed a priori and the patterns identified in the data. This corroboration between theory and evidence was aided by a range of focusing strategies through logical ways of organising information and highlighting key structures and relationships. In particular, the researcher used matrixes, superordinate and subordinate arrangements, taxonomies, hierarchies, overlaps, and networks to organise key insights and contribute to theory development (Saldana 2021).

***Table 9** - Provisional codebook*

| Categories | Subcategories | Code descriptions | Coding examples |
|---|---|---|---|
| **Political values and economic ideas** | Policy ideas and beliefs | Ideas about the workings of power markets, economics and politics, which constitute the belief system of stakeholders driving their actions. | Free markets, equity, efficiency, growth, innovation, environment, security of supply |
| | Objectives and visions | Policy priorities, optimal trajectories for change and expectations for future market developments. | Decentralised markets, energy-only market, market integration, locational pricing |
| **Interests and motivations** | Material gains | These codes reveal motivations for actions of stakeholders who stand to gain some material benefit. | Market share, consumer prices, gain access, revenues, penalties, budget size, cost of capital |
| | Non-material incentives | These constitute motivations characterised by non-material benefits. | Reputation, political gain, public support, influence |
| **Actions and strategies** | Material strategies | These refer to the actions and strategies pursued by power system stakeholders to influence policy in fulfilment of a specific objective. | Lobbying, networking, investment withholding, legal litigation |
| | Discoursive strategies | Refer to the use of discourses and narratives to influence policy in fulfilment of a specific objective. | Sponsoring research, strategic interpretation of rules, public media statements, narratives deployment, applying reputational pressure |
| | Interests' intermediation | The negotiation and intermediation of interests by those responsible for designing policy. | Negotiation, postponement, voluntary-based requirements |
| **Institutional conditions and processes** | Policymaking procedures, rules and structures | Structural and procedural characteristics of the institutional environment that shape the capacities and scope for action of decision-makers at different levels of governance and the ability of different interest groups to influence the governance of power market design. | Participation and accountability in policy process, government capacity, organisation o interest groups, information asymmetries, organisational missions and legal frameworks institutional coordination, relational networks ownership structures, structural power |
| **Economic and technical constraints** | Technical constraints | A set of 'hard' constraints shaping the electricity mix, and the technical and economic characteristics of the power system. They determine the technical options available to decision-makers to deal with VRES integration, and influence the interests, positions and strategies of other stakeholders in the power system transition. | Indigenous energy resources, market and system size, phase of VRE integration, distribution of assets in relation to grid capacity, grid infrastructure development and interconnections, power plants flexibility |
| | Economic constraints | International economic exogenous forces and domestic characteristics affect the scope for action of different actors by shaping incentives and the resources available. They can influence the economic dynamics of price formation in markets and the options for the integration of VRES and investment in certain technologies. | Demand size and growth, fuel prices, energy imports,<br>technology cost,<br>economic composition, investment capital availability, market failures |
| **Market design outcomes** | | These descriptive codes serve to classify in which section of the power market change has occurred or is likely to occur according to participants. | 1. Low-carbon investment<br>2. Pricing in short-term energy markets<br>3. Design of balancing and reserves mechanisms<br>4. Long-term investment and capacity renumeration mechanisms |
| **Policy, regulatory and market frameworks** | | These descriptive codes label policy interventions based on a set of categories based on the policy tools used. | Energy strategies, legal frameworks, policies and programmes, power market codes and rules, regulatory frameworks and decisions |
| **Achieved trade-offs** | Policy objectives trade-offs | These codes identify the trade-offs achieved in the actual design and implementation of certain policy and rule changes. | Short-term operational efficiency, long-run efficiency and investment, RES investment, distributional and fairness issues, open access and non-discrimination, simplicity and transparency, innovation and industrial competitiveness |
| | Balance of interests in policy outcomes | These codes try to provide an indication of how the decisions taken strike a balance across the interests of different stakeholders. | Exclusion/inclusion in market, change in exposure to risk, opportunities to … |

# 5 Background on case studies

This chapter sets the background for the three cases. First, it provides a short summary of their respective liberalisation journeys, market design models, and power mix evolution. Second, it discusses the institutional context including the characteristics of government, the political economy model, sector-specific institutions, and multi-level governance arrangements. Finally, a description is provided of legacy market structures and the main interest groups. All these characteristics are summarised in Table 10 below and discussed in more detail in the next sub-sections.

***Table 10** - Summary of key characteristics of case studies*

| | **Britain** | **Italy** | **California** |
|---|---|---|---|
| **Legacy wholesale market design** | Decentralised dispatch with bilateral trading, sequential balancing market, single national wholesale price. | Semi-centralized dispatch with auctions and unit-commitment, integrated scheduling of balancing and reserves, zonal pricing. | Centralised security-constrained economic dispatch, complex bidding, energy and reserves co-optimisation, nodal pricing. |
| **Political economy model** | With a traditionally liberal political economy model, the UK was a pioneer of power sector liberalisation in the 1990s. | A more government-dominated logic prevails here, with power sector liberalisation externally driven by the EU in the 2000s. | Higher support for public intervention than US average. Liberalisation halted after major crisis in 2000 leading to more direct state control over power sector. |
| **Power sector liberalisation** | Generation and transmission fully unbundled and fully privatised. Retail fully liberalised but often conducted as an integrated activity with generation within large suppliers. | Generation and transmission fully unbundled with pockets of state ownership of key assets. Retail liberalised but partially conducted as integrated activity with distribution and generation. | Generation and transmission fully unbundled with pockets of local public ownership. Retail was never liberalised and is carried out by incumbent distribution utilities but new local retailers are growing. |
| **Government incentives, structure, effectiveness, and openness** | Government structure is highly centralised with limited role for local government. The civil service generally has high technical capacity and effectiveness, openness, transparency, and accountability. | Government is fairly centralised but with some key functions devolved locally. Italy exhibits lower government effectiveness due to political instability. Civil service has discrete technical expertise but exposed to political influence. | Complex and fragmented governance with a plural executive multiple state agencies, public power and direct democracy at the local level. State agencies have high technical capacity, effectiveness, and transparency. |
| **Sector-specific institutions (regulators)** | Energy regulator Ofgem has high institutional quality, independence, technical expertise, has taken an increasingly strategic role in power sector decarbonisation and tends to have an innovative approach to regulation. | Italian regulator ARERA has high independence and technical expertise. Over the years there have been tensions with the government and an increase in political interference. | The CPUC is a powerful state agency with strong mandate whose remit has been expanding to manage complex transition. It has extensive stakeholder engagement but criticised for regulatory capture and ineffectiveness. |
| **Sector-specific institutions (system operators**) | Since liberalisation, National Grid owned and operated transmission grid acting as a residual system balancer. In 2019, operation and ownership were unbundled to promote more strategic role. NG has high technical capacity and expertise. Openness and transparency have increased since separation of activities. | Terna owns and operates the transmission grid and dispatching services. It is partially owned by state, has high institutional capacity, technical expertise and influence. Sometimes criticised for conflicts of interest and lack of transparency. The energy market is managed by market operator GME under control of the Government. | CAISO operates the transmission grid, wholesale energy and balancing markets but does not own transmission. It closely follows state policy as its board is directly appointed by governor (a legacy of the energy crisis), though it is regulated at the federal level. CAISO has extremely open stakeholder engagement. |
| **Multi-level governance** | Until 2020 UK was part of EU single energy market, which it left following Brexit. Over the years, EU institutions have expanded and provisions about market design have become more prescriptive. | Italy is part of the single EU energy market. Over the years, EU governance framework has expanded and provisions about market design have become more prescriptive. | Since the crisis, California has conflictual relations with federal regulator FERC, which was never able to impose a US standard market design. CAISO manages the Western single imbalance market. |
| **Wholesale market structures** | Market structure evolved towards the so-called 'Big Six' European utilities and some major independent power producers. | Market structure characterised by two major incumbent partially state-owned utilities (Enel and Eni), several European and local utilities. | Market structure characterised by a mix of large IPPs with significant market shares, incumbent investor-owned utilities, and several municipal public utilities. |
| **Generation ownership** | Large generators traditionally owned conventional generation including gas, coal and nuclear. In the late 2010s, some incumbents made substantial investment in renewables divesting fossil fuel | Most large generators traditionally own conventional generation assets, especially gas. Hydro remains owned by large former monopoly Enel, while the ownership of RES is mixed with | Since liberalisation, independent power producers acquired most gas generation assets. Former utilities retain ownership of nuclear and hydro. RES ownership is mixed with utility-scale generation owned by |

| | | | |
|---|---|---|---|
| | plants. Renewables tend to be utility-scale and utility-owned. | some utility-scale and a large share of smaller producers. | IPPs and significant presence of distributed generation. |
| **Electricity demand composition** | Industry constitutes 26% of electricity demand, mirroring a decline of the manufacturing sector in the last decades. | Italy exhibits higher industry share in electricity demand 42%, mirroring the importance of this sector for the national economy. | California has the lowest industry share (22%) in electricity demand mirroring a decline in manufacturing. |
| **Variety and organisation of interest groups and access to policy** | UK exhibits a moderately corporatist system. British incumbents rely on large resources, organisation and influence while the role played by smaller or decentralised actors tends to be limited, mirroring a centralised market structure. Recent convergence of energy industry under one association. | Italy has a highly corporatist system and interest associations are key for discussing national strategies. Former monopolies often identified as particularly influential compared to other producers. Industrials are well-organised and key participants in policy debates. Recent convergence of energy industry under one association. | California's interest groups are numerous and competitive, mirroring a highly pluralist, polarised system and a market undergoing fragmentation. Beyond large producers and incumbent utilities, there are influential environmental and decentralised energy groups, local power and trade unions. |

## 5.1 Britain

### 5.1.1 Power sector liberalisation

Until 1990, the GB power sector was nationalised, with generation, transmission, distribution, and retail under the control of a public monopoly, the Central Electricity Generating Board (CEGB) operating across England and Wales. This model had enabled considerable infrastructure expansion to meet rising demand in the post-war period but, in the 1980s, the CEGB's was increasingly criticised for inefficiency (Newbery 2019). Around this time, Margaret Thatcher's government initiated a major wave of reforms to limit state presence in the economy and break labour unions' power [interview1]. This coincided with a broader global shift towards neoliberal economic ideologies (Leautier 2018).

With the Electricity Act of 1989 Britain became the second country in the world to liberalise its power sector. The first step was the restructuring of the CEGB to separate transmission and generation. In the following years, supply, transmission and retail of electricity were further unbundled and privatised. By 2001, 62% of the electricity market (by industry revenue) had been deregulated (Newbery 2019). The initial iteration of the GB power market featured a mandatory power pool managed by the CEGB (BEIS 2020). Generators above 50MW submitted their bids into the day-ahead electricity pool, specifying the prices and quantities for each unit, which allowed the system operator to determine the unconstrained system marginal price (Newbery 2019). Alongside the pool, a capacity payment was introduced to ensure long-term resource adequacy (Grubb and Newbery 2018).

During its 11-year existence, the power pool faced mounting criticism for enabling market power (BEIS 2020). Eventually, in 2001, the New Electricity Trading Arrangements (NETA) replaced the pool with a self-dispatched energy-only market (Grubb and Newbery 2018). NETA initially covered only England and Wales, but after further revisions in 2005, it expanded to become the British Electricity Trading and Transmission Arrangements (BETTA) encompassing England, Wales, and Scotland.

### 5.1.2 Wholesale power market design

The British market model is highly decentralised and characterised by simple bidding, continuous bilateral trading, self-dispatch and a sequential balancing market. Further, locational transmission availability is not accounted for in wholesale price formation, with a single national price. Locational signals are instead provided through transmission network and balancing charges set administratively.

The self-dispatch model assumes that every balancing responsible party self-balances its position to guarantee the compatibility of operators' scheduling with actual system realities (BEIS 2020; UK Gov 2015). Bilateral trading was selected in Britain due to its potential to stimulate greater competition and efficiency (Grubb and Newbery 2018). Further, at the time of NETA, Britain did not experience significant grid constraints [Interviews 20,25,29,1]. Hence, a single national price was chosen for

maximising liquidity and reducing hedging costs. Finally, the energy-only market model was introduced based on the assumption that short-term price signals would incentivise the necessary long-term investments (ibid).

Figure 15 offers a timeline representation of the British power market. Power contracts are made in forwards and futures markets from multiple years up to 24 hours ahead of a certain half hour delivery period. Buyers and sellers of electricity submit voluntary simple bids revealing their willingness to pay/produce. Prices are bilaterally negotiated or determined through demand and supply matching on public power exchanges (UK Gov 2015). Power exchanges and energy brokers offer market players the possibility to continuously adjust their contracted positions from 24 to 1 hour up to delivery. All the deals are bilateral and settled at the price recorded on power exchanges, bilaterally set or via a broker. Electricity can be traded on several power exchanges like the N2EX (the UK name for NASDAQ OMX Commodities and Nord Pool Spot energy markets) and AP.

After gate closure, the system operator procures services needed to maintain and restore active power balance through the balancing mechanism. This a short-term market taking place in the hour between gate closure and real time with the system operator as the central buyer (Joos and Staffel 2018). Discrepancies between what generators and suppliers, the so-called balancing responsible parties, physically did (actual delivery or offtake) and their contractual positions are 'cashed-out' at the settlement price, which is determined administratively by the system operator (UK Gov 2015).

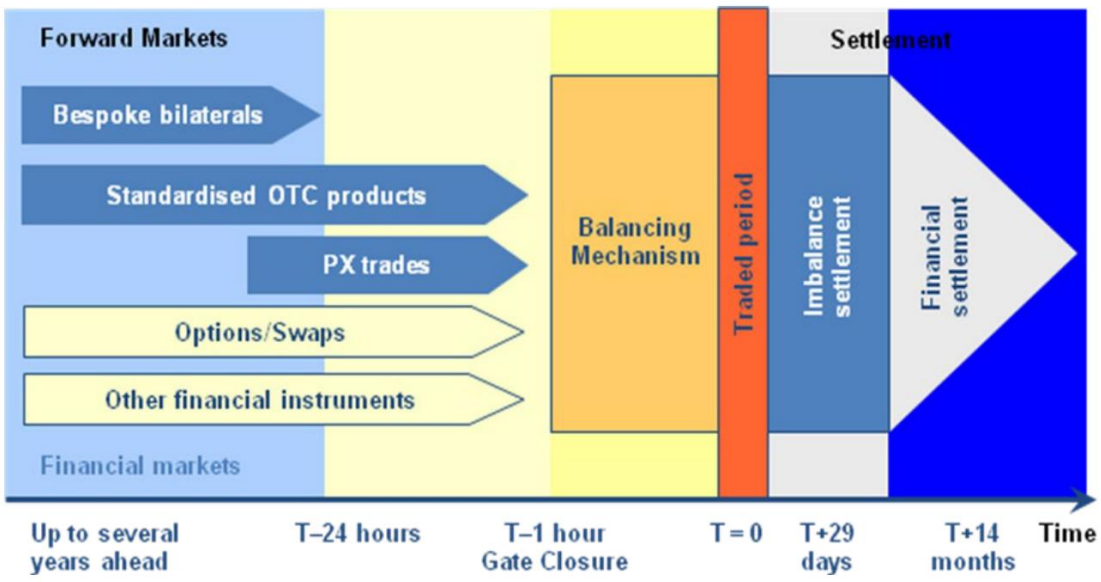


***Figure 15** - Trading arrangements under BETTA (BEIS 2020)*

### 5.1.3 Power mix evolution

Figure 16 illustrates the evolution of the UK power mix over the last three decades. It can be observed that by 1989, just before restructuring, the UK power system was dominated by coal generation with nuclear and oil taking up the rest. The 1990s saw the 'dash for gas' whereby the large-scale build out of new gas-fired Combined Cycle Gas Turbines (CCGTs) brought a technological transition from coal to gas as the main power fuel in the UK (Newbery 2019). In just 15 years gas generation jumped from 0% to roughly 40% of total production, still roughly today's share. Nuclear continued to play an important role over the last three decades ranging between 20 and 15% of generation. In the 2010s wind generation experienced a dramatic spike in investment, mostly large-scale onshore and offshore wind power plants. As for 2021, onshore wind amounted to 9% of total electricity generation, while offshore wind to 11% (Crown Estate 2021).

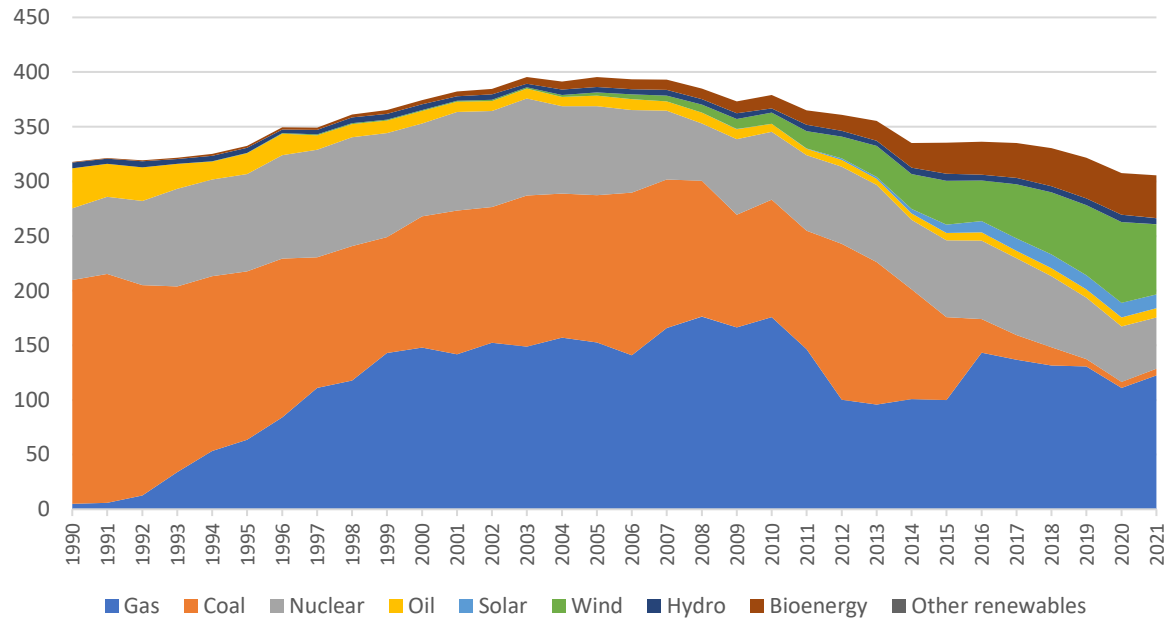


***Figure 16** - Electricity production by source UK (TWh) (Our World in Data 2022)*

### 5.1.4 National government

The UK has a constitutional monarchy, a parliamentary system and a prime minister heading the executive (Loeffler and Bovaird 2018). Devolved governments exist in Scotland, Wales, and Northern Ireland, but governance remains predominantly centralised, with significant influence from Westminster over devolved administrations' spending powers. In 2016, the UK had a low average number of municipalities per 100,000 inhabitants (0.6), with local government expenditure accounting only for just above 10% of total expenditure (OECD 2017; World Bank 2021).

Over the past three decades, the UK's energy ministry structures have been evolving in line with changes in government and political priorities. In 2008, the Department for Energy and Climate Change (DECC) consolidated functions previously scattered across various departments with a greater focus on decarbonisation. In 2016, DECC was merged with the Department of Business, Innovation and Skills, forming the Department for Business, Energy, and Industrial Strategy (BEIS). At the time of writing, BEIS oversees policy formulation in the electricity sector, with three core objectives: ensuring a reliable and secure energy system, delivering affordable energy to households and businesses, and promoting clean growth to address climate change (Hinson 2020).

The UK traditionally scores high in government capacity and effectiveness, regulatory quality, and control of corruption (OECD, 2017; World Bank, 2021). BEIS tends to have a well-educated and specialised workforce. Beyond in-house specialists, it can draw upon a larger pool of expertise including academic institutions, think-tanks, and technical entities like the system operator, the regulator, and the Climate Change Committee[10] (CCC). However, participants note that, especially in some areas, the Government is heavily reliant on external advice from private consultants, leading to a form of 'governance by consultancy' [interview2]. The prevailing logic in government operations is managerial, emphasising outcomes and evidence-based instruments (Loeffler and Bovaird 2018). Civil servants are generally perceived as impartial and independent from political influence, ranking above the EU average, despite a slight decline in recent years (ibid). The UK also scores well in accountability, stakeholder engagement and open access to government data (OECD 2017; World Bank, 2021).

[10] See Section 9.1 for a description of the CCC.

Overall, the British power sector governance can be described as coordinated and forward-looking [interviews4,22]. There is a tendency to approach reforms systematically as part of a reform packages, often accompanied by institutional reforms to adapt underlying governance structures to new objectives. An important constraint in BEIS' scope of action identified by participants relates to its relationship with the UK Treasury, the finance ministry [interviews2,3,12]. This in turn affects the way budget is allocated: "there is something in those institutional relationships that is more finance ministry than economic ministry if you like, so more interested in balancing that come through their accounts rather than what is the overall economic impact" [ibid].

### 5.1.5 State-market relations

Traditionally, the UK has been characterised by a liberal political economy model. The prevailing logic is a market logic, which is exemplified by the fact that the country scores low in all indicators of government involvement in product market regulation, ranging from direct control over enterprises, involvement in business operations and command and control regulation (OECD 2017). This is exemplified by UK pioneering power sector liberalisation reforms, whereby privatisation and restricting were very throughgoing, and which introduced a very market-based model for electricity dispatch (see sub-section 5.1.2).

Nevertheless, recent years have seen increased government intervention in the electricity sector. Over the last decade, there has been a progressive re-configuration of state-market relations with an increased role of the Government in setting power system outcomes. The 2014 Electricity Market Reform[11] (EMR) put new functions under DECC like the management of new schemes created to incentivise renewable and capacity investment. As part of this, the previous focus on competition and free markets was replaced by two key strategic objectives: security of supply and decarbonisation. When the EMR was first introduced, DECC had limited experience and technical capacity in acting as a manager of system change: "civil servants had no idea how any of those markets actually functioned" [interview7 – senior policymaker]. According to participants, Government's capacity and expertise have since grown substantially to match its new strategic role, gradually reducing information asymmetries with the industry [ibid].

### 5.1.6 Sector-specific institutions

#### *5.1.6.1 The energy regulator*

The Office of Electricity Regulation (OFFER) was established during the liberalisation process to regulate the energy sector. OFFER was designed to be accountable to Parliament while remaining independent of government influence to foster long-term regulatory certainty, encouraging market entry and investment. Its primary focus was to minimise consumer costs by 'squeezing efficiency out of the system' through competition [interview10 – senior official at regulator]. In 2001, OFFER became Ofgem, the Office of Gas and Electricity Markets.

Ofgem is often described as an institution with high institutional quality, independence, capacity and technical expertise (OECD 2019; EC 2019a). Some international experts even go so far as claiming that "Ofgem is the best electricity regulator in the world" [interview40 – energy economist]. They observe that, while a degree of political influence on regulation is inevitable, "Ofgem is respected by the Government, more than in other jurisdictions" [interview21]. Others note that Ofgem consistently adopted innovative regulatory approaches, reflecting a forward-looking organisational culture [interviews22,38].

Observers note that Ofgem has recently undergone significant institutional change with an expansion of its regulatory remit [interviews3,4,10]. As noted by this senior Ofgem official, "we have moved some distance away from being a very purist economic regulator, preventing the worst excesses of monopoly

[11] The 2014 EMR is a sector-wide policy package that introduced several market design changes including new renewable investment incentives and a targeted capacity market (see Chapters 8 and 9).

power […] we now have duties to represent the interests of future consumers and particularly creating a sustainable energy system, of which a big part is the decarbonisation of the power sector, but also supporting the decarbonisation of the transport and eventually the heat sector" [interview10]. Over time, Ofgem's scope of action has broadened, requiring it to oversee new mechanisms and regulatory aspects adopting a more strategic approach to market regulation [interview3].

Ofgem's 'ambition to go further up the tree into strategy' can be seen as an institutional response to changing system conditions [interview3]. The original role of the independent regulator, designed around a 'static market whose fundamentals would remain stable over time', is no longer adequate in the context of a system ongoing 'deep transformation among considerable uncertainties' [interview7]. Since 2012, Ofgem had two chief executives, Martin Cave and Jonathan Brearley, both 'reformist' leaders with a strong agenda [interview4]. This occasionally generated tensions: "certain times Government has clipped its wings and said no get back in your box stop doing strategy. That's our job. Ofgem you can help with implementation" [interview3].

#### *5.1.6.2 The system operator*

Since liberalisation, National Grid has owned and operated the high-voltage electricity transmission network in England and Wales with the mission of ensuring the reliability and resilience of the power grid. Given the decentralised British market model, National Grid operates the grid acting as residual balancer (see sub-section 5.1.2). National Grid also leads the development of balancing services markets, administers some power system codes. As the EMR Delivery Body, it also implements changes to market rules in the capacity market as approved by BEIS and Ofgem [interview11].

Originally, National Grid operated as a Transmission System Operator (TSO), whereby transmission ownership and operation are bundled. The TSO was fully privatised as part of liberalisation and was acquired by a mix of shareholders responsible for appointing its board (Financial Times 2021; NGESO 2020). National Grid adheres to regulation by Ofgem, subject to specific conditions and codes of practice. For over two decades after liberalisation, transmission assets were regulated through the 'RPI-X' formula, also referred to as 'sweat the assets', which sharply incentivised to reduce costs by capping allowed revenues and rewarding cost-savings (Bolton and Foxon 2015). In 2013, the RPI-X formula was substituted by the RIIO formula (Revenue = Incentives + Innovation + Outputs) (Ofgem 2010; Stewart and Bell 2021). RIIO emphases innovation rather than the traditional focus on cost efficiency [Interviews1,9,10,14].

In 2019, a major reform marked the institutional separation of National Grid into two legal entities: the Electricity System Operator (ESO) and the transmission owner National Grid. In fact, the previous TSO design was identified as leading to conflicts of interest, incentivising National grid to prioritise its own assets over alternative solutions in the procurement of system services (see Section 7.1). This reform also aimed to foster a more strategic role for the ESO in line with the changing energy landscape [interview8,16].

Participants agree that, following the institutional separation, the ESO has been at the forefront of power sector strategy development [interview5,8,11]. As put by this senior expert at the ESO, "we want to be a system operator which is pushing boundaries and being able to do things that hasn't been done before. We felt it would be better to be ahead of the curve rather than these changes being made to us" [interview11]. Notable initiatives include a major reform of balancing markets (Section 7.1) and the launch of the Net Zero Market Reform Project in 2021, exploring potential options for the future British market design (NGESO 2022). Many participants also noted that the ESO has also improved the openness and transparency of its industry engagement, conducting workshops, co-creation sessions, and open consultations, striving to engage non-traditional market players and ensure technological neutrality [Interviews 5,8,19].

### 5.1.7 Multi-level governance

The UK became a member of the European Union (EU) in 1975, and formally exited in 2020 after 45 years of membership. Throughout this period, EU policies significantly influenced the development of British energy policy and is hence a key aspect to consider in the context of this thesis. To prevent redundancy, a comprehensive overview of the EU's institutional framework and governance structure is provided in sub-section 5.2.7, within the context of the Italian case. It is important to emphasise that the relationship between the UK and the EU was not unidirectional. The UK played a substantial role in shaping EU policies, as evident in liberalisation reforms, in the design of the EU market model, and the development of climate goals [interviews1,4].

The Brexit referendum of 2016 marked a pivotal moment when UK citizens chose to discontinue their participation in the project of European integration with significant consequences for power sector policies and regional power market integration (Geske et al. 2019; BEIS 2021). Brexit reflected a shift in public sentiment towards notions of sovereignty, self-determination, and independence (Lockwood et al. 2017). Additionally, a lack of strong European identity among voters, with 63% lacking regional identity before the referendum, contributed to this outcome (Gastinger 2019).

### 5.1.8 Market structures and interests

In the late 1990s, the GB market structure gradually became less concentrated due to somedivestments by incumbents, which signified a shift from a de-facto price-setting duopoly to a competitive structure with dozens of generation companies (Newbery 2019). This period saw the entrance in the GB market of European utilities and some independent power producers (IPPs) investing in merchant gas production financed by banks and other private finance. As divestment created lower concentration, the structure evolved towards the so-called 'Big Six' European utilities and some major IPPs (Figure 17). In 2015, the Big Six supplied just under 90% of the domestic consumers and generated about 70% of total power output (CMA 2016). Lately, the Big Six's market shares and level of vertical integration have decreased due to some divestments. Nevertheless, the level of market concentration has remained stable with the largest 10 producers generating 80% of electricity in 2021 (Ofgem 2021).

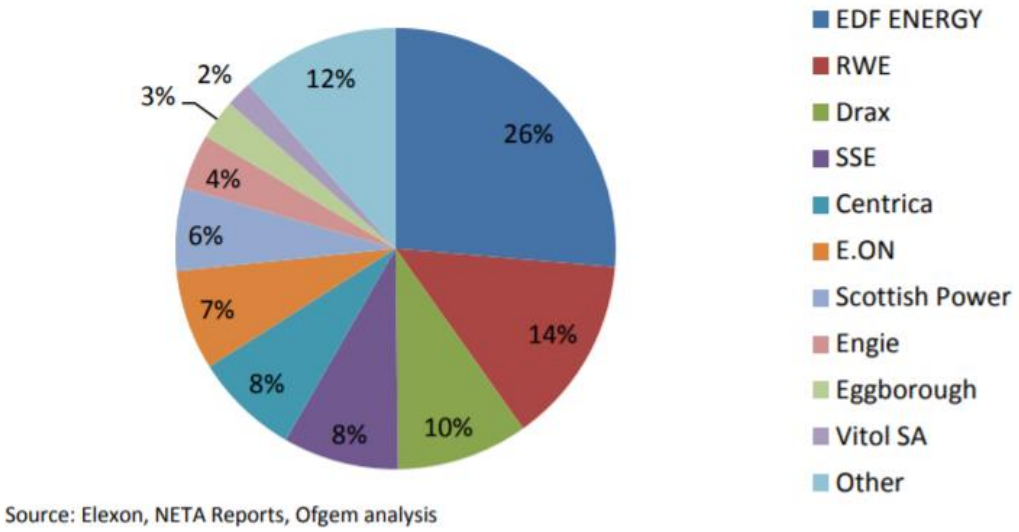


***Figure 17 -*** *Generation market share by largest generators in 2014 (Ofgem 2014)*

Incumbent generators in the UK traditionally held significant stakes in conventional generation assets, including gas, coal, and nuclear (Figure 18). However, during the late 2010s, some incumbents made substantial investments in renewable energy and divested fossil fuel plants, shifting their economic focus [interviews4,5,12,13]. As of 2021, utilities owned 63% of UK offshore wind capacity, followed by financial investors (19%) and the oil and gas industry (15%) (Crown Estate 2021). Notably, there has

been a shift from equity investment to debt finance, with new financial players like commercial banks and institutional investors entering renewable financing [interviews7,12,13,16].

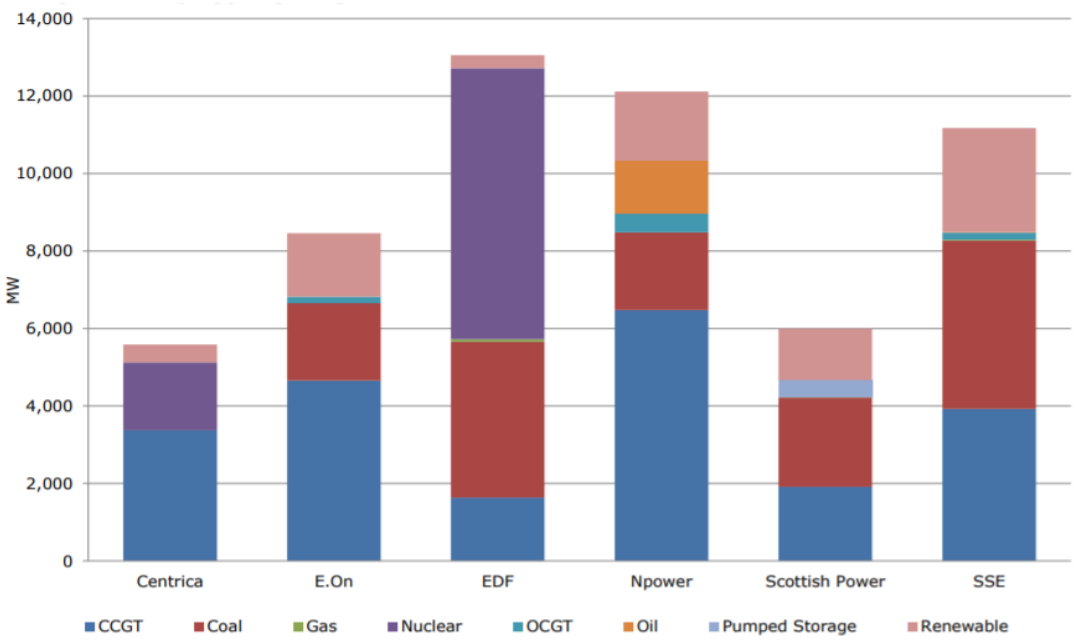


***Figure 18** - Electricity generation capacity (MW) of the six largest energy companies in 2013 (Ofgem 2014)*

British incumbents possess extensive technical expertise and resources, enabling them to conduct their own research and construct narratives to influence policy [interviews3,4,5,10]. As noted by this representative of a large incumbent generator: "you need to be making positive proposals about what could change practically, how that can achieve the outcomes that you want but also help with what they [policymakers] want to achieve" [interview12]. Participants note that incumbent energy companies and the financial industry tend to have preferential access to policymakers and a degree of structural power [interviews2,3,4]. World Bank (2021) indicators show that both the energy and financial industry are both important contributors to national GDP.

In contrast, smaller or decentralised actors have traditionally played a more marginal role in policy debates [interviews3,4,5,14,18]. These entities have limited resources to influence policy including limited personnel to engage in lobbying and responding consultations compared to incumbents with dedicated regulation departments [interview19 – representative of non-traditional flex provider]. More recently, increased flexibility needs and changes in the regulatory regime create a fertile ground for the rise of new business models for the provision of system services [interviews 6,11,19]. As widely explored in Chapter 7, both incumbents and new market players have entered this arena, diversifying the political economy of the sector: "nowadays if you look at the amount companies that are active in the in the electricity market and also the scale companies, the diversity as well, you have a lot more sunk costs for a lot more people" [interview5 - market design expert].

The UK has good stakeholder engagement and exhibits a moderately corporatist system (Loeffler and Bovaird 2018). Industry players tend to find common positions before interacting with the government: "collective engagement tends to have a bigger impact because government will then know that there's a consensus" [interview13 – representative of large incumbent generator]. The renewable energy industry and conventional generators have recently converged under a single association, Energy UK, with a focus on consumers and decarbonisation. While it represents a wide spectrum of generators, some argue it is still dominated by larger players [interview4,14]. Other niche groups, such as onshore renewables and decentralised energy resources, have their respective associations.

According to participants, direct consumer engagement in decision-making is limited [interview7]. Residential consumers' interests are primarily represented by the regulator Ofgem and advocacy organisations such as Citizen Advice. Over the last 20 years, large consumers' interests have become less influential in policy decisions due to progressive deindustrialisation of the UK economy. In 2019, the industrial sector accounted for 26% of total electricity demand (UK Gov 2022). Finally, the UK has a moderate trade union intensity (at 23%) (OECD 2017). The oil and gas industry historically provided significant employment (0.05 of national workforce in 2019), especially in regions like Scotland (EC 2019). However, recently the renewable has become an important source of employment (0.08% of workforce in 2019), and a strategic sector in the UK national economy as discussed in Chapter 9 (Statista 2019).

## 5.2 Italy

### 5.2.1 Power sector liberalisation

Before liberalisation and restructuring, the Italian power system was also centrally managed by a public monopoly, the Ente Nazionale per l'Energia Elettrica (Enel). Compared to Britain, Italy's journey towards liberalisation commenced a decade later and was primarily instigated by external factors, driven by EU regulations [interviews25,33]. In the late twentieth century, the European Union initiated a series of reforms aimed at liberalizing the energy sectors of its member nations, taking inspiration from the UK's pioneering efforts (Bevacqua et al. 2020).

The initial step in this process was the 1996 Directive 96/92/EC, titled 'on the Creation of an Internal Energy Market' (MISE 2019; Bevacqua et al. 2020) This marked the first opening of electricity generation and supply to competition, alongside the introduction of accounting unbundling for transmission and distribution activities. Italy formally incorporated these changes into its domestic legislation in 1999 through the 'Bersani Decree' (ibid). Between 2003 and 2011, Italy's liberalisation framework underwent several revisions in response to new EU-level directives that further deepened the liberalisation of the power sector (Table 11).

***Table 11 -*** *EU policy reforms for liberalisation and market integration*

| Name of package | Year | Description |
|---|---|---|
| **First Energy package** | 1996 | Generation and supply of electricity were first opened to competition and accounting unbundling for transmission and distribution activities was introduced. The package also involved the creation of National Regulatory Authorities. |
| **Second Energy Package** | 2003 | Functional unbundling was introduced, as well as the establishment of wholesale power markets and retail competition. |
| **Third Energy Package** | 2009 | Ownership unbundling was pushed forward and new measures were introduced to encourage cross-border trading. In particular, a new legal framework, the European Network Codes, was created to define the technical rules for a single electricity market, the so-called European Target Model. |

As part of the liberalisation process, the former state-owned monopoly Enel underwent gradual restructuring and privatisation. However, in contrast to the UK, where privatisation and restructuring were extensive, Italy pursued a more moderate approach. Partial public ownership persists and the process of unbundling of Enel is not complete (see sub-sections 5.2.5 and 5.2.8). Retail was also liberalised, however, a state-owned entity, known as 'Acquirente Unico,' is responsible for supplying electricity to small consumers who do not participate in the retail market.

### 5.2.2 Wholesale power market design

Italy's legacy market model combines features of both centralised and decentralised dispatch. It is characterised by gate closure at H-4[12], discrete trading, unit-based commitment, an integrated scheduling process, and zonal pricing [interviews 29,31]. There is significant distance between the financial nature of exchanges conducted on the British market from those of the Italian market, which is directly linked to physical scheduling of units (ARERA 2019a). This choice of a physical scheduling and zonal approach was driven by its capacity to yield more efficient outcomes in Italy's context [interview27,29]. In fact, due to its unique geographical configuration, the country historically faced substantial network constraints and infrastructure costs [ibid].

However, the Italian market still retains characteristics commonly found in other European markets, such as an intraday market, a separate balancing market. At the time of liberalisation, this hybrid approach enabled to strike a balance between maximising efficiency and mitigating political acceptability issues. As one expert noted, "the informing principle was that to create as much as possible an optimal market through a second-best design that would also protect final consumers. Without these compromises, politically, it would have not been possible to undertake liberalisation in Italy" [interview20]. Moreover, implementing a fully centralised nodal system would have presented significant implementation complexities, contributing to explain the adoption of a simpler design [interviews27,29].

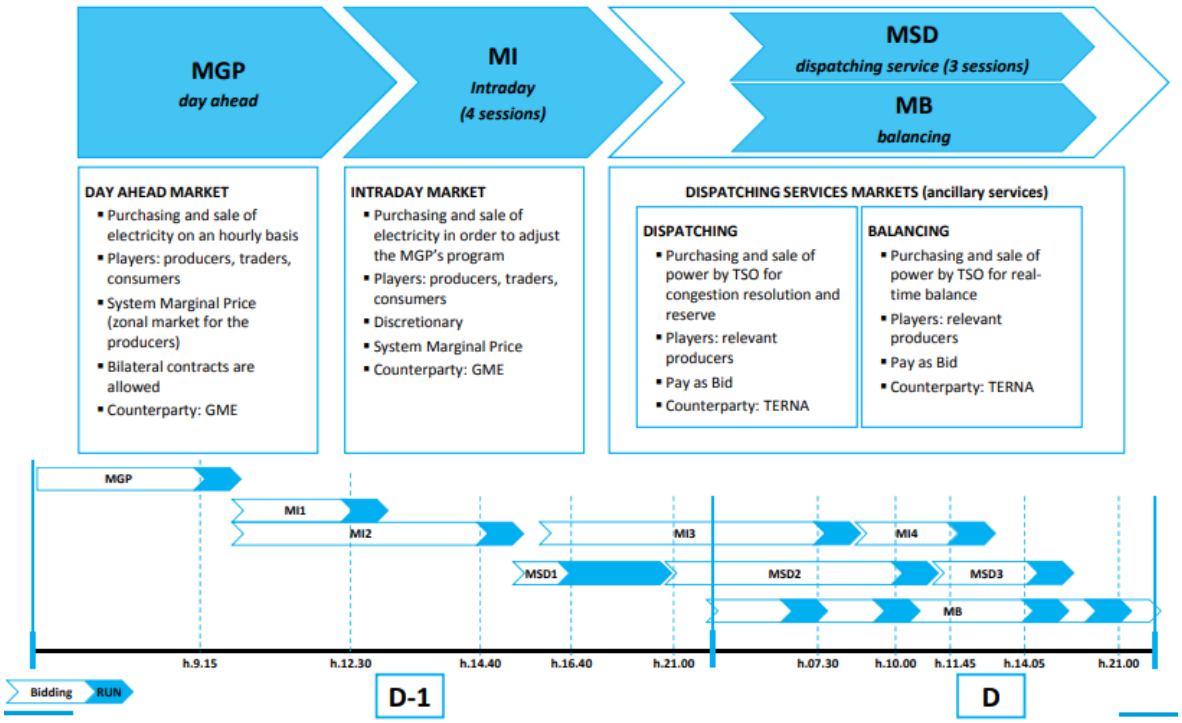


***Figure 19 -*** *Trading arrangements in the Italian Power market (Iacovone 2019)*

Figure 19 illustrates a timeline of the Italian wholesale power market. This includes trading years in advance in the forward electricity market known as the Mercato Elettrico a Termine (MTE), day-ahead trading in the Mercato del Giorno Prima (MGP), or intraday trading in the Mercato Infragiornaliero (MI) (Iacovone 2019). Electricity trading can occur through the Italian Power Exchange (IPEX) or bilaterally. Unlike the continuous trading model in the UK, the Italian MGP follows an auction-based approach where prices and volumes are determined based on the equilibrium between bids and offers for each of the 24 hours of the next day. Market participants submit simple bids/asks indicating quantity and price range at which they are willing to trade. These are accepted based on economic

[12] - i.e. 4 hours before dispatch.

merit-order and accounting for transmission congestions between zones (ibid). The Intraday market enables participants to modify their programs derived from the daily market. Supply offers and demand bids are sorted based on merit-order for each hour of the next day, and accepted demand bids are priced at the zonal rate (ibid).

In Italy's dispatch model, the system operator plays a key role through the integrated scheduling process – whereby balancing, reserve procurement and congestion management are executed concurrently (Marneris & Biskas 2015). The integrated scheduling process is conducted through the Mercato dei Servizi di Dispacciamento (MSD), in which Terna selects bids to deal with residual congestions and procure reserve margins, while balancing is conducted through the Mercato di Bilanciamento (MB) (Iacovone 2019).

### 5.2.3 Power mix evolution

Figure 20 illustrates the evolution of the power mix in Italy. Before restructuring in the late 1990s, the Italian power mix was dominated by oil, followed coal and hydro (Figure 20). Like Britain, following liberalisation Italy also saw a boom in gas investment up to 2010 marking a gradual transition away from other fossil fuels. As for 2020, Italy relied for on gas for almost half of its power output. Over the last 30 years, hydro generation maintained a stable share of the power mix at around 20%. From 2008, Italy saw a major wave of investment in renewable technologies, especially wind and solar. Compared to the UK, in 2019 Italy had a much lower share of wind output (around 7%) and a larger solar output (8%). Consequently, the average renewable plant size in Italy is lower with significant shares of distributed generation assets, especially PV installations.

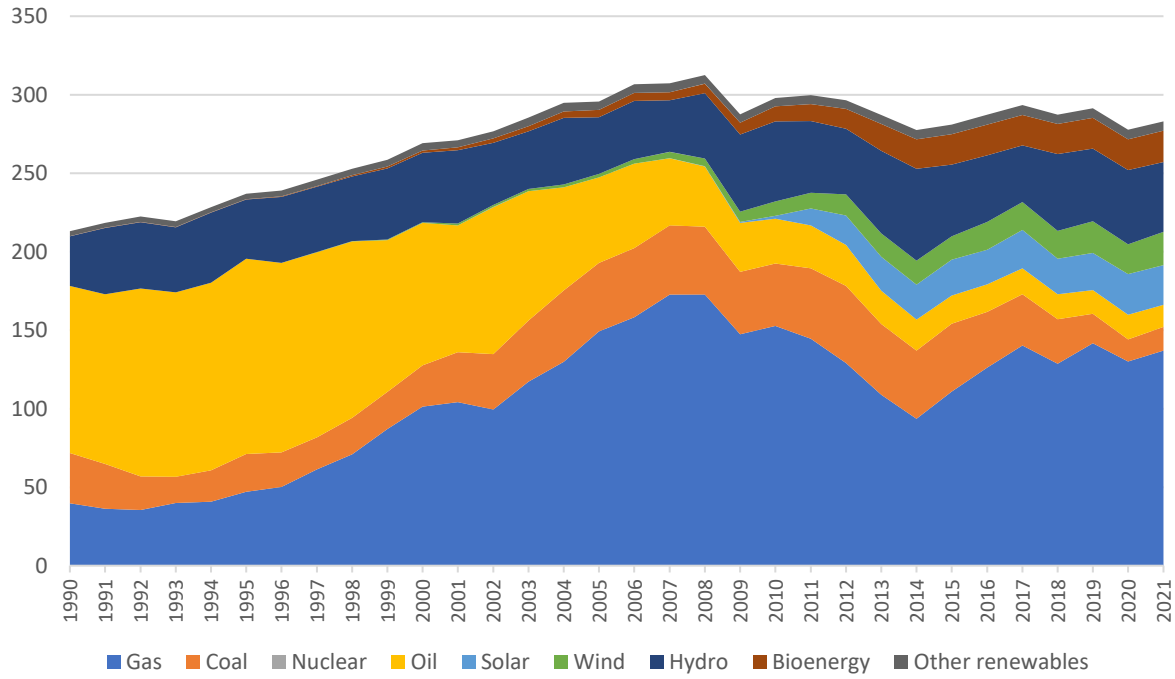


***Figure 20** - Electricity production by source in Italy (TWh) (Our World in Data 2022)*

### 5.2.4 National government

Italy is a parliamentary republic with a president of the council heading the executive (Cepiku 2018). Overall, Italy's government structure is less centralised than in the UK with an average of 13.1 municipalities per 100,000 inhabitants and local government spending at 14% of GDP in 2016 (OCED 2017). As noted by this participant, "in Italy there is a proliferation of local entities and authorities playing an important role in energy planning" [interview35].

The Ministry of Economic Development (MISE) traditionally held responsibility for energy policy in Italy. It oversaw areas such as the national energy budget, energy infrastructure, security of supply, renewable energy support, and the development of the single electricity market (EC 2021). Key objectives included ensuring energy security and affordable energy prices to support economic development, particularly in the industrial sector. In 2021, MISE was merged with the Ministry of Environment to form a new department, the Minister for Ecological Transition, reflecting a trend at the EU level to treat energy and climate as a unified policy issue.

Compared to the UK, Italy ranks lower in terms of political stability, government effectiveness and regulatory quality (OECD 2017; World Bank 2021). Since 2000, Italy has seen 11 different governments, each with an average duration of two years. According to participants, frequent government changes have led to policy uncertainty undermining the coherence of MISE's policies, as each new government introduced a new vision [interview26,34]. In terms of the knowledge infrastructure, MISE relies on a range of public research institutions like RSE, ENEA and CNR[13] that play a key role in policy development [interviews29,35]. Several observers noted that MISE has historically tended to look at energy policy as a 'technical issue', often delegating key decisions to the regulator and key interest groups with higher technical expertise [interviews21,26,37]. However, they note that this has recently been changing with the ministry taking an increasingly active role in policy implementation [ibid].

The Italian public administration is generally viewed as slow-moving and somewhat inefficient, although with significant variation, including pockets of extremely innovative practice (Cepiku 2018). Italy's public service culture is characterised by a strong juridical approach, policy design and implementation often follow a legal framework, with limited consideration of empirical evidence and pilot results. Factors like risk aversion, lack of coordination and monitoring in local public services were identified as sometimes hindering policy implementation (ibid). When it comes to impartiality and accountability, the Italian public administration performs among the worst in the EU (Cepiku 2018; OECD 2017; World Bank 2021). There has been a trend of politicisation of the top civil service, with politicians exerting increasing control over appointments/dismissals, and private interests influence in policymaking. The civil service remains closed and stakeholder consultation does not always occur. Corruption also remains a concern (ibid).

### 5.2.5 State-market relations

Compared to the UK, a more government-dominated logic prevails in Italy. The country scores higher in OECD indicators of product market regulation such as direct control over enterprises, involvement in business operation and command and control regulation (OECD 2017). Power sector liberalisation was externally imposed by EU regulation and Italy pursued a more moderate reform approach compared to Britain, where privatisation and restructuring were very through-going. The Italian Government retains partial ownership of key infrastructures: a 24% stake in the largest power producer, Enel; a 30% stake in the first fossil-fuel company and second-largest electricity producer Eni; and a 30% stake in the system operator, Terna (MEF 2021; Terna 2021b).

This has led many experts to conclude that the boundaries between the state and incumbent utilities are often blurred [interview21,22,25,29]. As noted by this power sector journalist, "in Italy, there is certainly a lot of porosity in the membrane sitting between the Government and Enel" [interview26]. This complex relationship is evident in the fact that, despite liberalisation has formally taken place, these companies still have 'personnel within the ministry' who 'act as the operational arm of the government' [interview21].

[13] - i.e. Ricerca sul Sistema Energetico, Agenzia Nazionale per le Nuove Energie, Consiglio Nazionale delle Ricerche.

### 5.2.6 Sector-specific institutions

#### *5.2.6.1 The energy regulator*

In 1995, Italy established an independent energy regulator, the Autorità per l'Energia Elettrica e il Gas. Initially limited to electricity and natural gas, the Authority's scope of action has been growing over time to include activities beyond energy (Ranci 2019). In 2018, the Italian regulator acquired its current name ARERA, which stands for l'Autorità di Regolazione per Energia Reti e Ambiente (Italian Regulatory Authority for Energy, Networks and the Environment). The regulator's mission is to promote "competition and efficiency in public utility services and protect the interests of users and consumers" (ARERA 2019).

There is a consensus that the Italian energy authority "was created and endowed with considerable independence" (Ranci 2019; EC 2019a). ARERA is often described as having significant internal technical expertise, and rules are in place aiming to ensure that it remains independent from political influence and industry's vested interests (OECD 2019). This is particularly relevant in the context of Italy, whose institutional regime has been historically characterised by political instability, regulatory capture and corruption (see sub-section 5.2.4). However, a closer look at these institutional relationships reveals the existence of some tensions.

As discussed in sub-section 5.2.5, despite liberalisation, the Italian state remains directly involved in the power system, which inevitably creates some frictions between the activities of the independent regulator and the economic interests of the state. During liberalisation, regulatory decisions deemed 'equitable' by the regulator were often challenged through legal proceedings or resisted by policymakers (Ranci 2019). As noted by former ARERA president Pippo Ranci, "the relationship between the regulator and the public sector entities that owned energy companies (central and local government) remained delicate for a long time" (ibid). The persistence of mixed feelings about liberalisation in political and bureaucratic corridors are exemplified by a series of new legislations in the 2000s that brought some competences of the regulator back to the Economic Ministry: "the Authority has seen a reduction in its room for manoeuvre […] compared to the institutional design of the 1990s" [interview25].

Contrary to Ofgem, ARERA does not have the same strategic role in power sector policy and was described as 'careful not to upset the balance of politics' with some going as far saying that the Italian regulator has been 'politically captured' [interviews21,22]. However, participants note that the relationship and coordination between the regulator and the government have been improving recently: "there has never been a lot of sympathy between ministerial structures and the authority. Now, things are changing quickly and improving" [interview37].

#### *5.2.6.2 The system and market operator*

The Italian TSO Terna owns and operates the transmission grid and the dispatching service, with the mission of maintaining the reliability and resilience of the Italian power system. Like NGESO, Terna conducts forecasts and planning assessments, and leads the development of balancing services markets and the grid code, and strategic change projects across both the wholesale and capacity markets (Terna 2021c). Terna has high degrees of technical capacity and expertise [interview22].

In initial post-liberalisation arrangements, transmission ownership and operation were separated. The former remained with the incumbent Enel, while operational functions were assigned to a separate entity, the Gestore della Rete di Trasmissione Nazionale (GSE 2022). In 2005, as part of Enel's restructuring, transmission ownership was transferred from the former monopoly to the newly formed Terna, and merged again with operational functions. The Gestore della Rete became the Gestore dei Servizi Elettrici (GSE), still managing Italian wholesale electricity markets, as discussed below.

Terna is partially owned by the Italian State, with the remainder of ownership divided among national and international shareholders (Terna 2021b). Its transmission and dispatching services are

remunerated through a tariff system established by the regulator ARERA (Terna 2021c). For two decades following liberalisation, the TSO was subject to price cap regulation. Starting in 2015, in line with a broader European trend, the regulatory framework gradually shifted towards an output-based model (Oxera 2016).

Concerns exist regarding potential conflict of interest in Terna's TSO structure [Interviews 31,36,38] (Italia Solare 2021). These stem from Terna's financial incentives to expand its regulated assets, a consequence of the bundling of its operations, which may inadvertently prioritise its own interests over overarching system objectives [ibid]. Instances of anti-competitive behaviour by Terna have also been cited, specifically, Terna's endeavours to engage in generation activities and system services, raising questions about its adherence to principles of market liberalisation [Interviews 21,37,31].

According to some, this is accrued by Terna being partially publicly owned: "the Government did not say anything because a part of that profit ended up in their hands. Private operators were really angry [...]. Terna has an enormous competitive advantage and very strong contractual power towards generators" [interview21]. Further, Terna's significant institutional capacity and technical expertise confers it a lot of policy influence: "Terna has a great capacity to influence public decisionmakers, the information asymmetry is too large. The TSO can say I need this investment, I cannot go without. Who is going to say that is not true?" [ibid].

Finally, according to participants, Terna's approach to engaging with other power market stakeholders sometimes suffers from lack of transparency, openness and accountability. An example is the modalities in which consultations are carried out, which can be 'extraordinarily complex' and have very short response times: "two weeks available for answering basically not responding. […] Every time we have to ask for an extension. Consultations are a formality imposed by the regulator but, in practice, Terna has already decided what to do" [interview37].

In addition to Terna, the Gestore dei Mercati Energetici (GME) acts as a specialised market operator responsible for managing various electricity markets, such as day-ahead and intraday auctions, forward contracts, gas and environmental product markets (GME 2021). GME serves as a central market platform, distinguishing itself from private international exchanges present in some EU countries, like Nordpool or EPEX[14]. Due to its limited scale, the GME has less technical capacity and sophisticated systems compared to these major international exchanges [interview26].

GME is fully owned by the Gestore dei Servizi Energetici, an umbrella organization overseeing various specialised policy and research bodies related to energy markets. These are owned by the Ministry of Economy and Finance, making these bodies more focused on implementation than shaping power sector policy. Participants highlight these institutions' susceptibility to political influence, as appointments often align with the government's short-term objectives: "people at the GME have shown distress in the face of these strong political interferences" [interview21].

### 5.2.7 Multi-level governance

Italy was one of the first countries to join the European Union (EU) in 1957 and is still a member state. The legal basis of EU energy governance can be found in the Treaty on the Functioning of the European Union of 1957 (European Parliament 2021). The Treaty confers EU institutions jurisdictional authority over a range of energy policy matters including security of supply, energy networks and the internal energy market. The treaty puts an obligation on states to incorporate directives into national law, but each nation retains a right to "determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply" (ibid).

The five core aims of EU energy policy are to: 1) diversify sources of energy, ensuring energy security through solidarity and cooperation; 2) establish an integrated internal energy market, removing

[14] European Power Exchange.

technical and regulatory barriers; 3) improve energy efficiency and reduce dependence on energy imports, cut emissions, and drive jobs and growth; 4) decarbonise and move towards a low-carbon economy; and 5) promote research in low-carbon and clean energy technologies (ibid). As noted in sub-section 5.2.1, the first major reform pursued by the EU has been power sector liberalisation. In the 2000s, decarbonisation has also emerged as a key objective, pursued by the EU through several directives with increasingly specific renewable energy targets.

As discussed above, one of the main goals of the EU is to establish a single market for electricity, the so-called Internal Electricity Market (IEM). This is motivated by a set of common concerns, including the need to integrate increasing VRES shares more efficiently, increase system reliability and utilisation of interconnectors, and improve overall system flexibility (IEA 2018). The IEM includes 26 countries. The EU regulatory framework for this regional market finds its foundations in the electricity Directive (2003/54/EC) and consists of further directives, as well as a plethora of guidelines and network codes.

Over time, EU provisions have become much more detailed and prescriptive and new institutional structures were created to facilitate greater harmonisation. The Third Energy Package considerably drove forward the integration process through the clarification of key rules governing power exchange across countries (EC 2021a). The key institutions currently monitoring and governing the IEM are as follows:

- The European Parliament, the Commission and the Council
- The Agency for the Cooperation of Energy Regulators (ACER)
- European Network Transmission System Operators for Electricity (ENTSO-E)
- The European Regulators Group for Electricity and Gas
- The Association for European Energy Exchanges

EU network codes are key in guiding the development of the internal market in that they provide a shared framework of technical and commercial rules across network security, third-party access, data exchange and settlement, emergency operational procedures, capacity allocation and congestion management for real-time, day-ahead and long-term markets (IEA 2018). The development of codes is managed through an iterative, multi-stakeholder process whereby ACER develops general guidelines, which are then turned into detailed proposals by ENTSO-E. ACER then reviews the network codes, which must be approved by the Commission. In line with the subsidiarity principle, member countries have discretion over implementation (ibid). In 2017, after a 4-year-long co-creation process, eight network codes and guidelines entered into force (Schittekatte et al. 2020). These are illustrated below:

***Table 12** - European Network Codes (adapted from Schittekatte et al. 2020)*

| | | |
|---|---|---|
| **Market codes** | How to integrate power markets? | • Forward Capacity Allocation (FCA GL)<br>• Capacity Allocation and Congestion Management (CACM GL)<br>• Electricity Balancing (EB GL) |
| **System operation codes** | How to seamlessly operate a power system? | • System Operations<br>• Emergency and Restoration |
| **Grid connection codes** | How to harmonise connection rules? | • Demand Connection Code<br>• Requirements for Generators<br>• HVDC Connections |

Hence, starting with liberalisation to more recent power market design changes, EU policy has played a key role in shaping Italian power market policy in line with the so-called EU Target Model [interviews 20,27,32,33,38]. There seems to be wide-spread recognition of the benefits of the IEM among key Italian stakeholders [ibid]. Though Euro-sceptic sentiments and narratives around self-determination were also growing among the Italian electorate, reflecting a wider regional trend, these never resulted

in an exit from the Union and the single market. Statistics reveal that only 39 per cent of Italians lack a European identity (Gastinger 2019).

To comply with EU directives “Italy implemented deep structural changes that it would have not done otherwise” [interview26], partially related to the uniqueness of the Italian market model (see sub-section 5.2.2). This has sometimes generated some tensions requiring intense negotiations between Italian policymakers and their EU counterparts, as discussed extensively in this thesis. This participant described the EU policy process as follows: “there is an issue of reconciling the various interests of the single national power systems, EU regulation is the result of a bargaining activity. As a member state you have to be able to engage in negotiations well and bring forward your national interests with a coherent logic” [interview20]. Hence, the EU position somewhat mirrors the balance of power in the region and dominant techno-economic ideas in large and influential member states [interviews20,29]. Single interest groups (e.g. different producers, traders) also directly participate in the EU policy process and engage in lobbying to influence final decisions.

### 5.2.8 Market structures and interests

Following liberalisation, Italy's electricity supply sector gradually became less concentrated due to divestment by incumbent monopolies and the entry of new European utilities and independent power producers. While Enel and Eni maintained a 35% market share in 2014, some European utilities had secured significant market shares (Figure 21). Italy also has numerous smaller municipal and regional utility suppliers with an average market share of less than 1%. However, if taken together, these amounted to 35% of total electricity output in 2014, a notable contrast to the UK's 12% (Figure 17). In 2018, the three largest utilities with 37.7% of generation also held a 46.3% market share in retail, of which three thirds was held by Enel alone (ARERA 2019; Iacovone 2019). Since 2014, the basic structure of the Italian market has remained unchanged, except for a reduction of Enel’s market share to 15.5% in 2021. The ten largest producers still controlled around 60% of the market, compared to the UK's 80%.

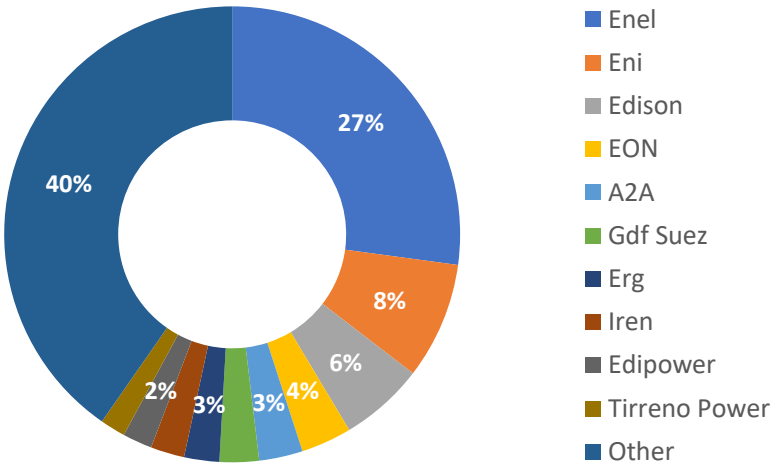


***Figure 21*** *– Generation market share by largest generators in 2014 (ARERA 2015)*

Italy's largest generators traditionally own conventional assets, particularly gas, coal, and hydro (Figure 22). In 2014 the second largest incumbent Eni had a fully fossil-fuel-based generation portfolio, while Enel had considerable amounts of hydro resources in addition to gas and coal. Ownership of renewable generation is less concentrated than in the UK. Only 14% of wind output in 2018 came from the four largest companies (ARERA2019). Figures are even lower for solar production (1%), with most output distributed across numerous smaller companies and producers. Compared to Britain, Italy's incumbents shifted their focus towards green technologies more gradually and marginally, albeit with

important variations. Erg leads among large suppliers with a 12.1% share of national wind output, followed by Enel and Edison. Like the in UK, there has recently been a financialisation of renewable investment with new private funds coming in (e.g. Falk Renewables) [interviews 20,22,26].

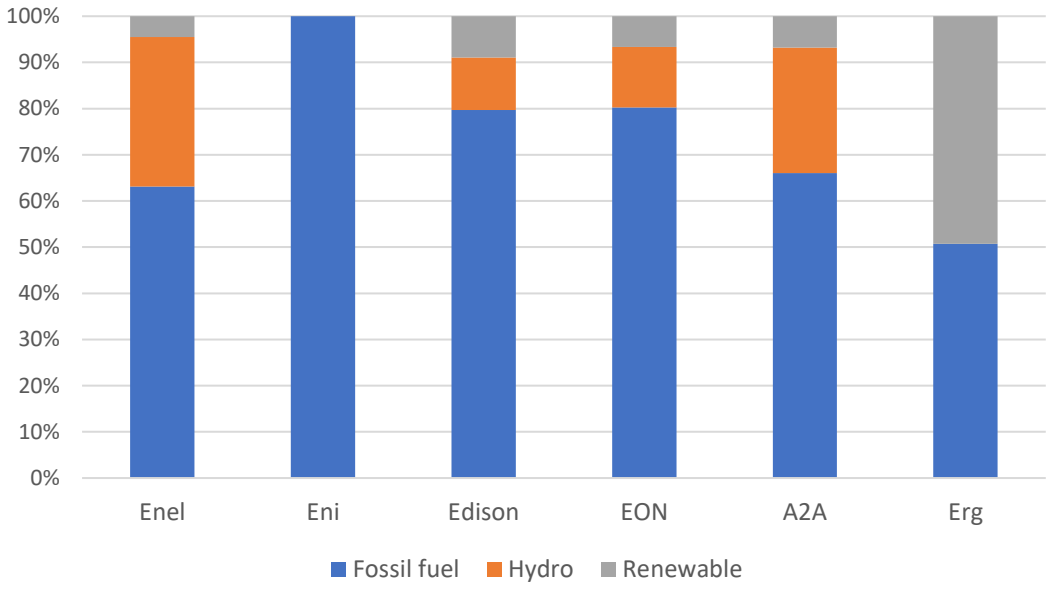


***Figure 22*** *- Electricity generation capacity (TW) of the six largest energy companies in 2014 (ARERA 2015)*

Major incumbents Enel and Eni hold significant sway over decision-making [interviews26,34,35,37]. The state's substantial ownership stake ties its interests to their success, as well as Italy's economic stability: "Italy has one of the largest debts in the world, we have to defend Enel and Eni because they are stock market jewels and our credit standing depends on what we do with our companies" [interview22]. Eni and Enel have expanded internationally earning them the status of 'national champions' [interview21]. Policymakers are hence 'more inclined to accept proposals from these entities', though their influence have waned over time [interview21,34]. Other incumbents, such as municipal utilities and EU-based companies, also play a role in institutional discussions, though not to the same degree [ibid].

Like in Britain, evolving system requirements have sparked innovation in services and business models involving batteries, DERs, and demand-side flexibility (see Section 7.2). While municipal utilities and emerging market players are also exploring new business models, the dominant force in this arena is Enel through its new subsidiary Enel-X [interviews21,27,29]. Notably, Italy did not fully pursue complete unbundling of distribution from other activities. During liberalisation, Enel agreed to downsize but convinced the government to refrain from completely breaking up its operations (Bevacqua et al. 2020). The former monopoly controls the distribution network through E-Distribuzione, serving approximately 86% of customers (ARERA 2019).

Italy's interest intermediation system is deeply corporatist, a legacy of fascism, when industries were organised into corporations (Cringoli 2019). Private sector actors 'consolidate policy positions' within these associations before approaching the government [interview35]. According to experts, participation in these associations is essential for companies, many of which join multiple associations to shape policies and access valuable information [interviews36,37]. The importance of interest associations as platforms for policy has been further elevated by political instability and lack of a 'coherent industrial strategy' (sub-section 5.2.4).

Industry associations typically operate within the umbrella organization Confindustria, representing Italy's entire business sector. Historically, Assoelettrica represented the conventional electricity

industry, while renewables had their own association, Assorinnovabili (Bevacqua et al. 2019). Post-liberalisation market entrants including international investors, EU utilities, and traders also formed associations like AIGET[15] and Energia Libera to promote their own interest through a more free-market agenda [interviews26,37]. In 2017, Assorinnovabili and Assoelettrica merged into a single association, Elettricita' Futura, with a greater focus on decarbonisation, albeit it also represents the interests of conventional generators (Bevacqua et al. 2019). Solar and decentralised energy industries have their own associations, less coordinated and influential.

Residential consumers have limited direct involvement in technical discussions, though they wield influence through local and national politics [interview25]. Interestingly, one participant noted that "at the public level of big masses, there is a strong ambiguity on what the energy market is, energy is often still perceived as a public good" [ibid]. Italy's industrial sector, constituting 42% of electricity demand, plays a pivotal role in policymaking (Terna 2021). Their primary aim is achieving lower energy costs, regardless of market design: "if tomorrow morning there is a single supplier at the national level and this allows electricity to cost one cent less per MWh, industrials would be happy to say goodbye to the market" [interview37]. This occasionally places them in opposition to electricity generators: "we find ourselves at these tables with us producers and them consumers fighting" [interview33 – representative of major producer]. Industrial consumers are also organised under Confindustria: "Confindustria has two souls: the soul of energy consumers and that protecting the interests of energy producers. […] This means that interests in Italy are never univocal but there is a lot of plotting and strategies" [interview37].

Finally, Italy has high trade union intensity reaching 34% (OECD 2017). While the energy industry represented a significant turnover and is important in national economy, as for 2019, Italy has a lower share of people employed in the fossil fuel (0.02%) and renewable energy industries (0.03%) compared to the UK and California (EC 2019; Statista 2021). Italy has scarce indigenous fossil fuel resources with its industry focusing on sourcing and refining resources imported from abroad with a major role played by incumbent Eni.

## 5.3 California

### 5.3.1 Power sector liberalisation

Before restructuring, California's power sector was dominated by private, vertically integrated utilities known as IOUs (investor-owned utilities) and publicly owned local utilities (POUs). In 1978, the federal Public Utility Regulatory Policies Act (PURPA) Act marked the initial step toward liberalisation, allowing non-utility generators to sell power to incumbent utilities at guaranteed rates (Burtraw et al. 2019). This shift occurred in the context of a changing global landscape, including the oil embargo and the rise of neoliberal ideology, eventually leading to Ronald Reagan's election [interviews39,52]. California embraced the liberalisation agenda enthusiastically, also given the state's history of high electricity prices. This is exemplified by the unanimous vote of the California assembly in favour of restructuring in 1996 (Hobbs and Oren 2019).

California took a leading role in deregulating the electricity sector, progressing with unbundling the functions of incumbent IOUs whose generation portfolio were partially divested to new entrants (Weare 2003; Burtraw et al. 2019). In 1998, the California wholesale power market adopted a structure similar to the UK and Italy, featuring separate trading platforms: a power exchange responsible for the day-ahead market (the California Power Exchange) and a real-time market managing balancing activities (ibid). This was combined with a zonal pricing system.

[15] Associazione Italiana di Grossisti di Energia e Trader.

In 2000, the notorious California Energy Crisis hit, marking a turn in power sector policy. This consisted of a series of major rolling blackouts, caused by a combination extreme system conditions and soaring prices triggered by significant market manipulations (Burtraw et al. 2019; Weare 2003). Later analysis has clearly shown that the regulatory framework had not conveyed appropriate incentives for forward contracting, while increasing the ability of some market players to exercise market power [interviews39,50]. The crisis had major financial implications, leading to several bankruptcies and extremely high legacy costs for consumers (Hobbs and Oren 2019; Burtraw et al. 2019). It also disrupted California's liberalisation process, leading to emergency legislation that temporarily suspended retail choice and made state agencies temporary providers for a significant share of retail customers (ibid). Presently, California has a competitive wholesale market, but distribution and retail electricity remain under regulated vertically integrated utilities. California's market is often described as a hybrid, blending strong regulatory oversight with elements of competition in wholesale generation and limited retail competition (ibid).

### 5.3.2 Wholesale power market design

During the crisis, the power exchange went bankrupt, leaving only the CAISO-managed market as a functioning option (Burtraw et al. 2019). In the subsequent years, the market design underwent various changes. Decentralised bilateral platforms temporarily operated in the day-ahead period, but the primary reliance was on the CAISO-operated real-time balancing market and mechanisms for allocating transmission access rights in the day-ahead period (ibid). In 2009, California's power market entered its final phase, with the CAISO market adopting a two-settlement arrangement consisting of a day-ahead and a real-time market. Today, California features a highly centralised market that incorporates centralised security-constrained economic dispatch, complex bidding, the co-optimisation of energy and reserves, and nodal pricing [interviews40,42,52]. This model meticulously reflects system conditions at a granular level and employs a dispatch logic based on optimisation and cost-minimisation [ibid].

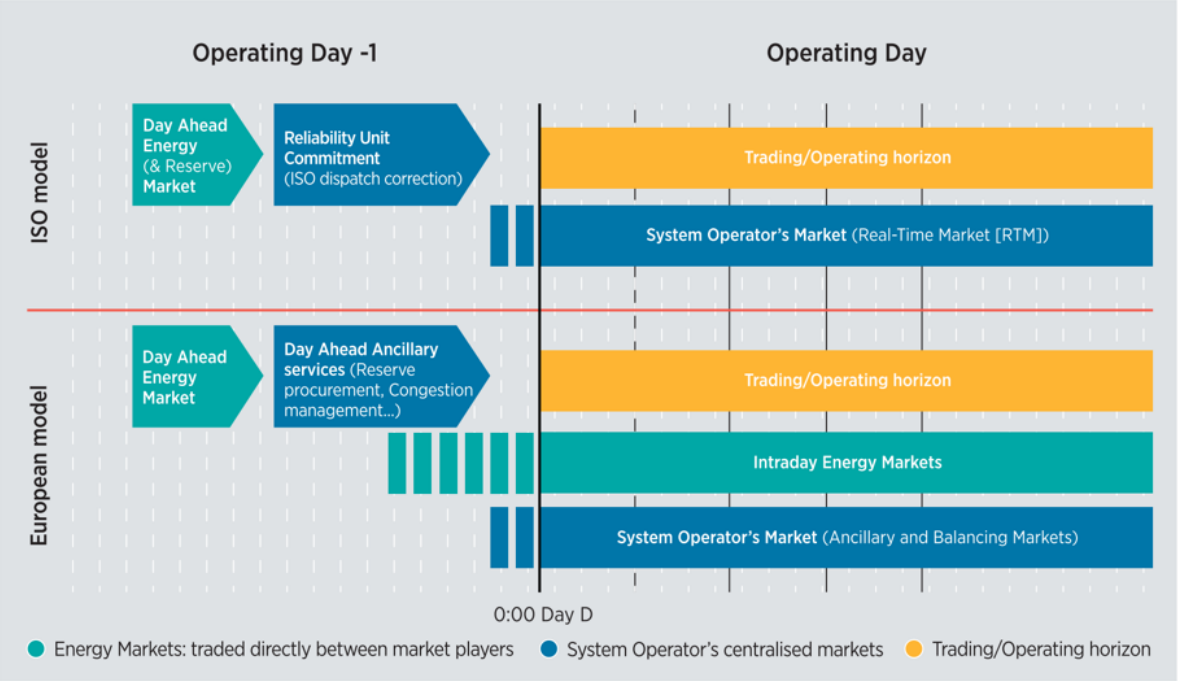


***Figure 23** - Short-term market time frames in the US and EU (IRENA 2017)*

A comparison of the US ISO and European market models is provided in Figure 23. In contrast to the EU market model, participation in the day-ahead market is mandatory in California. Another noteworthy difference is the fully integrated security-constrained dispatch performed by the CAISO,

where reserves are co-optimised with energy in the day-ahead market, and balancing is managed within the real-time energy market [interviews40,42]. Unlike the simple bids submitted by participants in the Italian and GB markets, market players in California submit complex bids that outline multiple cost and performance characteristics. The ISO then resolves these bids for least-cost (bid-in cost) operations using mixed-integer programming in the so-called optimal-dispatch-based dispatch (IRENA 2017). Prices are determined based on the marginal system cost, with pricing calculated at a granular level to account for local transmission constraints through locational marginal pricing for each transmission node.

### 5.3.3 Power mix evolution

Figure 24 shows the evolution of electricity supply in California. Before restructuring, in the late 1990s, California's power system was already dominated by gas, followed by nuclear and hydro. The years following liberalisation up to 2010 saw further investment in gas plants and, as for today, gas continues to play a major role in the state's power mix. Hydro and nuclear shares have been on a decreasing trend. Already in the beginning of the 2000s, wind entered the power mix, mostly large-scale turbines. Wind shares have been increasingly steadily up to the mid-2010s and stabilising at a 7% share. Around this time, solar picked up dramatically going from zero to 15% in just a decade. Like Italy, California's average RES plant size tends to be lower compared to the UK due to the presence of many distributed PV generators.

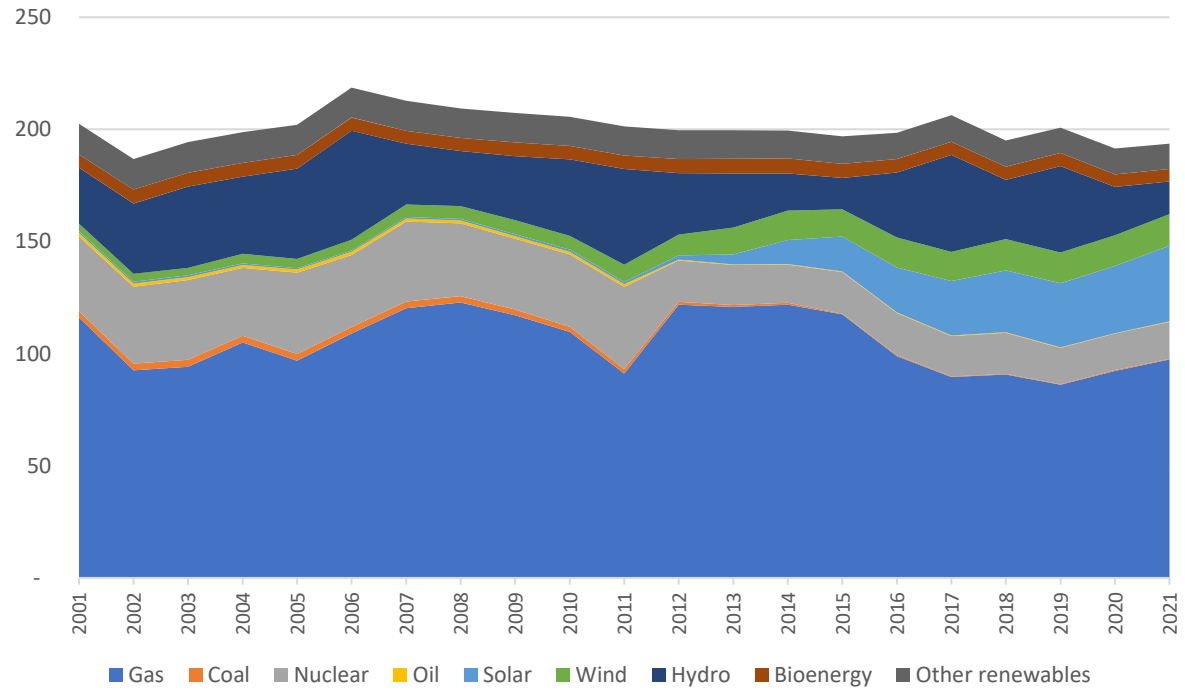


***Figure 24** - Electricity production by source in California (TWh) (CEC 2021)*

### 5.3.4 National government

California has a more fragmented governmental system compared to most US states with a blend of state-level agencies and federal institutions all playing an important role (Karapin 2016). It has a highly plural rather than unitary executive, with ten state-wide elected offices, including the governor, lieutenant governor, treasurer, controller, attorney general, secretary of state, insurance commissioner, and a board overseeing tax policy (ibid). The governors wield average institutional powers, and the state has a bicameral legislature with notably high capacity compared to other US states (ibid). The State Assembly shapes energy policy direction by enshrining specific targets into state law.

Often labelled a 'one-party' or 'quintessential blue' state, California's allegiance to liberal values, epitomised by the Democratic party, combines with its aspiration to lead the global fight against climate change, cultivating a culture marked by an "ideological commitment to decarbonisation that borders on the religious" [interview43]. This shared objective traditionally fosters coordination within a complex and fragmented governance structure, with all key power sector institutions "marching to the same drum" [interview40].

Compared to the UK, the US system leans towards decentralisation, illustrated by the average number of municipalities per 100,000 inhabitants, standing at approximately 11 (OECD 2017). California uniquely features a strong role for direct democratic procedures, which constrain the executive's power by subjecting the governor to recall and diffuse legislative authority (Karapin 2016). Unlike Italy and, particularly, the UK, where power sector governance ultimately falls under national agencies, California boasts a more diverse institutional landscape, encompassing various market actors collectively termed 'public power,' which are not directly under state regulatory agencies' jurisdiction. These include, for example, municipal public utilities.

In terms of government effectiveness, the US scores three times higher than Italy (World Bank 2021). California exhibits robust administrative capacity for policy and strategy formulation (Karapin 2016). The state has historically maintained well-staffed, independent, science-based agencies pivotal in policy development and implementation. Beyond considerable internal expertise within state agencies, Californian policymakers also rely on a wide range of highly competent academic and non-academic research institutions to inform their decisions. Regarding corruption control and government data transparency, the US falls between the UK and Italy but excels in stakeholder engagement and policy process transparency (OECD 2017; World Bank 2021).

### 5.3.5 State-market relations

Though embedded in the strongly market-driven US context, in California's there is moderate support for government intervention compared to the national average (Karapin 2016). This is even more so in the context of power sector policy. As noted in sub-section 5.3.1, while California enthusiastically undertook liberalisation in the 90s, the energy crisis marked a dramatic shift in attitudes and in the governance approach: "we tried markets, and we failed so people went the other way to really have much more control and make sure this never happens again" [interview47 – government consultant].

Large parts of its electricity system remain tightly controlled by the state through direct regulation, and state agencies retain a high degree of control over system planning. As noted by this participants, "the crisis showed that the state has unlimited powers when they feel threatened, from the policy perspective, everything is designed to avoid another major disaster" [interview50]. The retail and the delivery of state policy programmes remains organised around incumbent regulated distribution utilities.

### 5.3.6 Sector-specific institutions

#### *5.3.6.1 State energy commissions*

In California, the strategic implementation of legislative targets primarily falls under two institutions: the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). Historically, the CPUC has a much larger role and scope for action in shaping power sector policy, but the allocation of responsibilities is often blurred, overlapping and evolving.

The CPUC, established in 1912, has a broad regulatory mandate, overseeing utilities in sectors such as electricity, telecommunications, rail transport, gas, and water. Its mission is to ensure consumers have access to safe and reliable utility services at reasonable rates, safeguarding them against fraud, and promoting the state's economic well-being (CPUC 2021a). The CPUC's unique status as a constitutionally authorised agency grants it the authority to develop rules and enforce policy programs with a degree of independence (Simeone 2016). However, the CPUC's five commissioners, appointed

by the Governor and approved by the Senate, make it susceptible to political influence [interview41]. When aligned with a clear political mandate and strong leadership, the CPUC can exert significant influence [interviews47,50], as widely demonstrated in this thesis.

The CPUC's activities in the wholesale market segment encompass regulating transmission rates, implementing changes in wholesale market design and operation, engaging in transmission planning and policy initiatives, and ensuring electric reliability (CPUC 2021a). Over time, the CPUC has expanded its regulatory authority over public utilities through rulemaking, often leading to legislative codification of these actions, which brings them under legislative requirements (Kaatz 2016). While this expanded scope reflects the need to manage an increasingly complex energy system, it was identified as potentially hindering effectiveness: “there’s so many things going on that they do not even have control of their own proceedings and strategies” [interview43]. Furthermore, ongoing market fragmentation (sub-section 5.3.8) adds complexity to the CPUC's role, which over time underwent adaptation with ad hoc jurisdictional expansions of its powers [interview45 – senior official].

CPUC procedures are conducted publicly and involve extensive discussion and engagement (Karapin 2016). However, the CPUC has faced criticism, including accusations of regulatory capture in 2015, stemming from perceived close ties with incumbent utilities during the rate-setting process (Simeone 2016). This, coupled with concerns about the CPUC's effectiveness due to its broad remit and recent high-profile energy disasters, led to institutional change. In 2016, California lawmakers passed a constitutional amendment, granting the Legislature the authority to reallocate or reassign CPUC's functions to other state agencies, notably the CEC, and reducing its special constitutional powers (Kaatz 2016).

As California's energy policy and planning agency, the CEC aims to create “the energy system of the future—one that is clean, modern, and ensures the fifth largest economy in the world continues to thrive” (CEC 2021a). Its role includes planning and policy development for renewable energy, energy innovation, clean transportation, electricity infrastructure, and emergency response (ibid). Historically, the CEC has fewer powers and independence compared to the CPUC in power sector policy [interviews46,47]. Like the CPUC, its commissioners are appointed by the Governor, but it lacks the CPUC's constitutional rulemaking authority. The CEC often played a supporting complementary role to CPUC’s activities. However, the CEC's budget, scope, and authority have expanded significantly in recent years [ibid]. For instance, it gained the authority to expedite permitting for large power plants and received increased funding for research and development. As a result, its technical capacity has grown rapidly, and it is often referred to as the 'state's research arm' [ibid].

The Department of Water Resources (DWR) also plays a role in power sector policy. Formally responsible for managing and regulating the state's water usage, the DWR has, on occasion, taken on significant functions in power sector governance under special appointments by the Governor, particularly during times of crisis [interview50]. For example, during the California Energy Crisis, “the state came out and said that some obscure state department [the DWR] is going to contract all the generation capacity” [ibid]. In 2022, the Governor assigned the DWR the responsibility for managing a newly created strategic reserve scheme to procure emergency generation during periods of system stress (see Chapter 8).

#### *5.3.6.2 The system operator*

In California, the transmission infrastructure is not owned by the system operator, instead, by private investors, following the common US ISO model. The California Independent System Operator (CAISO) not only operates the power system but also manages wholesale electricity and service markets, a typical practice in integrated market designs [interviews40,42]. Beyond operational duties, CAISO is responsible for planning, grid connection management, and conducts technical analyses in support of state policy.

Differing from other ISOs, CAISO's Board of Governors is appointed directly by California's Governor, confirmed by the Senate, based on nominations from a stakeholder process [interview41]. Before the crisis, the board was elected by stakeholders comprising of both market and non-market participants: “during the crisis the market participants gained a majority on the board. It was alleged that that’s why the crisis happened because they were able to coalesce and manipulate the price. The state used that to justify replacing it with a board appointed by them” [interview51]. Some note that this unique institutional set up is also partly rooted in a distrust of federal institutions, particularly the federal regulator responsible for overseeing US transmission operators [interviews41,48] (see sub-section 5.3.7).

Hence, CAISO's activities are closely aligned with state policy and politics, as one participant noted, “CAISO is not in the driver's seat” [interview50]. This is evident in the subordinate role it plays in decision-making processes: “if the ISO wants to talk to the CPUC as a peer and negotiate something, they really can't do that, the CPUC won't permit it. Instead, they have to come into a proceeding and submit their testimony and argue with all the other parties. Then you know, maybe they get a little bit of special consideration because they really are experts and they tend to be pretty independent. They [CAISO] are technically superior, but politically subordinate” [interview43]. In the realm of electricity market design, the CPUC typically submits informal filings to CAISO, which are refined and finalised before formal approval by the federal regulator (CPUC 2021).

CAISO is known for its transparent and open engagement process [interview41]. Any stakeholder within the electricity system can propose rule changes. Unlike most other entities, CAISO does not adhere to a formal committee structure based on sector representation (Lenhart et al. 2016). Instead, it uses an iterative consensus process for decision-making, involving open stakeholder meetings, oral and written comments, without formal voting. These meetings are recorded and publicly accessible. The openness of CAISO's processes is, to some extent, a result of its authorisation through California statute, which places it under more direct jurisdictional control by the state. Consequently, CAISO must adhere to open meeting laws and state requirements applicable to public state entities. It was noted that this openness “facilitates collective learning and engagement” [interview41].

### 5.3.7 Multi-level governance

The Federal Energy Regulatory Commission (FERC) is an independent authority regulating various energy-related activities across the US with the mission of ensuring the delivery of “economically efficient, safe, reliable, and secure energy for consumers” (FERC 2021). Among other things, it regulates transmission and wholesale electricity and natural gas sales, and conducts energy markets’ monitoring. FERC's jurisdiction expanded over the last century through a series of congressional acts (FERC 2018). However, efforts to broaden FERC's authority have historically faced opposition from state legislators [interview45]. Hence, key aspects of electricity regulation remain under the purview of state public utility commissions (FERC 2021).

FERC operates as an independent regulatory agency within the US Department of Energy, with five President-appointed commissioners approved by the Senate through a bipartisan system (FERC 2018). FERC's decisions are typically not reviewed by the Senate or the President but fall under federal courts’ jurisdiction. FERC's budget is determined by Congress and funded through charges on regulated industries (ibid). Participants note that, although designed to be independent from political influence, FERC's agenda can be influenced by politics, as seen during the Trump administration [interview40].

In the 1990s, FERC attempted to advance the liberalisation of the US power sector through a series of orders (Hobbs & Oren, 2019). However, as noted by Isser (2015), “FERC was mandated to open up electricity markets to competition without the authority to override state regulators when it came to transmission, generation, and retail sales.” FERC’s efforts were also jeopardised by the California’s Energy crisis, which increased scepticism toward markets nationally [interviews39,47]. Hence, the US presents a heterogeneous landscape with a mix of power sector arrangements. Nevertheless, FERC

continued to promote a standard US market design, featuring integrated markets with locational marginal pricing (Hobbs and Oren 209; Isser 2015). In regions where integrated utilities resisted regional integration, FERC gradually tightened the screws, increasing the regulatory burden (ibid). In recent years, to accommodate renewable energy growth and new market entrants, FERC has taken a more proactive role in power market design introducing important orders affecting power market rules [interviews39,41].

FERC's role during the California's crisis has had deep-rooted consequences for the state's governance and policy approach. In fact, "from the perspective of the governor the FERC didn't come in to help address and put price caps to stop the crisis" [interview41]. This has resulted in a 'long-lasting mistrust' of the federal regulator, with institutions 'structured to avoid federal regulation' [interview48]. State policymakers are also concerned about interference by federal politics, which might undermine the state' ambitious decarbonisation goals [interview45]. Observers also note that California often leads in experimenting with innovative power market designs, setting a model for FERC policy [interviews39,41]. Finally, FERC was described as a 'slow' and 'litigation-oriented institution' [interview40].

In 2014, California initiated real-time market coupling with neighbouring states through the Western Energy Imbalance Market (EIM) (Hobbs and Oren 2019; IEA 2018). The EIM, discussed extensively in sub-section 6.3.1, has unique governance arrangements. Participation is voluntary, CAISO operates the market, and the Western Electricity Coordinating Council oversees it, involving representatives from participating utilities and state regulators (Lenhart et al. 2016). The governance hence remains fragmented, involving multiple sub-regional balancing authorities, planning organisations, and bilateral contracts. This stems from political variations among Western US states, differing in their attitudes and priorities, especially regarding climate policy [interviews39,41]. California, with aggressive climate goals and renewable energy policies, differs significantly from more conservative states like Arizona, Utah, Colorado, and Wyoming, which retain substantial coal generation. Further, California plays a disproportionally large role in the Western Interconnection due to its sizable power system and CAISO's position as the market operator. This is perceived with concern by other states due to CAISO's close link with state policy.

### 5.3.8 Market structures and interests

Following liberalisation, the Californian electricity supply sector became less concentrated thanks to divestment by incumbent utilities and the entry of several IPPs. The market share of IOUs went from 65% of large-scale generation in 1996 (when liberalisation formally started) to 35% in 2001 (EIA 2021). In contrast, IPPs increased their share from around 10% to over 40% during the same period (ibid). Additionally, California's market features a substantial presence of smaller PUOs municipal utilities, collectively serving 25% of the state (CMUA 2023).

California never fully liberalised its retail sector with IOUs continuing to provide vertically integrated services to their customers. However, since 2015, a novel retail arrangement, community choice aggregation[16] (CCA) has been gaining prominence in the retail segment of IOUs' service territories. CCAs accounted for 25% of peak load by 2020 (John 2019; CPUC 2019). Hence, there is a reduction trend in the level of vertical integration of distribution and retail activities.

Following liberalisation, incumbent IOUs divested most of their gas and geothermal generation assets, which were acquired by IPPs (Figure 25 and Figure 26). Similar Britain and Italy, the years after liberalisation saw significant investment in new gas power plants, especially by IPPs. IOUs retained ownership of nuclear and hydro assets, which they still operate today. Most of large-scale RES investment also came from IPPs. Like Italy, California the ownership of renewables is less concentrated

[16] Programs allowing local governments to procure power on behalf of local consumers from an alternative supplier while still receiving transmission and distribution service from their existing utility provider.

than in the UK due to the significant presence of small-scale solar installations. In 2016, out of the 15% solar share in total generation, a third was generated by rooftop solar (Penn 2017).

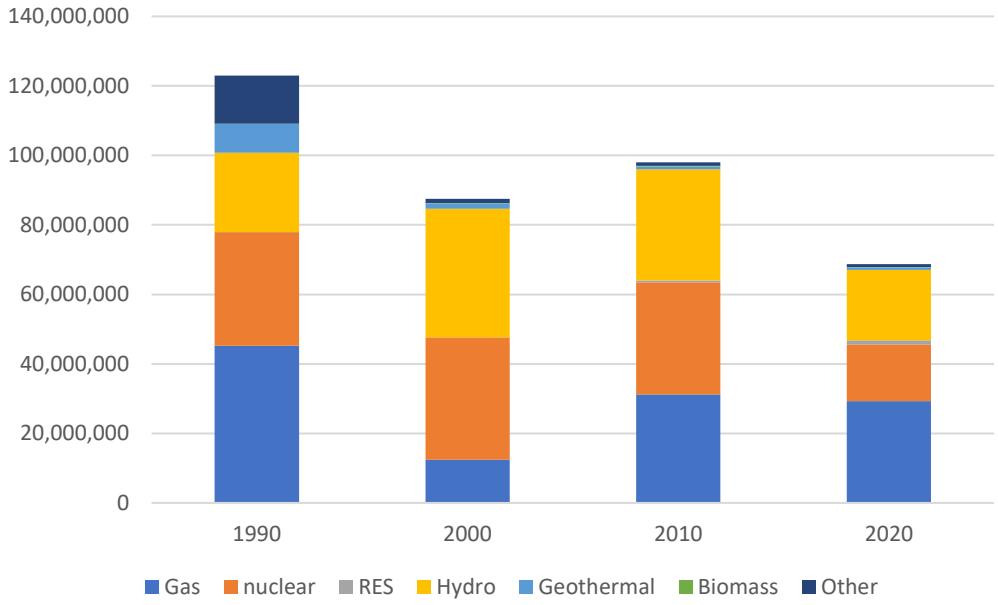


***Figure 25** - Utilities annual generation by source (MWh) (EIA 2021)*

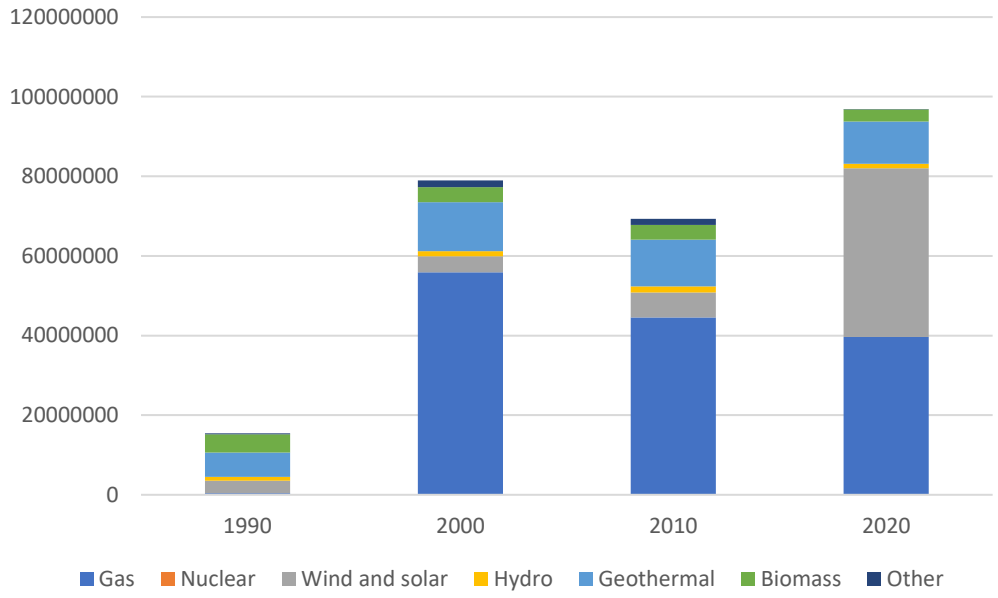


***Figure 26** - IPPs annual generation by source (MWh) (EIA 2021)*

Often described as 'conservative' or 'very bureaucratic like government', incumbent IOUs are regulated by the CPUC based on a guaranteed rate of return [interviews39,48]. Their priorities include system reliability, cost reduction, expanding their assets and customer base [ibid]. Observers say these companies are a 'strong lobbying presence at the legislature' and 'dominate proceedings', with considerable expertise and 'armies of 300 regulatory analysts and hundreds of attorneys' [interview52]. Recently, their position has faced challenges from frequent wildfires, for which they are financially liable, and emerging market entrants, particularly CCAs [interviews43,45]. CCAs were initiated by local communities of 'lefty environmentalist liberals near San Francisco' wanting to directly purchase renewables [interview39]. They have since expanded rapidly becoming 'powerful entities'

legitimised by elected local officials [interview49]. Nevertheless, participants note that “utilities are always gonna take care of themselves […] as guaranteed revenue puts them above everyone else” [interview47].

IPPs also play a significant role in California’s power market policy. As they are usually invested in either gas plants, utility-scale renewables, or a mix thereof, they tend to advocate for market designs favouring utility-scale assets [interviews39,52]. Among them, gas generators see themselves as ‘the last man standing’, but have also recently been investing in battery storage [interview48 – large IPP representative]. IPPs are ‘long-term participants in policy debates’; being large international companies, they have access to considerable resources and information, which they use strategically [interview43]. Beyond large-scale RES owned by IPPs, there is a sizeable presence of distributed PV producers in California, often described as a ‘really politically powerful lobby’ [interview49]. Finally, California also features publicly owned municipal utilities, which operate within CAISO territory with their control areas. PUOs are vertically integrated, regulated based on asset base, and fall under the jurisdiction of local authorities. Their priority is to retain control within their areas, avoiding state or federal jurisdiction [interview41].

Mirroring this heterogeneous market landscape, California’s interest groups are numerous and competitive, heavily involved in electoral politics through financing campaigns, and lobbying (Karapin 2016). It was estimated that interest groups draft around 60% of the bills submitted to the legislature (ibid). Interactions among stakeholders are often confrontational, to the extent that certain groups are forbidden “from speaking publicly in any kind of disparaging way about other groups” [interview39]. A policymaker observed that this can result in a ‘messy’ policy process: “there's a lot of a lot of talking that needs to happen to move anything, sometimes I get sort of amazed that it works” [interview46]. California’s pluralist style of interest intermediation is in stark contrast with the corporatist models seen in the UK and especially Italy. Unlike the convergence of energy industry interests under larger umbrella associations, California's interest groups maintain distinct associations to advocate for specific technologies and concerns including multiple renewable groups.

Consumers groups are also described as influential with ‘a lot of political sympathy’ [interview43]. While their main goal is affordable electricity, some point to some conflicts in their agendas: “they are fundamentally conflicted because […] their ideology tends to be very supportive of green and carbon reduction, at the same time, there's supposed to be protecting consumers. And consumers are paying a very high price for our policies” [ibid]. As opposed to Italy, industrial and manufacturing interests are important but not as pivotal in the policy process, with the sector accounting for 22% of electricity demand (Statista 2018).

Environmentalists also hold significant influence in California, in line with the state's strong commitment to decarbonisation [interviews43,47,52]. Additionally, local energy justice groups have gained prominence following blackouts and wildfires, advocating for local power systems to enhance local communities’ resilience [ibid]. Finally, labour unions have considerable bargaining power [interview41]. California has high employment in the energy sector, traditionally in the fossil fuel industry (0.39% of national workforce in 2019), but increasingly in green jobs (0.33%) (E2 2019; LACEDC 2019). Hence, there is a clear interest to keep these jobs inside the state [interview41]. Interestingly, unions often form a coalition with incumbent IOUs: “the labour unions agree to support the interests of the utilities in legislative and regulatory activities […], they form a powerful coalition” [interview52].

# 6 Evolution of short-term energy markets design

This chapter analyses recent changes in short-term energy market design implemented to enable VREs integration in Britain, Italy and California. Specifically, it reviews changes across day-ahead and intraday/real-time markets covering a variety of aspects ranging from market coupling, scheduling rules, market timeframes to pricing rules. It is important to note that California has a different market structure from Britain and Italy whereby energy and reserves are co-optimised, instead of being procured in a separate market (see sub-section 5.3.2). To simplify comparison, an artificial distinction has been drawn between market design elements relevant to energy trading and those focusing on reserves and ancillary services. This section deals with the former aspects, while the latter are treated in Chapter 7 focusing on the evolution of balancing market design.

## 6.1 The evolution of short-term energy markets in Britain

### 6.1.1 Day-ahead and intraday market coupling

As a former EU member state, Britain took its first steps towards market coupling in 2014 when it joined the EU Single Day Ahead Coupling (SDAC) in compliance with EU's regulation and vision for the Internal Electricity Market (see Figure 30) (EC 2015). The presented rationale is that further market integration enables the optimal allocation of cross-border resources resulting in the dispatch of the most economically efficient plants and, hence, lower average prices (Pollit 2019; Castagneto Gissey et al. 2019). Interconnection across different geographies also allows cross-border transfers of power that can help meet reliability needs during times of scarcity or excess generation made more frequent by a growing VREs fleet (Roques 2021).

SDAC is a coordinated electricity price-setting and cross-zonal capacity allocation mechanism designed to allocate scarce cross-border transmission capacity in the most efficient way by coupling wholesale electricity markets from different regions through a common algorithm, simultaneously considering cross-border transmission constraints thereby maximizing social welfare (MISE 2019). SCAD was extended[17] to GB borders physically connected to continental Europe and to the Single Electricity Market across the island of Ireland (BEIS 2021). Evidence suggests that these arrangements drove efficiency in dispatch and allowed Britain to import more overall and to export in moments of excess-generation (Newbery et al. 2019).

Two years later, the 2016 Brexit referendum, whereby the UK formally withdrew from the European Union, spurred a dramatic turn in national strategy on the project of further EU market integration. Political notions of sovereignty, self-determination and independence came to shape the Government's agenda (Lockwood et al. 2017a). Additionally, a lack of strong European identity among voters, with 63% lacking regional identity before the referendum, contributed to this outcome (Gastinger 2019). This had important repercussions for power sector policy, which saw the fall of the legislation that had supported day-ahead market coupling and the end of the single GB clearing price[18] (BEIS 2021). Some studies have attempted to untangle the economic implications for the GB power sector (Geske et al. 2019; Guo and Newbery 2021). Though they have come up with different estimates, they all show a net economic loss.

The British experience demonstrates how political considerations and shifts in national priorities can override techno-economic economists' prescriptions on cost and efficiency (Lockwood et al. 2017a).

[17] The implementation of this reform in Britain had taken several years to be finalised due to complexities related to the coupling of interconnectors and coordination of two main exchanges operating in Britain, EPEX and Nord Pool, so that transactions could be cleared on a single GB clearing price in the EU Day-ahead auction (BEIS 2021).
[18] UK power will continue to be traded on the N2EX and EPEX exchanges, but these will now be separate auction processes with separate order books. Interconnector capacity for the interconnectors between the UK and the EU will also be traded in explicit day-ahead auctions (Watt-Logic 2021).

Evidence also suggests that market decoupling was introduced in spite of general opposition in the power industry and a recognition of the benefits of the single market among energy policymakers [Interviews 3,4,10]. This is exemplified by the words of this energy economist: “it took a long time and a lot of re-design to put it in place. Why the hell would you give it up? It's pure political gesturing […] it’s just imposing barriers which are not necessary to the disbenefit of both sides” [interview2].

From 2015, the EU has also been advancing the coupling of intraday markets through the EU continuous market coupling solution, known as CrossBorder Intraday (XBID), as illustrated in Figure 31 (EC 2015). However, intraday cross border arrangements were not extended to the GB market before Brexit. As such, due to the political decision of leaving the Union, the techno-economic benefits from intraday coupling have never been exploited in this jurisdiction.

### 6.1.2 Day-ahead and intraday market rules

Since the introduction of NETA/BETTA in the early 2000s, the British wholesale energy market has not undergone any major modifications in terms of its fundamental design features – pricing, bidding, time dimensions have stayed the same. The British market model remains decentralised, based on bilateral, continuous trading and portfolio bidding (see sub-section 5.1.2). This model is closely aligned with the EU Target Model, also based on a decentralised logic with self-dispatch (Oxera 2020). According to participants, GB actively influenced the EU preference for decentralised dispatch when it was still part of the single market alongside other influential countries, notably Germany, with a similar preference [Interviews 20,25,29,1].

The long-standing commitment to this market model can be partially explained in terms of specific beliefs on the roles of market, dominant philosophies on power system operation and the appropriate trade-offs to be drawn across transparency, security, costs and liquidity (sub-section 5.1.2). Self-dispatch, the argument goes, should drive optimal operational decisions based on decentralised market signals and bilateral trading (BEIS 2020; UK Gov 2015; Oxera 2020). Some argue that this might also partially related to historical system conditions: Britain and other EU countries that have been endorsing a more decentralised dispatch originally had less network constraints at the time of liberalisation [ibid]. Further, some experts suggest that traders, who play a much larger role in decentralised market models as compared to physical systems, might have been historically influential in directing EU and GB policy towards more decentralised market designs [interview2] (Cramton 2017).

Although there is no consensus in the techno-economic literature, proponents of the decentralised dispatch model argue that this is particularly suitable in the context of a high-VRE system as it provides economic incentives for VREs producers to operate in a more system-compatible way (IRENA 2017; Hu et al. 2018). In fact, closer-to-real-time gate closure, which is complementary to this model, allows production scheduling optimisation thanks to reduced forecast errors minimising the need for reserve margins and, hence, balancing costs (ibid).

However, the recent growth in balancing costs and reliability challenges have led several power system stakeholders to question the legacy British power market model. Notably, the system operator NGESO has been advocating for a move to a more central dispatch logic, which would overhaul all key design features currently found in the GB market (NGESO 2022). A more centralised dispatch, the argument goes, would allow to have a better representation of physical system conditions through the introduction of locational pricing (ibid). However, such a shift is likely met with stark opposition by some RES operators located in constrained locations as it would affect the value of energy, creating winners and losers (discussed more extensively in sub-section 6.1.4). More radical changes in the GB market design might occur in coming years as market arrangements are undergoing a comprehensive review as part of 2022 BEIS’ Review of Electricity Market Arrangements (REMA) (BEIS 2022).

Finally, one policy implemented by the EU consists of increasing the time granularity of settlements allowing renewable operators to re-adjust their imbalances based on updated forecasts (Schittekatte et al. 2020). Specifically, the European Commission introduced regulation requiring market operators

to allow energy trading in intervals equivalent to imbalance settlement periods of 15 minutes both in the day-ahead and intraday market frames (EC 2017, 2019b). Interestingly, the regulator Ofgem requested an exemption from this reform on the basis that the costs for consumers related to implementation would outweigh potential efficiency gains (Ofgem 2020). Again, this highlights differences in the dominant understandings of costs and benefits of different market enhancements among the policymakers of different states.

### 6.1.3 Wholesale price regulation

Since BETTA was introduced up until the time of this research, Britain has not directly intervened to regulate wholesale power prices. The economic rationale of this approach has been to pass through economic signals to market participants especially for investment in new generation, which is in line with purist economic theory (Stoft 2002; Hogan 2013). However, it is important to note that, while it did not directly intervene in wholesale markets, the regulator Ofgem introduced a retail price cap in 2019 due to mounting political concerns over affordability (Ofgem 2019). This sets a limit on the amount that suppliers can charge certain consumers for a unit of energy on default (or standard variable) tariffs (ibid).

The retail energy cap marked a shift in the regulatory logic towards a more interventionist, administrative approach [interview16]. According to a senior policymaker, the introduction of the cap was “not that controversial politically, but very controversial within the institutions. Most people were trying to convince you to think if you put a price cap you end up with supply shortage so you know you can imagine the sort of conversations we had internally and certainly with most of the industry” [interview7]. Some participants argue that exposure of non-integrated suppliers to market risk has been accrued significantly by the introduction of a retail price cap due to traditional hedging difficulties faced by smaller suppliers [interviews 4,16,19]. When wholesale gas prices began spiking in Summer 2021, smaller utilities that had not properly hedged found themselves exposed to large risks as compared to traditional vertically integrated suppliers who had purchased long-term products for the coming winter in January 2021 [ibid]. As a result, 31 energy companies have left the GB market, which used to serve over two million customers (Cyrus 2022).

### 6.1.4 Locational pricing

Britain has traditionally not included a measure of locational constraints in its wholesale power price, instead, this is done through network charges (Pownall et al. 2021). Recent years have seen important modifications in network charging methodologies reflecting evolving system conditions and new political priorities with different policy trade-offs being over time. In principle, “charges should be fair, efficient and cost-reflective” (Newbery 2019). However, the British experience illustrates that these objectives can often be in conflict and that the distribution of network costs raises difficult political questions.

From 2010, the Connect and Manage scheme had allowed new RES generation assets to connect to the transmission network before completion of reinforcements (National Grid 2013). This reform, implemented in the wider context of the 2008 Climate Change Act (Section 9.1), aimed to enable quicker grid connection for renewables, prioritising decarbonisation over efficiency considerations [interviews 4,6]. Coupled with renewable energy support, this led to an increase in congestion costs as RES assets began clustering in windy locations less-well connected to transmission infrastructure (Joos and Staffel 2018). Transmission network charges have since increased rapidly for RES generators, fuelling concerns that this would undermine decarbonisation efforts [interviews 1,6,15]. The emerging geographical distribution of wind curtailment rates is illustrated in Figure 27 below.

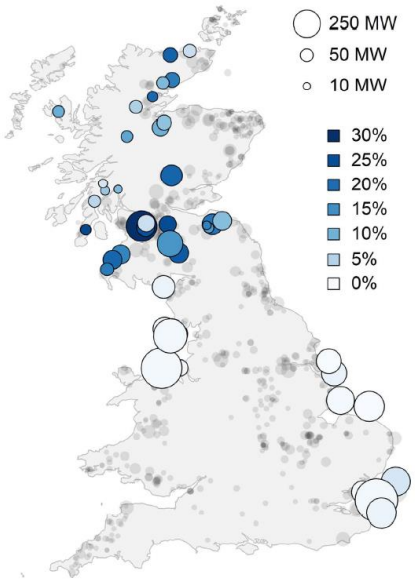


***Figure 27** - Curtailment of wind farms participating in the balancing market 2015-2016 (Joos and Staffell 2018)*

In 2014 Ofgem's Project Transmit reviewed how transmission residual costs should be recovered – i.e. the costs of providing and maintaining shared electricity transmission assets (Ofgem 2014a). The reform first shed light on a major 'philosophical stroke over the merits of cost-reflective pricing among different stakeholders' resulting in 'political battles with North-South connotations' lasting to this day [interview1]. Broadly, proponents of cost-reflective pricing tend to be in less constrained areas, while those located in more constrained areas, typically in the North, argue that "electricity is an essential good and should be available at the same price everywhere like postage stamps" [ibid]. Project Transmit moved some costs onto conventional generators and introduced incentives for RES operators to locate in less congested areas. Nevertheless, network charges remained high in some areas (see Figure 28).

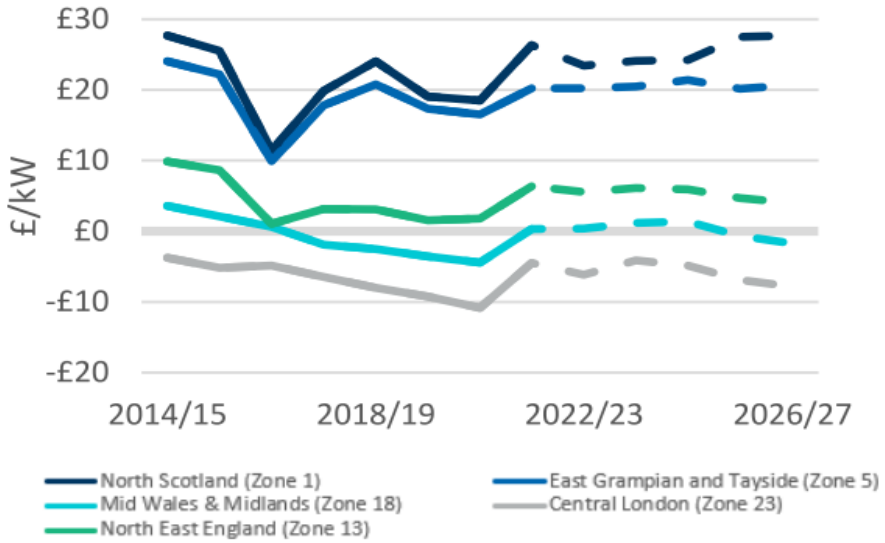


***Figure 28** - Transmission generation tariffs for intermittent renewables (NGESO 2021)*

In the mid-2010s, policy discussions also focused on the issue of 'embedded benefits' (Ofgem 2019a). Large generators began lamenting that network charging arrangements gave an 'unfair' advantage to smaller distributed generators connected to the distribution network who faced less costs compared

to transmission-connected producers [interviews 6,7]. These distortions became evident in the first round of the capacity market when small diesel generators outcompeted larger, more efficient gas plants (Section 8.1). According to participants, this gave rise to a decade-long 'regulatory fight' with large generators advocating for an overhaul of network charging methodologies, and embedded generators fiercely resisting change [interviews 6,7].

Since 2017, the regulator initiated comprehensive reforms to address various emerging issues including the recovery of growing fixed costs, distortions related to embedded benefits, and enhancing locational signals to promote efficient network utilisation. A key initiative was the 2017 Targeted Charging Review, which focused on residual charges for transmission and distribution fixed costs levied on generation and demand (Ofgem 2019a). The review marked a substantial shift in regulatory principles from cost-reflectivity to fairness as the guiding factor for defining residual network charges (Ofgem 2019a; Clark 2018). The rationale, as articulated by one participant, was to 'charge it as fairly as possible when no obvious location or time of use element is present' [interview6].

Often described as extremely controversial, the reform once again highlighted deep ideological fractures in the industry over the merits of cost-reflectivity and understandings of fairness in the distribution of system costs among different generators and consumers across the network [interviews 1,6]. For example, on the question of how charges should be levied on final consumers, those able to adjust their consumption advocated for consumption-based levies, while industrial consumers for charges based on connection points [interview 18 - representative of decentralised energy industry]. In the end, the regulator opted for a fixed band system based on capacity as the other two models would have disproportionally penalised small consumers unable to adjust their consumption [interview 10].

Complementary to the aforementioned reform, the Forward-Looking Charges Review, launched in 2018, has aimed to revamp forward-looking charges and access rights to enhance price signals for generators and consumers, promoting efficient network use (Ofgem 2022a). While the Targeted Charging Review focused on fairness in fixed cost recovery, the Forward-Looking Charges review prioritises cost-reflectivity to encourage investment compatible with the system and new flexibility solutions (BEIS and Ofgem 2017). This reform has faced significant controversy and delays due to the same political dynamics discussed earlier and remains ongoing at the time of writing[19].

Meanwhile, growing network congestion, particularly at the Scottish and East of England boundaries, has led to increased curtailment and constraint costs (see Figure 29). Some experts argue this is accrued by the fact that current transmission charging arrangements fail to provide short-run locational signals that reflect real-time system needs (ESC 2019; Policy Exchange 2020; Pownall et al. 2021). Several research institutions with a market-oriented approach hence advocate for the introduction of locational marginal pricing (ibid). The system operator NGESO also strongly supports nodal pricing, believing it would enhance efficient dispatch, reduce balancing costs, provide correct signals to interconnectors and storage, and unlock demand side value (NGESO 2021, 2022b). Since 2021, NGESO has been lobbying Government in support of this reform [interview 11 - senior market expert at system operator]. This ambition to shape the market design is seen by many as a by-product of the recent institutional separation of NGESO, which has led it to take a more proactive stance in the sector's governance (sub-section 5.1.6.2).

[19] So far decisions include the introduction of shallower charges in distribution connections, better definition of flexible access, and the extension of transmission charges to distributed generators (Ofgem 2022a).

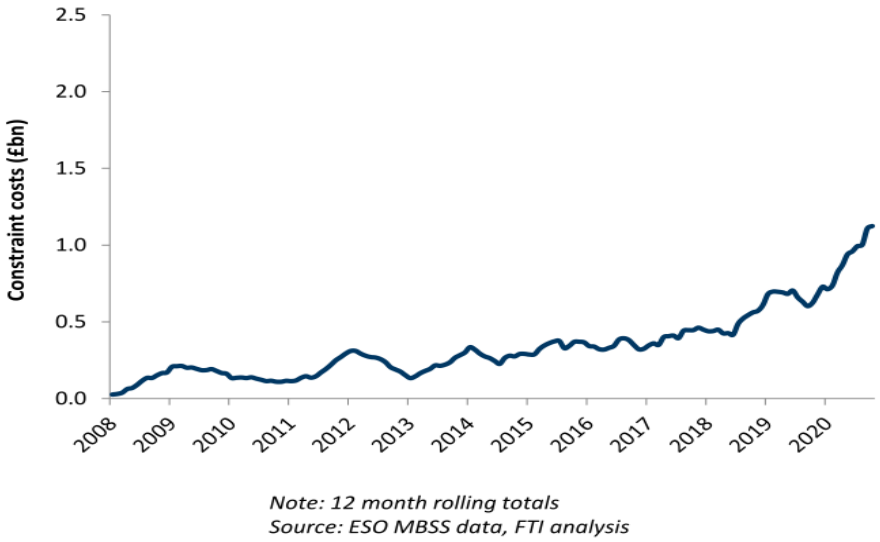


***Figure 29*** *- Historical constraint costs (NGESO 2022; FTI analysis)*

The same political struggles that have influenced network charging reforms are also shaping the LMP debate, often considered the most contentious issue in GB power market design [interviews 3,6,7]. Incumbent companies, which heavily invested in renewables based on current uniform pricing in windy locations, resist nodal pricing [interviews 12, 13 - representatives of major incumbent generators]. Scottish renewable energy producers have lobbied for reductions in network charges and fear that nodal pricing would exacerbate these issues [interview 15 – representative of Scottish RES industry]. They argue that the UK will not achieve its decarbonisation goals unless operation and investment become more economical in windy and remote areas where construction is politically acceptable [ibid]. In addition, several participants note that "splitting England and Scotland is politically horrible" and would generate considerable political tensions across Government and devolved administrations [interviews 2,7].

Stakeholders hence disagree on the economic principles and technical aspects of LMP and its effects on market actors' responses to price signals, impacting their perceptions of the reform's costs and benefits. Many participants also emphasise that the issue of locational pricing cannot be disentangled from recent developments in transmission regulation and planning [interviews 3,12,16]. Grid congestions might be alleviated through transmission expansion, but the planning process is often referred to as 'slow' and 'inadequate' [interviews12,16]. Regulatory and policy changes have been introduced to address this, such as the RIIO regulatory regime, incentivising a more strategic approach to network planning and operation (sub-section 5.1.6.2). Significant grid upgrades are also in the works, including the B6 binary between England and Scotland (NGESO 2022). While congestion costs are expected to rise in the 2020s, they may stabilise in the long term with the implementation of transmission upgrades (ibid). Some changes have also been implemented in the NOA (Network Options Assessment), the process for identifying needed major transmission projects, to open it up to participation by distribution network companies for a more wholistic and system approach to network planning (ibid).

## 6.2 The evolution of short-term energy markets in Italy

### 6.2.1 Day-ahead and intraday market coupling

Driven by the same rationale that led to market coupling in Britain (see sub-section 6.1.1), Italy joined the EU SCAD around 2015 when it coupled its day-ahead market with Slovenia, France and Austria (ARERA 2019; MISE 2019). However, unlike the UK, the day-ahead market coupling process has further

progressed since, and Italy has recently integrated its market with Switzerland Greece and Montenegro (ibid). Contrary to Britain, in 2021 Italy has also been moving forward with intraday coupling through CrossBorder Intraday XBID (Figure 31).

Hence, Italian power sector policy has grown increasingly aligned with the EU's and there seems to be wide-spread recognition of the benefits of the IEM among key Italian power system stakeholders [interviews 20,27,32,33,38]. Though Euro-sceptic sentiments and narratives around self-determination were also growing among the wider Italian electorate, reflecting a wider regional trend, these never resulted in an exit from the Union and the single market. This likely reflects differences in political economy of the two countries especially in terms of historical relations with the EU (see Chapter 5). For example, statistics reveal that only 39 per cent of Italians lack a European identity as compared to 63 in UK before the referendum (Gastinger 2019). Anti-EU sentiments have decreased considerably following Brexit, which revealed the significant adjustment costs related to leaving the Union (ibid).

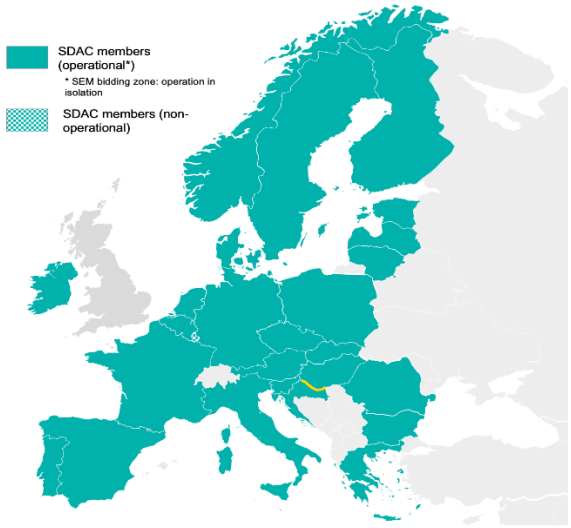


***Figure 30 -*** *EU Single day-ahead coupling (ENTSO-E 2022)*

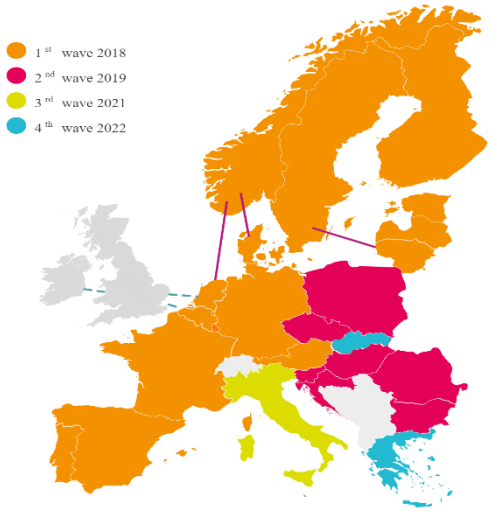


***Figure 31 -*** *EU Single intraday coupling (ENTSO-E 2023)*

Nevertheless, participants note that the process of intraday market coupling highlighted the existence of significant tensions between Italian power sector institutions and other major EU states rooted in different dominant philosophies for power system operation [interviews 20,22]. In fact, to comply with the EU Target Model, Italy had to implement significant changes to its intraday market design due to

historical differences between the Italian market model and predominant arrangements in the EU [interviews 21,27,29,31] (also see Section 5.2). As shown in Figure 31, Italy introduced market coupling after most other EU jurisdictions due to implementation complexities further discussed in the next sub-section.

### 6.2.2 Day-ahead and intraday market rules

In recent years, Italy's day-ahead market rules did not undergo major modifications. On the other hand, to implement intraday coupling, Italy introduced an extensive reform of its intraday market spanning across all the main design elements – i.e. time dimensions, bidding rules, trading formats etc. This was launched by the regulator ARERA in 2019 as part of the Testo Integrato del Dispacciamento (TIDE), a comprehensive strategy to reform the dispatch model spanning across short-term energy and balancing markets (ARERA 2019a). The overall aim of TIDE is to comply with comply with the EU Target Model, improve price signals (temporal and locational) to make the market model fit-for-renewables and incentivise system-compatible operation (especially for renewable operators) in the context of increased intermittency (ibid).

XBID, the EU model for intraday coupling is based on a very decentralised logic with continuous trading, portfolio bidding, self-dispatch and gate closure H-1 (Oxera 2020). This model mirrors the legacy market structures of some influential EU countries, particularly Germany (and Britain before Brexit), who actively advocated for it (see sub-section 6.1.2). Decentralised dispatch, the EU argument goes, is fit for a high-VREs world in that it provides economic incentives for VREs producers to operate in a more system-compatible way (ARERA 2019a). Closer-to-real-time gate closure in fact allows production scheduling optimisation thanks to reduced forecast errors minimising the need for reserve margins and, hence, balancing costs (ibid). Continuous trading, whereby bids are accepted gradually until gate closure, and portfolio bidding, whereby market participants can manage their assets more freely, are both complementary to gate closure H-1 (Terna 2020).

Such decentralised market structure differs greatly from Italy's legacy market model characterised by central dispatch, gate closure at H-4, discrete trading, and unit-based commitment [interviews 29,31] (see sub-section 5.2.2). Hence, there is significant distance between "the commercial/financial nature of exchanges conducted on EU markets from those of the Italian market, which is directly linked to physical scheduling of units" (ARERA 2019a). These two distinct power market operation philosophies are rooted in historical system conditions. In fact, due to its geomorphic configuration, Italy has historically experienced more network constraints and costs associated with infrastructure development as compared to other central European states (ibid).

Though Italian institutions have been acknowledging the advantages of closer-to-real-time trading for VREs integration and the benefits of market coupling, they have been reluctant to adopt the fully decentralised model proposed by the EU, which they perceive as 'inefficient' [interview 27 - senior official at regulator; interview 28 - senior market expert at system operator]. Representatives of both the system operator and the regulator argue that market outcomes from self-balancing (with allocation of transmission based on first-come-first-served logic) do not accurately reflect physical network constraints and are economically sub-optimal [ibid]. This in turn undermines the reliability of system operation and leads to costly interventions by the TSO.

In terms of the interests of key stakeholders, evidence suggests that the RES industry actively supported the move to a more decentralised dispatch, which enables them to respond to system conditions [interview35 - representative of major RES generator] (ANEV 2019). While the most influential energy companies and industrial consumers recognised the potential benefits of further market integration and closer-to-real time gate closure, just like policymakers, they show a strong ideological commitment to a central dispatch logic and called for a careful consideration of the 'costs and benefits' of the reform [interviews 32,38].

Hence, national policy institutions engaged in an intense process of negotiation with their EU counterparts in which "ARERA has been defending the central dispatch model tirelessly" [interview 31]. Such negotiations led to the development of a hybrid model for Italy sitting between the two dispatch philosophies, first outlined in the 2019 TIDE consultation document (ARERA 2019a). This is characterised by gate closure H-1 but, instead of a fully continuous trading, it comprises of three implicit auctions and a mechanism to allocate capacity interconnection. Portfolio bidding has been allowed in addition to unit bidding, but operators are bound by feasibility intervals. The implementation of this solution has been complex and also required adjustments in the MSD (dispatch service market), such as the adaptation of the dispatch algorithm used by Terna and introduction of some restrictions for operators, to make sure that it could be efficiently integrated with the new intraday design (Terna 2020).

As noted in sub-section 6.1.2, the European Commission also introduced regulation requiring market operators to allow energy trading in intervals equivalent to imbalance settlement periods of 15 minutes both in the day-ahead and intraday market frames (Schittekatte et al. 2020; EC 2017, 2019b). The techno-economic logic behind this reform is to increase the temporal granularity of markets to encourage flexible, system-compatible behaviour by market participants, especially intermittent generators and new flex providers based on up-to-date forecasts (ibid). Hence, Italy is in the process of reforming the granularity of its market products transitioning from an hourly to a 15-minutes trading resolution, to be completed by 2025.

Evidence suggests that VREs producers have been actively supporting this reform: "all renewable operators in Italy have been insisting a lot to have a mechanism that would allow them to potentially re-align every 15 minutes reducing their imbalances as these are penalised and penalising" [interview 35 - representative of major RES generator]. These operators stress the importance of "the principle of rewarding virtuous behaviour rather than mere cost-allocation, with a punitive spirit, on technologies that are intrinsically less programmable" [ibid]. Interestingly, these concerns are diametrically opposite of those expressed by Italian large industrial consumers, who stress the principle that "cost-allocation should be able to guarantee less costs for consumers and more responsibility placed on all market participants for their imbalances" [interview 38 - representative of industrial consumers]. Evidence suggests that implementation of this reform has seen some delays, which might be traced back to the existence of these political tensions and complexities related to implementation.

### 6.2.3 Wholesale price regulation

In recent years, Italy's approach to wholesale price regulation has also been undergoing adaptation to become more consistent with EU regulation (MISE 2019). In line with the more traditional strand of economic theory discussed in Section 2.1, the model proposed by the EU has traditionally followed an energy-only market logic with a strong focus on efficient market signals to provide flexibility and investment incentives needed for cost-effective VREs integration. EU regulation explicitly forbids posing limits, both positive and negative, to energy prices exchanged across all timeframes (EC 2015). This applies not only to explicit price cap regulation measures but also to any interventions that might indirectly affect price formation in wholesale markets (ARERA 2019a). This is driven by the need to harmonise pricing rules for the expanding IEM. In fact, differentials in price limits across EU countries can lead to distortions in cross-border trading by creating artificial spreads and, hence, arbitrage opportunities [interviews 26,29].

As for positive price limits, Italy has complied with EU regulation by setting the caps at the value-of-lost-load – i.e. 3.000 €/MWh for the day-ahead market and 9.999€/MWh for the intraday market (MISE 2019). However, in contract with EU prescriptions, Italy has not yet formally introduced negative prices and, instead, maintains a bidding price floor at 0€/MWh (Oxera 2020). Plans for removing bid floor in both the intraday and day-ahead market frames were laid out in the 2019 TIDE strategy but progress

with this reform has been slow (ARERA 2019a). In fact, evidence points to the existence of disagreement on the merits, implications and design of negative price reform across key power system stakeholders, including policymakers and market participants.

In terms of institutional positions, some observers suggest there has been degree of opposition by the system operator Terna due to concerns over a likely rise in the balancing costs faced by the TSO [interview 26]. This seems to be validated by the attitude of a TSO representative interviewed as part of this study, which dismissed the issue of negative pricing as a "non-urgent issue" [interview28]. On its side, the regulator ARERA openly recognised the potential of negative prices in improving management of excess generation, signals for flexibility investment and the harmonisation of rules for EU coupling (ARERA 2019a). However, the regulator also expressed a set of concerns around the implications of this reform (MISE 2019). Specifically, these consist of potential distortions resulting from the interactions of negative prices with RES subsidies: "in a market characterised by incentive instruments, offer bid strategies are driven by the logic of cost opportunity so it could be convenient to export power any time in which the sum of the negative price and the subsidy is positive, which could distort the use of the instrument" [interview 35 – representative of major electricity producer].

A second set of concerns expressed by the regulator revolves around an increase in price volatility and hence risks for potential investors (MISE 2019). The latter has been echoed by RES industry representatives: "we highlight that this reform could be penalising for VREs who, in order not to risk losing priority dispatch, might have to be forced to offer at negative prices giving up part of their revenue streams triggering a dangerous downward competition" (ANEV 2019). Finally, one participant also argued that the reform might have also been opposed by retailers as negative prices would put more pressure on their profits as the current price floor acts as a hidden-cross subsidy [interview 20]. However, this seems to be in contrast with the official position expressed by the largest power industry interest groups, Elettricita' Futura, which advocated for the introduction of negative prices across all timeframes and called into question ARERA's interpretation[20] of EU regulation (Elettricita' Futura 2019,2020). This position has been justified through a market efficiency logic, as the removal of the bid floor is expected to remove the obstacles and introduce incentives for unsubsidised VREs units or aggregators to provide ancillary services (especially downward) (ibid).

### 6.2.4 Locational pricing

Contrary to most EU countries, Italy has a sub-national zonal pricing system (see Figure 32 for a configuration of zones) in which only generators are exposed to the full zonal prices while consumers are not. This hybrid model, introduced at the onset of the Italian market, was seen to strike the perfect balance between leveraging market forces and mitigating issues of political acceptability of price signals: "the informing principle was that to create as much as possible an optimal market through a second-best design that would also protect final consumers. Without these compromises, politically, it would have not been possible to undertake liberalisation in Italy" [interview20].

Italian experts and policymakers tend to consider the EU preference for single pricing inefficient and often attribute the Union's decision to maintain a system based on national boundaries to Germany's "long-standing political decision not to divide the country in zones, despite the inefficiencies this has created from a transmission-use perspective" [interview 29 – Italian government consultant]. They note how Germany's position is particularly influential on EU policy, being the largest and most interconnected country, positioned right in the heart of the continent [ibid].

In terms of the configuration of zones, changes in system dynamics resulted in some modifications over time [interview21]. In 2018, in line with EU regulation (EC 2015), the TSO Terna completed a review of zonal structures, which reduced zones from 6 to 5 due to price convergence and determined

[20] While ARERA has committed to remove the bid floor in the day-ahead and intraday markets, it explicitly said it will not do so in the MSD, or Italian balancing market. In fact, there are fears that negative prices might further accrue problems of market power already present in some zones (ARERA 2019a).

some shifts in boundaries (Terna 2019) (see Figure 32). Interestingly, participants noted that some proposed changes that could have been justified from a techno-economic perspective were not implemented due to political reasons – e.g. dividing the North zone into North-East and North-West due to the presence of network constraints. In fact, market participants located in the North of Italy who were set to lose from this reconfiguration opposed it. As pointed out by a participant discussing this issue, "there are always politics getting in the way so there are never perfect engineering solutions, rather approximations" [interview 25 - Italian energy policy expert].

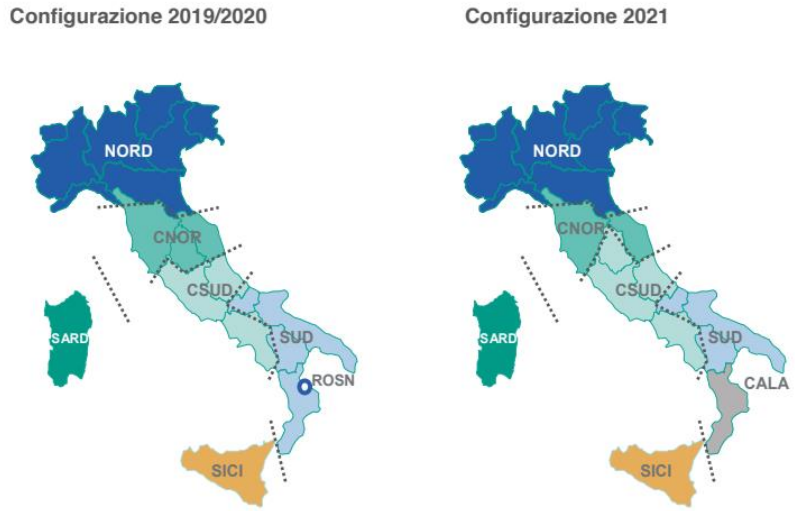


***Figure 32** - Market zones of the Italian power system in 2019/2020 and 2021 (Terna 2019)*

As noted above, while Italy exposes generators to zonal prices, the so-called PUN (Prezzo Unico Nazionale) paid by consumers is computed based on a weighted average of zonal prices based on the demand in a certain area (ibid). PUN was originally introduced due to specific political conditions at offset of the Italian market. At the time, the most costly and inefficient generation was in the South of the country and on the islands [interview29] (Oxera 2020). As these areas have also traditionally been the least economically developed, a pure zonal market would have been highly regressive. For some years the PUN ensured that richer consumers in the North were 'subsidising' consumers in the South. However, due VREs and network expansion, energy prices have generally converged (Figure 33) and energy flows have inverted, changing these distributional dynamics (ibid). Observers note that this represents an important policy window that has fuelled calls for change (ibid).

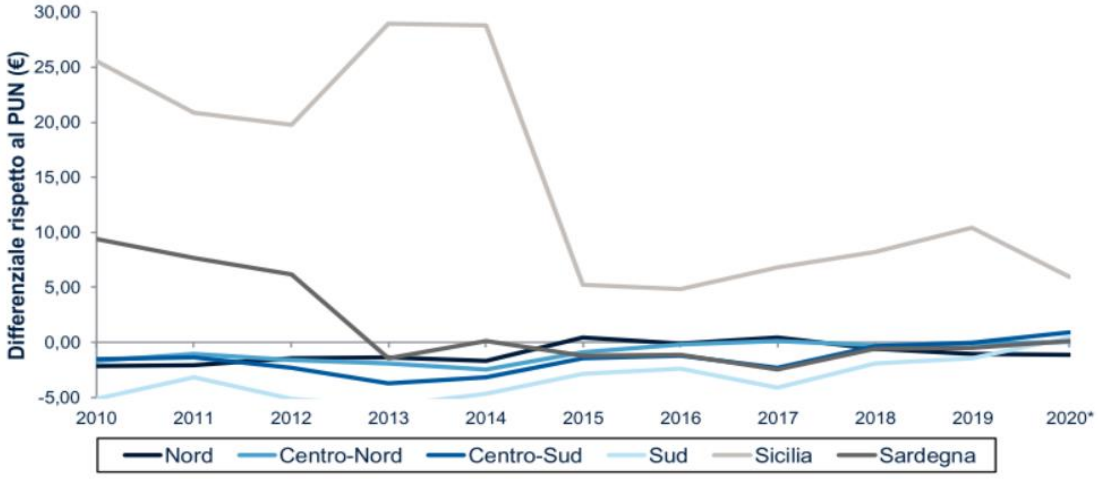


***Figure 33** - Differential in zonal prices as compared to PUN (Oxera 2020)*

The 2019 TIDE strategy acknowledged that exposing consumers to zonal prices would improve demand response and storage incentives needed for enabling VREs integration, while further aligning the Italian power market design to principles set out in EU 2019 regulation, which stresses the role of price reflectivity (ARERA 2019a). However, the reform has encountered some delays compared to the timeline initially proposed. Experts note that this is related to uncertainties around the distributional implications of the reform for different market participants and the need to weigh them carefully [interviews 20,29]. For example, while the DSR industry has shown great enthusiasm for the reform, which would result in more nuanced market signals increasing the profitability of their activities, Northern industrial consumers have expressed concerns (Italia Solare 2021; Confindustria 2021). Considered their inability to move their load based on geographical price signals, they have been asking for adequate instruments to participate actively to market activities – e.g. tariff structures promoting installation of on-side renewables and more support for local aggregation (Confindustria 2021).

Despite its zonal pricing regime, just like Britain, Italy has been facing important challenges in the management of infrastructure constraints. Highly productive zones in the South and the Islands have seen large investments in VREs, but the existence of transmission constraints limits flows of surplus power to Northern areas with higher load leading to consistently lower prices and growing curtailment rates in the South (Terna 2019). Several interviewees attribute this to the failure of transmission investments to keep up with system needs [interviews 35,36,38].

One important barrier to new transmission investments identified by several participants is political opposition by local communities and local authorities to new infrastructure – i.e. NIMBY[21] [interview20]. Some economists argue that this might have been inadvertently accrued by the fact that the PUN regime shields consumers from locational signals, creating a cross-subsidy that conceals the benefits of transmission expansion from them [ibid]. Coupled with significant problems related to political acceptability of new RES projects (Section 9.2), this has led to inefficient geographical distribution of infrastructures and is seen by many to be undermining the Government's decarbonisation objectives [interviews 20,29,36].

This has led several experts to conclude that, while the zonal pricing regime has been useful in signalling where congestions are, it was not able to promote the most efficient location of generation and infrastructure assets in a strict economic sense [interviews 25,38]. Again, this highlights the importance of arrangements for central transmission planning and the regulatory regime for the system operator. Following the same logic and somewhat emulating the innovative UK RIIO approach, Italy is also undergoing modifications[22] in its regulatory network regime to promote more strategic investment (Oxera 2016; Bovera et al. 2020).

## 6.3 The evolution of short-term energy markets in California

### 6.3.1 Day-ahead and real-time market coupling

While Europe moved forward with the coupling of day-ahead markets first and later initiated intraday[23] market coupling, already in 2014 California initiated real-time market coupling with neighbouring states but has yet to move ahead with day-ahead market coupling (Burtraw et al. 2019). The rationale behind real-time market integration has been to enable more efficient dispatch and use

[21] - i.e. not in my back yard. This term is often used in a pejorative sense to refer to local communities' opposition to infrastructure projects.

[22] While it maintained a more traditional regulation regime based on a mix of price cap and cost-of-service up until 2019, it is in the process of applying a new paradigm based on the total expenditure (TOTEX) approach, combined with incentive menus and output-based incentive schemes with the aim of introducing a more strategic and systemic approach to infrastructure management.

[23] Real-time in the US.

of cross-border resources and mitigate negative day real-time prices in California caused by high VREs output by allowing other states to receive compensation for absorbing its surplus (Hobbs and Oren 2019; IEA 2018). Initially this came in the form of an ad hoc bilateral agreement between CAISO and Pacificorp, one of the largest operators in the West of the US (Burtraw et al. 2019). However, over the years the so-called Electricity Imbalance Market (EIM) has been gradually expanding incorporating a growing number of neighbouring US states, two Canadian provinces and the northern portion of Baja California in Mexico (Figure 34).

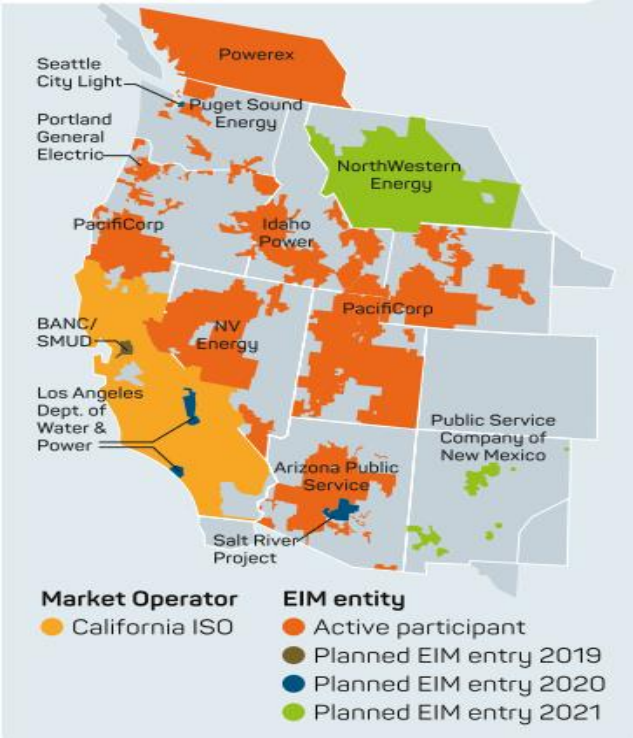


***Figure 34 -*** *Western Energy Imbalance Market (Burtraw et al. 2019)*

As part of this process, CAISO's existing 5-minute EIM has been gradually expanded to other markets, which can join on a voluntary basis (ibid). The dispatch of resources is run centrally based on security constrained economic dispatch, but each local market operator retains responsibility for ensuring that their balancing area has enough resources on-line to satisfy operating reserve criteria. Participants widely regard the EIM as a success [interviews 39,41,42,45]. Numbers seem to tell a similar story: it was estimated that the EIM has saved market participants approximately $1.3 billion since its inception in 2014, while helping to reduce renewable energy curtailment by approximately 1,400 GWh (Newsom 2021).

Over the years, there have been repeated calls by economists and attempts by CAISO to extend coupling to day-ahead markets given the significant efficiency and reliability gains that could be achieved as more intermittent renewables come online (Walton 2019). CAISO estimated the potential aggregate gross benefits at over $200 million annually (ibid). Nevertheless, day-ahead coupling has been struggling to move forward. Experts agree that this can be largely attributed to the nature of political relations among states in the US West [interviews 39,41,44,45,50]. Important differences in fact exist in terms of dominant political attitudes and policy priorities (sub-section 5.3.7). While California is the 'quintessential blue state' with aggressive climate targets and RES policies, other states in the Pacific North-West and desert South-West (e.g. Arizona, Utah, Colorado and Wyoming) are much more conservative and retain large shares of coal generation [ibid].

In turn, this raises some politically charged questions – e.g., how to distribute the costs of decarbonisation and account for greenhouse gas emissions embedded in power imports/exports

[interview 44]. In fact, conservative states “are less interested in paying for more renewables and […] don’t want to abide by other state-level [renewable] mandates” [interview39]. Those benefitting from low energy prices thanks to coal or hydropower resources have been reluctant to further integrate their markets with California’s, seen to rely on ‘expensive electricity’, as this would contradict their mandate ‘to protect consumers’ [interview41]. For their part, some influential environmental groups in California have resisted the project of further integration worrying that this would undermine the state’s decarbonisation efforts by allowing out-of-state fossil fuel resources to service its demand [interviews 39,41] (Burtraw et al. 2019). Further, multiple Western states fear the decline of the coal industry upon which many of their communities depend for jobs [ibid]. Similarly, labour unions in California are concerned that further integration might potentially undermine its clean energy labour market [ibid].

Another set of major controversies revolve around reliability. Some balancing authorities fear that systems chronically short on resources, especially California, might end up ‘lean’ on them (and their investment efforts) to meet their reliability needs [interviews 39,44] (Walton 2019). As noted by this expert, “there is always this anxiety that if something happens in California and prices spike here, resources get sucked into that market because it's more valuable, and our states will be left with no resources” [interview50]. Another participant expert labelled this dynamic as the ‘game of musical chairs’: “the chairs are the resources and the children are the demand. The question is we're short of resources, we have nine chairs in the entire West, but we have 10 children. Who is not going to get electricity when the music stops?” [interview44]. This problem already manifests in the EIM during West-wide power shortages, which usually occur in the summer due to high temperatures or fall, when hydro resources are low.

To mitigate these fears, clauses were introduced in the EIM restricting real-time participation by balancing authorities lacking resources necessary to meet demand [initerview44]. From a techno-economic perspective, this is a sub-optimal design as instances of power shortages are when an imbalance market would prove most valuable by allocating scarce resources where most needed [ibid]. These issues, coupled with controversies around the definition of the reliability test for participating and penalties for non-delivery are often identified as a major obstacle to day-ahead market integration [ibid]. Achieving day-ahead market coupling also entails states coming to an agreement on numerous other market design aspects including pricing methodologies, ancillary service design, the definition of resource adequacy products and transmission cost-allocation [interview44]. For example, the EIM has so far avoided the contentious question of transmission-cost-allocation by letting the market operate based on available transmission [interviews 39,41] (Mathai-Jackson 2018; Burtraw et al. 2019). The integration of day-ahead markets would involve finding a political solution to this problem [ibid].

Due to these controversies, the coupling of day-ahead markets raises difficult questions in terms of governance and control (Burtraw et al. 2019). These tensions are compounded by the fact that California plays a disproportionately large role in the current Western Interconnection because of its power system’s size and the fact that CAISO is the operator of the coupled market [interview50]. For historical reasons related to the energy crisis, CAISO has unique institutional arrangements whereby its board of directors is directly appointed by the state Governor (sub-section 5.2.6.2). Such close alignment of CAISO’s strategy with state policy is perceived as a significant threat by neighbouring states (Lenhart et al. 2016; Burtraw et al. 2019).

The EIM has so far managed to partially overcome these political barriers through unique governance arrangements (ibid). In fact, while CAISO oversees market operation, the EIM has its own governing board, the Western Electricity Coordinating Council, which includes representatives from participating utilities and regulators. Further, the EIM governance is highly fragmented leaving some degree of control to multiple balancing authorities, planning organisations and local utilities operating at the sub-

regional level (ibid). However, according to experts, states are likely to continue resisting day-ahead market integration until the issue of CAISO governance is addressed [interviews 41,50].

Some attempts have been made to overcome this gridlock. Between 2016 and in 2017, under the push of Governor Brown several bills were introduced in California to change the statute so that CAISO could transition into a more regional RTO (Mathai-Jackson 2018). However, observers note that these attempts repeatedly failed due strong resistance from some environmental groups and labour unions within California, which mobilised to keep renewable generation jobs within the state [ibid]. In addition, more regional governance arrangements would expose some local actors like municipal utilities, which have historically been independent, to FERC jurisdiction [interviews 39,41]. Driven by the desire to retain local control, some of these have also mobilised in opposition to the project [ibid].

It is important to note that there is an ongoing initiative by CAISO, the so-called Extended Day-ahead Market, aiming to develop an approach to extend participation in the day-ahead market to the EIM entities in a framework similar to the existing EIM approach for the real-time market, rather than requiring full integration into the California ISO balancing area (CAISO 2019b).

### 6.3.2 Day-ahead and real-time market rules

California experienced VREs integration issues early on due to its early RES expansion policy. Already in 2011, CAISO published a strategy to deal with emerging challenges, the Renewables Integration Market Vision and Roadmap (CAISO 2011; NERC 2013). The initiative aimed to identify ways to improve market signals to enable cost-effective VREs integration as it was felt that incumbent arrangements designed around a fossil fuel generation were no longer fit-for-purpose (ibid). As part of this, CAISO implemented some initial changes wholesale market rules. For the most part, these early efforts focused on the real-time markets, while day-ahead markets saw limited adjustments (CAISO 2019).

One of the key objectives of the 2011 Roadmap was to change the bidding behaviour of VREs in real-time markets incentivising them to operate in a more system-compatible (flexible) way, hence maximising the ability of real-time economic dispatch to resolve over-generation and congestion using economic bids (CAISO 2011). This required available incentives to decrease the number of resources that were either self-scheduled or unwilling to curtail output based on market mechanisms (ibid).

The legacy framework, the so-called Participating Intermittent Resource Program (PIRP) had been designed to shield RES operators from balancing penalties if they failed to deliver due to forecasting errors (ibid). PIRP minimised RES exposure to schedule deviations by netting those deviations in all 5-minute periods across an entire month (15 minutes source) (CAISO 2011). When PIRP was introduced, the priority was encouraging RES deployment: “in the early days of the RPS program, intermittent generators were viewed as must-take resources that would have to run whenever available and to the full extent of their generation potential” (CalWEA 2017). PIRP had been the result of significant pressure from renewable operators: “we were like, no, we shouldn't be penalized at all because we can't predict the wind 24 hours in advance” [interview49 – representative of large wind generators].

Following the emergence of VRE integration issues in the early 2010s, CAISO challenged PIRP on the basis that it would not lead to cost-effective VRE integration (CAISO 2011). As part of the Renewables Integration Market Vision and Roadmap, CAISO concluded that VRE generators would be increasingly exposed to more cost-reflective price signals based on the principle of cost-causation: “load and resource variability and the associated settlement risks are best managed by those market participants directly responsible for serving load or developing and operating resources” (CAISO 2013a). The definition of the cost-causation principle sparked a major controversy in the industry on how the cost of imbalances and risk of intermittency should be allocated (ibid).

Large incumbent distribution utilities strongly advocated for the introduction of cost-causation, which is rooted in their role as the main electricity retailers in California (see sub-section 5.3.8). For example,

SDG&E[24] recommended placing "the incentive to mitigate variability squarely on the entity responsible for that variability [i.e. RES operators]" (SDGE 2011). Other major incumbent SCE[25] argued that "causation-based cost allocation will save California Ratepayers money in the long-run, and provide appropriate operating signals for all resources" (SCE 2011). IOUs applied considerable pressure on CAISO as exemplified by this threatening consultation statement: "should the CAISO fail to apply cost-causation designs, SCE (and likely other stakeholders interested in market efficiency) will seek a superior design through FERC" (SCE 2011).

In contrast, the renewable energy industry expressed reservations about the cost-causation narrative, arguing that IOUs and consumers should handle this risk, as they are better equipped to assess and mitigate costs [interview 49 – representative of large wind generators]. The Large Solar Association, for example, emphasised that this would ensure lower RES financing costs and PPA prices (LSA 2011). The RES industry also stressed the need to differentiate among types of VERs based on their ability to meet system operational needs (CalWEA 2011). Notably, the CPUC questioned CAISO's definition of cost-causation, suggesting that integration costs should not necessarily be allocated directly to VER generators: "CAISO should examine a broader range of players and decisions that affect integration costs […] load serving entities (LSE)[26], including investor-owned utilities, contribute to integration costs through their selection of resources and contract terms to meet their RPS and other requirements" (CPUC 2011).

CAISO's response to these comments maintained that ratepayers and the ISO were not in the best position to manage uncertainty or minimise integration costs, and the responsibility should lie with those "directly responsible for building, operating, or scheduling resources. […] that can directly manage the risk through contract terms or by using complementary technologies that add resource flexibility and controllability" (CAISO 2013a). In the following years, gradual modifications were introduced to incentivise real-time market participation by RES resources including more appropriate cost-allocation mechanisms, and incentives to submit decremental[27] economic bids (ibid). Incentives for flexible procurement by LSE were also addressed as part of resource adequacy policy (Chapter 8).

Eventually, PIRP was phased out in 2013 on the basis that it was fundamentally inconsistent with the principle of cost causation (CAISO 2013). The development of the new market framework, implemented in the same year, was also shaped by changes in federal regulation. Specifically, FERC Order No. 764 required that transmission service providers change their open access transmission tariffs to offer all generators the option of scheduling transmission service at 15-minute (Herrero et al. 2016). FERC's techno-economic rationale was that more granular scheduling would reduce the amount of imbalance energy and, hence, overall costs (ibid).

Hence in 2013 CAISO introduced a 15-minute market for both internal and imported resources whereby generators are dispatched using 15-minutes ahead forecast information to incentivise them to submit timely and accurate forecasts to minimise imbalance payments in real-time (CAISO 2013). These new arrangements produce financially binding prices for VERs, allowing them to buy/sell deviations from the day-ahead market at the real-time price. Just like in Italy, the RES industry generally supported the introduction of the reform, which allowed to adjust their positions and minimise their imbalances, but pressed for some transitional support measures, especially for intermittent operators less able to adjust their scheduling (LSA 2011; CalWEA 2017).

As noted above, up to the end of the 2010s, the policy focus had mainly been on improving real-time markets to enable cost-effective VRE integration. In 2018, CAISO launched a more comprehensive reform program addressing the question of how to render the day-ahead market fit-for-renewables,

[24] San Diego Gas & Electric Company.
[25] Southern California Edison.
[26] Entities acting as electricity retailers.
[27] - i.e. sub-hourly.

the so-called Day-Ahead Market Enhancements (DAME) initiative (CAISO 2018,2019a). The aim has been to ensure better representation of actual real-time ramping needs with proposed changes including a move to more granular sub-hourly day-ahead scheduling, better alignment between energy and balancing products and the definition of a flexible reserve product for the day-ahead timeframe (see Section 7.3) (CAISO 2018). It is important to note that one of the core objectives of the DAME initiative has been to extend these market rules changes to a region-wide market but this has found significant barriers (see sub-section 6.3.1).

California's decision to move to 15-minutes scheduling in the day-ahead market is particularly interesting as there is no consensus in the US as to whether sub-hourly schedules should be adopted in this timeframe (FERC order 764 only mandates this in the real-time) (IRENA 2019). CAISO has stressed the techno-economic benefits of the reform: "the SCED for the day-ahead market is currently hourly and the SCED for the real-time market is every fifteen-minutes and five-minutes. […] intra-hour net load changes have increased to a degree that the day-ahead market's hourly schedules do not align with the real-time load curve; this results in a need for the real-time market to make up for granularity differences and uncertainty" (CAISO 2019).

### 6.3.3 Wholesale price regulation

Since the Energy Crisis, California has maintained both a positive and negative wholesale energy price cap. According to experts, the political 'desire to retain control over market volatility' is particularly strong in California, where the price spikes registered during the California energy crisis had long-lasting consequences [interviews 47,50] (see sub-section 5.3.1). Nevertheless, some modifications have occurred in recent years that have gradually relaxed these limits, driven by changes in techno-economic conditions (i.e. a significant increase in VRE-integration challenges and extreme system events), and the need to harmonise the market rules with other systems' participating in the EIM.

First, there has been a progressive increase of the positive price cap, which was changed from 1000 to $2000 per MW hour. The rationale was the same underlying EU regulation introduced to wholesale price regulation in states participating in the single market, that is, that price cap differentials in coupled markets lead to distortions [interviews 44,48]. California directly experienced the effects of these distortions during times of region-wide resource scarcity when it struggled to secure resources in the EIM: "California capped its price at $2000 per MWh, furthermore, there were some inefficiencies in pricing whereby, even when there were rotating blackouts, the prices were well below that level. Arizona, which is not subject to price cap, is willing to pay $5000. So it actually turned out that California exported electric power during the August 2020 event because of these artificially low prices because of the price cap" [interview44].

Further, in 2012, California lowered its negative cap from -30 to -$150/MWh as part of the Renewables Integration Market Vision and Roadmap (see sub-section 6.3.2) (CAISO 2011; Hobbs & Oren 2019). This was done to incentivise more economic bidding to mitigate over-supply conditions, strengthen market price formation, and further align cost allocation with cost-causation (ibid). Specifically, it was identified that the previous floor was not sufficient to compensate reductions in energy output from VREs receiving additional revenue from outside the ISO market, preventing these resources from submitting economical decremental bids. The new cap was introduced to offer a stronger incentive for these resources to curtail production from previously scheduled levels and for demand (including exporters) to increase energy purchases when there is excess supply and overgeneration (ibid).

### 6.3.4 Locational pricing

California has had LMP in place since 2009 providing extremely granular locational signals (Figure 35). This approach had been adopted because often considered the most economically optimal in the literature, and because in the US grid constraints were usually more significant than in Europe where single national pricing tended to be the preferred option [interview2,20]. Like the Italian zonal pricing regime, California's LMP was design to shield final consumers from the full locational price signals to

avoid a 'political backlash from consumers' (Wolak 2019). Specifically, customers in any utility service territory pay a wholesale price equal to the quantity-weighted average of all load-withdrawal nodes in the utility's service territory (ibid). As noted by Wolak (2019), "this approach to pricing to loads captures the reliability and operating efficiency benefits of an LMP market while addressing the equity concerns regulators often face with charging customers at different locations prices that reflect the configuration of the transmission network."

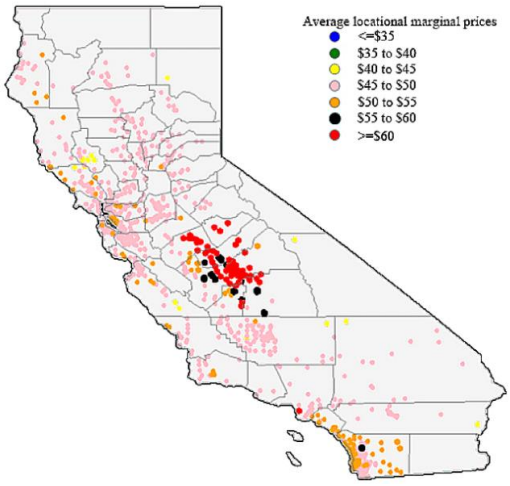


***Figure 35 -*** *Locational marginal prices in California (Zheng and Sahraei-Ardakani 2020)*

Experts widely regard California's pricing regime as successful in providing an accurate representation of system conditions and real value of energy, hence leading to economically efficient dispatch [interview40] (Wolak 2019). However, LMP's role in driving efficient investment across the network is more disputed, as participants note that these investment decisions are also heavily shaped by available RES incentives and long-term take-off agreements, as wells as network planning, charges and connection rules [interviews 39,40,50]. Like Britain and Italy, California has also been experiencing an increase in grid congestions, especially in some load pockets in Central and Southern California and across the state's boundaries due shortages of transmission lines [ibid].

Several participants trace this back to the existing governance regime for transmission expansion, specifically, a 'reluctance of the CPUC to approve transmission upgrade requests submitted by utilities' and the 'fragmentation of the authority over transmission siting' in the US network expansion regime [ibid]. In fact, the fact that authority over transmission siting is not centralised under FERC and remains dependent upon local approval from relevant authorities has been identified as a major obstacle to the efficient use of transmission and generation assets, especially when it comes to cross-border resources [ibid]. To tackle this, a new legislation was passed in 2022 conferring the Department of Energy increased authority over transmission planning whereby, if there is a financing issue, they can buy capacity up to 15 years and re-sell it in the market (DOE 2022). This was to tackle a chronic lack of investors willing to make long-term commitments in this area (ibid). Nevertheless, many feel that this problem cannot be resolved without the introduction of a more centralised governance structure for US transmission planning [interviews 39,40,50].

Like Britain, California has also seen important discussions on network charging methodologies. As distributed solar resources grew and integration costs began rising over the 2010s, concerns started to emerge around 'embedded benefits' – i.e. distributed generators related to their ability to avoid some network costs thanks to the favourable charging regime. In fact, the legacy regime recovered sunk transmission and distribution grid costs through a per unit charge, which "favors investments in distributed solar generation over grid-scale solar generation, even if grid scale solar is cheaper on a levelized cost of energy basis, what is referred to as economically inefficient bypass of grid-supplied electricity" (Wolak 2019).

This also contributed to a growing sense of 'unfairness' among other ratepayers who picked up the costs avoided by distributed generators: "people who can't afford solar who are going to pay higher rates" [interview 43 - energy regulation consultant]. Incumbent utilities were extremely vocal advocates for change deploying the so-called 'utility death spiral' narrative: "we're going have fewer customers left that we serve, and we're going to raise our rates on them. Those higher rates are going to drive more of our customers away to seek alternatives and then we're going to have to raise our rates even further" [interview39].

On its side, the distributed solar industry resisted change. Their viewpoint is succinctly captured by a representative of distributed PV generators who has been actively involved in legal proceedings aimed at halting the policy shift: "they're saying that they need to charge me because the other customers without rooftops or are subsiding me. It is a big shell game. Nobody is subsidizing anybody, I'm producing my own power" [interview51]. By that time, the solar industry had consolidated its position and ability to influence policy: rooftop solar […] is now a really politically powerful lobby that can now call all of their customers and get them to show up the CPUC, get them the right letters, show up at rallies" [interview 49]. This resulted in a long and controversial reform process. Eventually, the CPUC introduced a fixed charge for interconnection and a time-of-use rate charge that distributed generators must pay for using utility energy, which decentralised energy advocates perceive as a 'discriminatory' policy [interview52 - advocate of local energy systems].

## 6.4 Comparison of short-term energy market evolution

Overall, the three jurisdictions exhibit similar techno-economic drivers and logics underpinning their recent approach to reforming short-term energy markets, as they face similar challenges related to the expansion of intermittent generation. Reform objectives include optimising the use of national and cross-border resource, providing stronger flexibility incentives through cost-reflective price signals improving operational performance of assets. However, as summarised in Table 13, there are also important differences in the scope of these changes, mechanism design choices and resulting policy trade-offs. This can be traced back to a set of key political economy conditions including legacy market arrangements and dominant operational philosophies, issues of political acceptability, multi-level governance arrangements, and the interest of key stakeholders. These are summarised Table 14 in discussed more extensively in the next-sub-sections in relation to each market design area.

***Table 13** - Comparison of key changes in wholesale short-term energy market design*

| | **Britain** | **Italy** | **California** |
|---|---|---|---|
| **Market coupling** | Coupled then uncoupled day-ahead market, never coupled intraday. | Coupled day-ahead and intraday markets. | Coupled real-time market and has yet to couple day-ahead market. |
| **Day-ahead and intraday market rules** | No major modifications to legacy day-ahead and intraday market rules – maintains decentralised dispatch logic and half-hourly trading. Ongoing major review of market model. | Significant modifications to all key intraday market parameters – shift to hybrid dispatch logic. Ongoing implementation of more granular trading frames in day-ahead and intraday. | Gradual modifications to market rules over time, but fundamental market model persists – ISO-led centralised dispatch. Introduced more granular trading frames in real-time and day-ahead market. |
| **Wholesale price regulation** | No direct regulation of wholesale prices but introduced retail price cap. | Positive price caps set at VOLL, ongoing discussions on the abolition of 0 negative price floor. | Maintains both positive and negative price caps but these gradually relaxed over time. |
| **Locational pricing** | Single national pricing persists. Gradual modifications in network charging methodologies. | Retains legacy zonal pricing model. Ongoing discussions on exposing consumers to zonal signals. | Retains legacy locational marginal pricing model. |

### 6.4.1 Explaining differences in the approach to market coupling

As discussed in sub-section 2.1.1, market coupling is widely identified by economists as an enabler of cost-effective VRE-integration. Accordingly, in recent years all three jurisdictions have seen a push for further regional integration of short-term wholesale energy markets. The techno-economic logic underlying market coupling is common across cases: to drive efficiency in the use of cross-border resources and increase reliability as more intermittent resources come online. Where market coupling was achieved, this resulted in net efficiency gains and an increase in the ability of these systems to manage growing intermittency.

Yet, there is high variation in policy outputs, particularly, the degree to which jurisdictions coupled different parts of the market. Evidence suggests this can largely be explained through differences in the political economy contexts of the three jurisdictions, particularly, multi-level governance arrangements, relations with neighbouring countries, and their interactions with national political priorities. Jurisdictions need to determine whether the efficiency gains related to market coupling outweigh 'giving up control' over national strategic issues (e.g. energy prices, reliability and industrial strategy). This is influenced by the degree of trust, alignment of policy objectives (e.g. decarbonisation, system costs, efficiency and national sovereignty) and the share of power across national and cross-border institutions. Further, the interests of stakeholders at the national level and their influence also play an important role.

Over time, the EU has managed to progress with both day-ahead and intraday market coupling and impose a harmonised market design for its member states through a coordinated, stepwise strategy. On the other hand, California's EIM started off as a bilateral experiment that has expanded somewhat organically as more states joined on a voluntary basis. It is also interesting to observe how, while the EU first proceeded with day-ahead coupling and then moved to the intraday timeframe, California has had a coupled real-time market for several years now but is still in the process of integrating day-ahead market. Finally, significant variation can be observed between the British and Italian cases: while Italy consistently moved ahead with the EU IEM, Britain has recently reversed the process.

When compared to states in the West of the US, EU member states appear to be more politically homogeneous and more aligned in terms of policy objectives – e.g. commitment to decarbonisation. Further, despite being composed of separate countries, the EU single market presents a more established and coordinated governance structure. This is the result of a 30-years political process whereby the EU has gradually 'tightened the grip', increasingly entering the details of power market design and setting legally binding rules (sub-section 5.2.7). As part of this, a web of institutions was set up, tasked with coordinating the single market and mange the transition in pursuit of common objectives. This has been key in managing differences among jurisdictions and creating trust. Overall, member states tend to recognise the mutual benefits deriving from further market coupling and there is a general acceptance of the authority of EU institutions (Gastinger 2019).

Nevertheless, it is important to note that anti-EU sentiments have been on the rise since the 2010s and countries vary in their commitment and attitudes towards the single market, as exemplified by the two cases analysed as part of this study. Italy, where trust in EU institutions and a sense of shared regional identity are generally higher, moved ahead with the project of further market integration. Britain, where EU identity is generally lower and the political value attributed to national sovereignty is higher, decided to interrupt its journey towards further integration. Here, tecno-economic considerations around efficiency gains of market coupling were outweighed by these political considerations.

This does not mean that EU coupling in other countries has been seamless. There are policy areas where the EU has less authority, and where countries are less aligned in terms of objectives and preferences, and legacy market arrangements. For example, in the EU the implementation of intraday coupling required addressing more complex implementational and political questions compared to

day-ahead coupling. In Italy the implementation of intraday coupling required substantial adjustments to its legacy market design and a tiresome process of political negotiation due to a clash in operational philosophies and market design preferences between national and EU institutions (see next sub-section). In turn, the EU position also mirrors the balance of power in the region and dominant techno-economic ideas in large and influential member states.

Compared to Europe, the US West presents a much more polarised political landscape. States have heterogeneous techno-economic and political contexts and, thus, political priorities – e.g. willingness to pay for RES expansion, consumer protection, energy employment and reliability. This has contributed to important political tensions in the definition of key parameters in the single electricity market. The relative political charge of these controversies has determined the extent to which different aspects of market coupling have managed to move forward – i.e. real-time coupling avoided many difficult political questions that would have to be addressed in the day-ahead timeframe. These controversies also put restrictions on the ability of policymakers to design key market rules based purely on efficiency-based considerations.

In turn, the existence of these political tensions has constrained the development of governance structures underpinning the single market, generating a feedback loop effect. Compared to the EU IEM, the Western EIM presents a fragmented governance structure put in place to try to maintain a difficult balance of power across heterogeneous set of participants. Mistrust is accrued by the fact that California plays a disproportionally large role due to its size, and CAISO is the designed market operator and the entity driving forward the market coupling process. CAISO's strong political link with Californian state policy in fact increases resistance to further integration by other states. Mistrust is also accrued by the fact that California had a major energy crisis in the past and is seen as 'risky system'. Finally, efforts to change CAISO institutional arrangements were jeopardised by a set of influential stakeholders within the state (environmental groups, trade unions and local utilities) demonstrating the major role played by interests and internal market structures in shaping market coupling outcomes.

### 6.4.2 Explaining differences in the approach to reforming day-ahead and real-time markets

Following the growth of intermittent generation and the rise of related operational challenges, policymakers in all jurisdictions have been grappling with the question of how to reform wholesale energy market parameters to enable more cost-effective integration of these technologies. In the early phase of RES deployment, their efforts had focused on shielding these technologies from market signals prioritising their dispatch. However, with the rise of integration challenges, the focus has shifted on finding ways to incentivise them to engage in more system-compatible, flexible operation. In line with prescriptions by several economists (sub-section 2.1.1), recent market rule changes have hence focused on increasing the time granularity and cost-reflectiveness of price signals provided through short-term energy markets to enable VRE operator to respond to increasingly fast-changing system conditions.

Yet, there is variation across cases in terms of the scope of recent changes, the chosen designs and dispatch logics, and the price signals granularity they achieved across real-time and day-ahead markets. Adding to previous findings on the key role played by path-dependency and techno-economic ideas in shaping power sector change (Section 2.4), evidence suggests that these differences can be explained in terms of legacy arrangements for market operation, dominant operational philosophies and beliefs on costs and benefits of different changes among key sector institutions. Multi-level governance arrangements and the interests of key stakeholders were also found to play a significant role.

Britain underwent least change having maintained its legacy decentralised dispatch model with a half-hourly trade resolution, albeit this might change soon due to an ongoing major review of its market arrangements. The Italian intraday market saw major modifications across all key design parameters with a partial switch in the dispatch logic. Further, 15-minutes trading is being introduced in both day-

ahead and intraday markets. Being a pioneer of large-scale RES deployment, California introduced early modifications to increase the time granularity of its markets but maintains its legacy central dispatch model.

While broadly the economic literature stresses the importance of improving market price signals to enable cost-effective VRE integration, there is no consensus on the most suitable way to organise dispatch and related market parameters as different solutions involve different trade-offs (e.g. across technical efficiency, liquidity, flexibility, balancing costs) (Section 2.1). As discussed in Chapter 5, the three jurisdictions historically exhibit very different market models and dominant operational philosophies, which mirror specific conditions at the offset of liberalisation. These inevitably affected their approach to VRE integration.

The EU and British models are based on a very decentralised logic with continuous trading, portfolio bidding, self-dispatch and gate closure H-60'. This approach, the argument goes, is fit for a high-VREs world in that it provides economic incentives for VREs producers to operate in a more system-compatible way through allowing continuous asset optimisation until gate closure. Instead, the traditionally dominant position among Italian and Californian market designers has been that self-balancing is inefficient and leads to less reliable, more costly operation. From this perspective, central dispatch by the system operator is best equipped to deal with the increase in operational uncertainty brought by VREs.

Data also point to the importance of multi-level governance arrangements in shaping recent change. In fact, to achieve further market coupling or other shared objectives, multi-level governance institutions might take steps to increasingly harmonise trading arrangements across wider geographical areas. For example, the introduction of 15-minutes trading in California and in Italy was driven by FERC and the EU, respectively. However, there are instances when jurisdictions might be asked to introduce changes to their market designs that contradict their national preferences and legacy operational philosophies. For example, Italian policymakers were reluctant to adopt the fully decentralised model proposed by the EU and influential member states including Germany, which they perceived as inefficient. Less able to shape the EU-wide position, Italian institutions engaged in an intense process of negotiation with their EU counterparts to maintain some key aspects of their legacy market design.

Finally, findings point to the increasingly important role played by RES producers in shaping these discussions, who have become a much stronger political force since the days of early RES policy. In fact, changing energy market rules involves important decisions on how to allocate the risks and costs of intermittency across generators and consumers, often leading to political tensions between the two groups. For example, this is exemplified by discussions and the policy process that led to move to more granular settlement in both California and Italy, and intraday trading reforms in Italy.

### 6.4.3 Explaining differences in the approach to wholesale price regulation

As discussed in Section 2.1, from a purist economic standpoint lifting restrictions on price fluctuations should enable more cost-effective VRE integration and flexible operation and investment. While narratives on refining price signals commonly feature in policy debates across all jurisdictions and there is a general trend of relaxing price caps, in practice, all use some form of price regulation at the wholesale or retail level. However, the three cases differ in the extent to which they lifted positive and negative price limitations in wholesale energy markets, which mirrors differences in their political economy contexts.

First, these findings confirm a widespread claim made in political literature that practical implementations of wholesale pricing often deviate from purist economic theory due to market power concerns and political acceptability issues (Section 2.4). In other words, governments usually want to retain some control over energy price volatility. However, comparison shows that jurisdictions differ in their traditional attitudes towards price spikes, which is rooted in different historical state-market

relations and dominant ideas on the risks and benefits of different pricing approaches among key sector institutions. Second, multi-level governance arrangements relations also play and important role, given a trend of further regional market coupling. Finally, the interests and views of key power sector stakeholders can also be a key determinant.

The three cases differ in the extent to which they lifted positive and negative price limitations in wholesale energy markets: Britain does not set limitations in wholesale prices but recently introduced a retail price cap; Italy increased its positive price cap at the value-of-lost-load but maintains a 0-price floor; California maintains caps in both directions but has been relaxing them in recent years. The desire to retain control over market volatility is traditionally strong in California, where the price spikes registered during the energy crisis had long-lasting consequences. Instead, Britain historically had a more market-oriented attitude and was more comfortable with price fluctuations. However, it is important to note that these attitudes (and state-market relations) might change over time, as exemplified by the recent introduction of the retail price cap in the UK, which marked an important shift in the regulatory logic towards a much more interventionist approach.

A common driver of recent price caps adjustments has been the need to harmonise pricing rules to enable the smooth functioning of single regional markets – i.e. market coupling. In fact, differentials in price limits across systems can lead to distortions in cross-border trading by creating artificial spreads and, hence, arbitrage opportunities. Further, it might lead to inefficient allocation of resources during times of scarcity as exemplified by the Californian experience. This is behind recent adjustments in positive price caps in both Italy and California. Given the high level of institutional coordination of its multi-level governance arrangements, the EU managed to impose uniform rules for wholesale price regulation across its member states. Instead, states retain control over price regulation in the EIM, reflecting a more fragmented governance and political context, and leading to the persistence of distortions due to price differentials.

However, it is important to note that, even in the EU, the harmonisation of price limits has been characterised by implementational challenges. For example, despite EU requirements, Italy has been delaying the introduction of negative prices. First, this can be attributed to differences in dominant understandings on the risks and benefits of negative prices between Italian and EU institutions. The Italian regulator expressed concerns on the potential implications of the reform, while the system operator seems to have openly resisted it. Second, evidence suggests that some industry stakeholders, specifically RES operators, opposed the reform on the basis that this would penalise them. Such disagreement on the merits, implications and design of negative price reform across key power system stakeholders is likely to have caused the reform delays.

### 6.4.4 Explaining differences in the approach to locational pricing

High VREs penetration often leads to a more constrained transmission network as registered in all jurisdictions. As such, the way congestion costs are reflected in energy pricing has emerged as a key market design issue in the context of VREs integration. Once again, increasing the locational granularity of price signals is often identified in the techno-economic literature as a key pathway to achieve cost-effective VRE integration due to its ability improve dispatch and drive investment in desirable locations (sub-section 2.1.1). However, jurisdictions vary greatly in terms of the extent to which they included a measure of transmission constraints in wholesale prices.

First, these differences can be explained in terms of legacy market arrangements, dominant operational philosophies, beliefs on the merits of granular locational pricing and acceptable policy trade-offs among government and key power sector institutions. Further, as it is consistently identified in the political economy literature (Section 2.4), this policy area is also consistently affected by issues of political acceptability and the interests of market participants located across the network both on the generation and consumption side. As differentiated locational pricing might expose different regions to different economic conditions, this market design aspect has also important ramifications

for political relations across layers of governance both within national governments and within regional institutions. Finally, the issue of locational pricing cannot be understood separately from developments in the transmission planning and network investment regimes, and related political economy dynamics such as the acceptability of transmission infrastructures.

Britain maintains a single national price but has seen important modifications to the network charging methodologies through which locational signals are conveyed. Italy and California use a zonal and nodal pricing, respectively, but shield consumers from full negative prices. These legacy approaches and operational philosophies can be traced back to the techno-economic conditions at the time of liberalisation: countries that had more grid constraints (e.g. Italy and California) developed a preference for more granular approaches to locational pricing. These historical decisions also mirror specific believes around power system goals: from the very beginning states drew different trade-offs in terms of implementation complexities, market efficiency, liquidity, transparency etc. These are also rooted in standard regional approaches as exemplified by the wider implementation of nodal pricing in US markets as compared to Europe's historical preference for single pricing. However, these preferences can change over time. For example, the British system operator and regulator have recently changed their attitude towards LMP following a spike in balancing costs. The introduction of LMP would represent a significant shift from administrative approach to managing network constraints to a more market-based logic.

Locational pricing has important distributional implications and is a highly politicised area across all jurisdictions. This has been so from the outset, as demonstrated by the decision to shield consumers from price differentials both in Italy and California. More recently, distributional concerns from consumers have delayed progress with removal of single consumer pricing in Italy. In Britain and California, these political tensions manifested long-lasting battles around network charging methodologies across different types of generators, consumers, and service providers. Further, large-scale wind generators in constrained locations are consistently identified as the major barrier to any potential implementation of LMP in Britain. Locationally differentiated pricing can also lead to tensions within layers of governance as it exposes different regions to different economic conditions. This is evident in Britain where policy discussions on dividing the country in zones have been met by fierce opposition by devolved administrations such as Scotland.

Findings also show that, although the three jurisdictions historically adopted very different ways to reflect transmission costs into wholesale market prices, they have been experiencing related transmission congestion issues related to VREs growth. While sub-national pricing is effective in providing a faithful representation of system conditions, it cannot guarantee optimal long-term investment decisions. In fact, the issue of locational pricing cannot be understood separately from developments in the transmission planning and network investment regimes. Transmission upgrades are in fact a complementary solution to integrating renewables as they enable networks to support increased power flows. All jurisdictions have experienced important challenges in network expansion related to political acceptability by local communities and constraints regulatory and institutional arrangements, which have resulted in sub-optimal use of generation and network assets. In all, jurisdictions reforms are underway to make infrastructure investment more strategic and tackle some of these issues.

***Table 14** - Political economy conditions found to affect the evolution of short-term energy market design*

| | Market coupling | Market rules | Price regulation | Locational pricing |
|---|---|---|---|---|
| **National politics and government** | - Dominant political ideas around the risks and benefits of market integration<br>- Dominant political attitudes towards sovereignty and national identity | - Evolution of political and policy priorities (decarbonisation and cost-effectiveness) | - Political acceptability of price spikes<br>- Evolution of political and policy priorities (decarbonisation and cost-effectiveness) | - Political acceptability of locational price signals<br>- Political acceptability of infrastructure<br>- Evolution of political and policy priorities<br>- Institutional relationships within government |
| **State-market relations** | | | - Dominant ideas on role of markets and price signals<br>- Legacy political economy model | - Dominant ideas on role of markets and price signals<br>- Legacy political economy model |
| **Sector-specific institutions** | - Legacy arrangements for market operation<br>- Dominant operational philosophies<br>- Independence of system operators | - Legacy arrangements for market operation<br>- Dominant operational philosophies and understandings of risks and benefits of granular trading among sector institutions<br>- Influence and capacity of system operator | - Dominant understandings of risks and benefits of price regulation among sector institutions<br>- Interests, capacity and influence of system operator | - Legacy arrangements for market operation<br>- Dominant operational philosophies<br>- Incentives, interests, capacity and influence of system operator |
| **Multi-level governance** | - Level of trust across layers of governance<br>- Level of capacity and coordination of multi-level governance institutions<br>- Level of homogeneity in political economy context of states<br>- Balance of power among states | - Dominant ideas on market operation in multi-level governance institutions<br>- Balance of power among states and policy influence in multi-level governance | - Dominant ideas on market operation in multi-level governance institutions<br>- Level of capacity and coordination of multi-level governance institutions<br>- Level of homogeneity in political economy context of states | - Level of capacity and coordination of multi-level governance institutions |
| **Market structures and interests** | - Legacy market structures<br>- Influence of local energy utilities<br>- Employment in energy sector and influence of trade unions<br>- Organisation and influence of environmental groups | - Legacy market structures<br>- interests and influence of incumbent utilities and different RES generators<br>- Economic composition of demand<br>- Interests and influence of different types of consumers | - Homogeneity and alignment of power sector stakeholder views<br>- Interests and influence of RES generators | - Legacy market structures<br>- interests and influence of incumbent utilities and different RES generators<br>- Economic composition of demand<br>- Interests and influence of consumers located in different parts of the network |

# 7 Evolution of balancing and ancillary services

This chapter analyses recent changes in balancing markets and ancillary service design implemented to enable VREs integration in Britain, Italy and California. It covers a variety of aspects including the evolution of balancing pricing mechanisms and ancillary service products, reforms implemented to widen access to non-traditional providers and emerging models for local flexibility procurement. It is important to note that California has a different market model from Britain and Italy whereby energy and reserves are co-optimised instead of being procured in a separate market (see sub-section 5.3.2). To simplify comparison, an artificial distinction was drawn between market design elements relevant to energy trading and those focusing on reserves and ancillary services. Other aspects relevant to the dispatch model and short-term market rules were addressed in Chapter 6 on energy markets.

## 7.1 The evolution of balancing and ancillary services in Britain

### 7.1.1 Balancing pricing mechanisms

In 2015, Great Britain launched a significant overhaul of its electricity market's balancing mechanism through the Electricity Balancing Significant Code Review (EBSCR). This reform was prompted by concerns that the imbalance prices, commonly referred to as cash outs, within the original market design did not accurately reflect the full cost of balancing actions taken by the system operator (UKGOV 2015). Specifically, there was apprehension that the inability of imbalance prices to adequately represent system scarcity conditions was undermining the effectiveness of long-term investment signals in new generation, a phenomenon often referred to as the 'missing money' market failure (see sub-section 2.1.3). The primary objective of the EBSCR was to align cash-out prices with incentives for suppliers to effectively balance their positions and make investment decisions that better account for scarcity conditions, particularly in light of growing shares of intermittent generation (ibid).

The EBSCR introduced a single pricing system, where short balancing responsible parties paid the same price as long generators (UKGOV 2015; Joos and Staffel 2018). This change aimed to make reliance on the centrally cleared balancing mechanism more attractive by reducing transaction costs. Additionally, it sought to lower costs for smaller parties that lacked the ability to influence the system imbalance and typically experienced zero imbalances over longer periods (ibid). Broadly, these adjustments are in line with economic literature, which generally favours single pricing due to its cost-reflective nature, its ability to enhance flexibility incentives, encourage trading among participants and participation of smaller participants (Hirth and Ziegenhagen 2015; Hiroux and Saguan 2010). This design aligned with the EU Target Model (Schittekatte et al. 2020).

The EBSCR also shifted cash-out prices to a more 'marginal' calculation, based on the most expensive action taken by the system operator to balance the system (Joos and Staffel 2018; UKGOV 2015). In essence, the imbalance price calculation was adjusted to better reflect the marginal costs caused by energy imbalances, real-time spot market prices and the scarcity of generating capacity (ibid). This change aligns with economic theory, which argues more convincingly for uniform pricing over pay-as-bid mechanisms (Hirth and Ziegenhagen 2015; Brijs et al. 2017; Hu et al. 2018). Setting the imbalance price at the marginal cost was seen as more efficient for resource allocation and encouraging flexibility investment, whereas average pricing as incentivising deviations from schedules, potentially discouraging VRE sources from improving their forecast accuracy (ibid).

To improve market signals and security of supply, EBSCR also changed the pricing methodology for reserves (UKGOV 2015). Specifically, it introduced a reserve scarcity pricing function, which prices reserve (when used) based on the prevailing scarcity in the system. In extreme cases National Grid can force some consumers to consume less energy (e.g. blackouts), and the imbalance price is set administratively at a VOLL of £6,000/MWh. This approach is also in line with arguments found in the techno-economic literature (Brijs et al. 2017; Hu et al. 2018).

In summary, the EBSCR implemented significant modifications to balancing pricing mechanisms that aligned with traditional economic principles, the British and EU traditions emphasising the importance of short-term price signals in driving efficient operation and investment. Yet it is important to note that, rather than relying exclusively on these enhanced price signals, the government pursued parallel initiatives to ensure long-term system reliability, notably, a capacity market that explicitly remunerates long-term capacity investment (discussed extensively in Chapter 8). It is in this context that political economy dynamics are most conspicuous.

The EBSCR's impact on imbalance pricing has been mixed, resulting in more volatile prices with higher spikes but lower average cash-out prices. Between 2016 and 2020, only nine settlement periods saw scarcity pricing setting the system price (Elexon 2021a). Government reviews concluded limited impact on investment due to generators predominantly selling energy in forward markets and high uncertainty around scarcity events, making scarcity rents risky for investors (BEIS 2020). Further, experts noted how Ofgem often struggles to distinguish efficient market operation from speculation-driven high prices, leading it to take a more restrictive stance, which in turns deters operators from capitalising on high prices [Interview 6 – electricity market design consultant].

Another important aspect to consider is the definition of the imbalance settlement period. The literature tends to support shorter settlements in view of their potential to reduce and better allocate balancing costs by adequately reflecting quickly shifting flexible balancing actions (Schittekatte et al. 2020; Hu et al. 2018). This approach, widely endorsed by the EU, should in turn incentivise balancing responsible parties to maintain their positions balanced contributing to mitigate the impact of an increasingly volatile generation fleet. Nevertheless, GB sticks to half-hourly settlement. This might be counter-intuitive if seen in the context of the EBSCR and the general British narrative, which puts much emphasis on cost-reflectivity. However, Ofgem avoided this reform on the basis that the costs for consumers related to implementation complexities would outweigh potential efficiency gains (Ofgem 2020). This points to a specific understanding of the costs and benefits of different market enhancements among the policymakers of different states, and on the appropriate trade-offs to draw.

### 7.1.2 Ancillary service products (and wider access)

In the latter half of the 2010s, the imperative to advance power sector decarbonisation while ensuring the power system's reliability drove significant changes in balancing and ancillary services [Interviews 7,9,11]. The integration challenges posed by VREs highlighted the need for greater system flexibility to address intermittency, hence, necessitating faster-acting balancing products and the optimisation of ancillary service procurement (Joos and Staffell 2018). Additionally, in 2017, BEIS and Ofgem outlined a vision for a more flexible and decentralized energy system, emphasising a more substantial role for DSR, aggregations and energy storage in the so-called Smart Systems and Flexibility Plan (BEIS and Ofgem 2017). National Grid faced increasing criticism for its complex product and market structures, seen as barriers to non-traditional flexibility providers (Schwidtal et al. 2021).

To encourage the system operator to play a more proactive role in reforming balancing markets, Ofgem introduced a new regulatory regime for the SO, the so-called RIIO formula (see sub-section 5.1.6.2), emphasising innovation rather than the traditional focus on cost efficiency [Interviews 1,9,10,14]. Concurrently, initial steps were taken towards the institutional separation of National Grid into two legal entities: the Electricity System Operator (ESO), responsible for system operation, and the transmission owner National Grid. The rationale was that the bundling of these activities led to conflicts of interest by incentivising National Grid to prioritise its assets in system service procurement, which conflicted with the Government and regulator's vision of a flexible energy system [Interview 7 – senior government policymaker]. The reforms also aimed to promote a more strategic role for the ESO, requiring a shift in its corporate culture from ‘relentless cost-cutting’ to ‘dynamic change and energy transition’ [Interview 16 – electricity asset management expert].

Participants widely agreed that the combination of changing system conditions and institutional arrangements led the system operator to take a more proactive role in reforming balancing and ancillary service markets, resulting in a significant shift in the organization's culture [Interview 8 – senior policymaker; interview 11 – senior market expert at system operator] (also see sub-section 5.1.6.2). Since 2017, the ESO has initiated multiple stakeholder-driven initiatives to streamline product categories, adjust technical specifications, and enhance access to DERs, aggregation, and storage within these markets (NGESO 2022a). Participants also lauded NGESO's efforts to increase transparency and engagement with the industry, particularly non-traditional market players, to improve the technological neutrality of its services [Interviews 5,8,19]. This highlights the importance of sector-specific institutional arrangements in driving market design change.

The groundwork for balancing markets reform was laid by the 2017 Reserve and Response Roadmap, which sought to standardise “market arrangements, rationalising the volume of products and simplifying our processes and contracts to facilitate market access for an ever-growing number of providers” (NGESO 2019a). Initial steps for lowering market barriers included a decrease in the minimum bid size to 1 MW and shorter trading times (NGESO 2022a). Further, during this period, the Enhanced Frequency Control Capability project marked the first attempt to source services from non-traditional providers. It explored innovative methods for maximizing the value of fast-acting response from variable sources like wind, solar, and distributed energy resources (ibid). Participants consistently identified this trial as a first key route into the market for battery service providers [Interviews 5,7,16].

In 2019, NGESO initiated the Wider Access to Balancing Mechanism Roadmap to facilitate market access for aggregators. This would align the mechanism with the government vision for a smart and flexible system also pursued by the EU through its framework for balancing products TERRE[28] (NGESO 2019; Ofgem 2019c). Originally, these services had been limited to licensed suppliers registered as balancing units, creating a hurdle for non-traditional providers. To address this, a new market entry route, the Virtual Lead Party, was introduced. This allows the aggregation of secondary balancing mechanism units with a minimum size of 1MW within a grid supply point. Furthermore, the entry requirement for Fast Reserve aggregators was reduced from 50 MW to 25 MW, accompanied by simplified contracts in both the Fast Reserve and STOR[29] markets (ibid). Participants highlight how these changes facilitated the first aggregations by both established players as well as newcomers, such as the company Flexitricity [Interviews 17,18,19].

From 2019, the Frequency Response Auction Trial tested closer-to-real-time procurement of ancillary services with the longer-term ambition of establishing a single, day-ahead market for frequency response and reserves, procured via a single market platform (NGESO 2019a). The two-year trial aimed to facilitate a transition from a monthly FFR[30] tender process to a weekly, pay-as-clear auction for the procurement of ancillary services, encompassing up to 100 MW of both static and dynamic frequency response. The rationale was that introducing ‘a more rapid procurement cycle and standardised services’ would avoid the problem of procurement fragmentation and ‘facilitate non-traditional providers to offer frequency response services’ (ibid).

In 2021, these experiments led to the launch of the first new product, Dynamic Containment. NGESO highlights this as a groundbreaking super-fast response product, stating, "It represents a significant advancement in managing frequency in a system with decreasing inertia and heightened potential losses" (NGESO 2022a). Subsequently, two additional products, Dynamic Moderation and Dynamic Regulation, have been introduced. For detailed technical specifications of these products, refer to

[28] EU TERRE is an initiative aimed at enabling the integration of electricity balancing markets across Europe, promoting cross-border cooperation and efficient use of resources to enhance grid reliability and flexibility (NGESO 2022a; Terna 2020; EC 2017).
[29] Short-Term Operating Reserve.
[30] Firm frequency response.

Table 15. Since 2020, the ESO has also been leading an ongoing consultation process aimed at reforming reserve products (ibid). The most notable change thus far has been the shift to day-ahead procurement in both STOR and fast reserve. This should encourage providers to submit their marginal prices, exerting downward pressure on overall balancing costs and expanding participation for non-balancing-market participants. However, many more changes are in development, driven by the pursuit of long-duration storage solutions, consistently identified as one of the major challenges currently faced by the system operator [Interviews 11,12,16].

***Table 15*** *- Characteristics of new response products (NGESO 2022a)*

| | **Dynamic Containment** | **Dynamic Moderation** | **Dynamic Regulation** |
|---|---|---|---|
| **Characteristics** | Designed to arrest the change in frequency following a sudden imbalance. | Designed to arrest the change in frequency following large imbalances. | Designed to correct small continous deviations in frequency. |
| **Procurement model** | Pay-as-clear auctions | Pay-as-clear auctions | Pay-as-clear auctions |
| **Procurement timeline** | Day-ahead | Day-ahead | Day-ahead |

These recent changes to balancing services hence created a fertile ground for the rise of new technologies and business models. Britain has become a leader in this area having one of the most accessible value streams for demand-side resources in Europe (Figure 36a), as well as the most diverse aggregation market (Figure 36b). It also saw a considerable increase in storage participation in balancing services. According to participants, the combination of these new services has led to a 'boom in battery investment' as they 'provided a source of finance for some of these technologies to get started' [Interviews 7,17,19].

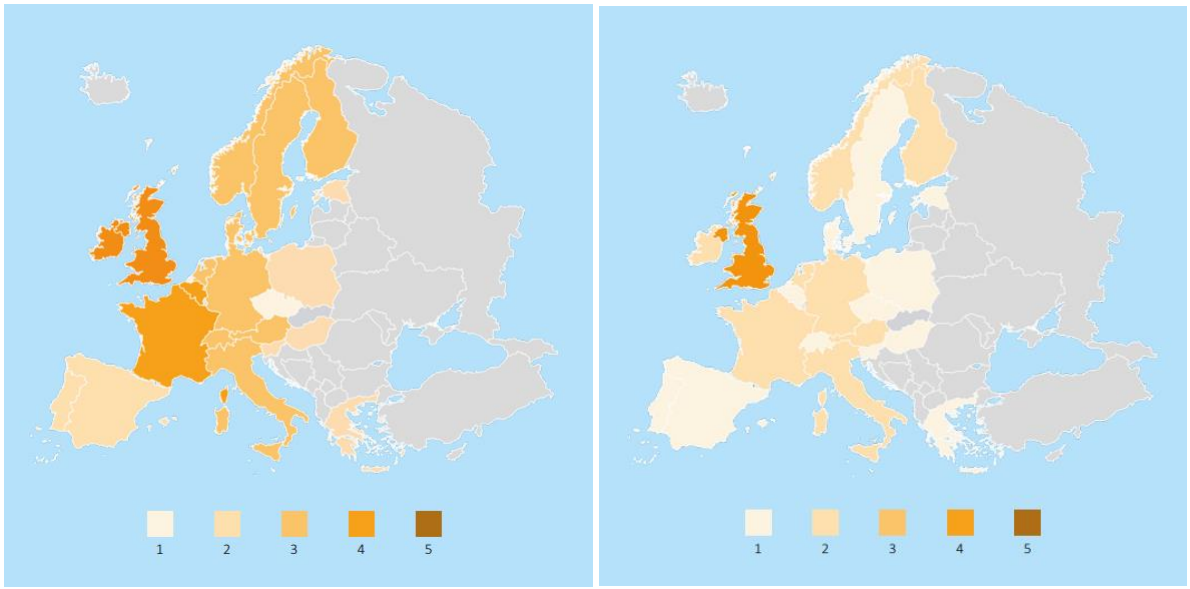


***Figure 36*** *- a) Degree of value-streams accessibility for DR; b) Degree of diversity of aggregation market (Murley et al. 2021)*

Figure 37 shows the 2020 Frequency Response market by technology. It can be observed that Enhanced Frequency Response and Dynamic Containment were dominated by battery assets and the Auction Trial also saw significant participation of aggregated demand-side assets. The Firm Frequency Response market has the broadest range of technology types, while the Mandatory Frequency Response market remains dominated by large conventional generators such as CCGT, biomass and coal units (NGESO 2022a).

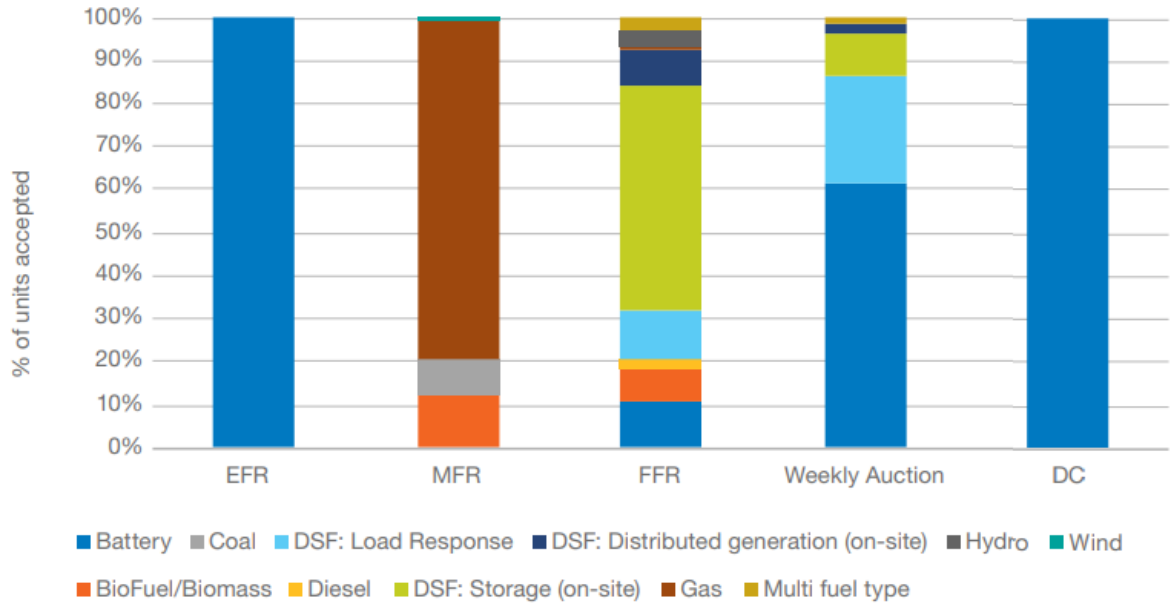


***Figure 37** - 2020 Frequency Response market by technology (NGESO 2022a)*

These services are being experimented with by both incumbents and new market actors, leading to novel dynamics in the political economy of balancing markets. Interestingly, it was noted that several incumbents, instead of resisting changes that would lead to new market entry, saw the business opportunity of bringing aggregated assets to the market: "the big generators aren't like complete monoliths like EDF, British Gas, Scottish Power, SSE, Drax, all of these big generation companies will also have aggregation and supply side stuff on the same side, so actually making it easier for them [new market entrants] is making it easier for the other parts of their business so they don't really mind" [Interview 6]. This in turn is bringing an initial shift in their interests: "you can see somebody from the generation businesses and from the aggregation business both part of EDF or whatever, but they're not necessarily arguing from the same position because they represent some different parts of their business" [ibid].

Further, evidence shows that the interests of new service providers can quickly become consolidated and come to constitute a force opposing further change. Specifically, those who have accessed the market thanks to NGESO's initial products have been found to resist further reform: "if you look at kind of the more established battery people, they've kind of pushed back and said: actually no, we've already got a business model that works and then there are these newcomers who kind of feel that they can't get in. Those two people I would have assumed would kind of see eye to eye, but they don't. I think that's it's all about market position, which they've already got" [Interview 11 – senior market expert at system operator].

Nevertheless, it is important to note that despite recent reforms, the share of services procured from non-traditional providers remains modest relative to the overall size of balancing markets (Figure 38). This is because frequency products have so-far seen wider participation of new flex providers, but these amount to much smaller size than reserve products, where traditional assets still dominate (NGESO 2022a). Among representatives of non-traditional providers there is a perception that new flex assets remain undervalued and 'old assets are favoured' as deemed more reliable: "if you're on the desk in the in the control centre, you tend to go to a solution that you know will work rather than one that you're not entirely sure about purely because you've never used it before. Nobody wants to be the person on the desk when the lights go out so" [Interview 19 – representative of non-traditional flexibility provider]. This points to the importance of legacy ideas held by system operators on the value of different resources, perceptions and incentives around system reliability.

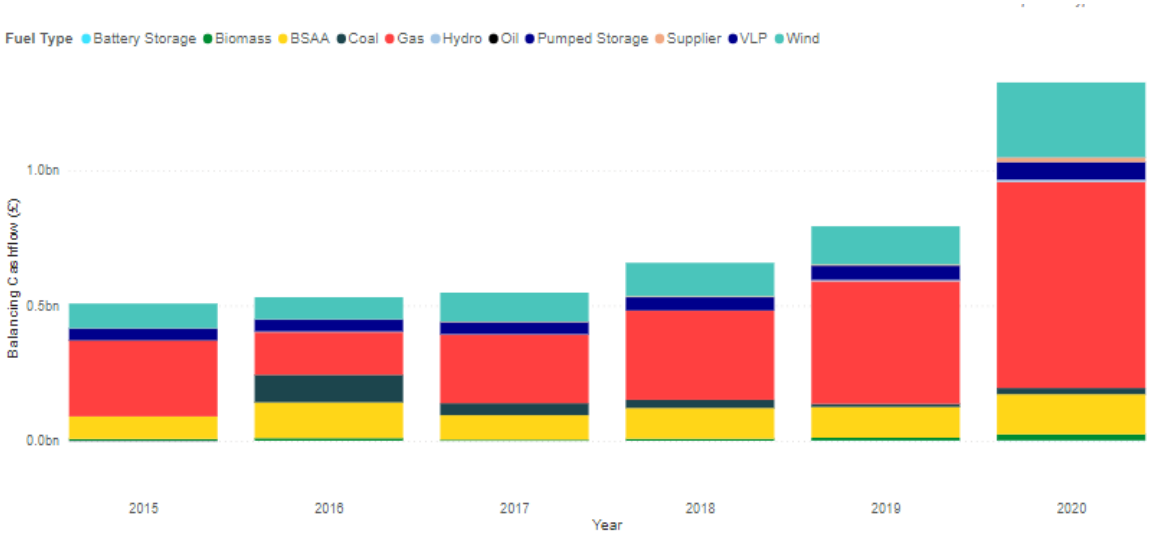


***Figure 38** - Net balancing cashflow by fuel type (Elexon 2021)*

Finally participants note that, significant questions remain around the long-term viability of business models of some new service providers [Interviews 7,9,16,18]. Grid services procurement is limited to the size of NGESO needs, hence, there has been a tendency for products to get saturated quickly [ibid]. Without a 'campground' in grid services, battery providers currently rely on arbitrage of spike periods opportunity cost and optimisation of different revenue streams. Relying on trading might not be sufficient to support their business model and long-term investment in these assets with implications for long-term capacity procurement mechanisms' design (discussed more thoroughly in Chapter 8 on resource adequacy).

### 7.1.3 Local flexibility procurement

According to the vision promoted in the Smart Systems and Flexibility Plan, British DNOs need to evolve from having a passive to an active role in power system operation, eventually becoming Distribution System Operators (DSOs) (BEIS and Ofgem 2017). This has been accompanied in changes to the regulatory regime with the introduction of RIIO explicitly rewarding network companies for innovation (discussed in sub-section 7.1.2 in relation to SO regulation). Participants also note how the late 2010s saw the launch of different pilots with new market platforms for the procurement of flexibility services by distribution companies to tackle local grid constraints (see for example the company Piclo) [Interviews 5,9,14,19]. Through regulatory sandboxes, Britain has also experimented with a variety of other market models other than a DSO-coordinated platforms based on more decentralised, transactive and community-based energy trading models [ibid].

This has led to the opening of an important debate in terms of the future of system architecture and the modalities of ESO-DSO coordination for the procurement and dispatch of flexible assets located on the distribution network (ENA 2019). There are in fact contrasting visions among different network operators: "different DNOs definitely have different flavours of where they think the DSO function is going. Some of them are far more towards eventually we will be a platform coordinating a whole load of market assets but we will be a quite neutral bit there. Others see a stronger role for the DNO itself to be providing flexibility. […] when you look at the ESO, I feel that their vision is that they want to expand the bit of the system that are coordinating reaching further and further into the distribution networks" [Interview 18 – representative of decentralised energy industry]. Providers of decentralised services argue that the extent to which dispatch is centralised has important implications for the 'stackability' of revenues for distributed resources offering these services [Interviews 18,19]. Maintaining access to both local and national markets has been identified as a key priority by these stakeholders [ibid].

## 7.2 The evolution of balancing and ancillary services in Italy

### 7.2.1 Balancing pricing mechanisms

Following the same techno-economic rationale as the GB EBSCR (see sub-section 7.1.1) and to align its market design with EU Target Model, Italian policymakers have long been discussing a move away from dual balancing pricing. The transition to full single pricing is supported by economic theory and the EU for its ability to better reflect system costs, which is increasingly important in the context of a high-VRE system. The main interest group representing the Italian power sector Elettricita' Futura has also shown support for this change arguing that "all units should be exposed to the same value system" and that "dual pricing can result in unproportionate penalisation of imbalances for some units", hence discrimination (Elettricita' Futura 2019).

A first step in this direction was taken in 2016 with the introduction of a the so-called 'single-dual pricing' (ARERA 2017, 2019a). This system effectively applied single or dual pricing for different resources based on the nature of their imbalances. In 2019, as part of the TIDE reform (see Section 6.2), the Italian regulator presented a more comprehensive proposal for reforming of balancing mechanism with the aim of introducing changes that would improve the efficiency, effectiveness, and transparency of the MSD[31] in the context of changing system conditions and further alignment with EU Target model (ibid). TIDE proposed the complete removal of dual pricing and a switch from pay-as-bid to system marginal pricing. As explored in sub-section 2.1.2, a switch to marginal pricing also finds roots in economic theory due to its ability to improve the efficiency of resource allocation and encouraging flexible operation and investment.

Nevertheless, while the long-term objective to switch the pricing mechanism have been set, progress has seen delays. Based on available data, this may be partially attributed to institutional inertia, or the complexity of implementing such reform from a technical perspective [Interviews 27,29,30] (Terna 2020). Further, while the removal of dual pricing is generally endorsed by the main industry interest group Elettricita' Futura, the association argued that this should not take place until the wider reform of ancillary services is completed (discussed in the next sub-section) (Elettricita' Futura 2019). There are also concerns related to the potential implications of these changes for market power, a long-lasting concern in the Italian MSD [Interviews 20,27]. These uncertainties and disagreements among key stakeholders on the merits of the reform might have contributed to the delays.

Finally, another key area of debate has been whether negative prices should be introduced in the MSD. This would have aligned the Italian design to the EU Target Model and has been endorsed by Elettricita' Futura, which advocated for the introduction of negative prices across all timeframes (Elettricita' Futura 2020). This position has been justified through a market efficiency logic, as the removal of the bid floor is expected to remove obstacles and introduce incentives for unsubsidised VREs units or aggregators to provide ancillary services (especially downward). Nevertheless, while ARERA committed to remove the bid floor in the day-ahead and intraday markets (sub-section 6.2.3), it concluded that it will not do so in the MSD (ARERA 2019a). In fact, it fears that this might accrue problems related to the exercise of market power in some bidding zones. This has led Elettricita' Futura to accuse the regulator of having interpreted incorrectly EU regulation, which explicitly mandates the removal of any price caps across all market timeframes including balancing (Elettricita' Futura 2020).

It is also important to note that there is an administrative shortage pricing mechanism operating in the Italian dispatching mechanism, also introduced to comply with EU regulation (MISE 2019). More specifically, when a system inadequacy condition is detected with respect to a balancing period, the TSO is required to resort to rolling disconnections of loads either in the scheduling phase of the Ancillary Services Market or, with at least 30 minutes notice, in the real-time phase of this market. In this case, the imbalance settlement price is automatically set to the VOLL. Nevertheless, just like Britain, rather than relying exclusively on these enhanced price signals, the Italian government pursued

[31] - i.e. dispatch service market.

parallel initiatives to ensure long-term system reliability, notably, a mechanism that explicitly remunerates long-term capacity investment (discussed extensively in Chapter 8).

Finally, in line with EU guidelines, Italy is moving to 15-minute balancing settlements to be implemented by 2025 (EC 2017, 2019b). The techno-economic rationale is that this should incentivise balancing responsible parties to maintain their positions balanced contributing to mitigate the impact of an increasingly volatile generation fleet (Schittekatte et al. 2020).

Broadly, these discussions underscore the complexities associated with implementing EU-driven market rule changes in Italy, aiming to enhance cost-reflectiveness within a country where the balancing market operates under a distinct zonal pricing model and is characterised by strong market power dynamics. This unique context not only makes implementation more complex but highlights the divergence in viewpoints among policymakers in different jurisdictions regarding the cost-effectiveness of various market enhancements and the appropriate trade-offs to draw.

### 7.2.2 Ancillary service products (and wider access)

Until 2018, the Italian balancing and ancillary services market remained largely inaccessible to non-traditional providers (Schwidtal et al. 2021). To comply with EU regulations, a reform program aimed at improving access for non-traditional providers and enhancing reliability amidst the growth of VREs has been underway since 2017, led by ARERA and Terna (ARERA 2017; Terna 2020a). As explained by a regulatory official involved in the reform process, “in 2017, the latest challenge began, which is still ongoing and the most difficult one. It involves thinking about how to replace the thermal power plants with other units for ancillary services” [Interview 27].

The reform of ancillary services was conducted as part of the much wider TIDE reform programme aiming to enhance the entire Italian dispatch model and align it with the EU market design (ARERA 2019a) (discussed in Section 6.2). Like in Britain, changes in ancillary services involve the introduction of specialised products to incentivise non-traditional providers, implemented through a series of pilot projects designed to eventually inform a more comprehensive market overhaul [Interviews 27,28,29,30]. Despite rapid progress with trials, at the time of writing, these have not yet culminated in a comprehensive reform, nor have they led to the introduction of finalised market products like in Britain, in line with TIDE deadlines. Observers attribute at least partially to the COVID-19 pandemic, regulatory and institutional delays, and the need to adapt EU regulations to the specific characteristics of the Italian market model [ibid].

Figure 39 shows how the framework has evolved over time. The first step in 2017 was experimentation with the so-called UVAC (unità virtuali abilitate di consumo) constituted by DSR assets and aggregation thereof, whose minimum size was moved from 10 to 1MW. Then, UVAP (unità virtuali abilitate di produzione) allowed aggregation of decentralised (small) supply assets including non-programmable and storage units (ARERA 2019; Terna 2020; Chiesa et al. 2017). In 2018, these trials were merged in the so-called UVAM (unità virtuali abilitate miste) including both demand and supply assets (ibid). UVAMs can offer services (upward or downward) to resolve congestions, for tertiary reserves and balancing (Schwidtal et al. 2021). They must have at least 1 MW of scalable capacity (both upward and or downward) but can in theory aggregate assets of any size, though this has so far been difficult in practice due to metering infrastructure limitations. The total amount of capacity to be procured[32] by the TSO amounts to 1000 MW, making it one of the most ambitious projects of DERs balancing service provision in Europe.

[32] Units are distinguished as contracted and non-contracted UVAMs with two potential remuneration mechanisms: a pay as bid mechanism for activation, i.e., the standard remuneration derived from balancing markets; an additional (temporary) tender mechanism with stricter conditions (ARERA 2019).

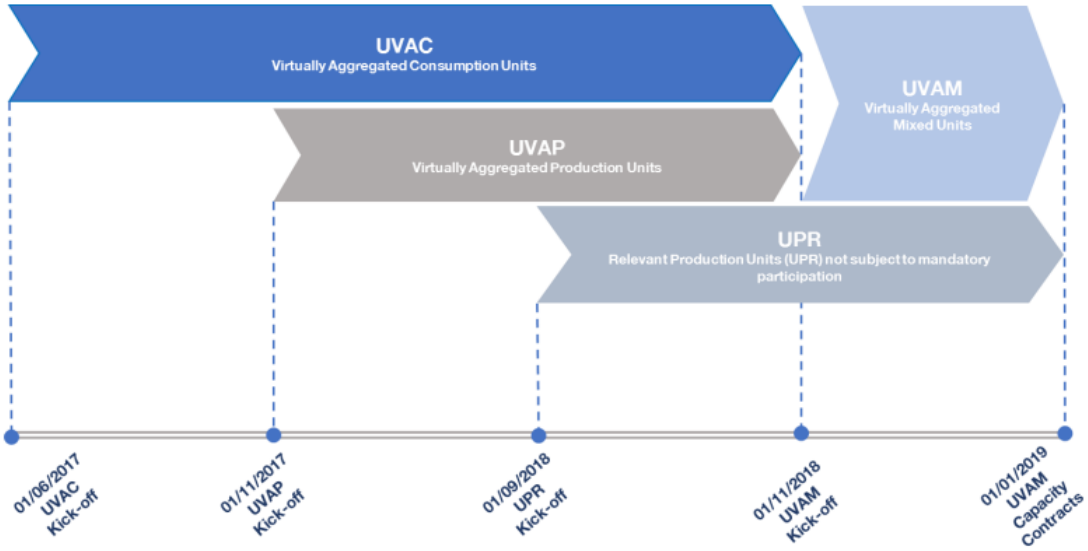


***Figure 39** - Timeline of balancing and ancillary services market reform (Terna 2020a)*

Terna also initiated a dedicated pilot project to enable the provision of primary frequency response by electrochemical storage systems, similar to enhanced frequency response products in the UK. The so-called Project UPI, which reached a capacity of 30 MW by 2020, allows production units to allocate their frequency containment reserve on a storage system integrated with the production units at a fixed renumeration assigned through pay-as-bid auctions (Chiesa et al. 2021; Terna 2020; ARERA 2018). Experts suggest that when this service was initially launched, it may not have been immediately required from a physical standpoint [Interviews 27,29]. However, the pilot project was undertaken in anticipation of future system requirements, particularly as the deployment of VREs is expected to increase [ibid]. This approach aligns with Italy's efforts to address integration challenges associated with the growing presence of VREs, although it should be noted that the pace of renewable energy deployment in Italy has slowed down compared to the UK (see Section 9.2).

Figure 40 shows the power allocated through the UVAC, UVAP and UVAM trials between 2017 and 2019. Since its launch in 2019, UVAM witnessed a substantial increase in participation, exhausting its entire 1GW capacity allocation. Interestingly, beyond capacity that secured long-term contracts, there has also been some participation on a merchant basis (Chiesa et al. 2020, 2021; Terna 2020a). Italy is in the EU average in terms of demand-side resources value streams access and competitive landscape for aggregation market (Figure 36a,b). The country has also seen an initial growth in battery capacity. The UPI tender has seen high levels of participation achieving cost-reductions compared to the tender price base [ibid].

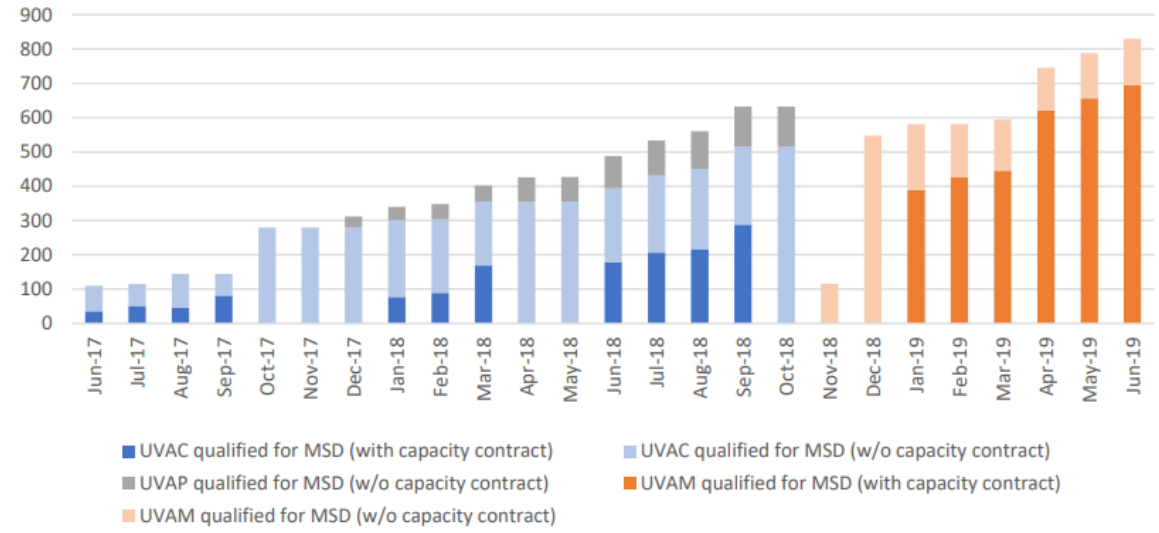


***Figure 40** - Power enabled and subject to contracts on the MSD in MW (Terna 2020a)*

It is worth mentioning that UVAM participating units have tended to be based on a single production site (68% in 2020) though this proportion has been declining, signalling the emergence of broader aggregations (Chiesa et al. 2020, 2021). Large industrial sites still dominate the DSR landscape. However, the aggregation of domestic or commercial loads is expected to gain further momentum with the deployment of second-generation smart meters. Italy has in fact positioned itself as a leader in the European Union regarding smart meter technology adoption, with widespread deployment led by major incumbent distribution utility Enel (Oxera 2020).

In terms of the diversity of service providers, interviewees note that there has been a strong incumbent presence [Interviews 25,27,38]. Specifically, there has been a notable participation from traditional utilities and trader operators, more familiar with market dynamics (Chiesa et al. 2020). Particularly notable is the role played by major incumbent Enel through its subsidiary company Enel-X specialised in DSR, which managed to secure a 38% share alone in the UVAM market in 2019 (Figure 41). Like in Britain, this suggests that rather than opposing changes that might lead to new market entry, the Italian incumbent is gradually shifting its interests towards new business models: “In the last 5 to 6 years, Enel has become a company that looks very much towards the future” [Interview 25 – Italian energy policy expert].

Nevertheless, observers note that there have been some new market entrants experimenting with new business models and the aggregation of smaller loads, “startups who are likely to eventually merge into larger companies” [Interview 27 – senior official at regulator]. Emerging market structures also have implications for how the benefits of participation are distributed across aggregators and service providers as pointed out by this representative of industrial DSR providers: “50% of margins are gained to whom offers the service, and another 50% percent is eaten up by the trader or the traditional producer, can we say that an industrial consumer gets a real benefit from participating?” [Interview 38- representative of industrial consumers].

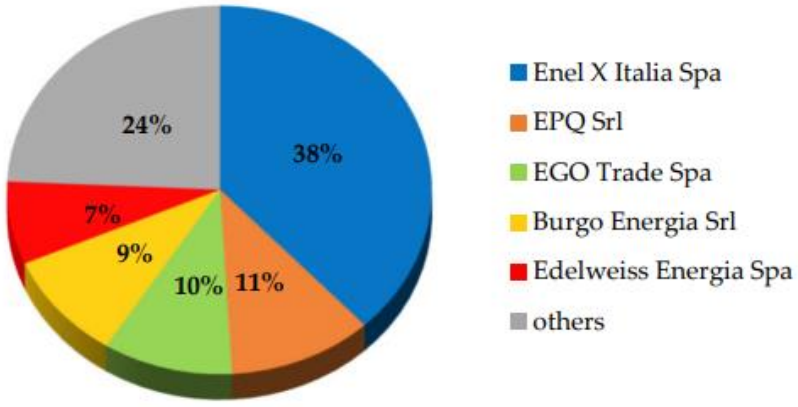


***Figure 41 –*** *UVAM market shares as of December 2019 (Schwidtal et al. 2021)*

Likewise, participants in the UPI tender have tended to be medium or large sized producers as, given the high costs of battery storage: "only who has their backs covered can afford the investment" [Interviews 27,33]. Like in Britain, participants raised important questions around the ability of storage service providers to rely solely on ad hoc procurement by the system operator, which saturates quickly, and market arbitrage [Interviews 33,35]. The theme of long-term flexible investment is treated more comprehensively in Chapter 8.

In summary, while these 'experiments' have provided a first route to the market for non-traditional providers making it possible to test their performance in the provision of ancillary services, their contribution is still limited as traditional resources still dominate the Italian balancing market (Oxera 2020). There is a perception among non-traditional providers that their services remain undervalued as exemplified by this statement from Italy's main DER interest association: "UVAM does not seem capable of harnessing the potential of these technologies, […] a relaunch and enhancement of the mechanism would be needed" (Italia Solare 2021). Renewable, DSR and DER groups have also mobilised to obtain wider access to the MSD as they can currently only offer services through the UVAM pilot [Interview20] (Italia Solare 2021; ANEV 2019).

Like in the UK, this highlights the importance of legacy ideas on the reliability value of different resources, and institutional arrangements for the system operator. Non-traditional providers lament that Terna often fails to "select offers for ancillary services based on economic merit and according to a criterion of technological neutrality" (ANEV 2019). This might find its roots in a conservative spirit towards the dispatch of resources due to significant uncertainties around the performance of these new assets. It might also be partially rooted in the broader regulatory framework of the Italian TSO that has come under criticism for having a conservative operational approach [Interviews 31,36,38]. Terna is currently undergoing a transition in its regulatory framework from price cap regulation to an output-based model, aligning with wider European efforts to encourage more forward-looking practices by system operators (Oxera 2016) (see discussion in sub-section 5.2.6.2).

Nevertheless, broader industry concerns have arisen regarding potential conflicts of interest within Terna [Interviews 31,36,38] (Italia Solare 2021). These stem from Terna's financial incentives to expand its regulated assets, a consequence of the bundling of its operations, which may inadvertently prioritise its own interests over overarching system objectives (sub-section 5.2.6.2). Market participants have voiced their dissatisfaction with Terna's endeavours to engage in generation activities and expand into areas involving physical asset management such as system services and security reserves, raising questions about its adherence to principles of market liberalisation [Interviews 21,37,31]. The lack of transparency and accountability in Terna's interactions with stakeholders,

especially in intricate and time-sensitive consultations, has also faced criticism [Interview 37 – representative of medium-sized generators].

### 7.2.3 Local flexibility procurement

Just like the Smart Systems and Flexibility Plan in Britian, the EU Clean Energy Package sets a clear vision involving a much greater role for active distribution networks and local energy communities (EC 2019c). Italy has introduced these objectives into national policy through the 2019 PNIEC 'Piano Nazionale Integrato Energia e Clima' (MISE 2020). In terms of local DSO-led markets, Italy has planned pilots for procurement of ancillary services at the local level but these were not yet in operation at the time of writing. This is partially related to the fact that the DNO-level infrastructure in Italy had not yet seen major constraints thus far, except in some specific locations like Rome [Interview 27]. Italy has recently taken tangible steps towards implementing EU Directives on energy communities, notably through the 2020 'Decreto Milleproroghe', which formally introduced into national law the definitions for 'prosumers' and 'renewable energy communities' (Chiesa et al. 2020).

The main distribution company Enel has shown interest in taking up an increased role in the procurement of local flexibility [Interview 33]. This is perceived with concern by some market actors such industrial and residential DER service providers, who highlight the presence of conflicts of interest with implications for the neutrality of service procurement [Interviews 21,38] (Italia Solare 2021). While Italy has embarked on a process of adjusting the network regulatory framework to incentivise more systemic thinking (Oxera 2016), these participants argue that proper unbundling should be pursued going forward if Enel is to act as the main local flexibility procurement body [Interviews 21,38] (Italia Solare 2021). Further, they note that Enel has been actively resisting more community-based models for system flexibility that would not involve its active participation [ibid].

Just like in the UK, there are different visions co-existing around future power system architecture among DNO, TSO, industrial consumers and local prosumers: "there is competition around the new dispatch model. Enel wants a bigger role for the distribution network and says let's pull self-consumption or energy communities aside. Terna tends to say, no, I want to retain coordination of the system. It is not clear what the reference model is going to look like" [Interview 21]. While there is a commitment by Italian decision-making institutions to retain central dispatch by the TSO, the future model for local flexibility remains less clear [ibid].

## 7.3 The evolution of balancing and ancillary services in California

### 7.3.1 Balancing pricing mechanisms

California has not seen any radical changes in the logics and mechanisms underpinning its balancing pricing regime based on co-optimisation of energy and reserves. The latter is frequently regarded as the optimal solution in economic theory, as the balancing price accurately captures the opportunity cost associated with supplying energy (or reserves) while considering the physical attributes of the system (Hogan 2013). The discussion of this approach, its operational philosophy, and its potential for addressing VRE integration challenges can be found in Sections 2.1, 5.3.2 and 6.3. Recent reforms in California have mostly focused on the definition of the time granularity of products and bid parameters that go into its optimisation model. This includes a transition to 15-minutes settlements and modifications in bid parameters to enable wider access for non-traditional service providers as discussed in the next sub-section.

Already in 2010, CAISO implemented scarcity pricing of ancillary services in both the day-ahead and real-time pre-dispatch processes (Hogan 2013). As in GB, Italy and most of the US, the Californian design procures administratively set fixed levels of operating reserves using an inelastic vertical demand curve whereby a demand bid is put for the entire quantity equal the contingency requirement at the VOLL price (ibid). Around this time, California began experiencing mounting VRE integration

challenges related to its pioneering decarbonisation efforts [Interviews 40,42,44]. This compelled CAISO to introduce a provisional compensation methodology for flexible ramping constraints in 2011, serving as an incentive for operational flexibility (CAISO 2011). This reform process culminated in 2016 with the introduction of the so-called 'flexiramp product' designed to boost scarcity price signals in short-term markets and encourage more flexible operation (Hobbs and Oren 2019).

Flexiramp renumerates resources held in reserve to generate electricity offered below the market price (CAISO 2020). These reserves are different from regulation-type reserves already integrated in the real-time market frame, as Flexiramp aims to ensure energy and regulation availability in future intervals. Flexiramp reserves consist of both upward and downward flexible capacity, in both the 15minute and 5-minute markets, and are remunerated based on lost opportunity costs (ibid). In other words, by creating an additional market revenue stream, flexiramp explicitly rewards attributes like flexibility, fast ramp rates, and reduced startup requirements [Interviews 40,42].

This reform aims to indirectly emulate the effect of more cost-reflective approaches to scarcity pricing found in other US markets [Interview 42]. Specifically, the so-called Operating Reserve Demand Curve used in Texas' ERCOT sets the incremental value of reserves above the minimum requirement to the VOLL during that period multiplied by the probability that incremental reserves might reduce potential curtailment (Hogan 2013). This is in contrast with California's (and the other two cases') legacy scarcity pricing mechanism where the marginal value of any additional MW is zero: "that vertical line means that there's volatility and there was no value to actually procure more than the minimum amount" [Interview 42 – electricity market design consultant]. This design, which might seem sub-optimal from an economic point of view, is much more widespread due to the limited political acceptability of high price volatility that might result from a full scarcity pricing mechanism (discussed in Section 2.4).

Participants note that, broadly, flexiramp has provided additional ramping capability in the market, which in turn has helped to deal with increased uncertainty linked to VREs [Interviews 40,42]. However, important challenges in the product performance have arisen in context of the coupled EIM [Interview 44]. Each balancing authority must make sure to have enough ramp capacity within their area, but some have significant network constraints: "suddenly it became clear that the flexible ramp product was not terribly useful because a lot of it would be acquired in generation pockets where it was bottled up by congestion" [Interview 44 – representative of system operator]. Figure 42 breaks down Flexiramp payments by fuel type. It can be observed that the EIM is heavily reliant for ramp capacity on hydro resources that are concentrated in certain states.

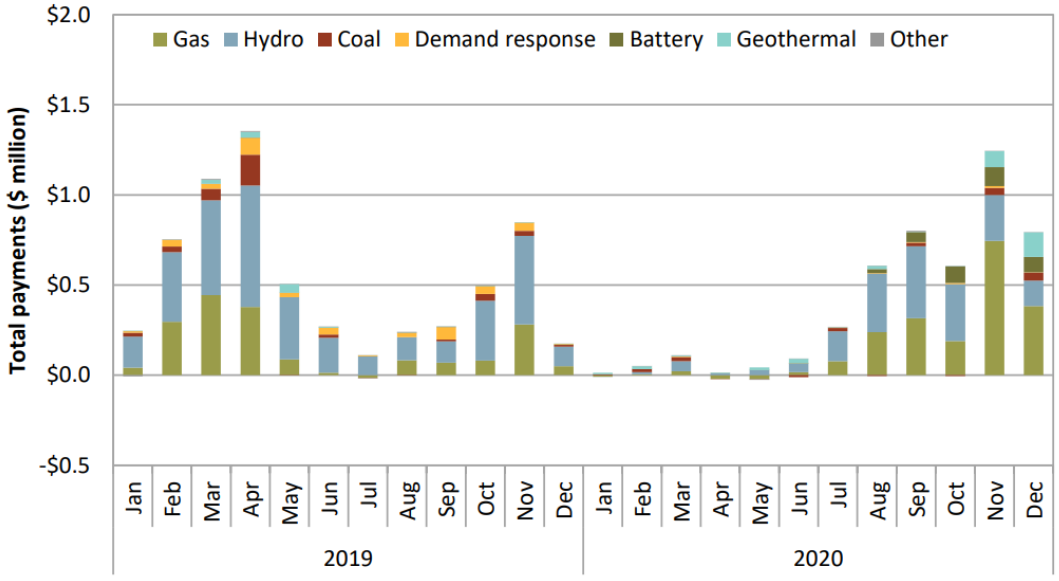


***Figure 42*** *- Monthly flexible ramp payments by fuel type (CAISO 2020)*

A CAISO's assessment concluded that often, in the event of high ramp needs, these were not met through reserves receiving the flexiramp payments but were sourced elsewhere (ibid). As such, CAISO set to acquire flexible ramp capacity on a more granular basis. As a first interim step is a new minimum flexible ramping product requirement introduced in 2020, paving the way for the future introduction of a nodal system (CAISO 2020). In addition, as part of ongoing reform of day-ahead markets, a new day-ahead flexible reserve product is being considered (CAISO 2018). This would compensate resources for must-offer obligation in real-time market to address net load uncertainty deriving from more intermittent renewables [Interviews 42,50].

Finally, it is important to note that, despite efforts to enhance the cost-reflectiveness of scarcity price signals and reward flexibility through short-term markets, just like Britain and Italy, California relies on out-of-market capacity mechanisms to convey appropriate incentives for long-term capacity investment. This is discussed extensively in Chapter 8.

### 7.3.2 Ancillary service products (and wider access)

Over the past decade, California has been at the forefront of efforts to enhance access to wholesale markets for non-traditional providers offering flexibility services. This process began as early as 2012, setting it apart from the other two jurisdictions. In fact, as a pioneer of VREs deployment, California experienced integration challenges early on. Moreover, California's institutional landscape is characterised by a culture of innovation, particularly concerning emerging low-carbon technologies, as detailed in Section 5.3. The state recognised the significance of new flexibility providers such as DSR and battery storage [interview 45,46 – senior policymakers].

Unlike other regions with separate balancing markets, California operates under a centralised co-optimised dispatch model. Consequently, the focus has been primarily on establishing new participation frameworks and making adjustments to critical bid parameters accounting for the unique techno-economic attributes of non-traditional providers to enable them to compete effectively alongside their more established counterparts. This approach differs from the strategies adopted in Britain and Italy, where the emphasis was on creating entirely new products through pilot schemes.

The 2012 Regulation Energy Management was an initial milestone, introducing a first participation framework for new resources like storage and demand response in regulation markets (CAISO 2012). The so-called 'Non-generating Resource' framework, born during this period, still remains an important pathway into ISO markets, especially for batteries (CAISO 2019a). In 2015, CAISO furthered its commitment, launching the Energy Storage and Distributed Energy Resources initiative (ESDER), refining participation frameworks for DERs, DSR, storage, and aggregators (CAISO 2016). According to participants, CAISO's sector-wide and open approach to stakeholder engagement played a pivotal role in removing major participation barriers, resulting in numerous Commission-approved tariff enhancements [Interview 41 – energy politics expert].

Between 2016 and 2021, the ESDER initiative introduced new market participation frameworks and modifications in bid parameters tailored to the characteristics of non-traditional resources, while streamlining agreements for participating in the market. For instance, it allowed storage providers to submit technology-specific information like the state of charge, bid decreases and increases in load through the new 'Load Shift Resource' participation model' (CAISO 2016a). The ESDER also further clarified how DSR could join markets by introducing new dispatchable bidding options for these resources, technology-specific parameters, and removed the single load-serving entity requirement for DR aggregations, eventually culminating in a new 'Proxy Demand Resource' framework (CAISO 2021a). Further, 2015 saw the launch of the 'Demand Response Auction Mechanism' pilot scheme, whereby the state's three large investor-owned utilities cooperate with the private sector to aggregate retail consumers for DSR and bid them into the day-ahead electricity market.

From 2016, a new tariff provision has also allowed small DERs unable to meet minimum capacity requirements individually to aggregate and participate jointly in the CAISO market through a new

market participant category, the so-called ‘DER provider’ (CAISO 2016b; Endemann et al. 2017). Evidence shows that DER providers had channelled a considerable amount of political capital to obtain this framework, which allows them to aggregate one or more small distribution-connected energy resources totalling at least 0.5 MW in front or behind a customer meter [Interviews 39,41]. This innovative approach inspired the Federal regulator FERC to introduce order 2222 mandating all ISOs and RTOs to allow DER aggregations in the wholesale market, showcasing California's leadership in such advancements (FERC 2020). As noted by the policy expert, “the tendency is for California to be a bit ahead of the curve in these things, we have kind of a fair amount of influence over where things go nationally” [Interview 39].

Order 2222 also shows a broader trend of FERC increasingly taking a lead in mandating states to widen access to wholesale markets for new resources: “starting in the 2010s FERC decided to try and get ahead of the game and passed a series of rules that said all these resources should be compensated on a level playing ground under the law” [Interview 41]. Right from the start, this more assertive approach stirred political tensions multi-level governance relations. First, observes reported resistance from state institutions, which perceived it as an intrusion in their jurisdictional authority [interviews 41,45,50].

It also generated a nation-wide pushback from incumbent generators who perceived this as a threat to their established business models. This is exemplified by the legal litigation surrounding FERC Order 745, introduced in 2011. This mandated that wholesale market operators compensate demand-side resources at the energy LMP price when they reduced their load as directed (FERC 2011). In 2014, the Electric Power Supply Association, a national trade association representing competitive power suppliers[33], filed a petition with the US Court of Appeals, arguing that "FERC's new rule goes too far, encroaching on the states' exclusive jurisdiction to regulate the retail market" (Cameron 2014). After a period of suspension in FERC's ruling, the Supreme Court ultimately upheld FERC's authority to regulate DR programs in wholesale markets in 2016 (Bade 2016).

Being ahead of the innovation curve, California has experienced less friction with FERC's initiatives, albeit with some exceptions. For example, tensions emerged around the 2018 FERC Order 841 requiring that wholesale markets should be opened to individual storage assets at any connection point (FERC 2018a). The CPUC contested this move, arguing it fell beyond FERC's jurisdiction, but their claim was ultimately dismissed (McGarry 2021). Since then, CAISO's energy storage market model has adapted to comply with FERC Order 841 requirements. This was done as part of a wider reform, the Energy Storage Enhancements initiative, launched in 2021 to enhance the optimisation, dispatch, and settlement of energy storage and similar resources. This involves developing bid enhancements to accurately represent the marginal costs of these assets in real-time markets, ensuring sufficient state-of-charge for critical periods, and exploring modifications to the ISO's dispatch and bid cost recovery mechanisms (CAISO 2021b). Additionally, battery storage has greatly benefited from utility procurement obligations and recent adjustments in resource adequacy credits allocation methodology (refer to sub-section 8.3).

As a result of these initiatives, participation by non-traditional providers in ISO markets has increased. Since 2015, total battery capacity participating in the ISO market grew exponentially totalling about 488 MW of discharge capacity by the end of 2020. Figure 43 shows the total capacity of standalone battery storage participating as non-generator resources represented both in terms of maximum output (megawatt) and maximum duration (megawatt-hour). On average, batteries continued to primarily provide ancillary services, including regulation up, regulation down, and spin reserves: “it's been most lucrative to participate in the kind of regulation up and down markets to maintain system

[33] members include both independent power producers and the wholesale supply businesses of utility holding companies.

frequency because that gives them the biggest rate on return" [Interview 46]. However, in 2020 batteries also began providing more flexible ramp up (CAISO 2020) (see sub-section 7.3.1).

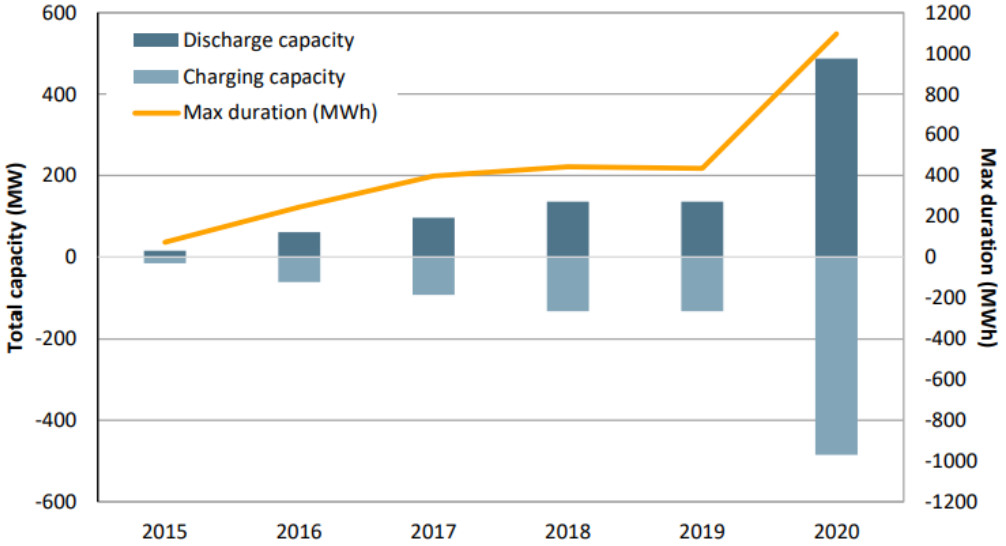


***Figure 43** - Total capacity MW of standalone NGR battery storage maximum output and duration (CAISO 2020)*

Figure 44 and Figure 45 illustrate the amount of DSR capacity contracted in 2020 by third parties or through incumbent utility-led programs, respectively[34]. First, it can be observed that DSR capacity is more likely to enter the market via utilities than other routes. While third-party demand response participating in the ISO market has grown significantly since 2016, this growth has flattened more recently (CAISO 2020). Another interesting observation is that third-party DSR capacity, albeit smaller, tends to be spread across a larger range of assets when compared to that in utility-led programs. This points to the nature of emerging market structures in DSR services.

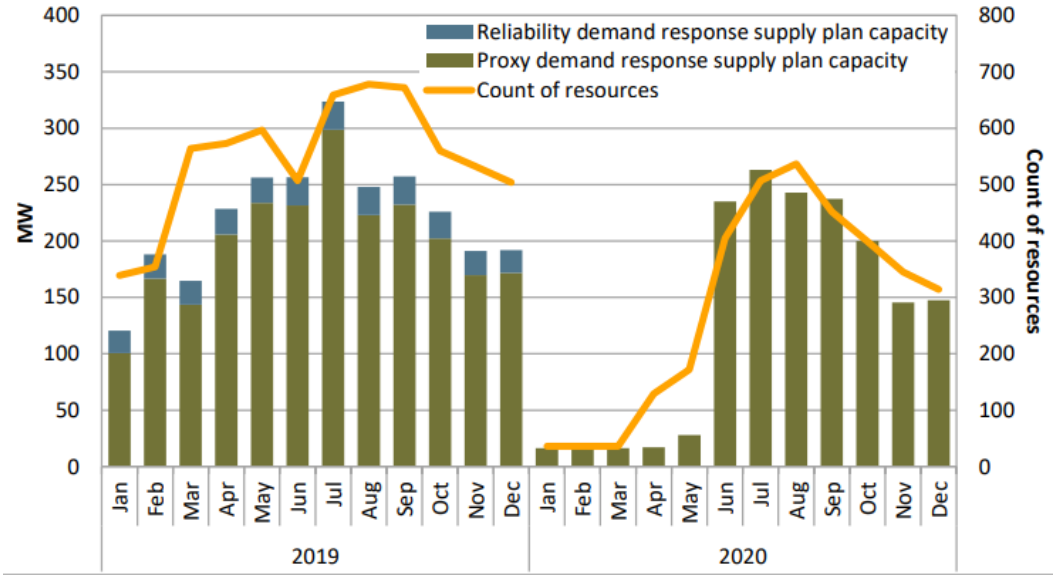


***Figure 44** - Third-party DR on monthly resource adequacy plans (CAISO 2020)[35]*

[34] Utility-operated demand response programs are not shown on monthly resource adequacy supply plans and are instead credited against (used to reduce) LSE adequacy obligations under local regulatory authorities.
[35] Third-party demand response capacity dropped between January and May 2020 because contracts from the CPUC's demand response auction mechanism (DRAM) did not become active until summer of 2020, as reforms were made to the program in the beginning of 2020.

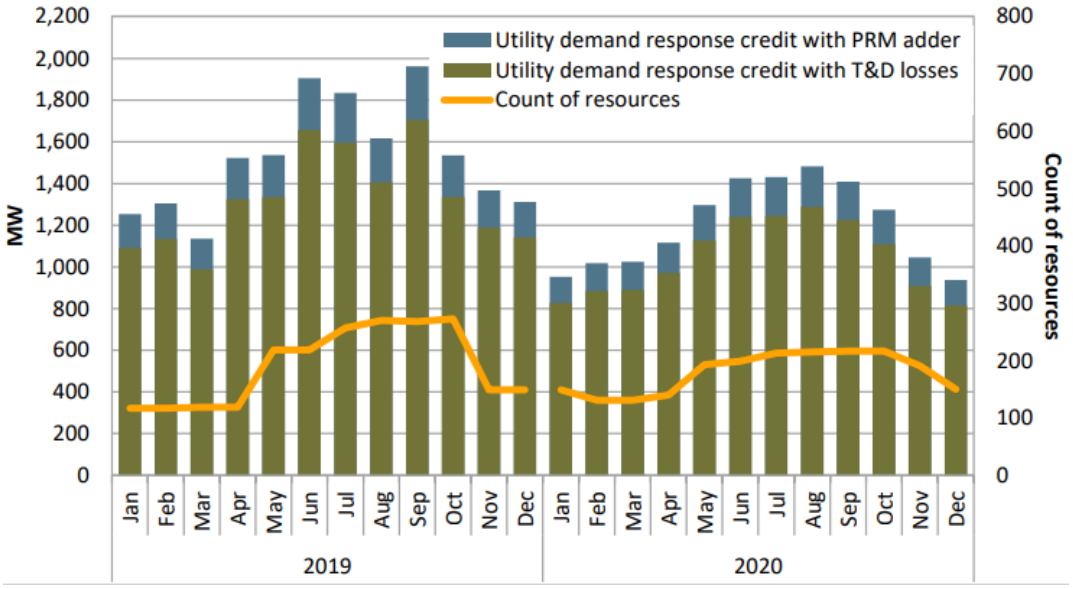


***Figure 45 -*** *CPUC jurisdictional utility DSR resource adequacy credits (CAISO 2020)*

Despite progress in this area, participants note there exist some important issues related to market participation by DSR and DERs aggregation. There is a perception that the potential value of these resources remains untapped, specifically, their technical capability to alleviate VRE-related operational challenges. Except during heatwaves, DSR was rarely scheduled in the ISO markets, with over half of third-party demand response capacity offered in the day-ahead market near the $1,000/MWh bid cap (CAISO 2020). Some proxy demand response resources have quoted such high commitment costs that their dispatch became uneconomical, even during peak load periods (ibid). These factors have contributed to significant uncertainties regarding the performance of DSR and DER aggregation, possibly nudging CAISO, whose primary aim is system reliability, toward favouring traditional resources [Interview 44 – representative of power system operator].

Technical challenges, including communication and response times, along with performance measurement complexities, account for part of these issues [Interviews 44,46]. Yet, non-traditional participants also highlight regulatory and institutional barriers [Interview 52 – advocate of local energy systems]. They argue that, despite California's pioneering regulatory frameworks for non-traditional participation, they have struggled to leverage them. They identified the inability of DER aggregations to secure resource adequacy credit a primary impediment, which they trace back to the institutional division and misalignments between the CPUC, responsible for adequacy credits allocation, and CAISO's operational activities [Interviews 51,52].

Participants identified a second set of issues, which include challenges faced by potential aggregators in coordinating DER providers, local utilities, and other local market actors [Interviews 44,46,52]. In California's historically centralised market structure, local utilities have traditionally served as the primary link between consumers and the bulk power system. While utilities are the natural choice for aggregating DERs and DSR, their involvement in this role has primarily been driven by external policy initiatives in the form of pilots, rather than voluntary engagement [ibid]. Their hesitance stems from concerns about cybersecurity, given the perceived vulnerabilities of these technologies, a historical reliance on centralised reliability approaches, and reservations about the reliability of individual homeowners [ibid]. Additionally, utilities are regulated based on a rate of return model, which means that new resources are seen as direct competitors that undermine their established business model (detailed further in Chapter 5). Further, while California's market landscape has evolved with the emergence of community choice aggregators who could potentially act as local flexible aggregators, their focus has so far largely remained on the retail side [interviews39,40].

### 7.3.3 Local flexibility procurement

Results suggest that California has had a limited and fragmented experience with local flexibility markets. Participants noted that some local flexibility pilots have been carried out by incumbent utilities, research institutions or local entities [Interview 44,46,52], but these are not part of a comprehensive strategy, not yielding sufficient experience for making the model scalable [ibid]. The reasons might be twofold. First, the CAISO system is based on a strong logic of central dispatch. Second, California has not completed distribution utilities unbundling and does not have full retail competition. Large IOUs therefore retain control over end-use supply and are regulated through asset-based that incentives them to build more centralised infrastructure to increase reliability [Interviews 46] (see Section 5.3). Representative of decentralised energy groups identified incumbent distribution utilities as openly opposing more decentralised market structures [Interviews 51,52]. Just like in the other two cases, evidence points to two broad visions co-existing for managing reliability characterised by strong political tension: one based on large, centralised infrastructure (supported by IOUs and large power producers) and model based on participatory local energy systems [Interviews 47,48,49,51,52].

However, observers note that Californian policymakers have recently gained interest in microgrids and DERs due to issues related to local grid reliability and energy justice [Interviews 45,46,47]. In fact, some disadvantaged communities are really exposed to consequences of rolling blackouts, wildfires and extreme weather events, and need backup power: “there is a proceeding on microgrids that the CPUC has been conducting for about three years now and it's moved very slowly. Unfortunately, we've been arguing for accelerated deployment of microgrids for resilience because California has been experiencing so many power outages. Many of them being pre-emptive, where the utility will shut down a transmission line and cause what they call a public safety power shut off. But they can last for days and cover large areas. […] but politically there is so much political power on the parties who like to build big assets” [Interview 52 – advocate of local energy systems].

## 7.4 Comparison of balancing and ancillary services evolution

Evidence shows that all jurisdictions implemented some modifications to legacy balancing market rules in response to the rise in VRE-integration challenges. While there are some common trends, there are also important differences in the scope of these changes, design choices and resulting policy trade-offs. Table 16 summarises the changes implemented in the three jurisdictions. The next sub-sections discuss the political economy conditions shaping the reform process, also outlined in Table 17. Analysis shows that political acceptability issues, sector-specific institutions including legacy operational philosophies and arrangements for system operators, liberalisation histories and legacy market structures, are all important to understanding change in this area.

***Table 16** - Comparison of key changes in balancing and ancillary service market design*

| | **Britain** | **Italy** | **California** |
|---|---|---|---|
| **Balancing pricing** | Introduced single marginal pricing for balancing, and a scarcity pricing mechanism in 2015. Retains half-hourly settlement. | Transition to single marginal balancing pricing initiated but to be completed. A scarcity pricing mechanism is in place. Ongoing switch to 15-minute settlements. | Legacy model based on energy and reserves co-optimisation. A scarcity pricing mechanism is in place. Flexiramp product introduced in 2016. Switch to more granular settlements. |
| **Ancillary service products and wider access** | From 2017, comprehensive reform of ancillary services already led to introduction of new products enabling access for non-traditional providers. | From 2017, comprehensive experimentation with new ancillary services enabling access for non-traditional providers yet to result in final market rules changes. | From 2012, gradual introduction of new market participation frameworks and modifications in bid parameters widening access for non-traditional providers. |
| **Local flexibility procurement** | From 2017, several experimentations with DSO-led flexibility markets and local transactive models. | Early stage of experimentation with DSO-led flexibility markets and limited experience with more localised procurement. | Limited experience with local flexibility markets. Growing interest in microgrids reliability potential. |

### 7.4.1 Explaining different approaches to balancing pricing

As detailed in sub-section 2.1.2, enhancing the cost-reflectiveness of balancing pricing is widely identified by economists as a key enabler of cost-effective VRE-integration. Accordingly, in recent years, all three jurisdictions have endeavoured to reform their balancing pricing mechanisms to better incentivise flexibility. While there are important similarities, there is also some variation in resulting policy outputs. These developments can be explained in terms of legacy dispatch model and operational philosophies, issues of political acceptability of price volatility, context-specific market conditions, sector-specific institutional configurations, and the degree of alignment in the positions of key stakeholders.

First, these approaches can be explained in term of the legacy dispatch model and operational philosophies underpinning the three systems. California's legacy model based on co-optimisation of energy and reserves and a very physical approach to system operation, is often praised in economic theory as particularly efficient in showing the opportunity cost of providing energy or balancing services. This remains largely unvaried except for gradual enhancements such as bid structures and granularity of settlements. On the other hand, mirroring a wider EU-wide regional approach, Britain and Italy have traditionally had more decentralised market models with separate balancing markets. Here, efforts have been directed towards adopting marginal uniform pricing, a concept endorsed by economic theory and the EU for its cost-reflective attributes, perceived as increasingly important in the context of a high-VRE system.

However, the two jurisdictions have achieved different progress with the reform. Britain underwent early and comprehensive reform by introducing a single marginal price system in 2015. In contrast, Italy is contemplating a similar direction, but progress has been partial thus far. These disparities can be attributed to differing historical market conditions and structures, including concerns about market power, which are notably high in Italy. This concern has also influenced ARERA's decision not to introduce negative prices in the Italian balancing mechanism. Furthermore, these delays can be linked to institutional inertia and the complexities associated with implementation, which have posed challenges to the overall dispatch reform in Italy. Additionally, disagreements among key stakeholders regarding the merits and timing of the reform may have been a further contributing factor.

Overall, the findings affirm a common assertion in political economy literature, which suggests that practical implementations of scarcity pricing often diverge from pure economic theory (as discussed in Section 2.4). This deviation occurs due to concerns related to market power and political acceptability, as governments typically seek to maintain some level of control over energy price volatility. In fact, while all three jurisdictions introduced administrative scarcity pricing functions, none opted for a full operating reserve demand curve albeit California introduced the flexiramp product to emulate the effect. Achieving cost-reflective pricing proves challenging within the context of balancing markets, which are susceptible to market power dynamics. For instance, Ofgem faced difficulties in distinguishing between efficient market operation and price increases driven by speculation in its scarcity mechanism. This led it to a more cautious approach, which in turn discouraged operators from capitalising on high prices.

Moreover, despite the inclusion of scarcity pricing, all cases depend on out-of-market capacity mechanisms to incentivise long-term investment. This not only aligns with economic theories concerning 'missing money' and 'missing markets' (sub-section 2.1.3), but also underscores the general inclination of governments to avoid sole reliance on short-term markets for security of supply, a theme explored in greater detail in Chapter 8. This points to the importance of state-market relationships in determining these choices.

### 7.4.2 Explaining different approaches to reforming balancing products and widening access

In all jurisdictions, increased VRE shares have compelled reforms of ancillary services in line with what suggested in the literature (sub-section 2.1.2). Specifically, there is a common trend of better defining

old and new ancillary service products to reward flexibility and widen access for non-traditional providers. All jurisdictions adopted reform programs targeted at enhancing access for storage, DSR and DERs aggregations. Design changes include, for example, lowering minimum bid sizes for single resources, creating frameworks for aggregation, simplifying of contracts, creating of more standardised products, modifying key market rules and parameters. While these reforms share common objectives, there are notable differences in their timing, scope, and outputs. Key conditions affecting change include specific system conditions, legacy market models, sector-specific and multi-level governance arrangements, legacy market structures and the interests of the main market players.

First, these differences stem from specific system needs and legacy market models. California initiated reforms early due to its early VRE expansion. Britain followed suit, driven by rapid wind growth in its island system. At the time of launch, the Italian pilots were more explorative and have yet to result in final market rule changes. In California reforms took form of gradual modifications to key market rules such as bidding parameters and participation frameworks accounting for the characteristics of non-traditional providers coupled with the introduction of flexiramp, a technology-neutral product that renumerates reserves at the lost opportunity cost. On the other hand, Britain and Italy's strategies have focused on the creation of new products designed around the specific characteristics of non-traditional providers in the form of competitive auctions. This can be traced back to different legacy procurement models for balancing and ancillary services: while California relies on energy and reserves co-optimisation and Britain and Italy traditionally use separate markets/auctions.

The findings highlight the critical role of institutional arrangements within the power sector. In Britain, significant changes in the institutional set up of the system operator was a key reform driver, leading to a shift in organisational culture and more neutral approach to reform. Under NGESO leadership and its open stakeholder engagement, Britain has swiftly progressed with the launch of new products and diversification of services. In Italy, EU regulations prompted an ambitious and comprehensive set of pilots, but institutional issues led to implementation delays. Participants also expressed concerns about the system operator's current institutional setup, which may not encourage innovative approaches and transparent industry engagement. California's innovation-oriented culture has made it a US pioneer when it comes to promoting wider market access. However, despite CAISO's open stakeholder engagement, coordination issues between CPUC planning activities and its short-term market reforms have hindered the procurement of flexibility services from some resources. Further, while the federal regulator has taken an increasingly proactive role in mandating market rule changes to level-the-playing-field, they have not reached the same level of harmonisation of their EU counterparts resulting in political tensions across layers of governance.

In all examined cases, there is a perception by non-traditional providers that the potential value of DSR and DERs aggregations remains untapped. In fact, despite improvements in access rules and conditions, for the most part balancing and ancillary services are still largely provided by flexible thermal generators in all jurisdictions. This partially stems from entrenched techno-economic ideas regarding the value of different technologies, specifically, a persisting bias towards traditional assets perceived as more reliable. These views reflect legitimate concerns about reliability and the performance of new assets, which may nudge operators towards favouring traditional resources, especially in the event of critical system conditions. British and Italian policymakers used extensive market-wide trials to manage these uncertainties and test non-traditional services' performance.

Emerging models for procuring non-traditional flexibility services are significantly shaped by the existing market structures and the interests of key stakeholders. Specifically, evidence suggests that in more liberalised markets like the UK, there is a greater inclination to explore diverse business models for aggregation of DSR and DERs. Conversely, systems dominated by legacy distribution utilities tend to lean towards centralised, incumbent-driven approaches. This is particularly relevant in California, where retail liberalisation never occurred and the system remains structured around incumbent utilities, and in Italy, where Enel remains the dominant player in both distribution and generation.

Further, incumbent players may react differently: US power producers and Californian utilities perceived some of these new services as threats and reluctantly engaged with them, while British and Italian incumbents actively engaged with some new solutions. These observations shed light on the importance of the incentives of distribution utilities and established actors within legacy markets. Furthermore, the political economy of the industry is expected to evolve as new interests consolidate. For instance, well-established battery storage providers in the UK have resisted further standardisation of balancing products. This underscores the dynamic nature of the power sector, where evolving market forces and stakeholder interests lead to different policy dynamics over time.

Finally, questions have been raised across cases around the long-term viability of the business model of new service providers. It has in fact been noted that grid services procurement is limited to the size of SO needs and relying on trading alone might not be sufficient to support long-term investment in these assets. Once again, this highlights strong interactions of balancing and ancillary services with the resource adequacy regime, which is often cited as a *sine qua non* for the growth of non-traditional providers (discussed more thoroughly in Chapter 8).

### 7.4.3 Explaining differences in emerging local flexibility procurement models

Overall, the three cases differ in their approaches to local flexibility markets. Britain leads the way with a comprehensive initiative delving into the potential of local flexibility markets and effective coordination between DSOs and TSOs. Italy has recently kick-started some experimentation with DSO marketplaces and legal definitions of energy communities. California has the most limited and fragmented experience with local flexibility markets though policy interest in local energy systems and microgrids has grown recently. These differences reflect specific policy priorities, institutional and regulatory settings, liberalisation histories and market structures.

Firstly, political priorities and multi-level governance arrangements play a pivotal role. GB's government outlined a clear vision for DSO evolution early on, introducing regulatory changes, funding trials, and establishing sandboxes to test various models. Italy, influenced by EU directives, has plans for DSO-led markets and energy communities but has not fully implemented them, also due to less urgent local infrastructure constraints. The Californian government has not outlined a comprehensive vision for the future of local energy systems. However, recent extreme system events pushed DERs and microgrids into the policy spotlight.

Furthermore, the realm of local flexibility markets is politically charged in all three cases, with different visions coexisting for the future of power system architecture. Central system operators tend to favour centralised dispatch logics and see local flexibility procurement as supplementary to their activities. Incumbent distribution utilities have engaged with local DSO-led platforms to differing degrees, depending on specific legacy market structures, unbundling levels, regulatory frameworks, and organisational cultures. In Britain, where unbundling has been more pronounced and the regulatory framework emphasises innovation, incumbent distribution utilities have engaged in local platforms more proactively albeit with variation across companies. Italy's major distribution company, Enel, expressed interest in a larger role in local flexibility procurement, but concerns persist regarding market neutrality due to bundled activities. In California, where retail was never liberalised, utilities retain substantial control over end-use supply and are regulated through asset-based models, there has been more reluctance to engage in these activities.

Further, in both Italy and California incumbent distribution utilities were identified as openly opposing more decentralised market structures based on local energy communities or transactive models, which are perceived as a threat to their business models. In contrast, local flexibility service providers advocate for retaining multiple pathways into markets, both nationally and locally, highlighting the importance of revenue ‘stackability’ and the need to address conflicts of interest in local procurement. In California, where some local communities have been exposed to multiple blackouts and extreme system events, there is an emerging coalition of energy justice advocates supporting microgrids as a

solution to these challenges. In all cases, the jury is still out on the extent to which these different models will be incorporated into power system architecture.

***Table 17 -*** *Political economy conditions found to affect the evolution of balancing and ancillary services.*

| | **Balancing pricing mechanisms** | **Ancillary service products and wider access** | **Local flexibility procurement** |
|---|---|---|---|
| **National politics and government** | - Dominant attitudes towards price volatility<br>- Level of institutional capacity and stability | - Level of institutional capacity and stability | - Evolution of national policy priorities |
| **State-market relations** | - Dominant ideas on role of markets and price signals | - Degree of unbundling and privatisation (liberalisation) | - Degree of unbundling and privatisation (liberalisation) |
| **Sector-specific institutions** | - Legacy arrangements for market operation<br>- Dominant operational philosophies<br>- Dominant ideas on appropriate trade-offs across cost-reflectivity, market power, implementation complexities and costs etc. | - Legacy arrangements for market operation<br>- Dominant operational philosophies and ideas on the reliability value of different resources<br>- Incentives, culture and openness of system operators<br>- Degree of coordination across key sector institutions | - Legacy arrangements for market operation<br>- Dominant operational philosophies and ideas on the reliability value of different flex procurement models |
| **Multi-level governance** | - Dominant ideas on market operation in multi-level governance institutions | - Dominant ideas on market operation in multi-level governance institutions<br>- Level of capacity and coordination of multi-level governance institutions | - Dominant ideas on market operation in multi-level governance institutions |
| **Market structures and interests** | - Homogeneity and alignment of power sector stakeholder views | - Legacy market structures<br>- Interests and influence of incumbent utilities<br>- Interests and influence of new service providers | - Legacy market structures<br>- Incentives, interests, cultures and influence of incumbent utilities<br>- Interests and influence of local energy stakeholders |

# 8 Evolution of resource adequacy policy

This section aims to identify the key differences in how the three jurisdictions dealt with resource adequacy in the context of rising VREs challenges and how these differences can be explained from a political economy perspective. As part of this, it summarises and compares the evolution of capacity remuneration mechanisms and related policy changes. These are analysed based on their key characteristics including their stated objectives, scope of change, modifications in key design parameters, resulting policy trade-offs and technological choices.

## 8.1 The evolution of resource adequacy policy in Britain

Through the 1990s Britain had a centrally managed electricity pool with capacity payments. In 2001, NETA introduced signified a transition to an energy-only market based on the principle that short-term markets would provide incentives for long-term investment through scarcity price signals (Grubb and Newbery 2018). In 2014, Britain saw another major shift in resource adequacy policy with the introduction of an explicit capacity market. This was introduced as part of a sector-wide policy package, the Electricity Market Reform, alongside a new contracts-for-difference scheme for incentivising renewables and a carbon price floor (DECC 2013; HoC 2013). While the latter two mechanisms aimed to speed up decarbonisation, the CRM to ensure that long-term system security would be maintained as the power mix evolved (ibid). Key events are summarised in Figure 46 and discussed in the next paragraphs.

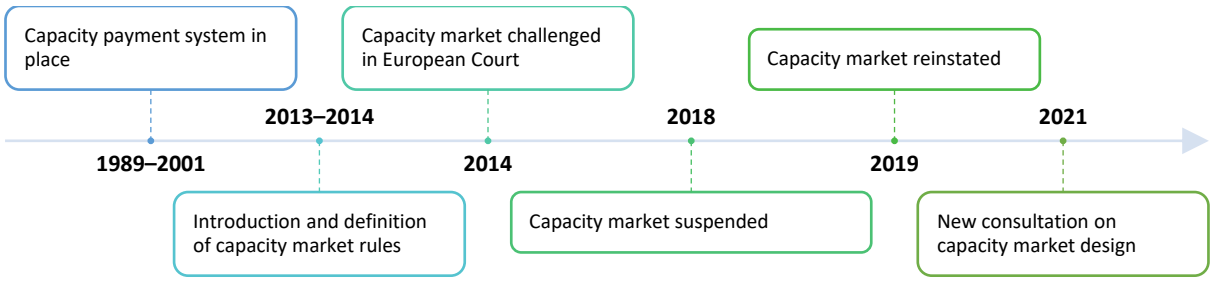


***Figure 46*** *- Evolution of resource adequacy policy in Britain*

### 8.1.1 The introduction of the British capacity market

Figure 47 illustrates installed generation capacity in relation to electricity peak demand on the British system. From 2010, the generation mix began transitioning from being dominated by conventional generation towards much larger presence of VREs (Ofgem 2015). In 2012, announcements were made for the retirement of 2GW of conventional generation, and it was estimated that a further 1GW would retire by 2015, mirroring low levels of profitability for gas-fired plants and uncertainties on future policies and market conditions (Ofgem 2013). As explored in the techno-economic literature (sub-section 2.1.3), it was predicted that VRE-growth in coming years would exert a further downward pressure on wholesale prices and load factors of conventional plants, thus resulting in lower capacity margins and less flexible capacity available for system balancing in the face of growing intermittency [interview11]. In 2010, Project Discovery, an investigation into the future of security of supply by the independent regulator Ofgem, concluded that existing market arrangements were unlikely to deliver secure, sustainable, and affordable electricity in future years (Ofgem 2010).

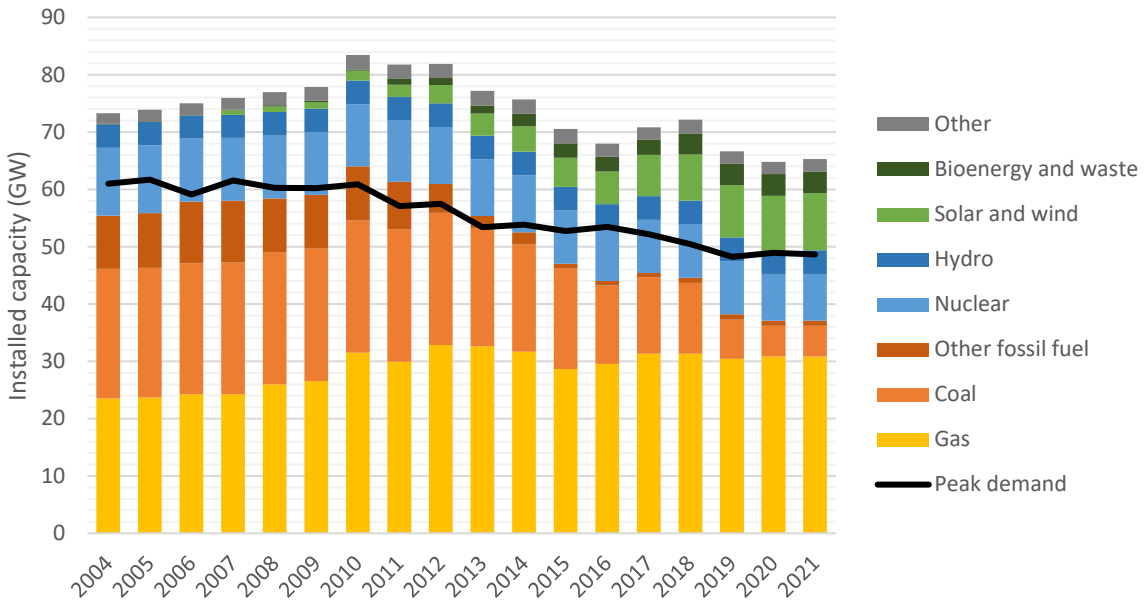


***Figure 47** - Installed capacity and peak demand in Britain. Source: UK Government energy statistics.*

Changes in techno-economic conditions and Ofgem's warnings were a major catalyst of change [interview11]. Faced with the possibility that 'lights might go off' the government was compelled to introduce a mechanism that would act as a 'reassurance to the public' that system security would be maintained as it pursued deeper decarbonisation and coal retirements [interview7,1] (DECC 2011). This reform was described as a 'fundamental shaker' that strongly reconfigured state-market relations in British electricity sector [ibid]. Specifically, it signified a significant paradigm shift in dominant techno-economic ideas towards a recognition that short-term price signals are insufficient for maintaining long-term capacity adequacy in a high-VRE system [interview2]. The market-led paradigm had in fact played a central role in UK energy policy since the 80s, but now more public intervention had become legitimised by two 'powerful strategic objectives': decarbonisation and security of supply [interviews10,3].

This shift encountered some resistance from within institutions: "there was blood on the floor of the board of Ofgem, two senior people resigned in protest because they basically felt Ofgem was abandoning the fundamental principles of competition as the primary aim of electricity regulation" [interview1]. Nevertheless, market and competition principles seem to have continued playing an important role by informing the CRM design choice [interview2]. When the decision on whether to adopt capacity market or a strategic reserve was being discussed, Ofgem firmly advocated in favour of the former mechanism because market-based and technology-neutral [interview1,14,4]. Several observers note that the stance taken by the independent regulator was pivotal in determining the final decision [ibid].

The reform also sparked a heated debate in the EU where the official position was an energy-only market. Specifically, explicit support for certain generators through national subsidy schemes contradicts EU principles on free competition and state aid, albeit diverging views coexist among member states. As noted by this participant, "there is a certain group of countries in the centre of Europe with the ability to increment cross-border transfers who are strongly against CRMs while […]. Countries with more structural constraints are favourable [to CRMs] such as Italy, Spain and the UK who have an interest in developing national resources" [interview29]. Eventually, the EU Commission approved[36] the British mechanism, which some argue was to avoid a political backlash: "the British

[36] Member states need to present a case to the EU Commission to obtain State Aid approval.

government was lobbying hard and they [the Commission] didn't want to further inflame the sort of anti-European sentiments" [interview1].

Evidence also suggests that the policy process was heavily shaped by incumbent interests. Due to worsening economics for their conventional plants, most of these companies "advocated for explicit support" [interviews12,13]. By the early 2010s, a consolidation of the power supply industry had occurred, which enabled greater coordination of incumbent interests and scope for influencing the policy agenda (see sub-section 5.1.8). Observers note how these actors contributed creating a sense of urgency by signalling looming capacity shortages, existing plant retirements and the withholding of future investment [interviews3,4,5,10].

In their analysis, Lockwood et al. (2019) argue that policymakers in Britain were particularly receptive to the threats of plant retirements and narratives on 'missing money' fostered by incumbents. They explain this in terms of information asymmetries, structural economic dependencies of government on incumbents' resources, preferential access to policy processes and high levels representation in interest associations. Existing research also suggests that, through their lobbying, conventional generators contributed to the selection of a capacity market design (ibid). Hence, some observers go as far as saying that the mechanism was 'essentially a subsidy for gas-fired power generation', even though technological neutrality had been presented as a key reason for adopting this design [interviews3,4,14].

The British capacity market is a centralised mechanism with descending-clock auctions held four years ahead of delivery, supplemented by year-ahead auctions for pre-qualified capacity (DECC 2013,204; Barillas et al. 2015; Creti and Fontini 2019). While most capacity is procured four years ahead of the delivery year, the year-ahead auction allows last-minute adjustments according to updated forecasts. Companies that bid successfully enter a contract whereby they commit to provide electricity (or reduce consumption) when required in return for a monthly payment (premium). The premium (in £/MW-year) is defined as the auction clearing price based on marginal price (Figure 48). The demand curve is administratively defined by the Government with supporting analysis by the system operator, alongside an auction price cap, and a set of eligibility criteria (DECC 2013,2014). Contracts vary in length based on the capacity type: one-year contract for existing assets, 3 for refurbishments and 15-years for new capacity.

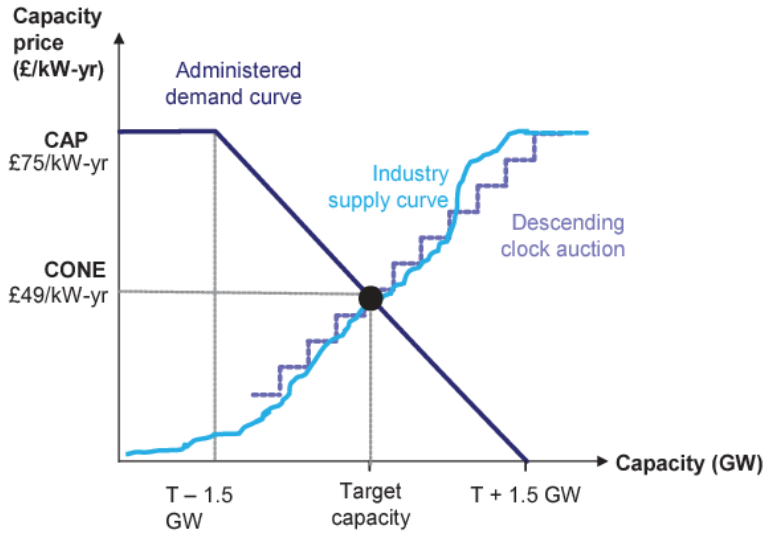


***Figure 48** - The British capacity market design (Barillas et al. 2015)*

Even after a decision to introduce a capacity market was taken, there were significant debates around the definition of key parameters key in shaping terms of access for different providers. Though one of

the core arguments for selecting a capacity market had been competition, effectively, the mechanism was not technology neutral: “ministers, and this is almost an open secret, had a very clear idea about what they wanted the outcome of the market to be before the market ran, so they wanted it to build new gas fired power stations they didn't want new demand side response or storage” [interview3]. Representatives of non-traditional providers such as DSR, batteries, aggregators and interconnectors argue that they faced unfavourable terms of access, especially in the early iterations of the mechanism [interview14,18,16]. They lament that key parameters were set in a way that did not account for their specific characteristics and undervalued their performance – e.g., high de-rating factors[37], long contract lengths[38] and high penalties for non-delivery (Lockwood et al. 2020). These groups were unable to match the resources of major incumbents, and hence their ability to shape the CRM design [ibid]. Further, inexperience and uncertainties around the performance of non-traditional providers might have created a bias towards more conventional solutions [interviews18,19].

### 8.1.2 Outcomes and later developments

Figure 49a illustrates the results of the first auction in 2014. 98% contracts were assigned to existing capacity because low clearing prices[39] did not encourage the construction of large new gas plants as originally intended [interview17] (Lockwood et al. 2020). Low prices were the result of market distortions caused by network charging rules, which disproportionally benefited distribution-connected producers enabling small diesel generators to outcompete larger, more efficient gas plants [interview6] (see sub-section 6.1.4). While existing gas was the most contracted capacity type, diesel and coal generators were awarded a sizeable portion of contracts causing ‘outrage’ among environmental groups and ‘embarrassment’ among policymakers as public money was used to subsidise the most polluting plants [interview14,1].

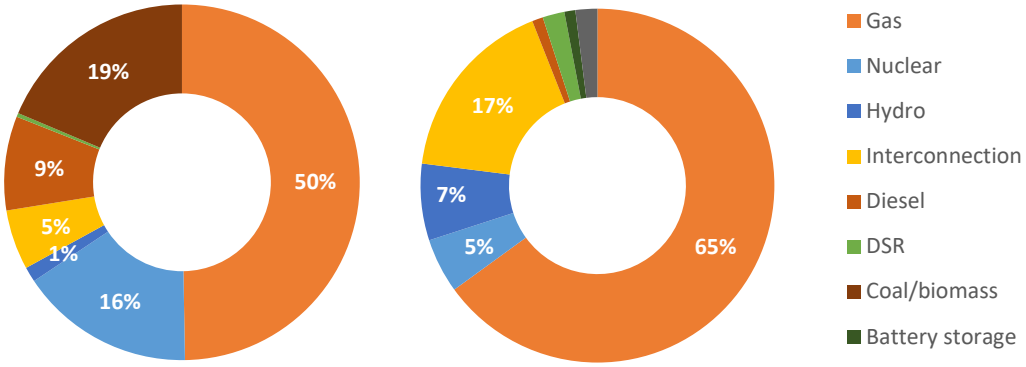


***Figure 49 -*** *Awarded capacity by technology – a) 2014 auction; b) 2021 auction (National Grid 2015; KPMG 2021)*

Another noteworthy outcome was that interconnectors, despite facing less favourable access terms, successfully secured several contracts. In Britain, interconnectors participate to markets as generation assets contrary to the rest of Europe. Here the generator-led approach is now mandatory, whereby cross-border single generation assets bid into the market and are responsible for securing interconnection capacity needed for their power transfers [interview 23]. At the time of introduction, the British approach had sparked an intense debate in the EU leading the Commission undertaking a sector enquiry in 2016 (EC 2016). The interconnector-led approach is often criticised based on its contribution to security of supply: “an electric line cannot participate in a capacity mechanism, first,

[37] These assign a de-rating value (in%) to the capacity contributions of resources based on availability.
[38] Set at one-year for existing assets and 15-years for new built.
[39] Around £19.40/kW/year compared to expectations of £49kW/year (Ofgem 2015).

because it does not provide any adequacy. If I pay you this amount of money, you have to guarantee you will able to dispatch a certain amount of electricity, but if there a scarcity condition in France at the same time as in the UK, the interconnector cannot do anything" [interview23 – CRMs expert]. Once again, this mirrors specific techno-economic understandings on the reliability value of different resources among policymakers in different contexts.

Figure 49 also shows that participation by other non-traditional provides in the first auction was almost non-existent. The DSR industry went 'up in arms' channelling considerable efforts into obtaining better terms of access [interviews4,18]. Particularly interesting is how the DSR coalition[40] leveraged the EU's legal system to exert pressure on national policymakers (Lockwood et al. 2020). In 2014, DSR company Tempus Energy challenged the lawfulness of the British capacity market in the European General Court on the basis that it discriminated against DSR (ibid). The Court ruled in their favour, auctions were suspended, and the government had to commit to modifying the scheme. According to participants, many perceived this as a 'transgression on British sovereignty' and was used as an example in the Brexit campaign [interview1].

Later modifications aimed to widen participation of non-traditional providers and limit that of the most carbon-intensive generators (KPMG 2019). These include a 'controversial' reform of network charges (sub-section 6.1.4), the exclusion of coal from the capacity market and modifications in parameters regulating access for non-traditional providers [interview6]. Latest auctions have seen no coal, limited diesel participation, supplanted by existing gas and a sizeable growth in interconnection capacity (Figure 49b). While DSR and batteries made an initial market entry, their shares remain marginal, at least at the time of writing. These groups' representatives argue is due to the persistence of unfavourable rules [interview16,19]. Additionally, despite the removal distortions, latest auctions encouraged a limited number of new gas plants as developers "face increasing challenges in attracting low-cost capital" [interview8].

Despite its bumpy journey and shortfalls, the capacity market is generally seen as working by the industry as it offered financial relief to existing plants and "acted as a reassurance to opposition to renewables" by explicitly addressing potential resource adequacy risks that might emerge during the transition [interviews2,12,13,7]. The mechanism has seen incremental changes over time, but the fundamental structure remains unvaried. This might change as capacity investment is one of the key aspects being reviewed in the ongoing government's Review of Electricity Market Arrangements (REMA) launched in 2022 (BEIS 2022). Particularly interesting are discussions on whether an explicit out-of-market mechanism should be established to leverage investment in battery storage assets and other low-carbon flexibility providers [interview 16 - electricity storage asset management expert].

## 8.2 The evolution of resource adequacy policy in Italy

In 2004, Italy had introduced a capacity payment as a temporary solution to growing concerns over long-term system reliability following a major blackout that shook the country in 2003. Following a decade-long policy process, in 2019, this was replaced by a capacity market with reliability options, marking an important change in resource adequacy policy (MISE 2019a). The presented rationale was similar to Britain's: that the mechanism would act as an insurance policy for system security during the energy transition and coal phase out, a support for struggling gas generators, a catalyser of new capacity investment and a price mitigator in energy and services markets (MISE 2020). Figure 50 summarises key events, which are discussed in more detail below.

[40] Made of DSR firms, NGOs and think tanks making the case for DSR.

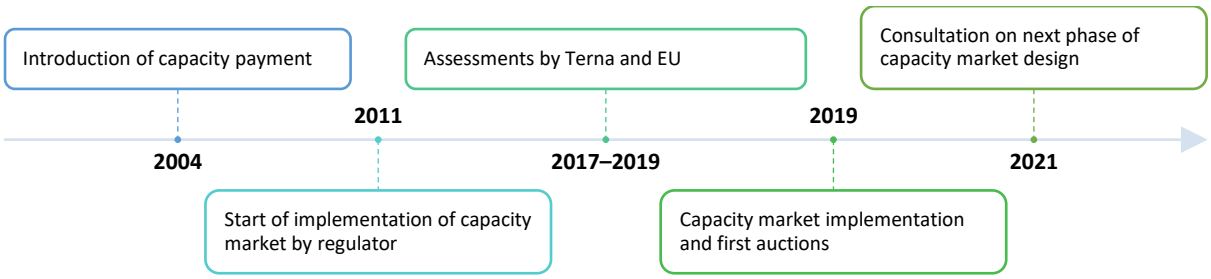


***Figure 50** - Evolution of resource adequacy policy in Italy*

### 8.2.1 The introduction of the Italian capacity market

Up to 2012, reserve margins in the Italian power system kept increasing resulting in substantial generation capacity in relation to peak load (Figure 51). Previous years had seen considerable investment in gas assets, further, Italy could rely on hydro resources, growing interconnection and renewable capacity (MISE 2019; Mastropietro et al. 2018; Kolokathis and Hogan 2019). Around 2012, reserve margins peaked with 130GW of installed capacity servicing only 56GW of demand (ibid). However, this was predicted to change. Steep growth in renewables coupled with flat demand[41] resulted in steep reduction in gas plants' load factors. Between 2012 and 2016, 15 GW of old thermal power was decommissioned, and it was predicted that other 5GW of would go out-of-merit in coming years (Mastropietro et al. 2018). The economics of newer plants were also affected, which had seen a major wave of investments in repowering and construction following liberalisation. Coupled with lower average prices due to the 'merit order effect', this discouraged new investment contributing to 'concerns around future system reliability' [interviews25,30].

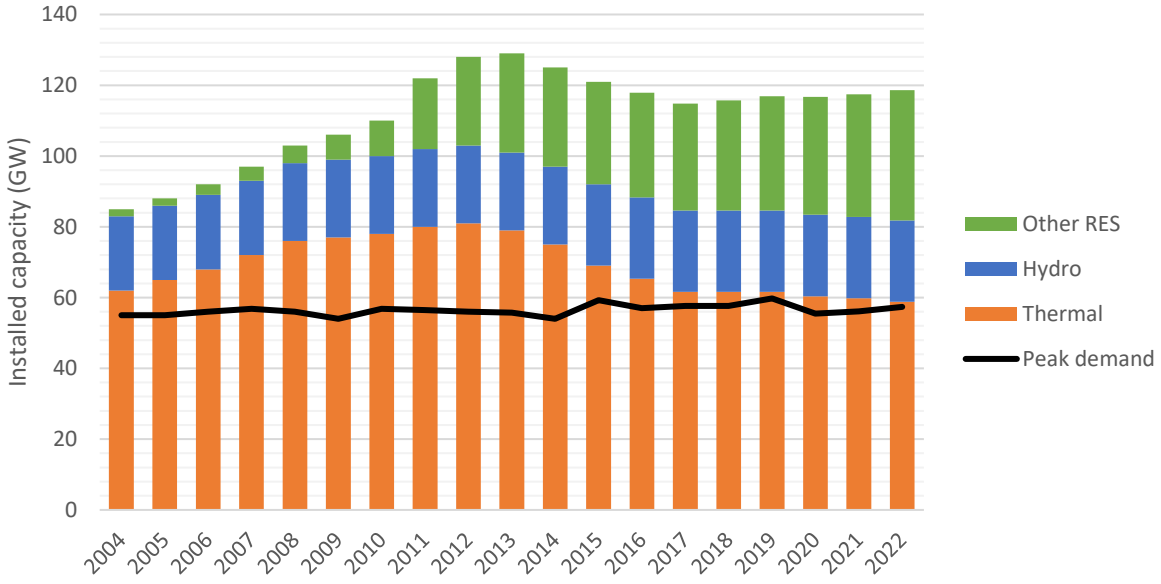


***Figure 51** - Installed capacity and peak demand in Italy (GW). Source: Terna electricity statistics.*

Hence, the conditions leading to the introduction of a capacity market in Italy somewhat differ from Britain's. First, the decision to introduce a system-wide CRM in Italy dates further back to the 2003 blackout, which had affected the whole Italian system for 12 hours (UCTE 2023). Rather than by a capacity shortage, this had been caused by faults in an interconnector at the border with Switzerland (ibid). Nevertheless, this event left behind a 'culture of risk-aversion' among Italian policymakers when it comes to resource adequacy [interviews 23,26]. A capacity payment was introduced as a temporary solution in 2004. Since then, in the aftermath of liberalisation, Italy witnessed considerable gas

[41] related to a slowdown in economic activity following the 2009 crisis.

investment that contributed to a significant growth in capacity margins[42] but that left these producers particularly exposed to a demand drop at the end of the decade [interviews 34,28,37].

Mirroring this ambiguous techno-economic situation, the CRM debate lasted over 15 years: "there has been a back and forth of proposals between the regulator ARERA and Terna. Interest faded at times because they came to the realisation that there wasn't a very urgent problem in terms of resource adequacy" [interview29]. Terna, who is responsible for ensuring system reliability strongly advocated for the introduction of a CRM (Kolokathis and Hogan 2019). To justify this, it conducted a resource adequacy assessment in support of the mechanism, but never made this information publicly available nor conducted a public consultation, which led some observers to condemn the system operator for 'lack of transparency' (ibid). Another factor that contributed to such a long policy process is the short duration of Italian political cycles: "during this time we have had several governments with different positions on the capacity market" [interview34].

Following multiple consultations and State-aid assessments, Italy finalised the introduction of a market-wide capacity mechanism in June 2019, just before the coming into effect of a new EU regulation[43] that would have potentially further delayed the policy process. In the vision laid out by the government, the Italian CRM would act as an insurance policy for security of supply and reliability, as a 'sine qua non for the phase out of coal' and a calming effect on prices on the energy and services markets[44] (MISE 2019,2020) [Interview 31].

Compared to Britain, the introduction of a capacity market in Italy represents a less radical shift in the political economy of the power sector. In fact, not only Italy had a pre-existing CRM, but has also been historically more comfortable with state presence in the market in the form of public ownership of key infrastructures (see Section 5.2). Nevertheless, decision-makers note that market and competition principles were key in informing the decision to opt for a capacity market with reliability options [interviews 27,28]. The fundamental difference from a simple capacity market is that, instead of being fixed, the premium received by operators in exchange for their services is 'linked to the wholesale market price' [interview29,21]. If the wholesale price exceeds a certain threshold, operators must give back the price differential. While sometimes criticised based on complexity, proponents of this design stress that it is more market-compatible and better shields consumers from price spikes [interviews 27,28]. The details of this mechanism design are discussed in more detail later in this section.

Like Britain, by introducing a CRM Italy deviated from the dominant EU paradigm: "Europe had not yet made the conceptual step towards recognising the need for long-term contracts to encourage investment. There was still a persuasion on the efficacy of spot markets. […] and a fear that long-term contracting might be configurated as a state aid" [interview28 – senior market expert at system operator]. The Commission was particularly wary of the Italian mechanism given the country's ambiguous techno-economic situation fearing that "support would be targeted at state-owned generators" [interview22,23]. Following 'many years of suffering and wars with Europe' [interview27 – senior official at regulator], the Commission approved the mechanism after requiring several modifications to the original design, deemed an 'overly explicit subsidy for fossil fuel generators' [interview23].

Given Italy's ambiguous resource adequacy situation, the introduction of a capacity market as a form of support for struggling gas generators is even more evident with data pointing to the pivotal role of these interests in the policy process. Most fossil fuel generators including major incumbent Eni, advocated for the reform, constituting a strong coalition of stakeholders in favour [Interview32,34,37]. Particularly keen was a group of medium-sized operators who had recently invested in new gas plants: "conventional generation suffered, and our company, who had contracted an important debt to build

[42] These were much larger here than in the UK when the capacity market was introduced.
[43] The Clean Energy Package.
[44] Italy historically suffered from higher prices compared to its EU neighbours.

new power plants, faced the risk of not being able to meet the commitments made during the financing phase" [interview34 – representative of gas generator].

Interestingly, some note that, despite the significant presence of gas assets in its portfolio, Italy's largest incumbent Enel exhibited a 'mild stance' on the capacity market, which they argue contributed to delaying reform as Enel's opinion often constitutes a turning point [interview37]. Given Enel's influence within Assoelettrica[45] and Italy's corporatist system (see sub-section 5.2.8), medium-sized operators formed Energia Libera, a new association with the capacity market as its 'workhorse' to advance their case [ibid]. A key narrative used by gas generators in support of the CRM was the fundamental role of gas in reliability, a '*sine qua non* for the energy transition' [interview32 – representative of major incumbent gas generator]. Like in Britain, gas producers contributed to creating a sense of urgency by signalling looming capacity shortages, the withholding of future capacity investment and plant retirements [Interviews21,33,34].

On the other hand, weak support or opposition to the CRM came from some residential consumer, environmental and DERs groups, which saw it as unnecessary and working against sustainability, affordability and decentralisation (ANSA 2019; Italia Solare 2021a). However, compared to gas producers, these groups have less influence in policy decisions (sub-section 5.2.8). Industrial consumers, who have much larger policy influence, did not have a strong position on whether a CRM was needed, however, they pressed for some key conditions in its design, specifically, the inclusion of price mitigation mechanisms (reliability options) and in the definition of price caps and floors[46] [interview38 – representative of industrial consumers].

The Italian capacity market design is a centralised auction mechanism with Terna as the central buyer of reliability options (MISE 2019). Auctions are held yearly four years ahead of delivery, supplemented by three to a year-ahead auctions to allow for later adjustments. Auctions are held on a zonal level to coordinate capacity procurement and network investment planning. Plant owners who manage to secure contracts have an obligation to make their production capacity available in exchange for a fixed payment (in €/MW-year). The premium (in €/MW-year) is defined as the auction clearing price based on the marginal price. The elastic yearly demand curve defined by Terna on an annual basis, alongside price caps and eligibility criteria. The product traded in the Italian capacity market is a reliability option: this means that market participants must return to Terna the difference, if positive, between the wholesale energy and service markets' prices and the strike price pre-defined by the regulator ARERA. Contract length varies according to the capacity type with one-year contract for existing assets and 15-years for new built.

Key design parameters in the Italian CRM faced heated debates. For example, a significant point of contention revolved around the determination of the price cap and floor. On the one hand, Elettricita' Futura and the gas operators' coalition argued that the initial price cap set by ARERA for existing capacity was too low and hindered their ability to recover fixed costs (Elettricita' Futura 2017). Conversely, the industrial consumers association, Confindustria, viewed the price cap as essential to mitigate price spikes and control balancing costs [interview38].

Further, although the capacity market was supposed to be technology neutral, non-traditional providers including DSR, renewables, aggregators and batteries argue they were excluded from participating (Kolokathis and Hogan 2019; SmartEn 2019; Italia Solare 2021a). They point to the same barriers as their British counterparts: low de-rating factors, excessive contract lengths and unfavourable rules on aggregation[47] (ibid) [interview21]. Similar issues applied to cross-border

[45] now Elettricita' Futura is the largest and most influential association representing the Italian power sector.
[46] These set limits to the premium received by generators.
[47] The business association SmartEn representing decentralised energy solutions criticised the Italian CM for not allowing aggregation and requiring all DSR sites to give Terna the ability to trip them directly (SmartEn 2019).

generators[48]: though under EU pressure Terna had introduced specific capacity auctions for these resources, according to participants, it set de-rating factors in a way that made participation uneconomical [ibid]. Beyond these groups' limited policy influence, the conservative approach to valuing their assets can be understood in terms of legacy operational philosophies among key sector-specific institutions: "the Italian market is really physical. Terna's reasoning was I cannot see the single units, I cannot control the asset so I will set a low de-rating factor" [interview21].

### 8.2.2 Outcomes and later developments

In the first auction of 2019, most capacity was assigned to gas generators, followed by hydro (Figure 52), mostly existing capacity (95%) (Terna 2019a). This is despite high prices[49] for both old and new capacity, and might be related to the ability of producers to exercise market power in a zonal market [interview23]. There was no participation by DSR, aggregators and batteries mirroring unfavourable terms of access. In the 2022 auction, conventional generators continued to dominate and clearing prices remained high (Terna 2022). Interestingly, there has been a modest increase in participation by cross-border generation and batteries (30% of new built), while DSR's contribution remains marginal (ibid).

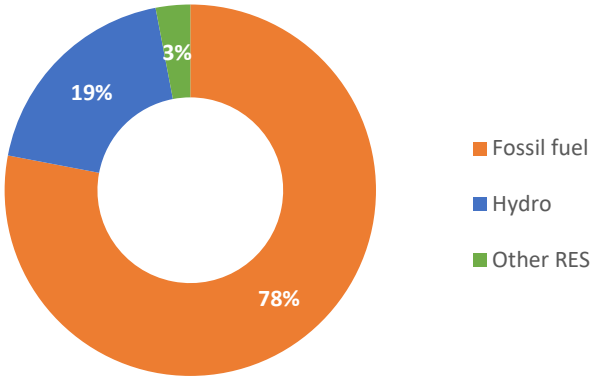


***Figure 52** – 2019 auction - assigned capacity by technology (Terna 2019a)*

Overall, the Italian CM has fulfilled its primary objective, to support gas operators, as consistently high prices have offered 'financial relief for existing plants' [interview33,34]. However, key design parameters remain fervently debated: conventional producers lament that the mechanism should become a 'more structural solution' [ibid], while non-traditional providers call for better terms of access (SmartEn 2019). As put by one participant "the Italian capacity market fundamentally doesn't satisfy anybody or a few" [interview37].

In addition, important questions remain around the ability of the mechanism to leverage appropriate investment in flexible storage capacity [Interviews 27,28,29,32]. As noted by a representative of the major incumbent Enel who recently entered this market, "we have taken a risk because the capacity market is not really an instrument that rewards these technologies through de-rating factors, in the hope that there will be another regulatory instrument coming" [interview 33]. In line with this, "Italy has been fighting on the European front to secure the possibility of long-term remuneration" [interview 27 – senior official at regulator]. On its side, Europe has recently recognised the need to adapt legacy CRMs or establish new out-of-market mechanisms to incentivise these technologies (Meeus and Nicolai 2023). Italy is currently in the process of defining a targeted market mechanism[50].

[48] Contrary to Britain, Italy has a generator-led approach for cross-border capacity (see sub-section 8.1).
[49] €33/kW for existing capacity and €75/kW for new capacity (MISE 2019).
[50] According to this government consultant [interview 29], in this market, potential investors in batteries or pumping plants would bid for the capacity requirements estimated by Terna at a zonal level over a long-term

## 8.3 The evolution of resource adequacy policy in California

California first introduced a decentralised obligations scheme in 2002 as a reaction to the notorious energy crisis, a series of major power blackouts that shook the state between 2000 and 2001. While the basic structure of the mechanism remains unvaried, since 2013, its "rules have been in constant flux" [interview48]. For example, the methodologies used by the CPUC for determining local and system reserve margins and the capacity values of different resources procured have evolved over time, as well as long-term resource procurement targets. Up to the end of the decade, the state's primary focus was on decarbonisation, but significant changes in its generation mix and market structures, and a series of extreme system events have recently determined a policy shift with a stronger focus on system adequacy and reliability. Key events are summarised in Figure 53 and discussed below.

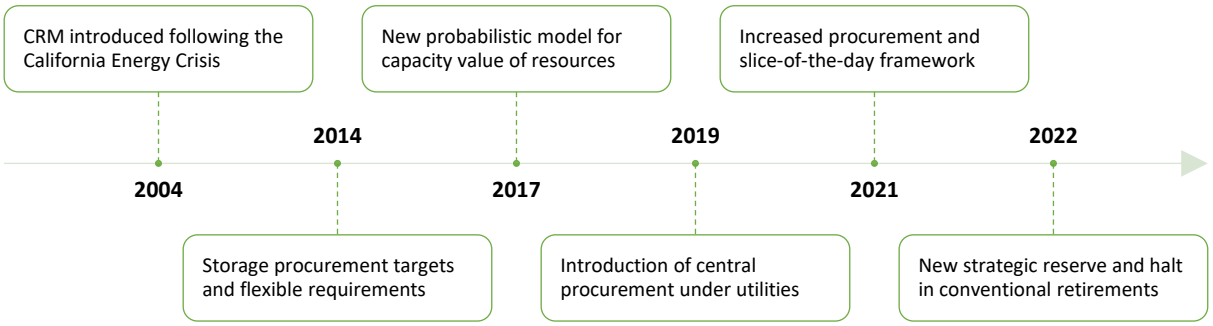


***Figure 53** - Evolution of resource adequacy policy in California*

### 8.3.1 California's decentralised obligations scheme

California's legacy decentralised obligations scheme (Figure 54) has two main mechanisms: a long-term resource plan, submitted by load-serving entities and approved by the CPUC to ensure adequate long-term capacity investment; and shorter-term local and system requirements requiring load-serving entities to procure enough capacity on a monthly and yearly basis to maintain reliability in the operational timeframe (Sener 2015; CAISO 2021; NARUC 2021). Load-serving entities, responsible for the delivering on resource adequacy obligations and targets, are all entities acting as electricity retailers. Traditionally, incumbent distribution utilities acted as the main load-serving entities, but the recent growth of new retail market actors[51] fragmented the responsibility for delivering obligations (John 2019; CPUC 2019).

horizon, possibly until 2030. The mechanism aims to remunerate investors for their investment costs and provide a fair profit for their storage facilities. However, after construction, facilities are not operated by the investors, but their storage capacity sold on another short-term market. This secondary market would be open to various market operators, with a tendency for renewable energy operators to participate. They could purchase options for time shifting their production, moving energy from low-price periods, such as solar generation during the day, to high-price periods in the evening.

[51] - i.e. community choice aggregators, programs allowing local governments to procure power on behalf of local consumers (see sub-section 5.3.8)

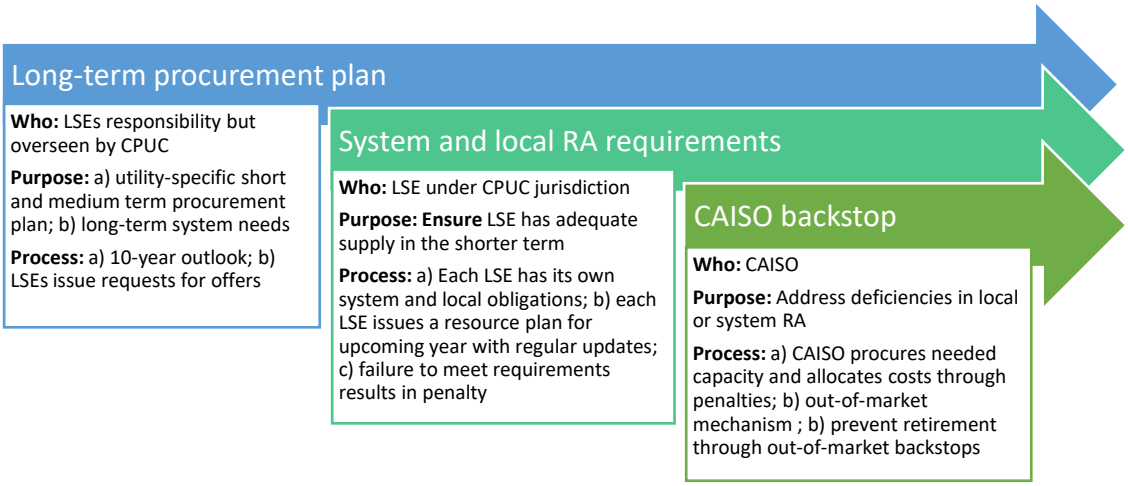


***Figure 54** - California's legacy decentralised obligation scheme (adapted from Sener 2015)*

First, load-serving entities must develop a non-binding 10-years procurement plan as part of the Integrated Resources Planning (IRP) process designed to ensure long-term resource adequacy (ibid). Through the 'procurement track' of IRP, the CPUC can set obligations for the procurement of specific amounts and types of capacity within specific timeframes. Second, load-serving entities must meet local and system requirements by procuring enough resources on a yearly and monthly basis to meet pre-determined reserve margins (Sener 2015; NARUC 2021). Resources entering forward contracts with load-serving entities are required to bid into wholesale markets. The methodologies used by the CPUC for determining short-term reserve margins and the capacity values of different resources procured by the load-serving entities have evolved over time (Specht 2022). CAISO also relies on an out-of-market mechanism to meet unsatisfied reliability needs, the so-called backstop mechanism.

Figure 55 illustrates California's installed capacity in relation to electricity peak demand. From 2010, the generation mix began transitioning from being dominated by conventional generation towards much larger presence of VREs resulting in a period of low prices that challenged gas plants economics: "independent producers and merchant generation were suffering, relatively new combined cycles that didn't plan retiring were going through bankruptcies" [interview50]. Further, about 5GW of old gas facilities reaching the end of contracts were expected to retire, and retirements of conventional generators (i.e. coal, nuclear and once-through-cooling plants) were actively pursued by state policy (Sener 2015; Clifford 2021). In 2014, the CPUC predicted that most coal, once-through cooling[52] and nuclear capacity would retire by the next decade, including Diablo Canyon servicing around 9% of the state's supply (ibid).

[52] - i.e. this refers to power plants that use coastal and estuarine waters for cooling purposes in California.

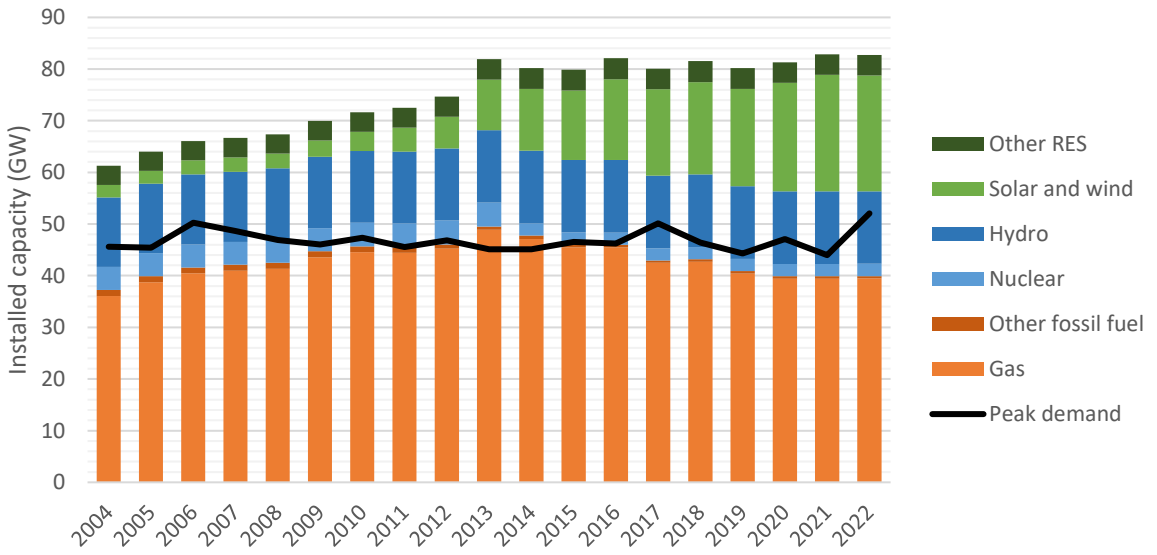


***Figure 55 -*** *Installed capacity and peak demand in California (GW). Source: CEC energy data.*

Meanwhile, California became increasingly reliant on out-of-state resources [interviews42,44,48,50]. Surrounding states historically had abundant hydro and coal resources but, from 2015, due changing weather patterns and coal retirements, it became clear that imports would not be able to fill the gap left by in-state retirements [ibid]. The state was also increasingly reliant on solar for reliability, whose output is highly correlated [ibid]. From 2017 "capacity shortages became very evident" [interview50]. Coupled with more frequent extreme weather, this caused California to have 'lots of close calls from a reliability perspective' [interview48]. Particularly noteworthy are the August 2020 outages when extreme heat drove demand up that could not be met by available resources (CAISO 2021).

Techno-economic conditions only partially explain California's approach to resource adequacy. Up to the mid-2010s, despite signs of potential future reliability issues, the state continued pursuing conventional generator retirements [interview50]. Only following extreme system events, it made a policy U-turn, as discussed later in this section. This seems to contradict a wide-spread assumption that governments are risk-averse when it comes to resource adequacy and can be explained through California's exceptional political commitment to decarbonisation, which some describe as 'bordering on the religious' [interview43]. This is exemplified by an anecdote shared by a participant: "when I was at the Commission, they needed to approve a natural gas plant for reliability in line with what they call the duck curve. The commissioners were apologetic, one of them was almost in tears. It was like he was violating a societal norm" [ibid – energy regulation consultant]. Strong opposition to conventional plants also came from local environmental groups and communities 'concerned about local ecosystems' [interviews52,47,50].

One of CPUC's first steps towards tackling emerging reliability issues was introducing explicit flexibility requirements in 2014, which must be met by load-serving entities when procuring capacity for short-term reliability (Jackson 2018; CPUC 2013). Under the so-called Flexible RA Must-Offer Obligation, CAISO develops Flexible RA capacity allocations and assigns those to local regulatory authorities (ibid). Flexible requirements have become increasingly stringent since. Further, in the same year, the CPUC introduced new long-term targets mandating load-serving entities to contract 1325MW of battery storage by 2020 (CAISO 2019a). Finally, in 2017, the California Legislature established a standard requiring a portion of the peak hour demand be met by clean resources (ibid). As a result, in 2019 California led the US in energy storage with 4.2GW of installed capacity (CAISO 2019a).

First, this mirrors California's ambition to become a 'leader' in the procurement of low-carbon reliability capacity [interviews40,42], pointing to a techno-economic culture open to experimentation

and a willingness to absorb innovation costs [interviews43,41,39]. One participant described California's strategy as "subsidise as much battery storage as possible as quickly as possible so that we are in a situation where we can allow fossil fuel retirements" [interview 47]. In addition, this approach based on explicit, binding storage targets reflects the state's traditional easiness with planning system outcomes: "as they always do in California, they put a burden on the utilities to go and contract for storage. […] It was the visible hand, not the invisible hand that did that" [interview40]. This is rooted in the state's bumpy liberalisation process (see Section 5.3), which left behind a desire to 'maintain control' [interview 47 – government consultant].

### 8.3.2 Outcomes and later developments

By the end of the decade, growing concerns around reliability and market fragmentation[53] led the CPUC to consider more radical changes, specifically, a move towards a more centralised procurement (CPUC 2019; CPUC 2019b; CPUC 2020). Among the options considered for a new mechanism was a CAISO-led capacity market, which would have drawn California's approach nearer to Britain's and Italy's. Eventually, the CPUC centralised procurement under incumbent utilities, a limited change from the pre-existing model [ibid]. Evidence suggests that this decision can be attributed to three main factors: institutional relations across layers of governance, legacy market structures and stakeholder interests.

First, key decision-making institutions (i.e. CPUC and the Energy Commission) opposed a CAISO-led capacity market fearing that this would "open state policy to federal jurisdiction" [interview41]. In fact, transmission-wide activities in the US are regulated by federal regulator FERC. As noted in Section 5.3, California's institutions exhibit a deep-rooted mistrust of FERC dating back to crisis: "the resource adequacy program was structured to avoid federal regulation" [interview 48]. Such wariness derives from a perception that the federal regulator did not adequately intervene to mitigate the effect of price spikes on consumers during the energy crisis [interviews45,48,41]. Further, state institutions fear that 'giving up control' over key policy areas would expose them to fluctuations in federal politics 'undermining state decarbonisation efforts' [ibid]. Interestingly, a potential CAISO-led central procurement option was ruled out by CAISO itself who declared it 'will not voluntarily accept a role as central buyer' (CPUC 2019b).

On the other hand, consultation documents reveal that the capacity market had found strong support among independent power producers who own most gas assets (CPUC 2019b). In 2018, they had even made a case that FERC should mandate a capacity market in California on the basis that "current arrangements prevented reasonable returns on their investments" (Bade 2018). However, gas producers' repeated calls never took hold. This perhaps reflects the limited influence of a single interest coalition in the context of such fragmented and pluralist landscape (sub-section 5.3.8), especially if their position diverges from that of key state institutions. In fact, the model that was eventually adopted, utility-driven procurement, had received backing from key stakeholders including the CPUC, CEC, and consumers (ibid). Conversely, CCAs, pro-retail competition groups, and decentralised energy advocates had opposed it, citing concerns around procurement neutrality by incumbent distribution utilities. Interestingly, utilities themselves were hesitant to take on this role and only agreed to do so temporarily (ibid).

As discussed above, up to 2020, California made different technological choices from the other two cases by actively pursuing the retirement of conventional generators (nuclear and gas) without incentivising new plants [interviews39,50,47]. Instead, it directed its efforts to maximising battery storage procurement[54]. Nevertheless, gas remains the most contracted resource in the short-term by

[53] - i.e. an increase in instances when load-serving entities were unable to meet obligations, especially smaller retailers (John 2019).

[54] In 2019, an additional 3300MW of capacity was mandated by 2023 (CPUC 2019a)

load-serving entities as shown in Figure 56 illustrating the resources committed local and system plans for 2019. This was followed by hydro, DSR, CHP and solar.

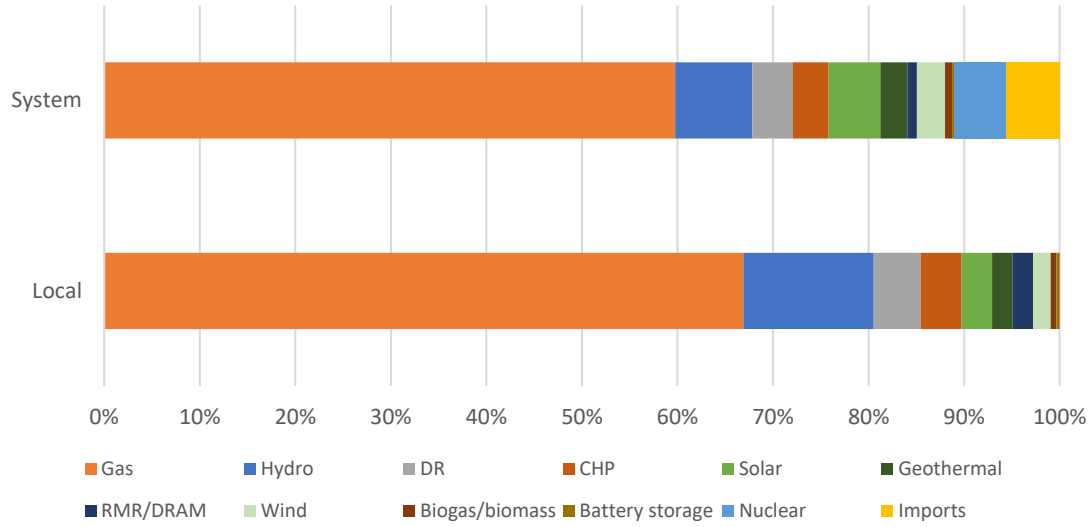


***Figure 56** - Yearly resources set in month-ahead plans for system and local requirements. Source: 2019 CPUC Resource Adequacy Report.*

As part of the resource adequacy scheme, every resource is assigned a capacity contribution credit determining its value towards meeting reliability requirements (Specht 2022; NARUC 2021). Remarkably, while VREs were not procured as capacity product in the other systems, for years, solar reliability contribution was highly valued in California, despite the high correlation in generation output [interview44,50]. According to several participants, the rationalisation of solar capacity contributions took several years due to strong opposition from the state's 'powerful solar industry', which had undergone major consolidation thanks to the state's favourable policy regime [interview49,43] (also see Section 9.3). Eventually, in 2017 a new statistical method[55] was introduced that reduced solar capacity value by approximately 80% (NARUC 2021).

Like their Italian and British counterparts, California's DSR and DERs argue that the reliability value of their services remains unappreciated [interviews51,52]. Some experts note how DSR's past underperformance contributed to a perception that these are not a 'viable solution' compared to other resources [interview44 – representative of system operator] (also see Section 7.3). For their part, decentralised energy advocates argue that both incumbent utilities and independent power producers have openly been opposing their business models, perceived as 'risky' and a 'threat to incumbent market positions' [interview 46 – senior policymaker, interview52 – advocate of local energy systems] (widely discussed in Section 7.3).

A major push to change adequacy requirements came in the aftermath of 2020 blackouts. First, the CPUC mandated the procurement of additional capacity, increasing procurement reserve margins and storage long-term targets (Mulkern 2022; CEC 2021b; Hilton 2021; Clifford 2022). Second, there was a policy U-turn in conventional plant retirements, including Diablo Canyon nuclear plant, a decision that would have been 'unthinkable ten years ago' [interview39]. Several gas plants meant to retire were contracted in a new strategic reserve scheme through which the DWR[56] should procure emergency generation for times of system stress (Mulkern 2022). Critics argue that this was a costly approach:

[55] The Effective Load Carrying Capability (ELCC), a probabilistic measurement of a resource's ability to generate when the grid is most likely to experience shortfalls expressed as a percentage of a resource's capacity (NARUC 2021; CPUC 2017).
[56] Department of Water Resources.

"we probably moved a little too fast with the retirement of baseload generators and now […] they're panicked so we are going to spend billions of dollars for getting electricity for 60 hours" [interview47 – government consultant]. This decision outraged environmental groups who see it as 'working against decarbonisation' [interview52].

The CPUC also introduced major modifications in system capacity requirement methodologies (Specht 2022). In contrast to the legacy framework setting single capacity requirements each month based on monthly peak load, a new 'slice-of-day' framework will set hourly obligations for a representative day in each month, determined using the load profile for the 'worst day' (i.e. with the highest peak load) (ibid). The framework, illustrated in Figure 57, also includes new methodologies for computing RES reliability contributions[57] and sets specific requirements[58] to optimise storage operation. This represents a shift in the techno-economic logic underpinning capacity procurement towards more explicit consideration of peak system needs and specific assets' performance. While generally welcomed by the industry given its simplicity, some argue this is a 'step into uncharted territory' as this design was never implemented elsewhere [interview48]. Sceptics also argue that this design relies on more simplistic methods than the legacy framework based on probabilistic grid modelling (Specht 2022).

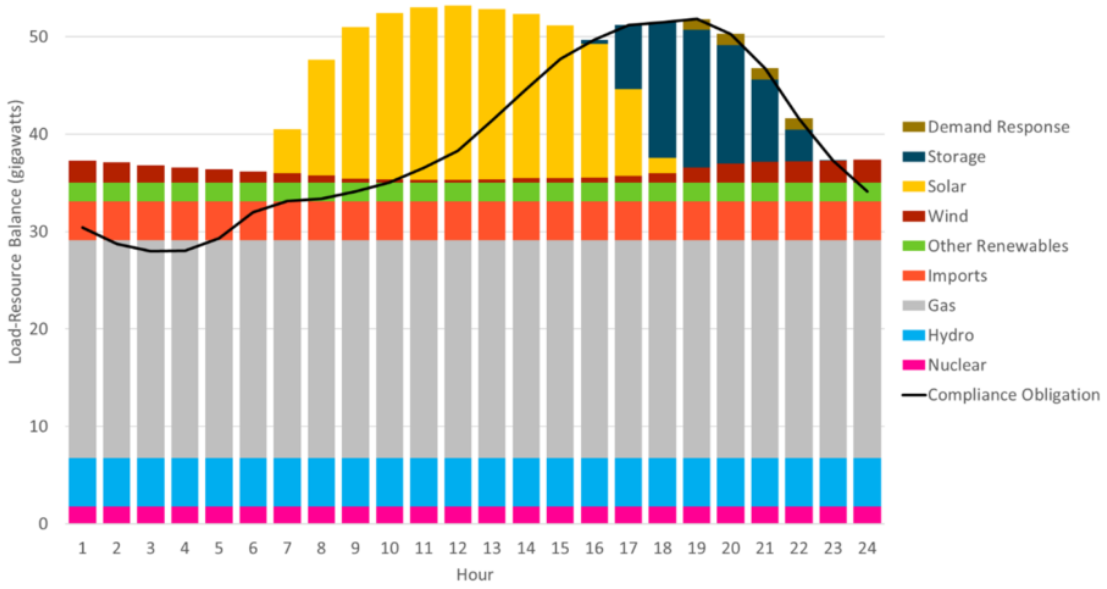


***Figure 57 -*** *Example hourly resource adequacy compliance by different resources for September (Specht 2022)*

## 8.4 Comparison of resource adequacy policy evolution

All jurisdictions implemented important modifications to their resource adequacy policy in response to changing system conditions. While there are common trends, there are also important differences in the scope of these changes, mechanism design choices, resulting policy trade-offs and technological outcomes. Table 18 summarises the key characteristics of recent reforms along these key dimensions, while the next paragraphs compare the key techno-economic and political economy conditions shaping the reform processes across cases, also summarised in Table 19. Crucial conditions include national political priorities, historical state-market relations, national and multi-level governance arrangements, legacy market structures and the interests of key power sector stakeholders.

[57] Now based on historical hourly production profiles instead of the legacy probabilistic method.
[58] i.e. that enough capacity is available to charge before discharging.

***Table 18 -*** *Summary of change in resource adequacy policy*

| | **Britain** | **Italy** | **California** |
|---|---|---|---|
| **CRM design evolution** | In 2014 major shift from energy-only-market to capacity market. Since then, gradual modifications to mechanism design parameters. Explicit flexible capacity mechanism considered as part of ongoing market design review. | In 2019, shift from capacity payment to capacity market with reliability options. Ongoing definition of mechanism for flexible capacity procurement following EU approval. | From 2014, significant modifications to legacy decentralised obligations scheme - i.e. procurement model methodologies, targets. Explicit storage procurement targets from 2014. U-turn conventional plant retirements and new strategic reserve. |
| **Reform(s) objectives** | Ensure future system reliability in the context of higher VRE shares and coal phase out, and support struggling gas generators. | Ensure future system reliability in the context of higher VRE shares and coal phase out, support struggling gas generators, mitigate prices in energy and services markets. | Different objectives over time: maximising procurement of low-carbon reliability, respond to market fragmentation and steep increase in reliability challenges. |
| **Policy focus** | From cost and competition to decarbonisation and system reliability. | From cost and competition to decarbonisation and system reliability. | From purely decarbonisation to decarbonisation and system reliability. |
| **Technology choices** | Mainly supported conventional generation (gas, hydro nuclear) and interconnectors, marginal but growing participation of battery storage and DSR. | Mainly supported conventional generation (gas and hydro), very marginal but growing participation of cross-border resources and battery storage. | Delay to conventional plants retirements, gradual shift away from VREs for reliability. Supported battery storage but limited participation of other non-traditional providers. |

As the three jurisdictions undertook deeper power system decarbonisation, they experienced similar techno-economic challenges. As predicted in the techno-economic literature (Section 2.1), VREs led to lower and more volatile wholesale prices, contributing to what economists call the 'merit-order-effect'. Coupled with flat demand, this undermined gas generators' economics leading to a wave of retirement announcements. Over the 2010s, technical projections pointed to a future decline in capacity margins and a halt in new capacity investment across all jurisdictions, who faced the prospect of relying on an increasingly intermittent pool of resources for future reliability. Eventually, this led all jurisdictions to review their resource adequacy policy.

However, the significance of the reliability challenges faced by the three jurisdictions and their policy responses present important differences. Britain decided to introduce a CRM in the early 2010s, when the system apparently had adequate capacity margins, but these were declining sharply due to announced retirements. Around the same time, Italy initiated discussions on the CRM, when the system reached the peak of overcapacity, but significant missing markets issues were emerging – an ambiguous techno-economic condition that partially explains delays in reform. Over the 2010s, California moved swiftly with conventional plant retirements, and in the following years, saw a steep reduction in capacity margins. More drastic resource adequacy measures only came in the aftermath of significant reliability events, made more frequent by changing weather patterns. While important, techno-economic conditions cannot fully explain the timing of jurisdictions' responses in relation to emerging reliability challenges nor their decisions in terms of mechanism designs and approaches to valuing different technologies.

In line with previous research (Karapin 2016; Gawel et al. 2017), the approaches taken by the jurisdictions can be partially explained in terms of the evolution of national political priorities and incentives of governments. The literature tells us that governments tend to be risk-averse when it comes to system security, as blackouts are particularly damaging politically (Hogan 2017; Leautier 2018). This seems to apply well to Britain and especially Italy where the prospect of decreasing reserve margins and future reliability problems compelled governments to support conventional generators as a political reassurance for a 'safe' energy transition. However, while in GB CRM implementation was swift, Italy saw an 8-year policy process with a back and forth of proposals mirroring frequent changes in government.

On the other hand, California's initial approach has been to aggressively pursue conventional generators retirements maximising low-carbon reliability procurement, even with the prospect of future reliability issues. Only when these materialised, did the state make a significant policy U-turn. This seems points to a different balance of trade-offs across reliability and decarbonisation across cases, with Californian institutions exhibiting a uniquely strong political commitment to being a decarbonisation leader even that involves absorbing some risk.

Evidence also suggests that the characteristics and actions of key power sector institutions are relevant to understanding policy responses, especially in terms of their cultures, independence, and influence over national policy (Gawel et al. 2017). The British regulator and Italian system operator Terna played a decisive role in setting the case for change and shaping the design of CRMs. CAISO's mission is also to maintain system security; however, its unique institutional design means that 'CAISO is not in the driver seat when it comes to resource adequacy' [interview50], instead, it closely follows state policy (and politics), which prioritised decarbonisation over reliability.

Findings also points to the importance of cultures and operational philosophies of these institutions to explaining technological choices (Breslau 2013). In all jurisdictions, uncertainties around the performance of non-traditional providers resulted in a conservative approach to valuing them albeit with important differences. For example, the Italian operator exhibits a particularly conservative attitude towards assets that it cannot control directly including cross-border capacity, more widely procured for reliability in the other systems.

The fact that all jurisdictions implemented a CRM in response to changing system conditions substantiates arguments in the 'hybrid markets' literature that the need to undertake the energy transition whilst maintaining system security can alter state-market relations even in traditionally liberal countries (Lenhart et al. 2016). However, differences in the liberalisation histories, legacy ideas around the role of markets and industry structures determined different approaches to designing CRMs (Guerriero 2016; Correlje and de Vries 2008; Lockwood et al. 2019).

By transitioning from an energy-only market to a CRM – along with other changes in the EMR, Britain underwent the most radical shift in the political economy of the power sector. This was underpinned by an intellectual struggle within decision-making institutions over what was perceived by some as abandoning market principles. In Italy, the CRM represents a more moderate shift as the state historically maintained a discrete level of control over the power system. Nevertheless, both countries have fully liberalised power markets and are historically committed to market principles, which continued to play an important role in the selection of the capacity market design based on the principles of competition and technological neutrality. Since the energy crisis, the CPUC retained a higher degree of control over system planning, and retail and the delivery of state programmes remain organised around incumbent distribution utilities. Hence, the CPUC's approach has been to explicitly mandate the procurement of specific technologies (i.e. storage) by incumbent utilities.

Evidence suggests that institutional arrangements and relations across layers of governance are also important to understanding recent reforms (Lenhart et al. 2016). Broadly, evidence points to the existence of important political tensions between national and supernational institutions due to a resistance to 'giving up control' over an extremely strategic policy area. This is most evident in California, where national institutions resisted the introduction of a capacity market, which would have opened state policy to federal jurisdiction and politics. This reflects the existence of historical institutional tensions and ideological differences between California and other US states (Karapin 2016).

By introducing a CRM, both Italy and Britain deviated from the EU preference for an energy-only-market model. The EU position was based on competition principles (i.e. fears that national subsidies might create unfair advantages for national producers) and a belief that short-term markets can deliver adequate capacity investment. However, in practice different visions exist among member states:

"there is a certain group of countries in the centre of Europe with the ability to increment cross-border transfers who are strongly against CRMs while […]. Countries with more structural constraints are favourable [to CRMs] such as Italy, Spain and the UK who have an interest in developing national resources" [interview29]. Hence, the EU position is also likely to reflect the balance of power among member states with different preferences. Both in Britain and Italy, national institutions engaged in intense negotiations with the EU and had to demonstrate the need for CRM before receiving approval. From its side, the EU had to strike a difficult balance: making sure these mechanisms do not undermine competition in the single market without fuelling anti-European sentiments that might undermine further regional integration.

Finally, the evolution of resource adequacy policy was found to be heavily influenced by some key interest groups, whose ability to influence policy varied across cases based on legacy market structures and the wider political environment (Karapin 2016; Gawel et al. 2017; Lockwood et al. 2019). Debates focused on overall mechanism designs and the specific parameters determining the reliability value of different resources. Broadly, evidence points to opposing positions on these issues between incumbents (utilities and conventional generators) and DSR, RES and decentralised energy groups, albeit these political dynamics are much more nuanced in practice.

Incumbent conventional generators strongly influenced the CRM design selection in both Britain and Italy. Reflecting centralised market structures, these producers formed a powerful coalition with a strong preference for a capacity market and were able to influence policy through threats of plant retirements, using interest associations and deploying narratives strategically. The Italian and British CRM mostly provided support for existing conventional capacity and had unfavourable terms of access for non-traditional providers with less policy influence – though these groups were able to obtain later modifications in the British mechanism through particularly effective lobbying. Reflecting their economic importance, Italian industrials were more involved in the policy process and were able to impose some conditions in the mechanism's design to safeguard their interests.

In California, repeated calls to introduce a market-wide mechanism by independent producers never had the same leverage, reflecting a more variegated and pluralist interest group landscape, ongoing market fragmentation. Plant retirements also mirror political opposition by powerful local environmental groups. Further, the relative influence of interest groups also explains why California attributed large reliability value to solar producers, who are well organised and resisted changes to the mechanism.

***Table 19** - Political economy conditions found to affect the evolution of capacity investment mechanisms*

| Categories | Specific conditions |
|---|---|
| **National politics and government** | - Evolution of national political priorities (decarbonisation and system security)<br>- Political stability and length of political cycles<br>- Dominant risk cultures and political acceptability of different approaches |
| **Legacy state-market relations** | - Dominant ideas on role of markets and price signals<br>- Legacy political economy model<br>- Degree of unbundling and privatisation (liberalisation) |
| **Sector-specific institutions** | - Legacy arrangements for market operation<br>- Dominant operational philosophies and ideas on the reliability value of different technologies<br>- Interests, culture, independence and influence of system operators and regulators<br>- Degree of coordination across key sector institutions |
| **Multi-level governance** | - Level of trust across layers of governance<br>- Level of capacity and coordination of multi-level governance institutions<br>- Level of homogeneity in political economy context of states<br>- Balance of power among states in the region |
| **Market structures and interests** | - Legacy market structures<br>- interests and influence of incumbent utilities and generators<br>- Economic composition of energy demand<br>- Organisation and influence of environmental, decentralised energy and consumer groups |

# 9 Evolution of low-carbon investment policy

This section aims to, first, identify the key differences in how the three jurisdictions dealt with low-carbon investment policy over time and, secondly, how these can be explained from a political economy perspective. As part of this, it summarises and compares key developments in some key policy areas including utility-scale renewables, distributed generation (DG) and nuclear policy, while also touching on related issues such as the planning and grid connections regimes. It is important to note that this chapter does not discuss changes in carbon pricing policy, which is beyond the scope of this thesis.

## 9.1 The evolution of low-carbon investment policy in Britain

For over a decade, the UK incentivised renewable energy investment mainly through a green certificate scheme, the so-called Renewable Obligation. This was replaced in 2014 by a feed-in-tariff with contracts-for-difference (CfDs). Broadly, low-carbon support in the UK has been targeted at utility-scale technologies, especially offshore wind. The CfD's basic structure persists today but has seen gradual modifications reflecting changes in policy priorities and system conditions. Key changes are summarized in Figure 58 below and they are discussed more extensively in the following paragraphs.

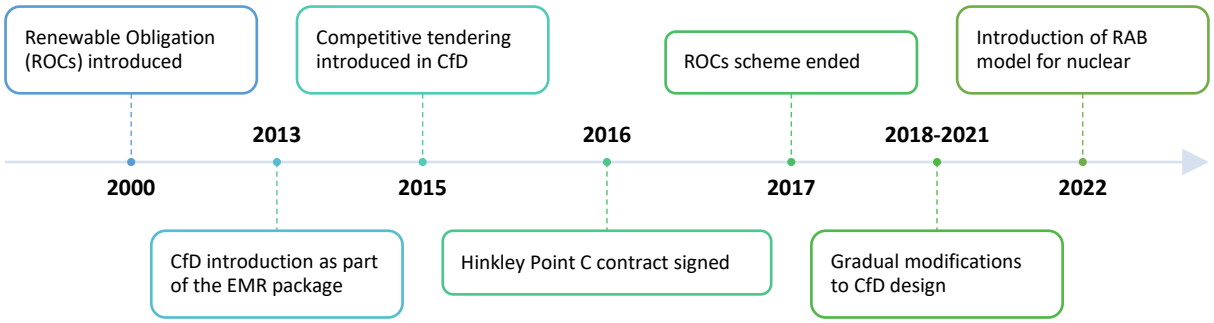


***Figure 58** - Evolution of low-carbon investment policy in Britain*

### 9.1.1 Early low-carbon investment policy

In the 1990s, during the establishment of the GB market, climate change considerations were secondary to competition and cost-efficiency concerns [interview10]. In 2000, the first major scheme incentivising utility-scale renewables was introduced, the Renewables Obligation Certificates (ROCs). ROCs mandated electricity suppliers to procure an increasing share of power from renewable sources, with certificates tradable among parties to demonstrate compliance (Hinson 2020). According to participants, this design was selected because it did not 'conflict with the market', it was technology-neutral and consistent with competition ideas dominant at the time [interview1].

Motivated by mounting concerns that the existing regulatory framework would fall short of achieving decarbonisation goals, the Climate Change Act was enacted in 2008. [interviews12,13]. This legislation set a statutory cap on total greenhouse gas emissions and established a legally binding framework for regular updates in carbon reductions (Hinson 2020). The first target was an 80% decrease by 2050 compared to 1990 levels (ibid). The 2008 Act also ushered in significant institutional changes, including the creation of the Climate Change Committee, an independent body advising the government on emissions targets, and the establishment of the Department for Energy and Climate Change to oversee the energy transition (see sub-section 5.1.4). This was a pivotal shift in power market governance, placing a renewed emphasis on decarbonisation [interviews1,12]. Around this time, a feed-in tariff scheme was also introduced to incentivise small-scale distributed generation (Hinson 2020).

In the early 2010s, there was a growing perception that the ROCs scheme could not deliver on decarbonisation targets, and government faced mounting institutional pressure to bolster renewables and nuclear energy while phasing out coal [interviews2,4]. First, this came from the EU, in the form of the 2009 Renewable Energy Directive (EC 2009). Second, the newly formed CCC highlighted the inadequacy of the existing market design in de-risking low-carbon investment [Interview1]. An energy economist explained, "ROCs raise the cost of capital by raising market risk, which is particularly high because it's subject to policy changes. It's about the most expensive way of financing renewables you could imagine" [interview2]. Eventually in 2011 the Government announced it intended to close the scheme to all new generating capacity by 2017 (Ofgem 2022).

Yet, some argue that this decision was also driven by a desire to "gain more control by government over budget and which projects get built" [interview 15]. While the ROCs had started as a general, market-based subsidy for renewable generators, over time it was 'tweaked' and 'targeted' to specific technologies [interview 10 - senior official at regulator]. The scheme was reformed with distinct bands for different technologies, recognising their varying levels of maturity and the need for some, like offshore wind, to cross the 'valley of death' [interview3]. Notably, by 2016, ROCs support was withdrawn for PV and onshore wind (Ofgem 2022). Participants agree that this also mirrors growing opposition to onshore renewables from local communities with sway in the national political agenda: "there was definitely a correlation [of these communities] with Conservative Party strongholds. It became a bit of a totemic issue for the right wing of the Conservative Party at that time they were in a fight with UKIP[59] for votes. Onshore wind was an unfortunate casualty of that" [interview15].

In parallel, important modifications in the planning authorisation regime introduced around 2011 worked as an additional significant barrier to onshore RES developers, particularly in England [interviews3,5]. Amon other things, to obtain planning permission, developers of plants under a certain capacity size must now obtain local community's support [interview35 – large RES developer].

### 9.1.2 The Low-carbon Contracts for Difference

In 2013, the ROCs scheme was substituted by another policy instrument, the contracts for difference scheme, introduced as part of the wider EMR (DECC 2012) (also discussed in Section 8.1). Illustrated in Figure 59, CfDs became the main mechanism to incentivise new large-scale low carbon power in the UK. Just like a traditional FiT, CfDs guarantee a certain electricity price (the strike price) that producers are given per unit of power output. However, it differs in that, as wholesale prices fluctuate, producers either receive a subsidy or pay back, so as to always receive the strike price value.

According to participants, one of the main reasons for choosing a mechanism building on a classic FiT structure was that "the design has a great simplicity: fix the price for a fixed number of years, what could possibly go wrong?" [interview 2 - energy economist]. Further, FiTs were already widely used in Europe and had been demonstrated to lower the cost of capital [ibid]. However, the CfD design also served country-specific policy objectives: "a CfD is basically like a feed in tariff only a lot more complicated, but it's complicated for reasons that suited the British system, which is rely on the wholesale market as much as possible and then government will underwrite the difference" [interview1].

[59] - i.e. UK Independence Party, a right-wing and Eurosceptic political party.

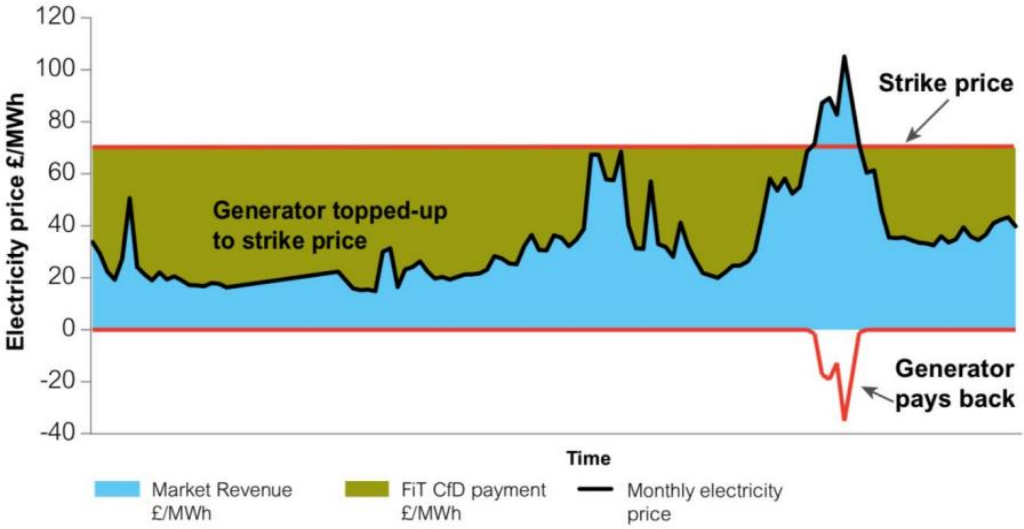


***Figure 59** - CfD payment mechanism (BEIS 2019)*

Initially, CfD FiTs were administratively set, with critics arguing they assumed an overly high weighted average cost of capital [interview2]. Participants note that Treasury 'violently opposed' these contracts, especially those for uncharted offshore technologies, viewing them as wasteful [interview1]. Instead, supporters argued that generous support was necessary to kickstart the offshore wind industry, a view reinforced by government conversations with major manufacturers like Siemens [ibid]. Observers note that this initial approach was also shaped by consultants and the financial industry, especially 'merchant and pension bankers', who advised the government to enable a high rate of return to attract investment [interview2].

A National Audit Office investigation revealed that initial CfDs, with administratively set strike prices[60] turned out to be more expensive than necessary to secure investment (NAO 2018). Recognising that these early contracts had been costly, the Government introduced auctions in 2015 [interviews3,7]. This marked a shift in the design logic from a pure focus on lowering RES cost of capital to harnessing competitive mechanisms to bring down cost, and it is was effective: "there's no question it was a bit embarrassing in some ways when the government, only six months later, held auctions and the price fell quite significantly" [interview1].

Participants also highlighted another motivation for adopting a FiT design, notably the government's desire to exercise greater control over expenditure. Despite subsidies for ROCs and initial CfDs being funded through energy bills, the Treasury considered them akin to taxes and sought to integrate them into their broader oversight of public spending [interview3]. While this viewpoint was contentious, it underpinned the budgetary caps imposed on each CfD auction round and the broader 'Levy Control Framework' within which these expenses had to be accommodated [ibid].

Additionally, this design also allowed policymakers to 'control the projects that get built' [interviews10,14,15]. There was an intense debate on whether different RES technologies should be funded through separate pots or whether they should be competing amongst each other [interview7]. Eventually, the former design was adopted. Having targeted pots allowed the Government to "drive the mix in a way that it isn't simply the market finding the most cost-effective way of meeting its broad objectives" [interview 10 - senior official at regulator]. Hence, it enabled to bypass the long-standing political opposition to onshore renewables by Conservative voters [interviews1,2,5]. Following the first auction in 2015, funding was withdrawn from established onshore RES technologies, more

[60] ranging from £105 to £150 per MWh.

economically viable but less politically acceptable. Instead, the bulk of support was targeted to more expensive but politically acceptable offshore wind projects [ibid].

Beyond offshore wind's large potential in the UK and local political acceptability concerns, participants identified additional factors influencing the government's technological choices. First is the political appeal of this technology: "offshore wind is something quite big, tangible and parliamentarians and ministers can go along and point at it, whereas the technologies that we represent are connected to the distribution network [and are hence less attractive]" [interview 14 - representative of UK renewable energy industry]. Secondly, the potential for different technologies to generate domestic manufacturing jobs was a consideration [ibid]. The offshore wind deal involved collaboration with several German blade manufacturers to establish production facilities in the East of England, instead, solar could not be manufactured in the UK.

Another key Government objective shaping the EMR policy package was the government's ambition to expand the nuclear fleet [interviews3,4,10]. Interestingly, this was accompanied by a shift in the decarbonisation narrative: "the government started to stop talking about renewable energy and talk about greenhouse gases because they were wanting to make the case for nuclear" [interview 14]. A spot market prices alone had been ineffective in leveraging investment in such a capital-intensive technology, the decision was made to place nuclear under the CfD scheme [interview12]. Being a general subsidy for low-carbon technologies, the CfD also allowed the UK government to bypass EU's state-aid rules on technology-specific subsidies [interview 4 - energy politics expert].

The CfD design was widely supported by the nuclear industry, largely composed of major incumbent EDF: "it is no real secret that EDF was one of the very big supporters of contracts […], there were lots of different options on the table at the time and we ended up with this contract for difference system, so they're definitely a winner" [interview3]. In 2016, the Government awarded a 35-year CfD to EDF for Hinkley Point C nuclear plant at an administratively set strike price of £92.50 per MWh (DECC 2016). This is often criticised by sector experts: "that Hinkley contract is totally expensive and really bad for consumers" [interview3].

Figure 60 illustrates the evolution of the strike price and capacity awarded by CfD round. The first CfD renewable auction after the introduction of competitive tendering [AR1] took place in 2015. It assigned 2.14GW of capacity at prices from £50 to £120 per MWh (DECC 2014). At this stage, onshore wind and solar still had access to funding and dominated the auction. In 2017, a second auction [AR2] saw major cost reductions for offshore wind, which represented most of the assigned capacity (BEIS 2017). Offshore wind prices dropped from about £114-120/MWh in 2015 to £57-75/MWh, a sharper decline than expected. Hence, CfDs are widely perceived as an extremely successful policy in the UK (BEIS 2019). By providing a fixed price, CfDs were able to significantly reduce investor risk: "the financial community just flooded in and said this is great" [interview13 – representative of major incumbent generator]. While competitive pressure achieved significant cost reductions, leading some to talk about 'buyers' remorse' [interview3].

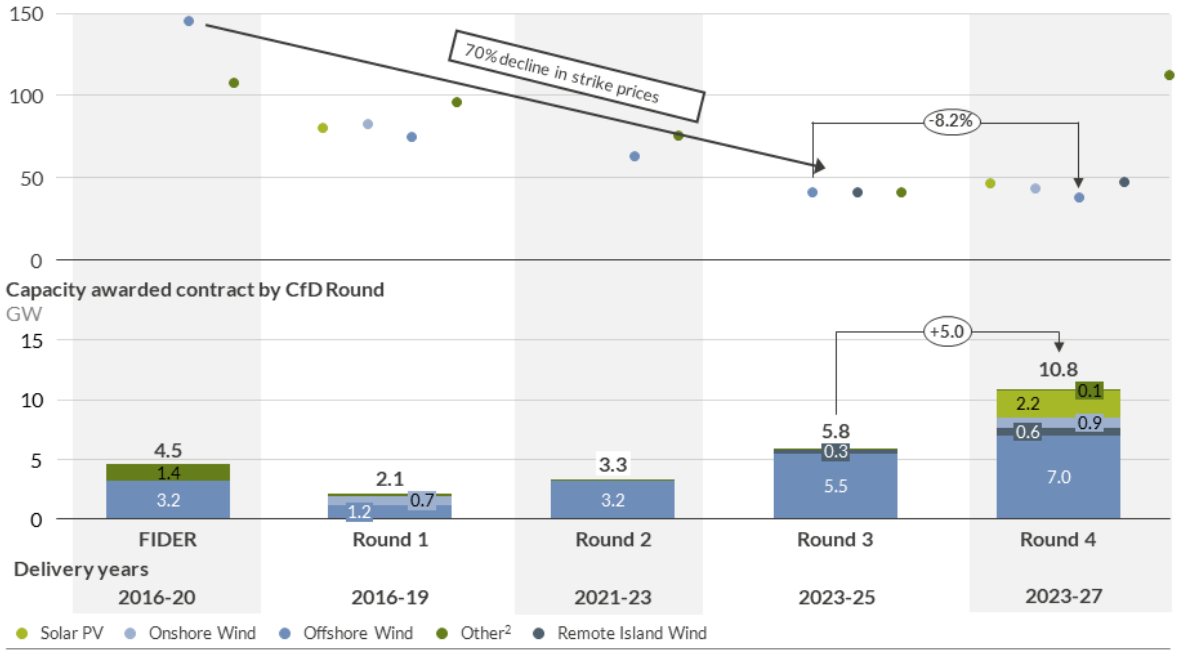


***Figure 60** - Strike price and capacity awarded by CfD round £/MWh (real 2012) (Aurora Energy Research 2022)*

Sector experts also note that the increase in policy support for low-carbon investment generated a feedback loop effect that reshaped the power sector's political economy [interviews4,5,13]. In fact, incumbents like Vattenfall, Orsted, Scottish Power, SEE, RWE, and EDF have increasingly shifted their focus from thermal generation to renewables [interview 13 – representative of large incumbent generator]. For some of these companies, RES technologies now constitute a significant portion of their profits (Ofgem 2020a).

Moreover, there has been a notable shift from equity investment to debt finance, with new financial players like commercial banks and institutional investors entering renewable financing [interviews7,12,13,16]. In the words of a representative a large incumbent generation company, “there's a lot of low-cost capital able to be deployed by what you would call low-return, risk-averse investors so essentially pension, funds, infrastructure funds, bank debt that's been lent” [interview13]. Additionally, despite reduced support, there has been some merchant investment: “people were telling BEIS back in 2015, when thinking about whether they wanted anymore onshore wind support, there'd be absolutely nothing. It has been more than that” [interview 7 - senior policymaker].

Towards the end of the 2010s, public concern rose regarding costs-implications of RES policy for consumers (see Figure 61). In 2017, BEIS commissioned an independent review on energy costs (Helm 2017). Helm's 'Cost of Energy review' sparked controversy, with many experts disagreeing with his analysis and conclusions [interview3]. Among other things, the review had suggested to shift RES policy costs to general taxation, arguing that cost recovery through consumer bills is regressive (Helm 2017). It also proposed exempting industrial consumers from legacy decarbonisation costs, citing the historically higher electricity prices faced by UK industry compared to European competitors.

The review did not bring any fundamental changes in the legacy approach. Treasury’s resistance to cost recovery through general taxation played a significant role, as their incentive is to “minimise the money that goes through its books and not to look at how money washes through the rest of the system” [interview7 - senior policymaker]. Additionally, the government rejected exempting industry from historical policy costs as this would put too much pressure on household bills and government expenditure (Clark 2018). This decision reflects the relatively low strategic importance of UK industrial activities and limited weight of industrial interests in policy decisions (see sub-section 5.1.8).

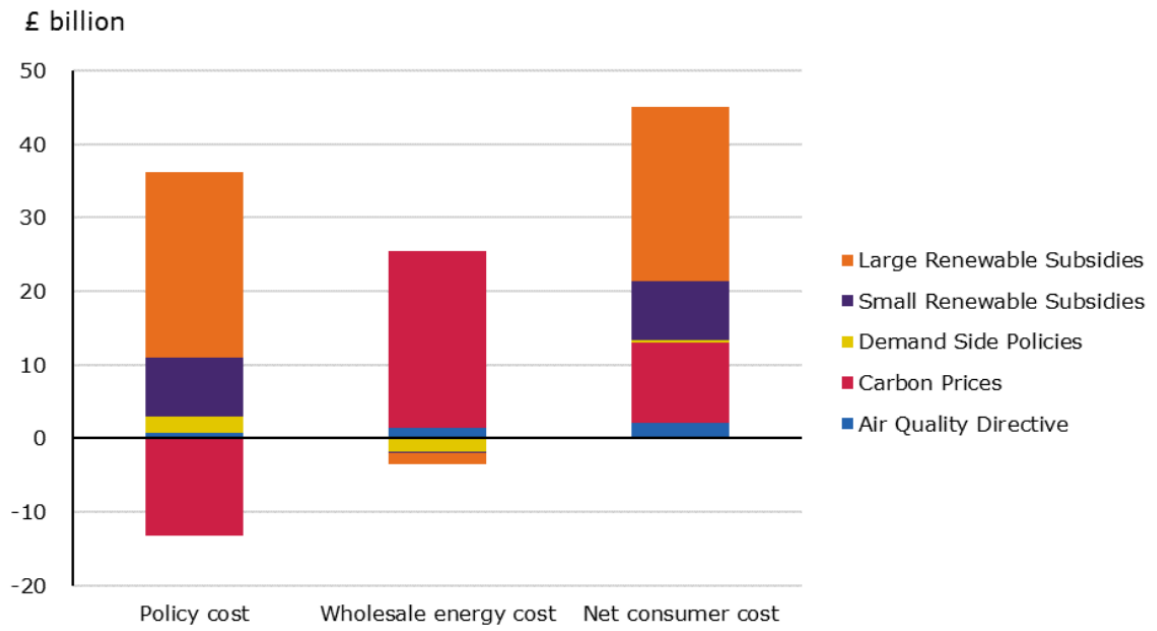


***Figure 61** - Estimated annualised cost of decarbonisation policies in electric sector 2010-2018 (Ofgem 2019b)*

### 9.1.3 Latest developments

Since its inception, the CfD scheme has not undergone fundamental changes, but some adjustments were made over time to align with evolving policy and political priorities. For instance, in 2018, the Government announced funding availability for a new technology category in auction AR3, namely onshore wind on remote islands (BEIS 2018). This was introduced as a mitigation mechanism for the expensive network charges faced by wind developers in some windy remote locations in Scotland (see sub-section 6.1.4). These actors made “made strong representation to ministers” to obtain support [interview15 - Scottish RES industry representative], and subsequently competed alongside offshore wind, securing some contracts (BEIS 2018a).

The 2019 auction [AR3] contracted 5.8GW of new renewable capacity at strike prices around £50/MWh (Figure 60), achieving further cost savings (BEIS 2020b). By then, offshore wind's declining costs had positioned it as a strategic sector in the UK's economic and industrial strategy: "offshore wind is now a badge of honour, and the UK has become the world's largest offshore wind market" [interview14 – representative of UK renewable energy industry]. This also contributes to explaining continued large policy support for this technology compared to other renewables [ibid].

Under the guidance of the CCC, in 2019, the UK Government committed to achieve a Net Zero target by 2050, necessitating a substantial increase in RES deployment (HoC 2023). In 2020, the government set targets to develop 40GW of offshore wind, including 1GW of floating offshore wind by 2030, as well as a sizeable portion of solar generation (HM Government 2020). This prompted discussions on how to design the next allocation round [AR4] to meet these targets (BEIS 2020b). A new third 'pot' structure was created targeting mature offshore wind projects. Additionally, a new technology category, floating offshore wind, was introduced, competing in Pot 2 against less-established technologies (ibid).

Further, some support was reintroduced for well-established onshore RES technologies (Dalton and Polito 2022). This was also the result of lobbying from the industry: “for the last four or five years we've been making the case that if this country has serious about net zero and about achieving it at the lowest possible cost, then it's bonkers to rule out high-value, low-cost onshore wind projects […]. We’re seeing a shift in that direction in some of the recent thinking. Maybe not driven by us, but certainly we've helped make that case” [interview12 - representative of large incumbent generator].

In 2022, AR4 allocated 11GW of low-carbon capacity, with offshore wind capacity reaching a record-low strike price of £37.35/MWh (LCCC 2022; BEIS 2022a). Capacity for onshore wind, solar, remote island wind, floating offshore wind, and tidal stream was also allocated at competitive strike prices. These results are observable in Figure 60.

Another significant change in the AR4 design was the removal of compensation for day-ahead negative prices (BEIS 2020b). This was driven a spike in VRE integration challenges, particularly, the rise in balancing costs (see Section 7.1). The provision of CfD support during negative prices was identified to hamper flexibility incentives for RES operators: "because you only get the contract strike price provided that you generate, you will, if necessary, bid negative prices to stay on the system and produce even though you may be displacing plants that would better run instead so it leads to a large number of constraint payments that are unnecessary" [interview2 - energy economist].

The 2020 government targets also put a renewed emphasis on nuclear power: "there's certain stubbornness in the British determination to try and hang on to nuclear power whatever the energy economics look like" [interview1]. This was seen as a security strategy, but was also fuelled by nuclear industry lobbying: "we probably have disproportionately been known for and have been responsible for making the positive case for future nuclear built [...] Crudely, if we didn't tell the positive story then who would?" [interview12 - large incumbent representative]. The CfD financing model had proven to result in excessive market risk, high cost of capital, and consumer costs (Addleshaw Goddard 2022; BEIS 2021a). Hence, calls for a regulated-asset-base model[61] emerged due to its potential to reduce the cost of capital and attracting a broader pool of investors by transferring some risk to consumers (ibid). This model was eventually introduced in 2022 (UK Parliament 2022), marking an important shift: "it is kind of moving back towards a direct government subsidy. It's treating nuclear more like a transmission system with Ofgem clawing over the returns they get" [interview1].

In recent years, significant changes also occurred in support for distributed generators. The previous FiT scheme was abruptly closed in 2019, replaced by the Smart Export Guarantee, compensating small-scale generators for exporting renewable electricity. This effectively represents a substantial reduction in support for these producers (BEIS 2020). This reflects a UK inclination towards utility-scale technologies, shaped by resource value perceptions of policymakers and the relative influence of small solar distributed versus large-scale generators in policy formulation [interviews3,14]. In fact, small solar producers faced challenges in opposing this policy shift due to limited political leverage [ibid] (see sub-section 5.1.8).

## 9.2 The evolution of low-carbon investment policy in Italy

Over the years, Italy implemented a plethora of renewable energy policies including tradeable green certificates, feed-in tariffs and premiums, and self-consumption incentives. Broadly, there has been a first phase characterised by high-RES incentives and growth, and a second phase characterised by a steep reduction in support and the rise of significant administrative barriers. More recently, to revive RES investment whilst containing policy costs, the Government introduced a CfD scheme. In terms of technologies, support has been targeted primarily at onshore solar and wind, though the degree of support for plants of different dimensions has changed over time. The main developments are illustrated in Figure 62 and discussed in the next paragraphs.

[61] Regulated Asset Base regulation is commonly used in the utility and infrastructure sectors. It allows regulated companies to earn a predetermined rate of return on the value of their assets, which includes the cost of building, operating, and maintaining those assets. The model provides a stable revenue stream for companies, often funded through tariffs or fees paid by consumers, or the government.

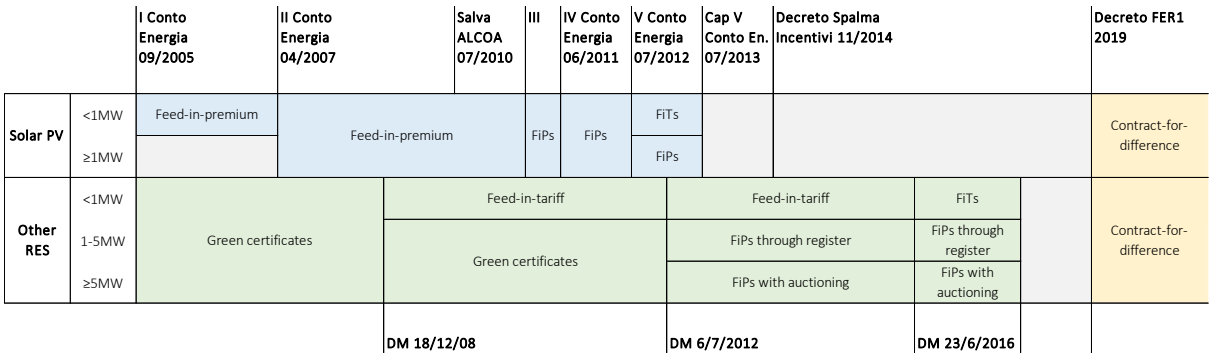


***Figure 62** - Evolution of low-carbon investment policy in Italy (adapted from: Iacovone 2019)*

### 9.2.1 Early low-carbon investment policy

The first push to expand renewables in Italy came in the early 2000s reflecting growing ambition at the EU level [interviews20,25,30]. In this initial phase, Italian policymakers introduced multiple mechanisms incentivising RES investment for different types of plants: "when it comes to incentives for renewables, in Italy we went wild" [interview30]. Onshore wind energy received support through two channels: green certificates, initiated in 2003, and an all-inclusive feed-in-tariff from 2008. Green certificates were granted to eligible producers and could be traded to meet renewable obligations or sold to the GSE[62], adding an extra revenue stream that could be traded on the market (Iacovone 2019). The all-inclusive feed-in-tariff targeted small renewable generators (excluding PV) and provided an alternative to green certificates, with eligibility limited to plants with a capacity not exceeding 1MW.

Solar energy, on the other hand, was primarily encouraged through the Conto Energia feed-in tariff targeting both large and small PV installations (Presidente della Repubblica 2003). Introduced in 2003, this policy underwent five iterations over the following decade, each with varying conditions and payment terms. Finally, Italy also introduced a net metering scheme targeting small DG generation. The so-called 'Scambio sul Posto' allowed DGs to offset their electricity consumption from the grid with on-site production and receive compensation from GSE based on injections and withdrawals based on the market value.

Unlike the UK, nuclear energy has never been seen as a decarbonisation strategy in Italy (Bevacqua et al. 2020). This goes back to a 1987 referendum, just after the Chernobyl disaster, when Italians decided to phase out all nuclear reactors. Around 2008, in the backdrop of high energy prices and pressure from industrial consumers, Silvio Berlusconi's government had reintroduced nuclear as a vital component of the country's energy and economic strategy (ibid). Agreements were made between Enel and France's EDF for four new reactors. However, these plans were halted in 2011 following the Fukushima disaster, which amplified Italians' deep-seated mistrust of nuclear power and skepticism of government competence: "there is this long-standing Italian mistrust towards everything that might kill you because fundamentally we don't trust the Government: the Japanese, who are very responsible people, had Fukushima; how can Italians manage nuclear?" [interview 26 – power sector journalist].

The first phase of the Italian RES incentive regime is widely regarded as particularly 'generous' [interviews21,25]. This coincided with increased EU ambitions in 2009, notably the 2009 EC Directives (EC 2009). Incentive mechanisms often did not include limits to capacity quotas or the size of the maximum reward made available to developers (Iacovone 2019). This approach, often referred to by participants as 'out of control', 'ad hoc' and 'without a clear strategy' [interviews35,37]. For example, decree Salva-ALCOA of 2010, introducing the second reiteration of the Conto Energia, extended it to all plants able to certify the end of construction works by 2010 and the start of operations by June

[62] See sub-section 5.2.6.2 for a characterisation of this institution.

2011 (L. 129/2010). This led to a boom of solar installations and, in some cases, to distortive behaviour by developers forcing the GSE to carry out inspections (Iacovone 2019). Research also suggests that that low institutional quality and corruption control facilitated involvement by the Italian organised crime, Mafia, who saw a business opportunity in RES policy support (Gennaioli and Tavoni 2016).

As a result of these policies, Italy became a front runner in renewable deployment, on track to meet 2020 EU targets in advance [interview21]. Between 2010 to 2012 there was an investment boom: "just drug trafficking and weapons would have guaranteed higher profits than those deriving from renewable incentives in Italy during that period, and the latter came with a lot less risk" [interview37]. Solar power thrived, with 2012 alone witnessing the installation of 400 thousand solar systems (Bevacqua et al. 2020). This exponential growth can be observed in Figure 63.

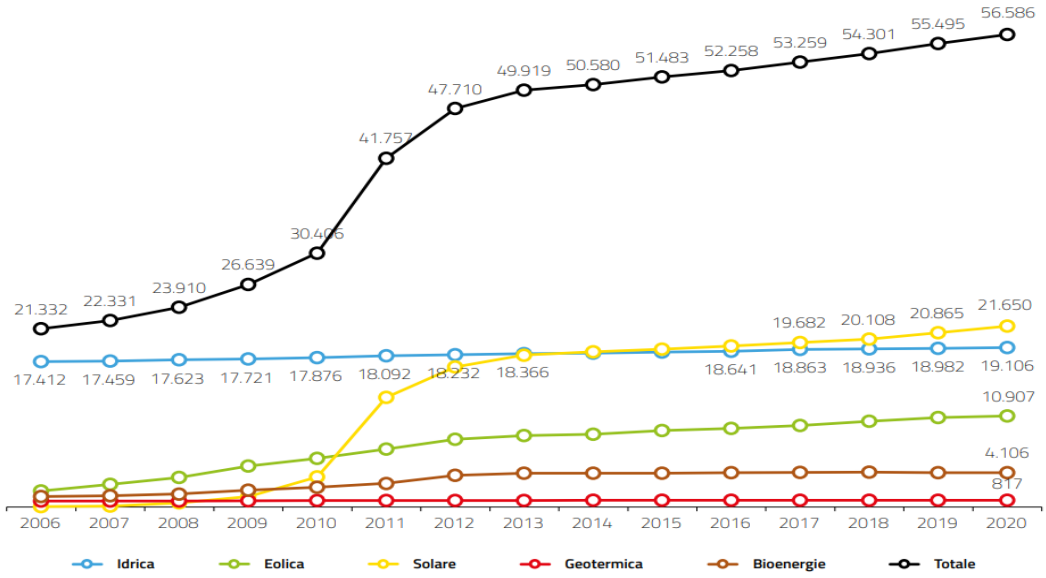


***Figure 63** - RES installed capacity by technology (MW) (GSE 2022a)*

This approach had important cost-implications: "the effect has been an explosion of costs, particularly in the tariff component dedicated to collecting funding for renewable incentives […]. This will remain high for several years to come" [interview37]. For example, the yearly cost of the second Conto Energia alone was estimated at over 3 billion euros compared to the 100 million of the scheme's first iteration (Iacovone 2019). Eventually, the rise in policy costs caused a political backlash and a shift in public attitude towards renewables. These came to be seen as "absorbing public resources, being expensive and leading to higher bills" [Interview20]. Further, Italian industrials, who had historically faced high energy prices, expressed increasing concern on the implications for industrial competitiveness. As noted by this participant, "public officials had various groups on the demand side, like Confindustria[63], pulling their sleeve to get discounts [interview22]. As discussed in sub-section 5.2.8, industry is a key sector in the Italian economy and these interests are a major force shaping national policy.

### 9.2.2 The second phase of Italian RES policy

The second phase of the Italian RES investment regime starts around 2014 and is characterised by a significant 'tightening' of incentives available to operators [interviews25,36]. As noted above, this was the direct result of growing political concerns over rising costs. Such a shift in political attitudes towards RES deployment is well reflected in changes of leadership that occurred in some key power market institutions. For example, around this time, the Government appointed to the direction of GSE "a

[63] Confindustria is Italy's primary association representing manufacturing and service companies, advocating for their interests and influencing economic and industrial policies.

person that had the priority to reduce costs rather than developing more renewables […] with a strategy that effectively aimed to slow down decarbonisation" [interview21].

Iacovone (2019) argues that these new measures, designed to curtail incentives, were often implemented on an 'ad hoc basis' and had 'penalising effects' on operators. In 2013, support for new solar projects was terminated, and in 2014, the 'Spalma Incentivi' decree significantly reduced incentives for PV installations exceeding 200kW (Presidente della Repubblica 2014). Concerning wind energy, the existing green certificates scheme was replaced by a sliding feed-in-premium system in 2014, with varying access conditions based on plant size. Under this scheme, RES generators could choose to sell power on the market or through the GSE's market trading service ('Ritiro Dedicato') or opt for a guaranteed premium. In cases where market prices exceeded the premium, RES producers would receive additional payments. Notably, large-scale generators had to compete in auctions for contract allocation.

Broadly, this contributed to a radical change in the investment environment and a sense policy instability among operators and investors, which attempted to challenge these measures through legal litigation (PwC 2021). Yet, the renewable energy industry was not able to effectively resist this policy U-turn. In fact, the shift of the political economy of the sector and the consolidation of renewable interests has been a slow process in Italy (see sub-section 5.2.8). During the early phase of Italy's RES policy, incumbent companies invested in traditional generation had resisted change (Guarnieri 2020). Up to the 2010s, there were still significant political tensions between RES producers and the broader electricity industry, particularly incumbent generators: "the PV industry benefitted from incentives that Assoelettrica[64] deemed excessive. The divergence of views on renewable energy between Assoelettrica and assoRinnovaibili[65] had taken quite snatchy tones. These signified difficulties of economic nature that were not easy to resolve" (Bevacqua et al. 2020).

During this period, RES developers also faced escalating challenges in obtaining local planning permissions, creating a significant barrier to RES investment [interviews28,33,35,36]. Local political representatives encountered mounting pressure from communities concerned about 'devastation of landscapes' and farmers vehemently opposing new RES projects [interview37]. There was a growing perception that while RES operators reaped substantial profits, communities received no benefits in return for the use of their land [ibid]. This ability of local institutions to influence these processes is rooted in Italy's governance structure [interview28]. Planning powers and the authority to veto new RES developments are delegated to regions, local authorities, and the Sovrintendenze dei Beni Culturali, government departments tasked with safeguarding cultural heritage and scenic landscapes [ibid].

A local political representative described the planning process as follows: "years of negotiations with local communities then the Sovrintendenza makes an appeal against the alteration of the mountains range's profile. And so, after having invested millions in the development of the project, developers find themselves stuck. It is really a swamp" [interview21]. As a consequence, if approved at all, permitting procedures in Italy averaged about seven years [interview 36 – representative of power sector]. This prompted developers to engage in strategic behavior, submitting multiple planning permission requests across various jurisdictions, hoping that at least one would eventually be approved, exacerbating permit backlogs (Bevacqua et al. 2020).

Another issue exacerbating RES development barriers is grid connections. A representative of a major RES company stated, "we struggle to connect new plants to the grid, and there's a secondary market for connections distorting the market. Discussing grid parity without proper infrastructure is naïve" [interview35]. Like planning permissions, developers began submitting multiple connection requests for the same projects, creating a 'perverse spiral' [interviews 21,29,36]. At the time of writing, there

[64] Interest association representing wider electricity industry.
[65] Interest association representing renewable industry.

were about 170 GWh of connection requests, double what required to meet Italy's 2030 RES targets [ibid]. Like renewable projects, grid infrastructure also faces opposition from local communities and their representatives: “slow authorizations, denial of permits, formation of committees against every new development, mobilization of mayors and priests against every construction site” (Bevacqua et al. 2020).

The changes in the regulatory framework described above significantly slowed investment, particularly in PV as illustrated in Figure 63. Additionally, the policy evolution has affected the average installed capacity of new plants (Iacovone 2019). Up to 2012, incentives had led to larger plants due to economies of scale. Between 2013-2015 incentives for large-scale plants diminished, leading to an increase in small and medium-sized plants. Around 2015, lack of support, technological maturity and economies of scale resulted in some investment in non-subsidised (merchant) utility-scale RES. Finally, these policy changes, along with planning and grid connection challenges, have also led to an inefficient geographical distribution of RES generation compared to productivity [interview20,29]. This is seen by many as undermining the Government's decarbonisation goals and increasing overall decarbonisation costs [ibid] (see sub-section 6.2.4).

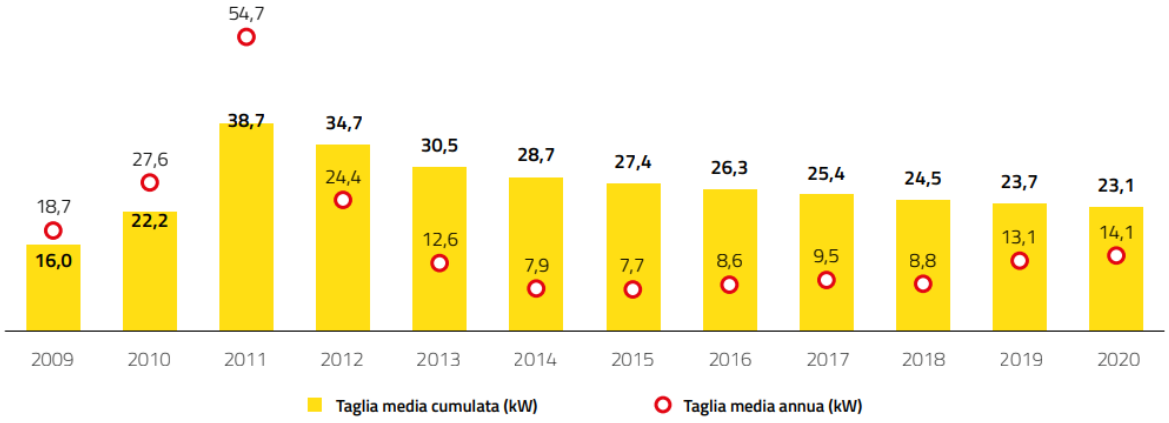


***Figure 64*** *- Average capacity size of installed PV (GSE 2022)*

### 9.2.3 Latest developments

The significant slowdown in RES deployment that occurred over the late 2010s undermined Italy’s position as a decarbonisation leader, causing concerns nationally and at the EU-level. Around 2019, following the 2018 EU Renewable Energy Directive (REDII), Italian policymakers set to revive the decarbonisation momentum (EC 2018). The so-called Piano Nationale Integrato Energia e Clima (PNIEC) updated RES targets with a 55% RES of final electricity consumption by 2030 (MISE 2020). This was to be delivered through important updates in existing RES support mechanisms, introduced through the so-called 2019 FER1 Decree (Novelli et al. 2019).

Interestingly, around this time, a shift occurred in the power sector's political economy, as incumbents increasingly began to embrace the energy transition more proactively [interviews21,22,33]. The sudden halt in RES support and challenges in obtaining planning permissions prompted the merger of the two main interest associations Assorinnovaibili, representing renewables, and Assoelettrica, representing the wider industry (Bevacqua et al. 2020). They formed Elettricita' Futura, representing the entire electricity industry with a stronger focus on decarbonisation compared to its predecessor. This became a significant governance locus due to Italy's corporatist style of decision-making (sub-section 5.2.8). However, different incumbents embraced change at varying speeds. For example, second largest incumbent Eni still retains a generation portfolio composed mostly of fossil fuel assets, and only in 2021 it included renewables in its industrial strategy rebranding itself as Plenitude [interview31].

FER1 updated the scheme to support new RES developments by introducing inter-technological competition (Canalini et al. 2021). Incentives are now allocated through annual auctions, categorised based on resources with similar cost structures. Those contracted by the GSE receive payments based on contracts for difference, where the incentive amount is calculated by subtracting the hourly zonal electricity price from the reference tariff (ibid). Similar to the UK, the introduction of CfDs aimed to 'stabilise revenues and protecting investors against price volatility while managing policy costs' [interview35 – representative of major RES company]. In fact, operators point out that, while in theory renewables reached grid parity in terms of price/cost, long-term security of returns remains a concern [ibid].

Between 2020 and 2022, nine tenders were conducted, allocating approximately 22GW of capacity (GSE 2022b). However, this falls short of Italy's RES targets as tenders have been chronically undersubscribed by RES developers. This can be observed in Table 20 showing the amount of capacity actually bid and contracted as opposed to the total available capacity. Over this two-year period, on average, only 26% of tendered capacity was allocated. Low participation has also impacted auction strike prices, with limited competitive pressure (GSE 2022b). For instance, prices for more established technologies in Pot A have hovered around 65€/MWh, just slightly below the price cap of 68€/MWh.

***Table 20** - Available, requested and assigned capacity under FER 1 tenders (MW) (GSE 2022b)*

| N. | Date | Available | Requests | Accepted | Share |
|---|---|---|---|---|---|
| **Tender 1** | Jan-20 | 730 | 772.1 | 587.5 | 80% |
| **Tender 2** | May-20 | 872.46 | 587.5 | 521.6 | 60% |
| **Tender 3** | Sep-20 | 1340.84 | 486.4 | 433.8 | 32% |
| **Tender 4** | Jan-21 | 1881.6 | 576.4 | 465.5 | 25% |
| **Tender 5** | May-21 | 2461 | 358.3 | 297.7 | 12% |
| **Tender 6** | Sep-21 | 3315.9 | 859.4 | 820.6 | 25% |
| **Tender 7** | Jan-22 | 4825.2 | 1828.6 | 1469.6 | 30% |
| **Tender 8** | May-22 | 3355.6 | 477.7 | 443.7 | 13% |
| **Tender 9** | Sep-22 | 2857.3 | 663.2 | 519.9 | 18% |
| **Total** | | 21639.9 | 6609.6 | 5559.9 | 26% |

Between 2020 and 2022, most contracts (85%) were awarded to onshore wind and solar technologies in Pot 1 (ibid). Funding was also allocated to hydroelectric plants and some specific low-carbon gas technologies. However, Italy lags behind the UK in adopting innovative technologies, especially offshore wind. As of 2021, Italy had limited offshore wind capacity, around 120 megawatts (MW), mainly due to the Mediterranean's steep continental shelf drop and political opposition from coastal communities [interview24]. Italy is in the early stages of developing its offshore wind sector, including floating offshore projects, with several initiatives in the planning and construction phases expected to increase capacity in the near future.

Experts attribute the low participation in renewable auctions primarily to planning permission and grid connection issues (Pagni 2022) [interview36]. In response to RES developers' pressure, the Government has initiated actions to streamline these processes, driven by the EU's REDII package fit for 55 and the need to accelerate renewable deployments (L. 199/2021). The newly formed Ministry for the Ecological Transition embarked on a reform program to streamline administrative processes: "the government is shooting out rapid-fire legislations […] it has simplified a lot the situation for operators" [interview29 - government consultant]. This involves important changes in the allocation of the responsibility for planning permissions with a trend of power centralisation whereby certain local entities' influence becomes advisory rather than binding (Law 77/2021). Each region also needs to designate the so-called 'idoneous areas' in their territories, where administrative procedures for

RES installations should be simplified [interview29]. Such 'regional burden sharing' approach has been described as particularly controversial [ibid].

Finally, recent years have seen some modifications in the DG support regime. The legacy net metering scheme underwent a process of streamlining and expansion. For example, in 2018, distributed generators were given the option to enter longer-term contracts for the sale of excess power, providing more certainty and stability for participants. While in 2019, the compensation paid for excess energy was increased, providing an even greater incentive for people to adopt distributed renewable energy sources. This mirrors a policy commitment to small-scale generation, which might be partially explained in terms of the presence of important solar resources in the country, but also in terms of national technological preferences and international pressure from the EU policy, which has been requiring member states to ramp up DG penetration and energy communities.

## 9.3 The evolution of low-carbon investment policy in California

Since the 1980s, California has been renewable energy policy leader with ambitious decarbonisation goals. Two main policy mechanisms have been used: renewable portfolio standards with obligations put on load serving entities[66], and a net metering scheme for distributed generators. In terms of technologies, support has been targeted primarily at onshore solar and wind, though the degree of support for plants of different dimensions has changed over time. The basic design of support mechanisms has remained stable, however, recent challenges like rising costs, VRE-integration and reliability issues have prompted some important changes such as more coordination in long-term resource planning and new technological choices. Key changes are summarized in Figure 65 below and they are discussed more extensively in the following paragraphs.

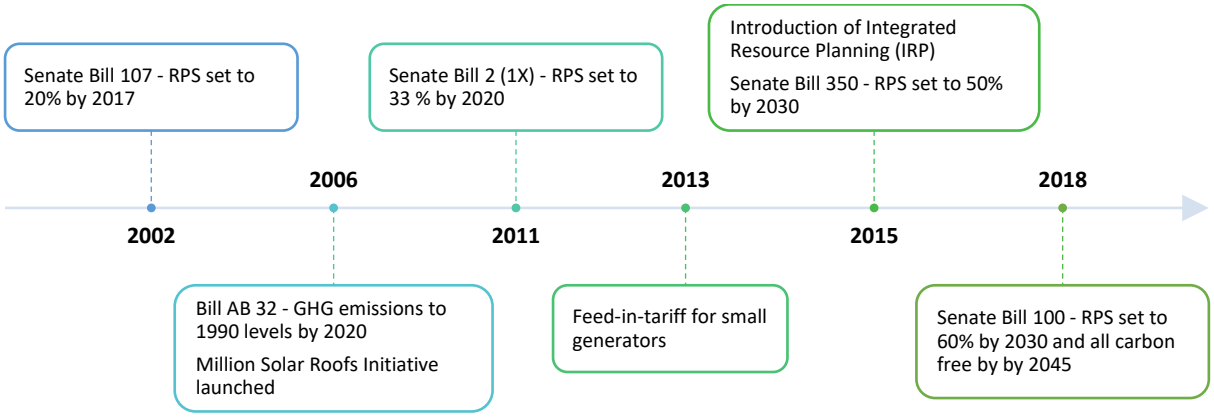


***Figure 65 -*** *Evolution of low-carbon investment policy in California*

### 9.3.1 Early low-carbon investment policy

The history of California's renewable energy policy began in 1978 with the introduction of the federal PURPA Act, which mandated utilities to purchase electricity from qualifying non-utility producers using renewable energy sources (Burtraw 2019). In the 1980s, California aggressively implemented standard offer contracts under PURPA, and in 1997, it allocated $340 million for RES projects (ibid). It is important to note that, in addition to state-level RES support policies, from the early 2000s federal-level incentives, such as production tax credits, have also supported RES expansion. However, this is beyond the scope of this research and this section mostly focuses on state-level policies.

While over the years California introduced different RES support schemes, renewable portfolio standards (RPSs) have been the core policy strategy to advance renewable developments. Introduced

[66] - i.e. entities acting as electricity retailers to final consumers.

in 2002, the scheme places a requirement on load-serving entities to source a certain share of energy from renewable energy resources, mostly utility-scale (ibid). The RPS design, common in the US, was chosen because "it fits better with the market having a tradable component" [interview 49 - representative of wind industry]. In 2002 the RPS was set at 20% of retail sales by 2017, but requirements have increased significantly since. Key changes in RPS targets are summarised in Box 2.

In 2006, during Governor Schwarzenegger's tenure, California enacted bill AB 32, which set ambitious targets to reduce carbon emissions to 1990 levels by 2020 (Nunez-Pavley 2006). This legislative move was accompanied by a comprehensive suite of climate policies, including the establishment of a statewide cap-and-trade system. The strong political backing for decarbonisation ushered a new era for California's renewable energy policy. A central figure behind these developments was Michael Pavley, a politician serving in the California State Senate, renowned for his environmental advocacy: "people wanted more clean energy on the system and that pushed our policymakers to say it's only gonna happen if it's mandated. […] the big part of our renewable supply came from one man who drove a lot of these efforts, Michael Pavley, very controversial. People saw the power of regulation, our Public Utilities Commission can be very strong if you have a powerful leader" [interview 47 - government consultant].

These early efforts focused large-scale renewable projects: "there was a lot of experimentation with these massive projects, thousands of megawatts, all these different technologies built in the desert like the weird solar concentration towers and things that nobody would build now" [ibid]. These projects, financed through RPSs mandated on utilities, are often criticised based on cost: "And it was by him [Pavley] mandating that IOUs swallow these really expensive contracts and, at the same time, he made these projects use labour unions' labour and that made the projects even more expensive" [ibid]. At the time, wind was the cheapest renewable technology and dominated the market. However, policy initiatives introduced under Schwarzenegger's government planted the seeds for change.

In 2006, California made international news by passing the Million Solar Roofs Initiative with the goal of building a million solar energy systems (IEA 2012; CPUC 2008; Lyons 2017). In 2007, the Go Solar California campaign allocated $3.3 billion to install 3,000 MW of grid-connected solar. To deliver on these goals, the CPUC initiated an investor-owned utility solar program, the so-called California Solar Initiative, introduced long-term rebates, and ramped up the level of support provided through the net metering scheme that had been in place since 1996 (ibid). The latter compensates PV production at the retail price, even when household production is higher than consumption (Hobbs & Oren 2019). These efforts mirror California's ambition to position itself as a global leader: "I'm convinced the only reason we had a million solar roofs [policy] is because Germany decided they were adopting a million solar roofs. 100,000 solar roofs would not have been suitable for an important place like California" [interview 43 – energy regulation consultant].

**Box 2 – Evolution of California's RPS targets (Burtraw et al. 2019; Berkeley Law 2019)**

- **Senate Bill 1078 (2002)** established the RPS. The bill required electricity providers to increase procurement of electricity from renewable energy sources by at least one percent per year with the goal of reaching 20 percent renewables by 2017.
- **Senate Bill 107** accelerated the 20 percent RPS requirement from 2017 to 2010.
- **Senate Bill 2 (1X) (2011)** increased the RPS to 33 percent renewables by 2020 with compliance period targets of 20 percent by 2013 and 25 percent by 2016.
- **Senate Bill 350 (2017)** extended the RPS to 50 percent by 2030, with interim targets of 40 percent by 2024 and 45 percent by 2027.
- **Senate Bill 100 (2018)** increases the RPS to 60 percent by 2030, with new interim targets of 44 percent by 2024 and 52 percent by 2027 as well. The bill further requires that all of the state's electricity come from carbon-free resources (not only RPS-eligible ones) by 2045.

### 9.3.2 The second phase of Californian RES policy

In subsequent years, California's commitment to renewable energy continued to expand (see Box2). In 2011, the RPS targets were elevated to reach 33% by 2020. In 2013, a feed-in-tariff was introduced, offering fixed-price contracts for small-scale renewable energy projects (CPUC D. 12-05-035), albeit observers note the scheme's contribution was limited due to low prices due to the policy design [interview49]. In 2017, Senate Bill 350 was enacted, mandating load-serving entities to procure 50% of their electricity from renewable energy sources by 2030. In 2018 RPS targets were further raised to 60% by 2030, aiming for 100% renewable and zero-carbon electricity by 2045 (CPUC 2019c).

During this period, significant support enabled a surge in renewable energy installations (see Figure 66). Load-serving entities not only met their procurement targets but often exceeded them (Berkeley Law 2019). Nevertheless, around this time, a growing trend of customers transitioning from traditional distribution utilities to CCAs raised concerns regarding these new entities' capacity to deliver on targets [interviews39,41]. It has also sparked controversies about the distribution of legacy policy costs among customers affiliated with different load-serving entities: "years of fighting over the CCAs having to pick up that cost [of heritage contracts]. Originally the CCAs didn't want any of that power and then they realized you can't just leave all that cost on everybody else when it was procured for your customers. Then they agreed to pay a stranded cost charge" [interview49]. Regarding the financing of RES projects, the primary source of funding has been project finance, typically obtained by dedicated developers with access to low-cost capital from international utilities and pension funds seeking predictable returns [interview50 – electricity investment banker]. In California, almost the entirety of RES investments are executed through PPAs [interviews 40,49].

Figure 66 displays annual new RES capacity installations up to 2018. Initially, wind installations dominated, but around 2011, solar installations surged despite their relative costliness at the time. This was influenced by California's attractive geography and increasing policy support [interview40]. Rooftop solar in particular benefited from both federal subsidies and net metering incentives. Simultaneously, growing local opposition to wind technologies further contributed to this shift [ibid]. In the latter half of the 2010s, the cost of solar dropped significantly, leading utilities to prioritise solar over wind to meet their RPS targets "they banked more on solar than wind" [interview47]. From 2013, new onshore wind installations plateaued: "we kind hit rock bottom around 2017. […] it was bleak, almost no wind contract got signed for about five years" [interview 49 -representative of wind industry].

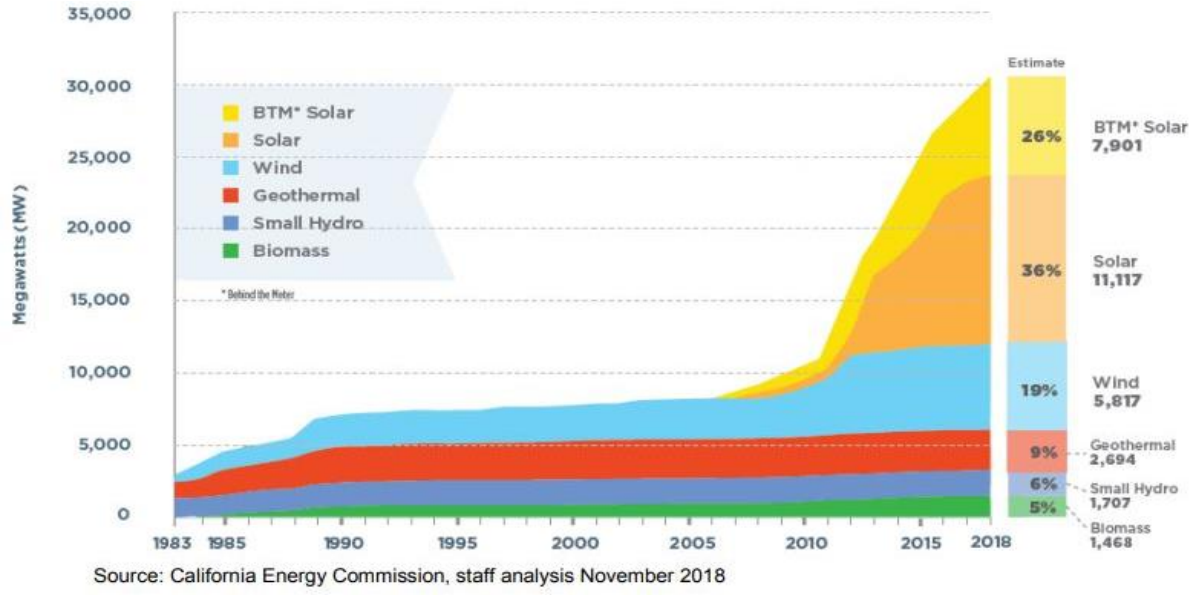


***Figure 66 -*** *Annual cumulative installed renewable capacity since 1983 (Weaver 2019)*

Over the 2010s, California also grappled with fundamental questions regarding the state's role versus market mechanisms in coordinating renewable energy expansion. In 2015, a state law introduced the concept of integrated resource planning (IRP), a unique mechanism designed to align long-term state-wide renewable goals with the individual procurement efforts of load-serving entities (Specht 2019). IRP is essentially an iterative process, wherein the state conducts modelling to create a state-wide resource plan. Subsequently, individual LSEs develop their plans, aiming for consistency with the state's plan. The law required IOUs, CCAs and almost all suppliers to submit an IRP plan to the CPUC every two years, while publicly owned municipal utilities must submit the plan to the CEC every five years (ibid). This process is illustrated in Figure 67.

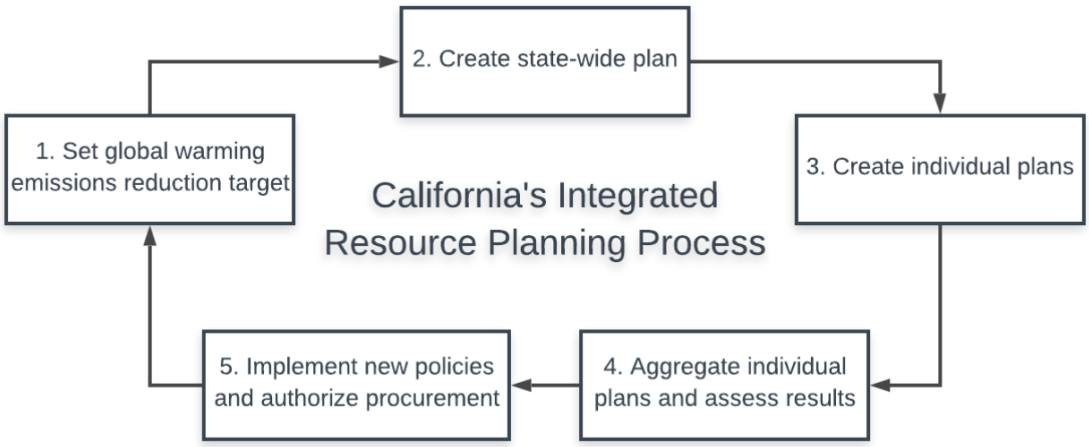


***Figure 67*** *- Integrated resource planning in California (Specht 2019)*

Observers argue that the introduction of IRP complemented the state's stringent targets, consolidating the role of state institutions in energy system planning [interviews4,47]. In the words of this regulatory consultant, “for the investor-owned utilities, everything they do in power procurement now is subject to regulatory micromanagement. They have to go through very detailed proceedings at the CPUC in the CEC with their resource plans […] this central planning perspective that has become dominant, which was a huge shift from when we had our restructuring, and the market perspective was very dominant [interview43] (also see Section 5.3).

According to participants, California's RES policy approach has incurred significant costs, particularly in terms of legacy RPS contracts [39,47]. These contracts, made decades ago, are seen as costly today, but ratepayers continue to bear the burden. As noted by this participant, “the cost of reducing carbon through the RPS in California was on the order of $200 a ton, which is a ridiculous cost to pay for carbon abatement” [interview43]. This is a direct consequence of California’s pioneering role in decarbonisation: “to the extent that California was first, they were at the top of the learning curve and kind of paid the cost for learning” [interview40]. However, over time there have been notable cost reductions in RPS contracts, with the average price decreasing by 10.3% annually between 2007 and 2021 (see Figure 68). In 2021, the average RPS cost was $26/MWh, down from $41/MWh in 2020.

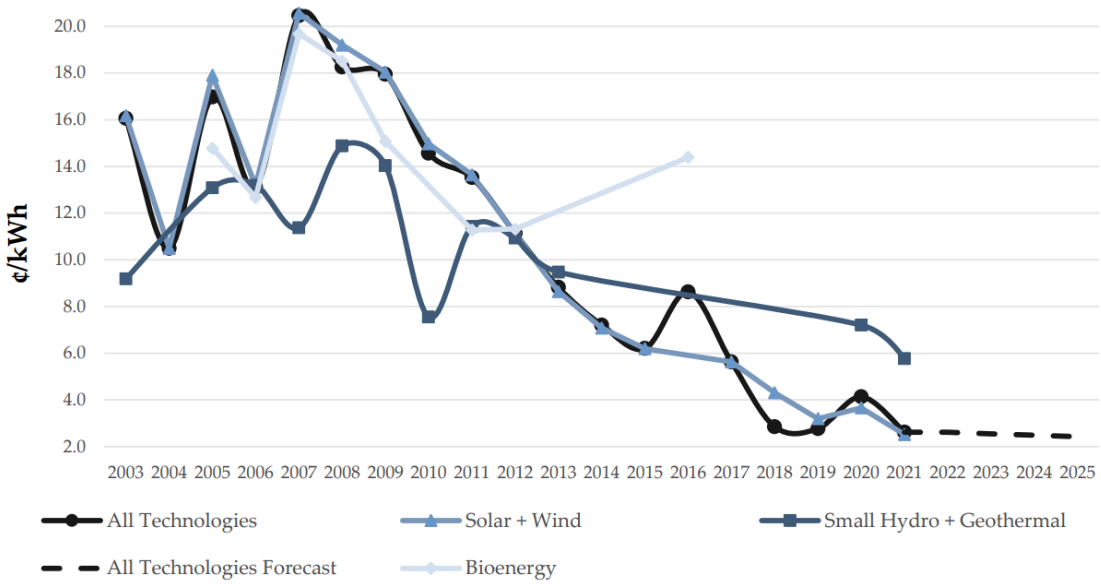


***Figure 68** - Historical trend of all LSE's RPS contracts costs by technology (real dollars) (CPUC 2022)*

Competitive mechanisms have played a role in California's pursuit of cost-effective outcomes. Distribution utilities have been directed to use such mechanisms since the early 2000s, employing a Least-Cost Best-Fit methodology (CPUC 2023; IEA 2015). Further, though the CPUC does not impose cost limitations for RPS procurement, it utilises the IRP process to identify cost-effective resource portfolios for future procurement. In 2010, the Renewable Auction Mechanism introduced a simplified market-based procurement process for smaller RPS projects (ibid). Nevertheless, critics argue that the overall cost of the RPS scheme remains high, with billions in excess payments (above the market) to renewable producers [interview43].

The growth of VREs also led to the rise in system integration challenges and costs as widely discussed in previous chapters. Some argue this was somewhat accrued by the technological choices made through RES policy: “all of a sudden we had too much [solar] power in the day […] forcing the system to sign up more batteries because you don’t have a good mix, […] there's a lot of risks associated with having all your eggs in one basket, they didn’t see that cost” [interview49]. This argument resonates particularly with wind generators who lament that, despite their higher reliability value, are undervalued by utilities prioritising short-term ‘price tags’ over system longer-tern considerations [ibid].

California's DG policy is also often scrutinised for cost-effectiveness. Some go as far as saying that “every time there's a solar roof, we get poorer because we spend so much more to generate [compared to utility-scale RES]” [interview43]. This view is particularly common among stakeholders with a preference for utility-scale technologies such as incumbent large generators and representative of distribution utilities [interviews43,48,49]. Another set of critiques contend that the net metering scheme used to incentivise rooftop solar was ‘too generous’ paying ‘*de facto* many times the wholesale market price’ [interview40]. Hobbs and Oren (2019) note that net metering payments under PG&E’s retail tariff reached $0.45/kwh at peak hours, while the wholesale cost may have been as low as Us$0.04/Kwh. DG also benefitted from embedded benefits as they avoided distribution network costs, picked up by other ratepayers as discussed in sub-section 6.3.4. All of this has important distributional implications: “people who can't afford solar who are going to pay higher rates” [interview39].

This has led some to conclude that California's policy decisions are ideologically driven rather than on grounded cost-benefit evaluations: “we have a one-party state, very ideologically committed and pretty coherent, […] cost considerations never really enter into setting the goal in the first place”

[interview43 – energy regulation consultant]. Others also explain California's approach in terms of the ability of the solar industry to influence key policy decisions [interviews 40,41,49]. Early policy support for solar, the argument goes, generated feedback effects marking the birth of a new powerful interest group, the rooftop solar lobby, with great sway in policy decisions. For example, this coalition is able to mobilise a great number of customers to engage with the PUC, write persuasive letters, and participate in rallies [ibid]. As discussed in Sections 6.3 and 8.3, small solar producers were able to put up an incredible political resistance to changes in resource adequacy policy and network charges that undermined their interests.

### 9.3.3 Latest developments

As previously discussed, the increased integration of renewables in California's energy mix has led to various challenges, including integration costs, curtailments and reliability risks. This raised important questions about how to incentivise system-compatible operation and investment, finding the optimal technological mix for accommodating more VREs, and reforming RES support and planning to align with California's ambitious decarbonisation goals.

A crucial aspect to consider is the evolution of RES contracts towards greater system compatibility, cost-efficiency, and alignment with wholesale markets. Since 2006, time-of-delivery factors have been included in some PPAs to encourage afternoon production, with some utilities offering time-of-delivery PPA prices, typically based on the net load profile (IRENA 2017). Policy changes to incentivise system-compatible operation also include legislation whereby east-facing panels are granted a 15% premium for all output, which should contribute to meeting the morning consumption peak (IEA 2018). However, participants generally believe that the fundamental design of RES long-term contracts has not shifted significantly towards greater market compatibility on a relevant scale [interviews40,41].

A related issue is how the responsibility for curtailment is allocated among market participants, and to what extent RES developers and procuring utilities are encouraged to factor that in at the time of investment [interview49]. While there is increasing awareness and discussions, participants note that (at the time of writing) this had not yet resulted in any systemic change, and the revenues gained by RES generators mostly tend to reflect purely their long-term contracts' price [interview40].

In response to increasing VRES integration challenges and costs, recent developments in long-term resource planning have aimed to align RPS procurement with system-wide electricity sector planning by the CPUC and CEC (CPUC 2022). The CPUC first updated the IRP framework in 2018, and in 2020, it released a proposal that incorporated RPS Procurement Plans into load-serving entities' resource plans filings, resulting in a more streamlined, coordinated schedule with RPS and IRP proceedings converging on the same timeline (ibid).

The challenges related to VRES integration and reliability have also influenced technological choices. The 2025 IRP plan emphasizes wind, hybrid solar and storage systems, batteries, and baseload geothermal as solutions to address reliability issues (see Figure 69 for the aggregated load-serving entities' plans by technology). Additionally, there is a growing interest in offshore wind, in line with awider national trend, as exemplified by support made available under the Biden administration [interview39]. However, offshore wind in California presents technological challenges due to the steep continental shelf, necessitating innovative solutions like floating offshore technology (CPUC 2022).

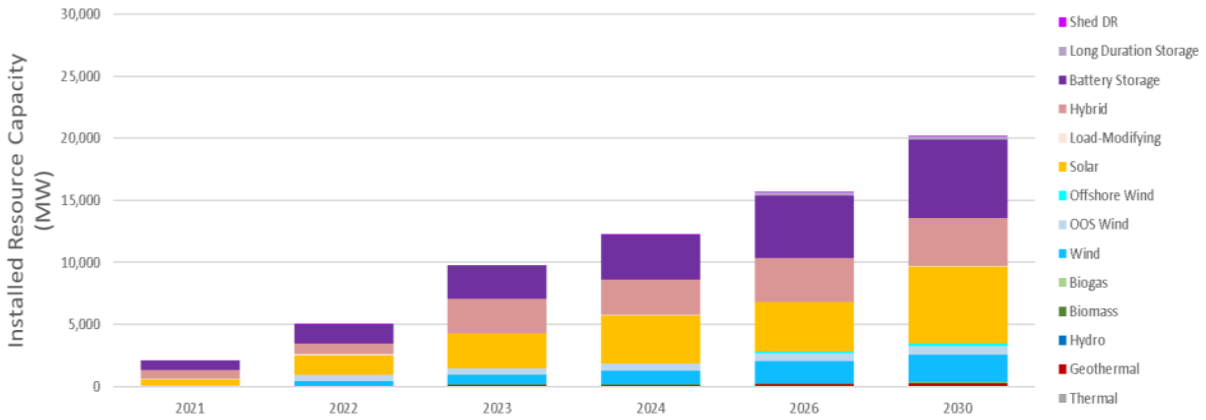


***Figure 69** - New resource buildout associated with the aggregated 46MMT plans to 2025 (CPUC 2021b)*

Recent changes in California's renewable energy landscape have also been influenced by local planning permissions and the challenges posed by growing sentiments of opposition by local communities [interview47]. Public opposition to renewable energy projects and transmission lines has become a sensitive issue for developers, leading to delays and increased costs [interview40]. The responsibility for granting planning authorizations historically rested with counties, allowing them to obstruct RES developments. Following significant pressure from the industry, a policy response emerged in 2022, granting the California Energy Commission the authority to streamline the permitting process especially for large-scale renewable projects [interview47].

Finally, there have been some changes in response to concerns about the costs and distributional effects of DG support policies. Incumbent utilities strongly built the case for change using the 'utility death spiral' narrative: "we're just gonna spiral down to our deaths because between people putting solar on their homes and businesses and the net metering, whereby they barely need to buy anything from the utility, we're gonna have fewer customers left that we serve, and we're going to raise our rates on them" [interview39 – energy policy expert]. As discussed in sub-section 6.1.4, important modifications were introduced in the network charging regime sparking controversy and resistance from the PV solar industry, which viewed it as 'discriminatory' [interview52 – advocate of local energy systems].

## 9.4 Comparison of low-carbon investment policy evolution

All the three jurisdictions set ambitious decarbonisations targets and introduced a plethora of mechanisms to support RES diffusion. Overtime, they all adjusted their low-carbon investment policies, resulting in different policy designs, trade-offs, and technological outcomes. Table 21 provides a concise overview of the main features of recent reforms, while the subsequent paragraphs delve into these changes in relation to the political economy conditions that influenced them, also summarised in Table 22 at the end of this section. Pivotal conditions include the evolution in political priorities, the acceptability of different renewable technologies and the evolution in market structures, particularly the emerging interest configuration of the low-carbon industry.

***Table 21 -*** *Summary of change in low-carbon investment policy*

| | **Britain** | **Italy** | **California** |
|---|---|---|---|
| **Policy schemes evolution** | - Shift from Renewable Energy Obligations to CfDs in 2014.<br>- CfD design adjusted over time – e.g., auctioning, resource funding, negative prices compensation.<br>- Feed-in-tariff for distributed generators removed in 2019.<br>- From 2021, regulatory asset base support for nuclear. | - Up to 2012, several schemes in place including multiple feed-in-tariff schemes, green certificates, and net metering.<br>- Followed by major withdrawal in policy support and rise in planning permission barriers.<br>- Recent introduction of a CfD and modifications to net metering policy. | - Maintains legacy Renewable Portfolio Standards scheme.<br>- Renewable targets significantly ramped up over time.<br>- Strong support for DG through net metering and targeted schemes.<br>- Introduction and strengthening of Integrated Resource Planning process. |
| **Reform(s) objectives and policy focus** | Decarbonise whilst maintaining market-compatibility and containing policy costs. Other objectives include industrial strategy and sustainable growth. Lately, the focus shifted on mitigating effects of VREs and diversifying resource mix. | Initial phase saw decarbonisation overriding other policy considerations, but then the focus shifted completely on containing costs. Lately, the objective has been to reviving RES investment while containing policy costs. | Strong and stable policy commitment to decarbonisation. This often took the priority over other considerations (e.g. cost, reliability). Lately, given growing system challenges, there is an ongoing attempt to diversify the resource mix. |
| **Technology choices** | Support mainly targeted at utility-scale technologies. Initially, this was mostly onshore RES, but then most support channelled to offshore wind and nuclear. | Support targeted primarily at onshore solar and wind including utility-scale and distributed installations, though the degree of support for different plants has changed over time. | Targeted primarily at onshore solar and wind including utility-scale and distributed PV installations, though the degree of support for different plants has changed over time. |

As widely predicted by the literature (Chapter 2), evidence shows that evolution of low-carbon policy was heavily influenced by techno-economic conditions. These include, for example, national geographies and the technical potential for specific low-carbon technological solutions. Another important factor influencing the deployment of these resources is the evolution in the cost of different solutions, often driven by exogenous global forces such as the growth of RES manufacturing in China. Nevertheless, techno-economic conditions alone are insufficient to explain recent developments, as widely demonstrated below.

In the 2000s, the three jurisdictions were at the forefront of renewable energy policy, driven by a growing political commitment to decarbonisation. In the UK, renewables were first supported through the Renewables Obligation scheme, later replaced by the Contracts for Difference in 2014 to ramp up investment in low-carbon technologies. Italy witnessed a surge in renewable energy policy support between 2004 and 2012, featuring various incentive schemes like feed-in tariffs, green certificates, and net metering. Meanwhile, California intensified its strong dedication to becoming a global leader in green energy, with ever-increasing RPS targets and various programs supporting distributed solar generators.

It is worth noting that multi-level institutions played a role in initially driving these developments. In California, early decarbonisation efforts were initiated in response to federal policy, albeit the state subsequently outperformed the rest of the US in terms of renewable energy policy. Similarly, many of the policy changes in the UK and Italy were initially set in motion by EU renewable energy directives. Additionally, the approaches taken by these jurisdictions align with broader regional trends, with feed-in tariffs being more prevalent in Europe, while renewable portfolio standards are a common approach in the US.

Inevitably, the need to undertake power system decarbonisation involved a reconfiguration of state-market relations in the power sector, with an expanded role for the government in actively promoting low-carbon investments through explicit support. In all cases, governments have made explicit choices about which low-carbon technologies to support while leaving others behind. However, this took slightly different forms based on context. For example, competition and market principles were weighted and applied differently, and overtime the jurisdictions have been comfortable with different approaches and interventions. Notably, in California, introduction of integrated resource planning in 2015 somewhat formalised a more centralised approach to planning RES expansion.

The initial wave of renewable energy deployment raised political concerns related to the cost of low-carbon policy in all cases. However, these were filtered through different national contexts, resulting in different policy responses and trade-offs. In the UK, there was a dual focus on decarbonisation and cost-control, particularly influenced by Treasury. The CfDs were designed to enhance budget control, to be market-compatible and, at a later stage, to leverage competitive mechanisms through auctioning. Despite initial high policy costs, CfDs achieved significant cost-reductions over time. In contrast, Italy adopted initially generous policies without stringent limits on support. Subsequently, escalating policy costs prompted a political backlash, eroding public support for renewables and resulting in a substantial reduction in government backing. More recently, the country also introduced a CfD scheme with auctions in the hope to achieve more cost-effective RES expansion. California, despite incurring substantial heritage policy costs, remained steadfast in its dedication to decarbonisation, prioritising this goal above all else.

The interaction between the political system and critical power market institutions holds significant importance too. In the UK, the Climate Change Act created an institutional framework enabling the independent CCC to exert influence on decision-makers in support of climate goals. Similarly, decarbonisation objectives were firmly embedded in key power-sector institutions in California. Conversely, Italy's government was able to replace the leadership of the GSE to align with new political priorities focused on cost-containment, thus halting renewable energy development. Consequently, the politicisation of sector-specific institutions has yielded notable consequences.

Apart from cost considerations, the initial phase of rapid onshore renewable energy diffusion sparked local community opposition in all cases, as extensively discussed in the literature (see Section 2.4). However, the degree and subsequent policy responses varied significantly. In the UK, political opposition from some local communities managed to influence the national political agenda. The CfD framework was utilised to redirect funding from onshore renewables to more politically acceptable large-scale offshore wind projects. Additionally, around 2014, new planning rules were introduced, requiring renewable energy developers to secure community support for planning permission. This posed an additional hurdle for onshore developers, especially in England.

In Italy, opposition by local communities found strong representation in the local political system, enabling them to block planning permissions due to the decentralised governance structure of the existing planning regime. Coupled with local political acceptability issues affecting transmission infrastructure and the growing challenges of grid connections, this significantly hindered Italy's progress in meeting its national targets. In California, local political acceptability issues predominantly affected onshore wind projects, tipping the balance in favour of solar in procurement decisions made by developers and utilities. This, too, is rooted in legacy governance structures. Hence, both jurisdictions have recently taken steps to further centralise the governance of planning permissions.

Political acceptability also played a crucial role in shaping the approach to nuclear power and its role in the low-carbon strategies of the three states. In the UK, the government's aspiration to expand its nuclear fleet influenced the design of the EMR package, aligning with nuclear energy development goals. This stands in stark contrast to Italy, where efforts to incorporate nuclear power into the national energy strategy were thwarted by public opposition reinforced by the 2011 Fukushima disaster. During the 2010s, California actively pursued the retirement of its nuclear fleet, primarily due to environmental concerns by local communities. However, there has recently been a notable policy reversal (discussed in Chapter 8).

It is worth noting that these decisions are not solely driven by political acceptability issues but are also deeply intertwined with industrial and economic policy objectives. In the UK, the government recognised offshore wind’s potential to stimulate local manufacturing jobs. Over time, offshore wind has evolved into a cornerstone of the UK's decarbonisation strategy, and a strategic national industry. A parallel can be established with California's initial RES contracts, crafted to kickstart a burgeoning

new sector and foster the growth of green jobs. In Italy, the decision to curtail RES policies was also partially motivated by industrial policy considerations, as rising energy prices stemming from policy costs were perceived as detrimental to industrial competitiveness, a critical sector in the national economy.

Additionally, the evolution of market structures and incumbent interests played a significant role in shaping subsequent policy developments across all cases. This mechanism is widely explored in the literature, often referred to as policy feedback investment effects. In the UK, renewable energy policies primarily supported large-scale renewables, especially wind power, with substantial investments from large incumbent utilities. This contributed to the consolidation of decarbonisation goals and sustained support for large-scale wind, particularly offshore. Solar and distributed RES producers never wielded the same level of political influence, which contributes explaining the later withdraw in support for these producers. Additionally, the increased support for nuclear energy can be attributed to lobbying efforts by the influential UK nuclear industry, primarily composed of powerful incumbents like EDF.

Italy's renewable energy landscape differs from the UK. Ownership of renewable energy generation is less concentrated, with more medium to small-scale solar installations owned by smaller companies and distributed generators. Italy's transition towards clean energy happened more gradually, with the RES industry and incumbents only recently aligning their interests around decarbonisation. This has likely enabled the major scale down in support in the second half of the 2010s, as renewable generators were not able to effectively resist change. Overtime, California has incentivised substantial investment in utility-scale renewables as well as a notable expansion of rooftop solar. This has contributed to the birth of multiple powerful renewable interest groups with considerable sway in the political agenda competing with more established players.

Beyond producers, other actors also play a significant role including industrial consumers, trade unions, and environmental groups. For example, Italian industrial consumers, significant contributors to the country's economic output, advocated for reduced electricity prices. In the UK, with a smaller industrial sector relative to GDP, debates about shifting decarbonisation costs away from these consumers were less prominent. Environmental groups and trade unions actively shaped policy developments in California.

Finally, VRE integration challenges and rising balancing costs have affected all three jurisdictions to varying degrees. From the mid-2010s to 2021, they encountered issues such as curtailments, reliability risks, and price cannibalisation[67] due to the increased presence of renewables. California faced integration challenges early on, notably with its ‘duck curve’ caused by a surplus of solar power during the day. The UK witnessed a rise in constraint costs as its transmission system struggled to handle power from geographically concentrated wind farms. Italy, while experiencing a RES deployment slowdown, also faced operational challenges related to the distribution of intermittent resources across its system.

A common response has been a drive to further diversify the low-carbon resource mix. For example, while offshore wind remains a key focus in the UK decarbonisation strategy, there has recently been some support for less-mature technologies such as floating offshore and tidal, a ramp up nuclear as a security strategy, and reneweds support for onshore RES technologies. The CPUC resource planning in California also reflected the need for a diverse resource mix to address VREs challenges. Emphasis was placed on wind, hybrid solar and storage systems, and baseload geothermal to enhance system reliability. New technologies also gaining traction included offshore wind, especially floating offshore more suitable to local geography. The retirement of the nuclear fleet was halted due to reliability concerns. In Italy, recent policy efforts mainly aimed to revive the struggling RES industry, primarily through a CfD with technology-neutral auctions. These were generally undersubscribed, but contracts

[67] Renewable price cannibalisation is when the growing supply of renewable energy drives down electricity prices, potentially affecting the profitability of existing renewable projects (Edwards 2020).

were awarded to onshore wind, solar, hydroelectric plants. Italy is also planning to develop some offshore wind capacity.

Another essential aspect to consider is whether RES contracts have evolved to encourage system-compatible operation. In this regard, particularly interesting is the UK approach with the removal of compensation in the event of day-ahead negative prices in the CfD scheme. California's RES long-term contract design appeared relatively unchanged in this regard, with alignment to wholesale market dynamics not achieved at a sizeable scale. In Italy, no related mechanism was introduced. In fact, not only is the country mainly focusing on reviving investment, Italy also has a zero wholesale price floor, affecting how these issues manifest in markets (see Section 6.2).

***Table 22 -*** *Political economy conditions found to affect the evolution of low-carbon investment mechanisms*

| Categories | Specific conditions |
|---|---|
| **National politics and government** | - Evolution of national political priorities (decarbonisation, policy costs and industrial strategy)<br>- Political stability, government effectiveness and structure<br>- Political acceptability of different low-carbon technologies |
| **State-market relations** | - Legacy political economy model<br>- Degree of unbundling and privatisation (liberalisation) |
| **Sector-specific institutions** | - Missions, culture, independence of sector-specific institutions |
| **Multi-level governance** | - Multi-level governance objectives, directives and policies |
| **Market structures and interests** | - Emerging renewable energy industry market structures<br>- Interests and influence of incumbent utilities and generators<br>- Economic composition of energy demand<br>- Organisation and influence of environmental, decentralised energy and consumer groups |

# 10 Discussion and conclusion

This thesis filled an important gap in the literature by adopting a comparative political economy perspective to systematically unpack recent changes in wholesale power market design for enabling wider integration of renewables in Britain, Italy and California. The aim was to determine how the scope and nature of these developments varies according to different political economy contexts, and to draw some lessons for the design and governance of power markets as we move to a high-VREs future. This final chapter provides a summary of key results answering the three research questions. As part of this, it offers a reflection on these findings, drawing key implications. Finally, it also highlights the main limitations and potential avenues for further research.

## 10.1 RQ1: What are the key wholesale power market reforms implemented in Britain, Italy and California to integrate a growing share of renewables on their power systems?

### 10.1.1 Key power market design changes in Britain

The structure of the British market design dates back to 2001 when NETA introduced a self-dispatched market with bilateral trading, a single national price, and a sequential balancing market. Originally this was an energy-only market based on the principle that short-term markets would provide incentives for long-term investment. The early 2000s also saw the introduction of the first major scheme to incentivise renewable investment, the renewable obligation, and the 2008 Climate Change Act mirroring a significant ramp up in decarbonisation ambition.

Up to the time of writing, Britain has seen the least change in short-term energy market design. Its decentralised dispatch model remains largely untouched with no relevant modifications in key design parameters in day-ahead and intraday markets. Britain coupled and subsequently uncoupled its day-ahead market, and never achieved further integration of the intraday market before leaving the EU. Despite a steep rise in transmission congestions, a single national transmission price persists. However, there have been some modifications in transmission planning to streamline grid expansion, and some major reforms in network charging with a mix of objectives – i.e. improving cost-reflectivity and fairness.

While the fundamental structure of the balancing mechanism also remains unvaried, there have been some significant enhancements in response to rising VREs integration challenges. In 2015, single marginal pricing and a scarcity pricing mechanism were introduced to improve cost-reflectivity and encouraging more system-compatible operation. From 2017, in line with the Government's vision for a flexible and smart energy system, the system operator NGESO has been leading a comprehensive reform of ancillary services products with the aim of increasing system flexibility and encouraging wider participation of non-traditional providers. This has already resulted in the launch of new products. Interesting experimentations have also been occurring with local flexibility markets including DSO-led platforms.

In 2014, the Electricity Market Reform introduced some fundamental changes in long-term investment mechanisms for both firm and low-carbon capacity with the aim of advancing decarbonisation whilst ensuring long-term system security. Specifically, a targeted capacity market was introduced marking a shift away from an energy-only market. Further, a new mechanism for incentivising renewable investment, the so-called contracts-for-difference, replaced the long-standing decentralised renewable obligation. The basic structure of these mechanisms persists today, although they have seen gradual modifications. More recently, there has been an important shift in the investment regime for new nuclear with the introduction of a regulated asset base model.

In terms of technologies, the British capacity market has mostly provided support for existing gas capacity though modifications in key parameters such as de-rating factors are progressively facilitating

wider participation by non-traditional providers such as interconnectors and battery storage. Low-carbon support has mainly been targeted at utility-scale technologies, especially offshore wind and nuclear.

It is important to note that the GB market design might see some fundamental changes across all key segments in coming years as market arrangements are undergoing a comprehensive review as part of the 2022 government Review of Electricity Market Arrangements (REMA) (BEIS 2022).

### 10.1.2 Key power market design changes in Italy

Since its outset in the early 2000s, the Italian power market has been characterised by semi-centralised dispatch with an integrated scheduling process, auction-based trading and a zonal pricing regime on the generation side. In 2004, a capacity payment was introduced as a temporary measure to boost resource adequacy. Around the same time, the country began implementing a plethora of policies to incentivise more renewable energy investment including tradeable green certificates, feed-in tariffs and feed-in premiums, and self-consumption incentives.

Over the last decade, Italy has seen important changes in the design of its short-term energy markets. These mostly aimed to harmonise its market model with the rest of the EU enabling deeper market integration in the region. The rationale is that this should improve competition, efficiency and reliability as more intermittent renewables come online. Italy completed day-ahead market coupling in 2015 and has recently been finalising intraday coupling. This involved major modifications to all key design parameters of the intraday market (i.e. gate closure, bidding and trading rules) effectively leading to a shift in the dispatch logic. Reforms are also under discussion for removing the negative wholesale price floor and extending zonal price signals to consumers to enable cost-effective VREs integration, however, progress with these reforms has been slow.

In 2019, a comprehensive plan to reform the balancing mechanism was launched, the so-called TIDE (ARERA 2019a). As part of this, single marginal pricing for balancing has been identified as a target solution to enable the cost-effective introduction of renewables, but its application has seen delays. Further, a major experimentation programme has been launched to trial new ancillary service products and encourage wider participation of non-traditional service providers. Learnings from trials have yet to be translated into actual market design rule changes, at least at the time of writing. The country is at an early stage of experimenting with local flexibility procurement and setting legal frameworks for energy communities and local energy systems.

As noted above, over the years Italy implemented several renewable energy policies. Broadly, there has been a first phase up to 2014 characterised by high-RES incentives and growth, a second phase characterised by a steep reduction in renewable support and the rise of significant administrative and planning barriers. More recently, to revive RES investment whilst containing system costs, the Government introduced a technology neutral CfD. In Italy, low-carbon support has been targeted primarily at onshore solar and wind, with the degree of support for utility-scale and decentralised installations changing over time.

Following an 8-year policy process, in 2019 Italy introduced a market-wide capacity market with reliability options to address concerns around long-term reliability and resource adequacy in the context of the ongoing energy transition. The Italian capacity market has mostly provided support for existing conventional capacity though gradual modifications have enabled the entry of some new resources such as battery storage.

### 10.1.3 Key power market design changes in California

California's market model is based on centralised security-constrained economic dispatch, complex bidding, the co-optimisation of reserves and energy and nodal pricing. A decentralised obligation for procuring resource adequacy capacity has been in place since 2002. From the 1980s, California has been a pioneer of climate policy introducing increasingly ambitious decarbonisation targets. The two main mechanisms to support renewables have been renewable portfolio standards, and a net metering scheme.

The basic features of California's wholesale market design have remained constant, but there have been some gradual adjustments over time. Being a pioneer of RES deployment, California completed early real-time market modifications including the introduction of more granular trading timeframes. More recently, it embarked on a more comprehensive reform of its day-ahead market that might lead to important modifications in market timeframes. California completed real-time market coupling with other power systems in the US West, but day-ahead integration has suffered from setbacks.

California has not seen any major shift in the logic and mechanisms underpinning its balancing pricing regime based on the co-optimisation of energy and reserves. Between 2016 and 2021, some changes were implemented in balancing and ancillary services to respond to new flexibility needs, like the creation of new market participation frameworks for non-traditional providers and modifications in bid parameters for different resources in the real-time market timeframe. Further, a new product was launched, flexiramp, rewarding operational flexibility in reserves. California has had limited experience with local flexibility procurement and markets but there is growing interest in local energy systems and microgrids.

California maintains its legacy decentralised obligations model for procuring resource adequacy. However, the mechanism's design has seen important modifications over time in response to changing system conditions and the rise of significant VRE-related challenges. Relevant changes include the introduction of explicit storage procurement targets and flexibility criteria, a shift to central procurement by utilities, changes in reliability requirements for different resources and, more recently, a new slice-of-the-day framework and a strategic reserve.

Similarly, the basic structure of the legacy low-carbon scheme based on renewable obligations has remained largely unvaried but has seen some modifications. Further, there has been a process of increased coordination in long-term resource and system development with the introduction of an integrated resource planning mechanism.

In California, low-carbon support has been targeted primarily at onshore solar and wind with a mix of utility-scale and decentralised installations. The state moved swiftly with the retirement of conventional generation but has recently made a policy U-turn halting this process for reliability purposes. Other shifts in technological choices include a progressive tightening of the reliability scores of solar energy and a growing focus on less mature RES technologies. Further, California adopted targeted procurement targets for utility-scale battery storage achieving large-scale deployment.

***Table 23** - Summary of change in wholesale market design by jurisdiction between 2013 and 2021.*

| | Britain | Italy | California |
|---|---|---|---|
| **Short-term energy markets** | • Coupled and uncoupled day-ahead market.<br>• No major modifications to legacy day-ahead and intraday market rules – i.e. decentralised dispatch logic.<br>• Maintains half-hourly trading.<br>• No regulation of wholesale prices.<br>• Maintains single national pricing but modifications in network charges.<br>• Ongoing major market design review. | • Coupled day-ahead and intraday markets.<br>• Significant change in intraday market rules - shift to 'hybrid dispatch' model.<br>• Introducing more granular trading in day-ahead and intraday markets.<br>• Removal of negative price floor delayed.<br>• Retains zonal pricing model - discussions on exposing consumers to differentiated pricing. | • Coupled real-time but not day-ahead market.<br>• Gradual modifications to market rules but legacy market model persists – i.e. ISO-led centralised dispatch.<br>• Introducing more granular trading in real-time and day-ahead markets.<br>• Maintains both positive and negative price caps but relaxed over time.<br>• Retains legacy locational marginal pricing model. |
| **Balancing and ancillary services** | • Introduced balancing single marginal pricing and an administrative scarcity reserve pricing mechanism in 2014.<br>• Ongoing comprehensive reform of ancillary services led launch of new products and participation of non-traditional providers.<br>• Trialling of local flexibility markets and DSO-led platforms. | • Single marginal pricing for balancing identified as target solution in 2019 but implementation delayed.<br>• Introduced administrative shortage pricing mechanism.<br>• Ongoing experimentation with new ancillary products and service providers yet to result in rule changes.<br>• Early-stage experiments with local flex procurement and energy communities | • Energy and reserves co-optimisation and early introduction of administrative scarcity pricing.<br>• New flexiramp product rewarding operational flexibility in reserves.<br>• New market participation frameworks and bid parameters for new providers.<br>• Limited experience with local flexibility markets but growing interest in local energy systems and microgrids. |
| **Low-carbon investment** | • In 2014, CfDs replaced decentralised renewable energy obligation.<br>• Incremental modifications to CfD – i.e., auctioning, funding for different technologies, and removal of compensation with negative prices.<br>• Recent introduction of a regulated asset base model for nuclear. | • Up to 2014, multiple RES support schemes including green certificates, feed-in-tariffs and net metering for distributed generators.<br>• Followed by steep reduction in renewable support and the rise of significant planning barriers.<br>• A CfD scheme with auctioning introduced in 2019. | • Legacy renewable portfolio standards scheme for utility-scale RES remains but adjusted over time – e.g. ramp in in RES targets.<br>• DG supported through net metering and other schemes.<br>• Introduction of integrated resource planning in 2015 – framework consolidated since. |
| **Resource adequacy** | • In 2014 major shift from energy-only-market to capacity market. Since then, gradual modifications to mechanism design parameters.<br>• Explicit flexible capacity procurement mechanism considered as part of ongoing market design review. | • In 2019, shift from capacity payment to capacity market with reliability options.<br>• Ongoing definition of mechanism for flexible capacity procurement following EU approval. | • Significant modifications to legacy decentralised obligations scheme – i.e. procurement, methodologies, targets.<br>• Explicit storage procurement targets from 2014.<br>• U-turn conventional plant retirements and new strategic reserve. |

## 10.2 RQ2: How did differences in political economy contexts of these jurisdictions affect their approach to reforming power market design to enable wider integration of VREs?

As the three jurisdictions undertook deeper power system decarbonisation, they experienced similar techno-economic challenges related to VRE integration and introduced important modifications to their power market design in response. Findings demonstrate how diagnoses found in the economic literature on the effects of VREs on power market dynamics are highly relevant for understanding change in this area. This is exemplified by the fact that the three jurisdictions often implemented some related solutions/market design changes. Some common policy trends include, for example, increasing the granularity of market price signals, furthering regional market coupling, the launch of new balancing and ancillary services and the introduction of capacity remuneration mechanisms.

Despite these common trends, there are also important differences in the scope of recent changes, mechanism design choices, resulting policy trade-offs and technological outcomes across the three cases. To some extent, these differences mirror their specific techno-economic conditions: the characteristics of their power mix, the specific nature and scope of emerging VRE-related challenges, and legacy infrastructures. However, findings consistently highlight that, if taken alone, these techno-economic drivers cannot fully explain recent developments. Rather, interdisciplinary analysis reveals that power market design evolution was also heavily shaped by a set of political economy and institutional conditions, pivotal to explain patterns of change both within and across cases.

Broadly, this validates the four key assumptions of political economy institutionalism: that states and markets are mutually constituted, that markets are politically constructed and maintained, that these co-evolve in a dynamic fashion (Section 2.2 offers a comprehensive discussion). Findings also highlight the usefulness of theoretical constructs from political and socio-technical theory to study change in the electricity sector. Policy developments were in fact determined by the interactions of physical system realities, interests, incentives, institutions and ideas within specific contexts, as posited in Figure 10 summarising the theoretical framework (see Section 3.2.2). Results also match expectations from the literature in terms of the broad categories of political economy conditions affecting power system change (Section 2.4). The key conditions identified through the cross-analysis of theory and evidence are summarised in Table 24 and discussed in the next sub-sections.

***Table 24 -*** *Political economy conditions found to affect the power market design evolution*

| Categories | Specific conditions |
|---|---|
| **National politics and government** | • Political ideologies, priorities and cycles<br>• Political acceptability of technologies and mechanisms<br>• Government incentives, structure, effectiveness, and openness |
| **State-market relations** | • Legacy political economy paradigm<br>• Dominant ideas on the role of markets<br>• Degree of unbundling and privatisation (liberalisation) |
| **Sector-specific institutions** | • Legacy power market model and operational philosophies<br>• Dominant ideas on technologies and mechanisms<br>• Institutional cultures, incentives and interests<br>• Capacity, independence, and policy influence |
| **Multi-level governance** | • Regional political homogeneity and relations<br>• Capacity, coordination and trust in multi-level institutions<br>• Dominant cultures and ideas in multi-level institutions<br>• Institutional independence and balance of power among members |
| **Market structures and interests** | • Market structures and ownership of key assets<br>• Economic composition of electricity demand<br>• Turnover and employment in energy sector<br>• Variety and organisation of interest groups<br>• Policy access and influence |

### 10.2.1 National politics and government

First, the approach to market reform in these three jurisdictions can be attributed to shifts in national political priorities, which dictate changes in policy focus and trade-offs pursued over time in the 'energy trilemma' (affordability, security, and decarbonisation). For example, this is evident in resource adequacy policy. In Britain and Italy, concerns about decreasing reserve margins and future reliability challenges compelled governments to support conventional generators to ensure a 'safe' energy transition, even of the reliability threat was not imminent. This is in line with what widely posited in the political economy literature that governments tend to be risk-averse when it comes to system security. In contrast, California initially pursued the aggressive retirement of conventional generators to maximise low-carbon reliability procurement, even in the face of potential future reliability issues.

Only when these materialised, there was a significant policy U-turn. This suggests a balance of priorities between reliability and decarbonisation. It is important to note that, beyond the traditional energy trilemma, policymakers often also consider other factors like industrial competitiveness and employment when making decisions.

Second, political acceptability issues consistently limit the range of available policy options. Public opposition to energy infrastructure projects significantly influenced technological choices. This is particularly evident in the evolution of low-carbon investment support, which tended to favour technologies with higher public acceptance. These issues also impacted decisions related to transmission infrastructure, gas and nuclear power plants, thus shaping resource adequacy policy approaches. Furthermore, political acceptability considerations influenced mechanism designs. For examples, findings seem to confirm a widespread claim in the political economy literature that practical implementations of wholesale pricing often deviate from purist economic theory due to the unacceptability of granular, cost-reflective price signals and a desire to retain control over price volatility. This manifests in various ways depending on context, as exemplified by the use of wholesale price limits and locational pricing across cases.

Lastly, the characteristics of the government, such as political stability, its structure, effectiveness and capacity, play a crucial role in shaping power market design outcomes. For example, frequent changes in government leadership in Italy resulted in delays in market reforms across various modules, while its decentralised governance structure allowed local political opposition to renewable energy projects to have national repercussions. Tensions across government layers also influence power market politics in Britain, with devolved administrations, particularly in Scotland, likely to resist the implementation of full nodal pricing due to its potential adverse effects on their constituents. In California, these dynamics affected the process of market coupling, as local entities, including public utilities, openly opposed further regional market integration and binding governance structures, fearing a loss of political control over their territories.

### 10.2.2 State-market relations

The evolution of power market design and policy mechanisms is also intricately linked to the historical political economy model, prevailing ideologies regarding the roles of states and markets, and the trajectories of liberalisation in different regions. When comparing the cases, it becomes evident that their traditional stances on cost-reflective pricing and energy-only markets reflect unique historical relationships between the state and the market in the power sector. For instance, California has a strong inclination to maintain control over market volatility, a sentiment stemming from the enduring impact of price spikes experienced during the 2001 energy crisis. Consequently, the California Public Utilities Commission has retained significant influence over system planning, the technology mix, and program delivery, all organised around incumbent distribution utilities. This has shaped the state's approach to resource adequacy and, more recently, its procurement strategies for battery storage capacity through explicit targets placed on incumbent utilities.

Conversely, Britain, a pioneer of liberalisation, has historically adopted a more market-oriented approach. The country has traditionally been more comfortable with price fluctuations in wholesale markets and used to rely on an energy-only market, assuming that price signals in short-term markets would naturally incentivise long-term resource adequacy investment. There was also a prevailing belief in the UK and Europe that arbitrage opportunities in short-term markets would suffice to encourage the development of flexible assets like batteries.

Nevertheless, intriguingly, evidence suggests that the imperative to navigate the energy transition is reshaping traditional state-market relationships, challenging established norms, even in historically liberal contexts like the UK and the EU. There is a noticeable convergence towards market design models that combine short-term markets for efficient dispatch with capacity remuneration mechanisms to ensure long-term system security. This aligns with the propositions in the ‘hybrid

markets' literature (Roques and Finon 2017), which argue that integrating increasing renewable energy shares whilst maintaining system reliability necessitates the introduction of out-of-market mechanisms or state-backed contracts to fulfil these multifaceted objectives. Furthermore, at the EU level, there is a growing recognition that explicit long-term contracting mechanisms may be essential to incentivise investments in low-carbon flexibility, a concept that is also gaining traction in Britain. Nevertheless, it is worth noting that market and competition principles continue to play a role, having influenced the design of capacity remuneration mechanisms in both Britain and Italy. These mechanisms utilise competitive auctioning to allocate contracts, emphasising the principles of competition and technological neutrality, albeit they were used in practice to target specific technologies.

### 10.2.3 Sector-specific institutions

Evidence also suggests that the characteristics and actions of key power sector institutions are relevant to understanding recent policy responses, especially in terms of their cultures, incentives, independence, and influence over national policy. Firstly, the prevailing risk cultures and perspectives on the value of different solutions among system operators and regulators significantly impact technological choices. Across all jurisdictions, uncertainties surrounding non-traditional providers like aggregators, DERs and DSR have led to a conservative approach to valuing their reliability services in balancing and capacity markets. Notably, the Italian operator has displayed a particularly conservative stance regarding assets it cannot directly control, such as cross-border capacity. However, there is a gradual shift in attitudes, with operators increasingly adapting market rules to accommodate the unique characteristics of these assets.

Also adding to previous findings on the key role played by path-dependency and techno-economic ideas in shaping power sector change, evidence suggests that differences across cases can be explained in terms of legacy arrangements for market operation, dominant operational philosophies and beliefs on the cost-benefit of different approaches among key sector institutions. Each jurisdiction has a distinct market model and operational philosophy, shaped by the conditions at the onset of liberalisation. This inevitably affected their recent approach to reforming markets for VRE integration. For instance, variations exist in how dispatch is organised and related market parameters. These distinctions are rooted in fundamentally different beliefs held by key sector experts about the trade-offs associated with different designs in terms of complexity, market efficiency, liquidity, transparency, reliability, and cost-effectiveness, as well as their potential in addressing emerging challenges. Importantly, these preferences can evolve over time. For example, the British system operator and regulator have recently adjusted their stance on centralised dispatch and nodal pricing following a spike in balancing costs, while Italy has modified its intraday market to align it with the more decentralised EU market model.

The significance of institutional arrangements, which shape the missions and incentives of sector-specific institutions, also comes to light. In Britain, the institutional separation of the system operator has driven proactive reform of balancing services markets. Additionally, a new regulatory framework for network companies has encouraged strategic thinking and the exploration of alternatives to network reinforcements. Consequently, Britain has emerged as a leader in this domain, offering one of the most accessible value streams for demand-side resources and aggregators in Europe. Conversely, concerns have been raised about conflicts of interest in the institutional setup of the Italian system operator, involving incentives to prioritise network solutions, and minimise costs accounted for in its books, rather than considering overall costs. Conflicts of interest concerns have also surfaced regarding Italy's largest generation incumbent, Enel, which also operates as the largest distribution company. Comparable dynamics regarding incentives for distribution utilities to procure flexibility from local and distributed resources are observed in California.

Finally, recent developments have been influenced by the institutional capacity, independence, and influence of sector-specific institutions, including system operators, regulators, and other technical

bodies. Notably, the politicisation of sector-specific institutions has had evident implications in Italy, where the government easily replaced the leadership of the market operator to roll back on RES policies. In California, the close connection between CAISO and state politics, due to its unique institutional arrangements, has impacted various areas, including market coupling and resource adequacy. Importantly, this influence is not unidirectional: the opinions of technical bodies often tip the balance in final policy decisions as it is evident from the analysis of multiple market modules including short-term energy markets, resource adequacy and balancing. The capacity, independence, ownership, and governance structures of these entities are key factors that determine their ability to influence policymaking in their preferred direction.

### 10.2.4 Multi-level governance

More regional integration of power systems and markets is emerging as a key solution to dealing with growing intermittency. This often entails increasing the harmonisation of market rules and governance arrangements at the regional level. Hence, power market design changes within jurisdictions are increasingly affected by the relationships across national and multi-level governance institutions. Specifically, evidence points to the existence of important political tensions between national and supernational institutions, especially, a resistance to 'giving up control' over strategic policy areas. This contributes to explaining differences in policy developments across cases. For example, while the EU managed to progress with both day-ahead and intraday market coupling and impose a harmonised market design for its member states, FERC attempts to impose a uniform market design at the US level were unsuccessful and California's regional market coupling process has suffered from setbacks.

First, this can be attributed to the level of political economy homogeneity in the region and relations among neighbouring states. The US presents a much more polarised political landscape compared to the EU. Western US states have different techno-economic situations and political priorities contributing to tensions in the definition of key parameters in the single electricity market. Despite being composed of separate countries, the EU single market presents a more established and coordinated governance, a web of institutions operating in pursuit of common objectives. Overall, member states tend to recognise the mutual benefits of further market coupling and there is a general acceptance of the authority of EU institutions. In comparison, the Western EIM presents a fragmented governance put in place to try to maintain a difficult balance of power across heterogenous set of participants. Lack of trust also explains Californian national institutions resisted the introduction of a capacity market, which would have opened state policy to federal jurisdiction and politics. However, EU countries vary in their commitment towards the single market, as exemplified by British experience. Here, EU identity is generally lower and the political value of national sovereignty higher, contributing to a reversal of the market coupling process.

Beyond the alignment of policy objectives across states and multi-level bodies, different outcomes can be explained in terms of degree alignment of dominant ideas on power market design and operation. For example, in Italy the implementation of intraday coupling required substantial adjustments to its legacy market design involving a tiresome process of political negotiation due to a clash in operational philosophies and market design preferences between national and EU institutions. Similarly, to introduce a capacity market, both Britain and Italy had to negotiate with EU institutions because their preference deviated from the block's official preference for an energy-only-market. As countries differ in their national preferences, the position of multi-level governance institutions also mirrors the balance of power in the region, dominant techno-economic ideas in the largest and most influential member states, and the ability of national industries to coordinate to influence regional policy. For example, Italy's strong corporatism enabled Italian policymakers to present a unified national position and effectively negotiate compromises with its EU counterparts.

### 10.2.5 Market structures and stakeholder interests

In line with the literature (Section 2.4), legacy market structures, asset ownership, and the economic composition of electricity demand significantly shaped the positions of key stakeholders in the policy

process. In turn, the strength and influence of interest coalitions advocating for specific policy designs often played a pivotal role in shaping final decisions. These dynamics span the various market modules. Incumbent conventional generators, for instance, exerted substantial influence on capacity remuneration mechanism choices in both Britain and Italy. Reflecting centralised market structures, these producers formed potent coalitions with a strong preference for capacity markets, leveraging tactics such as threats of plant retirements, interest associations, and strategic narratives. In contrast, California's more fragmented and pluralistic interest group landscape limited the influence of independent producers' calls for a market-wide mechanism.

The evolving political economy of the low-carbon sector and changing incumbent interests also held implications for subsequent policy developments. For example, UK RES policies mostly supported large-scale renewables with significant investments from incumbent utilities. Over time, this contributed to the consolidation of decarbonisation objectives and sustained support for large-scale wind, particularly offshore. In Italy, where RES generation ownership is less concentrated, the transition of incumbents towards clean energy happened more gradually, which enabled the U-turn in low-carbon policy. California's RES policies supported both utility-scale renewables by large independent producers as well as more distributed solar generators, resulting in the emergence of several influential RES interest groups. This not only influenced later RES policy but also had implications for other market modules.

The findings also underscore the growing role of RES producers in shaping discussions on short-term market rules due to the progressive consolidation of their interests. Changes in price signals and incentives often involve decisions regarding the allocation of intermittency-related risks and costs among generators and consumers, leading to political tensions. Disagreements among stakeholders frequently lead to policy process delays. Instances of this can be observed in policy processes related to granular settlements, intraday trading, balancing reforms, and locational pricing. For example, distributional concerns among stakeholders delayed progress with the removal of single consumer pricing and the negative price floor in Italy and the reform of network charging methodologies in Britain and California. Further, large-scale wind generators in constrained locations are consistently identified as a major barrier to the potential implementation of nodal pricing in Britain.

In addition, particularly in countries where the industrial sector plays a significant role in the national economy, consumers can be a driving force for change. Italian industrial consumers actively engaged in in policy processes, advocating for reduced electricity prices and influencing the design of different mechanisms to safeguard their interests. In the UK, where the industrial sector has a smaller economic footprint, discussions about shifting some decarbonisation costs away from these consumers did not gain traction. Additionally, trade unions and environmental groups also play influential roles, particularly in California, where they jeopardised CAISO institutional reforms related to market coupling and drove conventional plant retirements through the CPUC.

## 10.3 RQ3: What are the implications for the design and governance of power markets in these jurisdictions and beyond?

Beyond contributing to theory, this thesis has practical policy implications. By providing a full account of the experiences of three leading markets for power sector decarbonisation, it can help inform thinking on power market design by other countries undertaking the energy transition. While there is no single design package that emerged as the optimal solution to deal with the issue of renewable energy integration, there are some common trends. Further, findings highlighted a set of key aspects to consider when approaching power market reform, key trade-offs of different designs, and potential unintended consequences of some policy changes.

In addition, by unpacking real-world policy dynamics, this thesis also sheds light on the key institutional and political conditions shaping change across the different market segments. For example, it

highlighted the role played by economic and political ideas, market structures, the importance of actor interests and power, and legacy institutional designs in defining the range of acceptable solutions. If the past tells us anything about the future, upcoming changes in market design will not simply mirror the least-cost or most-efficient solution. They will also be shaped by the interests of key actors and their ability to influence final decisions, given current and emerging institutional and market structures in a process that is inherently political. This is important in terms of building a coherent governance framework for managing the transition to a high-VRE system. Key policy and governance implications are discussed below across the four market modules.

### 10.3.1 Implications for short-term energy markets

The three jurisdictions share common techno-economic rationales guiding their recent efforts to reform short-term energy markets in response to the expansion of intermittent generation. Firstly, they all recognised the considerable advantages associated with further regional market coupling to optimise cross-border resource utilisation and address increasing intermittency. Nonetheless, market coupling entails substantial institutional and political challenges that often impede progress. Not only does it raise questions of 'control' between national and multi-level institutions, but it can also involve significant changes in market regulations that may conflict with entrenched local operational philosophies. This underscores the importance of effective governance arrangements to navigate this process.

One key insight is that jurisdictions embarking on regional market integration should initially focus on the 'low-hanging fruit' — those market segments where coupling faces fewer political and implementation hurdles. For instance, the EU began with day-ahead coupling, while California first initiated real-time market coupling. By doing so, they can defer the most complex political questions, with the expectation that the benefits of increased coupling will gradually become more apparent, bolstering support and trust. Trust is a crucial factor; without it, market coupling cannot advance. The EU's success in achieving high levels of integration and harmonisation over the last three decades serves as an instructive example. The EU gradually defined single market rules and institutions, which fostered trust and helped manage differences among member states. Drawing from this experience, insulating federal regulation and EIM governance from political influence whilst establishing accountable institutions are prerequisites for advancing regional integration in the US context.

Furthermore, even in countries that have chosen self-determination over the benefits of more integrated markets, such as the UK, the question of harmonisation cannot be ignored, especially in the context of the ongoing energy crisis. As the UK contemplates a radical overhaul of its power market design, careful consideration must be given to how such a shift might interact with the EU single market. While Brexit theoretically granted the UK the freedom to pursue its own power market policy, it effectively reduced its ability to influence EU-level discussions, to which its future remains inexorably linked. In fact, since the referendum, there has been a notable increase in the level of interconnection with other European countries. In contrast, thanks to its corporatism, Italy has refined its ability to influence EU policy, despite interfacing with more influential countries like Germany, which often hold different market design preferences. Indeed, internal consensus makes external negotiation easier, a stark contrast to California's struggles to advance regional market coupling and governance due to deeply polarised internal politics where key stakeholders often struggle to find a common position on market design issues.

Secondly, findings underscore a shared aspiration (or at least a policy narrative) to enhance the granularity of temporal and locational price signals in short-term markets to incentivise flexible and efficient operations and investments. While increased price granularity may align with economic efficiency principles, a political economy perspective reveals the challenges of implementing it in practice. What economists might see as ‘second-best’ solutions may be more appropriate for managing political complexities, particularly in contentious policy areas. For instance, as the UK contemplates implementing more granular locational pricing, a simpler zonal system, shielding

consumers from full price differentials (as implemented in Italy), could be a politically viable alternative to a full nodal system. Furthermore, while enhanced granularity might yield benefits for efficient short-term operations and dispatch, it often falls short in driving efficient long-term investments. Longer-term system planning and coordination mechanisms are often better positioned to leverage efficient transmission and generation investments to achieve long-term strategic goals.

Lastly, a long-standing debate has resurfaced regarding the optimal dispatch logic and the associated market rules to facilitate increased renewable integration. On one end of the spectrum, the EU approach involves moving trading as close as possible to gate closure through continuous, portfolio bidding and self-dispatch. This approach, it is argued, is suitable for a high-VRE world as it incentivises VRE producers to operate in a more system-compatible manner by allowing continuous asset optimisation until gate closure. On the opposite extreme, the CAISO model, based on centralised economic dispatch, is grounded in the belief that system operators, not decentralised market actors, are best equipped to address growing uncertainty through a physical approach to system operation.

Analysis reveals that there is no one-size-fits-all operational model; rather, decisions largely depend on context, including prevailing ideas among key sector institutions and the most politically feasible trade-offs within a specific jurisdiction. While overall a more centralised form of dispatch could lead to more efficient outcomes, especially in the context of higher VRE penetration, its implementation in Europe could be challenging given the existence of path dependencies. The EU has spent many years formulating its harmonised Target Model and implementing it across its member states, hence, a market design overhaul might involve significant transaction costs. Additionally, changes in market design arrangements significantly impact consumers and producers, and all the other vested interests of stakeholders already operating in the market. For example, traders would have a much more limited role in a more centralised market design and are likely to resist change. Finally, some influential countries in Europe might oppose such change based on local political priorities (see chapter 6 for a comprehensive discussion). Such political conflicts would have to be managed while transitioning to different operational model.

### 10.3.2 Implications for balancing and ancillary services

Evidence suggests that legacy market designs often fall short in harnessing the flexibility required to manage the substantial influx of VRE sources in short-term operations. There's a growing trend of redefining both existing and new ancillary service products to incentivise flexibility and fast ramp rates, crucial for securing system inertia and frequency control. These product revisions played a pivotal role in the initial entry of battery service providers into the Italian and UK markets. The pursuit of enhanced operational flexibility is intrinsically linked to broadening access to balancing and ancillary services for novel providers, including storage, DSR and DER aggregations. All three jurisdictions have implemented reform initiatives aimed at facilitating access for these resources, as part of their VRE integration strategies. Nevertheless, there's a prevailing perception that the potential of non-traditional providers remains untapped, with an enduring dependency on fossil fuel plants for balancing. The political and economic factors constraining the ability of jurisdictions to diversify the procurement of flexibility services are explored below.

Firstly, entrenched techno-economic beliefs within key sector institutions tend to favour more traditional assets, often deemed more reliable. While these perceptions are rooted in valid reliability concerns, the emergence of innovative approaches necessitates challenging established assumptions. British and Italian policymakers have effectively employed market-wide trials to assess new ancillary products extensively. This approach allowed them to glean valuable insights into the performance of non-traditional services and providers before finalising market regulations. This governance-by-experimentation, grounded in systematic learning-by-doing, is well-suited to navigate uncertainty and should be considered by countries embarking on balancing market reforms.

Reforming balancing services may also entail revising the incentive structures of system operators and other key institutions overseeing these markets, fostering a more strategic and innovative approach. For instance, the institutional separation of the British system operator has encouraged a proactive role, facilitating a swift transition from trials to the launch of new products and diversification of balancing service markets. Unbundling ownership and operation to resolve conflicts of interest in service procurement should encourage a neutral and open approach to market reform. Policy processes should prioritise transparency and engage various providers to ensure a level playing field. These lessons are particularly applicable to Italy, where stakeholders frequently cite conflicts of interest and a lack of transparency within the system operator. Beyond adequate incentives for system operators, efforts should focus on making sure that key institutional roles are well-defined, and that system operators have the right tools to manage change. This is particularly relevant in the context of California, where misalignments and coordination issues between CPUC planning activities and CAISO short-term market reforms were identified as a barrier to wider procurement of flexibility services from DERs.

The development of models for procuring non-traditional flexibility services across different system levels is also influenced by legacy market structures, as well as the visions and interests of key stakeholders. In more liberalised and liquid markets, we are likely to witness experimentation with new business models (e.g., aggregation, local flexibility markets) involving a diverse range of players. Conversely, regions with a stronger presence of legacy distribution utilities may opt for more centralised, incumbent-based approaches, particularly in local procurement. Encouraging innovation in flexibility procurement does not necessarily demand complete liberalisation, as incumbents may possess the scale to deliver innovative services and business models. However, adopting incumbent-based solutions necessitates designing incentives for utilities to adopt a neutral, system-wide perspective through appropriate regulations and, potentially, structural measures. Moreover, the political landscape of the industry may evolve as new interests consolidate; for instance, more established battery storage providers resisted further standardisation of balancing products in the UK. It is essential to remain mindful of these political dynamics as we proceed with defining balancing markets.

Lastly, evidence indicates that balancing market reform should not be treated in isolation from broader market arrangements, particularly resource adequacy policy. The latter is often considered a prerequisite for the growth of non-traditional technology providers who frequently require multiple revenue streams to enter the market. New ancillary service markets tend to saturate quickly, and arbitrage opportunities in the energy market alone may not suffice to support long-term investment decisions. This necessitates careful consideration of whether existing capacity remuneration mechanisms are well-suited for their intended purpose and whether explicit out-of-market mechanisms are required to support long-term investments by non-traditional low-carbon flexibility resources. This aspect is explored in greater detail in the following subsection.

### 10.3.3 Implications for resource adequacy policy

Evidence shows that capacity remuneration mechanisms have come to constitute an inherent characteristic of power market design and resource adequacy policy, rather than a temporary fix: “as you start to put more renewables on, you ask the question about energy security, and you inevitably end up with capacity markets or some other form of intervention” [interview7 – senior policymaker]. Similarly, there is a growing consensus that low-carbon flexibility procurement might need explicit out-of-market mechanisms to encourage further deployment of storage technologies to deal with growing intermittency. In fact, despite ongoing efforts to improve short-term markets and the introduction of capacity mechanisms, current arrangements may fall short in providing long-term investment signals for low-carbon flexible capacity.

However, the exact policy trade-offs drawn by jurisdictions (i.e. across security, decarbonisation, affordability) and mechanism design choices are highly dependent on the political economy context.

These decisions are in fact constrained by the evolution of political priorities, legacy market structures, state-market relations, multi-level governance arrangements, dominant cultures and incentives of sector institutions. For example, there is no silver bullet on the balance to strike in the use of planning and market-based mechanisms in long-term capacity procurement. Jurisdictions with historically interventionist approaches may lean towards expanding resource planning and setting specific mandates for certain technologies. Conversely, countries committed to market principles might favour technology-neutral or competitive mechanisms like auctions and reliability options. Similarly, there is no universal best practice for designing mechanisms targeting long-term flexibility procurement, which can involve introducing new targeted out-of-market mechanisms or reforming key parameters in existing capacity schemes.

In a 'hybrid market', prices signals cease to be the only force driving the short- and long-term behaviour of market players and, hence, system evolution. The design of contracts hence becomes a key factor in driving investment decisions in different technologies. The negotiation of who can access which contracts at which conditions, is a fundamental area of contestation where winners and losers are made ex-ante. For example, in capacity markets key parameters include de-rating factors, penalties for non-delivery and contracts' length, while methodologies for computing capacity credits of different resources are critical in systems with decentralised obligations. These parameters are often biased to support more traditional power plants as opposed to new forms of flexibility from storage, DSR and DERs. This calls for a reflection on whether existing governance processes enable participation by new technologies and providers alongside incumbents, and how their relative ability to influence decisions is reflected in the final design of CRMs.

Further, as for balancing markets, findings point to the importance of legacy techno-economic ideas in driving key decisions, which in turn should decision-makers to question their assumptions to allow for the emergence of innovative approaches. All of this has important implications for the definition of future technological pathways and their potential to deliver on key policy objectives (e.g. reliability, affordability and decarbonisation). In fact, the benefits of diversifying the capacity mix are magnified in a high-VRES system as too much reliance on a limited range of technologies and providers might have serious reliability and cost implications. The Californian experience also shows that, as climate change effects begin to be felt, power systems might also have to withstand more disruption.

### 10.3.4 Implications for low-carbon investment policy

A primary lesson derived from this analysis underscores that the energy transition is not necessarily irreversible; it can be vulnerable to political pressures, even in countries with established track records of leadership in renewable energy adoption. These pressures typically manifest in two ways: resistance to renewable energy support policies due to concerns over costs and affordability, and local political acceptance. However, the impact of these challenges varies depending on the specific context, particularly the design of mechanisms and institutions. This yields valuable insights on how to effectively manage these political obstacles for countries looking to accelerate their renewable energy policies.

First, renewable energy incentive schemes should ideally be designed to be cost-effective, leveraging competitive mechanisms and aligning with market dynamics to minimise the financial burden on end consumers and secure long-term support for decarbonisation. For example, contract-for-difference mechanisms that link premiums to market prices have proven beneficial in delivering cheaper capacity compared to other schemes. Further, during the ongoing energy crisis, operators under CfD contracts had to return extra profits obtained thanks to soaring gas prices, making them cheaper than renewable obligations or standard feed-in-tariffs. Equally important is the equitable distribution of renewable energy policy costs among various consumer groups, balancing industrial competitiveness, and addressing energy poverty concerns. In cases where political acceptability hampers the energy transition, transitioning to cost recovery via progressive taxation could be explored, albeit this might present implementation hurdles.

Political commitment to renewables is also more likely to stick where there has been a consolidation of economic interests (of incumbents or new players who become large enough to exert influence) around the energy transition, and decarbonisation objectives have been locked into the design of key institutions. The stance of industrial consumers, particularly whether they view renewables as either facilitating or obstructing energy price reductions, also matters. Further, addressing local political acceptability issues, a common barrier to renewable energy expansion, underscores the importance of designing effective governance structures for planning, capable of managing conflicts at both national and local levels. For instance, centralising infrastructure planning powers under the central government has been adopted in both Italy and California to address these challenges. Moreover, community engagement and direct benefits from renewable energy projects should be considered essential components of planning processes.

Second, it is crucial to adopt a holistic and strategic approach to renewable energy expansion, emphasising diversification of renewable supply to mitigate the challenges posed by intermittency. Political dynamics within the renewable energy industry, the relative influence of different renewable energy groups, and local considerations such as political acceptability and transmission infrastructure availability often shape the renewable technological mix. Thus, effective governance of transmission expansion, network regulation and the governance of the planning regime play a critical role in supporting appropriate renewable energy expansion.

The evolution of long-term renewable energy contracts toward greater system compatibility, aligning with wholesale markets, presents an opportunity to improve market dynamics. For example, contract designs can incorporate temporal and locational signals, discouraging over-bidding during periods of negative prices and encouraging renewable energy operators to consider grid constraints when making investment decisions. However, the successful implementation of such mechanisms requires careful consideration of their interactions with other market modules, particularly those involving short-term market signals. Further, the introduction of market-compatible mechanisms is also faced by political hurdles. For example, locational signals in RES contracts would reduce profits in very desirable and politically acceptable locations so there would be a huge amount of pushback from operators in these areas. Alternatively, jurisdictions might achieve more system-compatible RES expansion by adopting a more strategic approach to RES procurement and planning. For example, in response to increasing system challenges, California has been consolidating its integrated resource planning regime.

Finally, most participants seem to think that low-carbon expansion will continue to be supported through long-term contracts in coming years given these resources' cost structures and the fact that renewables face a significant long-term risk due to price cannibalisation. Hence, perhaps the right question is not whether renewables should continue to be contracted on a long-term basis, rather, who should be the contracting counterpart. For countries such as the UK and Italy, currently relying on public contracting, PPAs are emerging as a viable solution, also recently endorsed by the EU in its latest reiteration of its market design model. For example, Italy is considering introducing a central platform managed by GSE that would lower transaction costs and encourage the start of a liquid PPA market. Similarly, California has been exploring the possibility of some form of centralised planning procurement body for RES PPAs (Burtraw 2019). In this context, governments should put in place mechanisms to manage a smooth transition from publicly backed contracts to PPAs as companies benefitting from legacy schemes might oppose change.

In conclusion, while the expansion of renewable energy may face political and economic challenges, a strategic and adaptable approach, cost-effective policy designs, and the alignment of economic interests can help countries overcome these obstacles and further their decarbonisation efforts. The choice of mechanisms and governance structures should be context-specific, with an emphasis on transparency, community engagement, and long-term policy stability to secure a sustainable renewable energy future. In fact, each approach discussed above has its own set of trade-offs and political feasibility considerations.

Striking the right balance between incentivising system-compatible decisions and attracting capital investment is critical. Managing change while maintaining stability and continuity is also essential for investor confidence as we transition to different contractual models. As noted by this participant, “governments give a sense of stability and continuity to reassure investors that they can make reasonably long-term bets. You don't want the minister to wake up on Monday morning and say, oh, we've completely changed the whole way in which the market is going to operate” [interview2]. At the same time, governments need to confront entrenched interests, as stakeholders might resist changes with wider system benefits. For example, the UK experience has shown that renewable investors may exaggerate their support requirements to secure favourable policy designs, and competitive mechanisms can provide a more accurate assessment of actual investment costs.

### 10.3.5 Implications for the analysis of power sector change

This thesis demonstrates the importance of political economy conditions in shaping power market evolution, emphasising the importance political economy analysis in explaining these processes alongside more traditional economic approaches. Market arrangements cannot be fully understood through neoclassical economic conceptualisations alone, as they rarely follow a purely market-driven logic. This has significant implications for how we understand, analyse and discuss changes in the power sector, as elaborated below.

While evidence shows that, in practice, we have moved away from the free-market orthodoxy dominant in the 1990s, this approach still prevails in the literature and in the rhetoric of some key power sector stakeholders. This rhetoric promotes the idea that robust market signals are the main driver of decisions by decentralised market participants, and hence the motor behind power system coordination. However, this research demonstrates that the idealized market logic has never been fully realised. Electricity, being a capital-intensive and strategically vital sector, is inherently influenced by political forces. The ongoing energy crisis has underscored the susceptibility of power markets to political intervention, especially when prices spike. As one participant noted, “again and again what happens is the civil servants and the politicians and the industry players design a free market, but when the inevitable price spike happens, they have to intervene artificially and stop the free market” [interview 16 - storage asset manager].

Notably, stakeholder attitudes toward market and planning mechanisms are not static but evolve cyclically, reflecting market conditions and resource availability. For instance, during times of low prices or overcapacity, “the generation sector argues that spot markets do not cover their variable costs” and calls for more public support in the form of long-term contracts, as seen in the discussions leading to the introduction of capacity markets [interviews 25, 28]. Conversely, when the market faces structural conditions of scarcity, “everyone [consumers] starts asking for more regulation and a comeback of long-term contracts and the single buyer. The average cost and the marginal cost are reversed, so people always want to pay the lower one” [ibid].

Market design will always be subject to these dynamics. This realisation challenges the notion of completely unrestricted markets and suggests that a balance between market dynamics and government intervention is essential in an increasingly decarbonised, complex, and volatile energy landscape. This calls for a change in the narrative regarding the role of the state and markets in the literature (as well as in policy dialogues) to reflect this reality. Furthermore, more research is needed to systematically unpack these political economy dynamics, aiding in a realistic understanding of power sector evolution.

### 10.3.6 Implications for the design and governance of hybrid markets

The three jurisdictions have made incremental adjustments to their market designs, transitioning towards hybrid models where short-term markets coexist with long-term out-of-market mechanisms. This reflects a broader trend of hybrid markets emerging as the international norm in nearly all liberalised power sectors. However, evidence suggests significant divergence in views regarding the optimal balance between market price signals, long-term contracts, and planning mechanisms, as well as on the design of key power sector mechanisms. These discussions have intensified amidst the ongoing energy crisis, which has placed immense pressure on policymakers to manage energy costs and facilitate an affordable transition to cleaner energy sources.

Some stakeholders, primarily those with a market-oriented perspective[68], argue that recent reforms have excessively constrained the market, leading to distortions and inefficiencies. They advocate for enhancing the granularity and cost-reflectiveness of price signals across wholesale, balancing, and retail markets. Conversely, others call for a more radical departure from market principles, suggesting a return to central planning, public ownership, and regulated tariffs. These arguments, driven partly by long-term concerns about renewables cost-structures and price cannibalisation, have gained traction amid recent energy price volatility. The dominance of gas as the marginal resource influencing electricity prices has led to substantial price increases, particularly in gas-dependent countries like the UK and Italy. Some stakeholders argue that the energy transition is essentially "a big strategic planning problem with socialization of costs": “I see a lot of colleagues desperately chasing a failing market. Maybe we need to acknowledge that energy is a matter of strategic planning and economies of scale” [interview 38 - representative of industrial consumers].

Both narratives have merit. While strategic planning is crucial for the energy transition, a complete abandonment of market models in liberalised markets is unlikely (and undesirable) in the short to medium term. Market-related benefits, such as innovation through competition and efficient resource allocation in coupled markets, are important considerations, especially in managing increased intermittency. However, fully embracing a market model is undesirable and unrealistic, as it would require accepting that price volatility is an inherent characteristic of markets. As noted by a representative of a free-market trade association, “in a market logic, excessive revenues are not really a thing” [interview 37 - representative of pro-competition interest association].

Consequently, hybrid markets offer a promising middle ground and are likely to persist, albeit evolving further. In this paradigm, marginal spot markets will continue to guide short-term operational decisions, but most resources will be secured through long-term contracts. As renewables gain market share, the role of spot markets in determining energy prices will diminish. These markets will eventually become adjustment platforms where flexible assets provide balancing services, and renewables adapt their schedules in the short term. This trend is being reinforced by the current crisis. For example, the EU has recently emphasised the importance of long-term mechanisms and contracts underwriting risk, especially for low-carbon flexibility assets that can mitigate future price volatility, and the importance of adequate hedging mechanisms (Meeus and Nicolai 2023).

While this thesis highlights that hybrid markets are the way forward, it does not offer a 'silver bullet' for their design or an objectively 'best' set of arrangements. Ultimately, the specific market design, including the balance between market-led and state-led mechanisms, will depend on the unique political and economic context of each jurisdiction. Nevertheless, this research can inform how to best organize policies according to the specific features and constraints of different political economy contexts. Some general guiding principles for policymakers considering power market reforms are discussed below:

[68] These tend to be purist economists, companies experimenting with new flexible business models and think tanks or trade associations with a liberal, free-market approach. Further, this perspective is more common among British stakeholders than in the other two jurisdictions.

**Market design decisions depend on the specific balance of policy trade-offs pursued by a jurisdiction.**

Different market designs lead to varying outcomes in terms of policy objectives such as cost, efficiency, energy security, decarbonisation, economic growth, and fairness. Decisions about power market policy extend beyond techno-economic optimisation and involve considerations of legitimacy, political struggles, and acceptable policy trade-offs in specific contexts at specific times. For example, solutions that are efficient on paper may be difficult to implement politically, leading to the adoption of what economists would label as "second-best" designs to manage political realities.

Market design decisions often involve irreconcilable trade-offs that might find legitimacy only through the political system. Ultimately, societies must collectively decide what is acceptable to them. Only through democratic accountability and an honest debate about the implications of different approaches can the energy transition be sustained in the long-term. It is crucial to first define clear policy priorities collectively and then choose the market design that best achieves them. Therefore, inclusivity, transparency in decision-making processes, and the quality of public dialogue on the wider energy transition are key considerations.

**Market design decisions are rooted in legacy market arrangements and ideas on system operation.**

Legacy market arrangements and prevalent ideas significantly influence the range of acceptable solutions for power market design changes. For example, countries with markets structured around incumbent distribution utilities might favour policy mechanisms that leverage these organisations, while jurisdictions with more liberalized markets might prefer different policy mechanisms. Similar considerations apply to the organisation of dispatch and emerging power system architectures. Choosing a design compatible with legacy systems often minimizes transaction costs and speeds up implementation, crucial for meeting climate targets.

However, this does not mean that radical changes are undesirable or that we should simply maintain the status quo. On the contrary, there are some areas where it is important that decision-makers challenge their assumptions to allow innovative approaches to emerge. For example, diversifying procurement of system services requires questioning legacy ideas on system operation and reforming incentives for system operators and distribution utilities to enable innovation. This has important implications for defining future technological pathways and their potential to deliver on key policy objectives such as reliability, affordability, and decarbonisation.

**Whatever model is chosen, policymakers should strive for coherence in market design and governance.**

Policymakers must strive for coherence in market designs, regardless of the chosen model. Misalignments across market modules can lead to distortions, necessitating better integration of long-term and short-term market mechanisms. This is evident in the interactions across resource adequacy and balancing markets, and the provision of locational signals across the system. Additionally, excessive fragmentation in integrated regional systems due to incompatible market designs should be avoided.

This implies ensuring coherent governance arrangements that evolve alongside emerging market designs. The power sector's complexity, with multiple interacting market and out-of-market mechanisms, highlights the need for coordinated, flexible governance capable of adapting to unforeseen circumstances. As one participant noted, “once you start diving into things and trying to fix individual bits of the market, you just create a new problem elsewhere. We described it to the government as squeezing an air balloon. You squeeze it, and it pops out somewhere else” [interview 19].

**Governing hybrid markets for the energy transition involves rethinking traditional institutional roles.**

As noted above, the complexity related to managing power sector decarbonisation requires a

coordinated governance structure. Traditional roles of regulators and system operators, which used to be narrowly focused on ensuring competitive and well-functioning markets, may need to be expanded or reformed to accommodate these changes. The exact design of such institutions would inevitably reflect legacy governance structures, the underlying market model, and acceptable trade-offs within specific contexts.

For example, the UK has taken steps in this direction by establishing the Future System Operator (FSO), which plays a larger role in system planning and market design evolution. The FSO will also have a net-zero duty, requiring decisions compatible with the UK's climate targets. Alternatively, jurisdictions might introduce a new independent public body tasked with strategically delivering power system change and creating further coordination. Such 'power system architect' or a 'strategic energy transition body' would be akin to the role of the California Public Utilities Commission (CPUC) in California.

Outsourcing more planning responsibility to any of these institutions begs an important reflection on the nature of control within the power system. Some advocate for decision-making with a long-term perspective beyond the short-sightedness of parliamentary terms: "tough decisions need to be made longer than the parliament, there might be short term trade-offs to have long term benefits" [interview11 – senior market expert at system operator]. While insulating power sector governance from politicisation might seem ideal, this thesis shows it is both unlikely and undesirable. Excessive technocratisation risks sidelining necessary political legitimacy. As noted earlier in this section, societies must decide collectively what is acceptable, and only through democratic accountability and honest debate can the energy transition be sustained in the long term.

## 10.4 Contributions, limitations and further research

This is one of the first studies to provide a systematic account of recent change in power market design in the context of growing VREs from a political economy, comparative perspective. In doing so, it directly contributes to building an interdisciplinary understanding in an understudied domain, taking claims made in the political economy literature and applying them in different real-world contexts. Findings demonstrate that change in power market design cannot be understood merely as a techno-economic process, rather, it is the result of co-evolutions across infrastructures, markets and politics. In turn, this highlights the complementary nature of economic, socio-technical and political approaches. Further, the chosen approach based on abductive thematic analysis proved useful for studying a fast-evolving, understudied policy area as it enabled flexibility and the emergence of novel insights. Beyond its academic significance, this thesis holds direct relevance for policymaking. It provides a systematic account of policy strategies and institutional reforms adopted by three global leaders in renewable adoption and integration. These insights offer valuable lessons for countries undergoing the energy transition. Further, it elucidates real-world transition dynamics and sheds light on the implications of diverse institutional designs and governance arrangements as the world moves toward a high-VREs future. This understanding is critical for crafting coherent governance and market design strategies, striking a balance between coordination and market-based mechanisms, and leveraging the value of different resources. These decisions will affect the speed at which states can support wider electrification of the economy and the retirement of fossil fuel generation, and the resulting trade-offs in terms of decarbonisation, system security and costs.

It is important to note that since the data collection concluded, electricity markets have witnessed significant disruptions. This refers especially the energy crisis (and the plethora of policy interventions introduced to mitigate the effects of price spikes) and the launch of major reviews of power market design (e.g. REMA in the UK and new EU market design directives) (BEIS 2022; Meeus and Nicolai 2023). Thus far, these events have not fundamentally altered the trajectory of power market change, and the core trends identified in this thesis remain highly relevant for comprehending ongoing

discussions. Out-of-market interventions introduced to mitigate the crisis have been designed to be temporary although, at this stage, it is difficult to predict whether they will evolve become a more permanent feature of market design, which also depends on how long the crisis will last. The author addressed some of the implications of the energy crisis in the previous sub-section.

The second set of limitations is related to the time and resource constraints faced by the researcher. Given the complexity of the subject matter, the analysis required sifting through a wide array of rule changes and extensive data, which poses the risk of potential data gaps. To mitigate this risk, drafts were reviewed by participants for factual accuracy and completeness. Additionally, the research predominantly focused on wholesale markets, making a somewhat artificial distinction across market modules. In reality, interactions across market modules are intricate and encompass aspects not directly addressed in this study. While efforts were made to touch upon these interactions where possible (e.g., transmission planning, local flexibility markets), some areas had to be omitted (e.g., retail market policy or carbon pricing regime). Finally, it is important to note that it is not always possible to capture all political dynamics as many of these processes often happen 'behind closed doors'. To one extent, this is just the nature of political economy research, especially when the scope of the investigation is so large. However, the use of anonymous interviews with individuals directly involved in policy processes, as adopted here, was possibly the most effective way to tackle this.

This thesis offers many avenues for further research. For example, future studies could adopt a similar approach to investigate power sector change in different contexts, including in power systems that have not undergone liberalisation. This exploration would enrich our understanding of whether a degree of liberalisation is a prerequisite as we move forward with VRE-integration or if alternative pathways exist. This is particularly pertinent for developing nations, many of which lack fully developed power markets and grapple with essential questions regarding the energy transition. It is by no means predetermined that all those aspiring to integrate more renewables must follow the same trajectory as European or other Western countries.

Another fruitful area for exploration pertains to the evolution of retail markets and their interactions with wholesale markets. These markets possess significant potential for delivering system flexibility and have garnered increased public attention during the current crisis. Retail markets represent the interface through which most consumers, or more precisely voters, engage with the power system, shaping their perspectives on broader sector policies. This study suggests that electricity is still predominantly viewed as a public good rather than a market commodity, raising crucial questions about engaging consumers in the flexible energy system envisioned by sector experts. Alternatively, research could focus on recent policy interventions implemented to mitigate the effects of the energy crisis, particularly how these interventions were influenced by different political economy contexts. Additionally, as power markets experience greater regional integration, the political economy dynamics of multi-level governance institutions at the EU or federal level become increasingly important and merit examination. Lastly, future research could delve deeper into the practical application of different market designs within diverse political contexts, bridging the gap between academic inquiry and policy implementation.

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