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Project Deliverable

Best Practice Report – Market Facilitation for DSO

Scottish & Southern Electricity Networks

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Executive Summary

The purpose of this review of international experience of future electricity market facilitation is to help inform the approach to market facilitation in the British electricity market.

Many countries are looking to the decarbonisation of the electricity sector to help achieve climate change and carbon commitments through electrification. The intent of this report is to understand why different countries may be approaching this challenge in different ways and over different timescales. This understanding will help assess the relevance of different approaches in the British market context.

TRANSITION identified a number of electricity markets where there are energy security challenges, the adoption of low carbon technologies is progressing, or both. A desktop review of available literature on those markets was then undertaken to better understand the relevance of the approaches in those markets to Great Britain and specifically to the objectives of TRANSITION.

The report does not simply look at the approaches in different markets. It seeks to understand the structure of the markets reviewed, their electricity mix, the remaining lives of their existing generating capacity, the plans for its retirement and the policies that promote a move to a low carbon electricity system.

Factors such as energy security, the remaining lives of existing plant, the degree of market unbundling (that is, the degree to which market roles, such as distribution, retail and metering, are separated; and hence the potential number of market actors and level of competition both in retail and in supply) and the regulatory obligations of different market roles were all deemed to be factors relevant to understanding the approaches in different territories and the relevance to TRANSITION.

The British electricity market is one of the most unbundled and consistently competitive electricity markets in the world. Combine this with the current retirement schedule for coal and gas generators as well as existing nuclear baseload generation means Britain will face capacity margin, system inertia and system flexibility challenges in the middle of the next decade. Equally, this presents an opportunity for leadership in electricity system decarbonisation and in the development of market mechanisms that will support the effective operation of a more decentralised electricity system, as well as some of the risks associated with early movement.

Australia

Australia is some way behind the British market in the transition to a low carbon energy system. However, Australia has already experienced some of the risks associated with growing penetration of intermittent, inflexible generation into its system. The significant blackout in September 2016 was directly related to insufficient flexibility being available to maintain system balance.

Structurally, Australia has similarities to the British market in terms of unbundling, with the separation of transmission, distribution and retail and many commercial market participants have taken the strategic decision to have positions in both retail and generation.

Regulation places consumer choice at the heart of decision making, leading to a focus on a market based approach. Energy Networks Australia's Electricity Network Transformation Roadmap also supports a market based approach. The Roadmap, which follows a similar timeline to that being considered in Britain, recognises the value that could accrue from enabling distributed energy resources to be accessed by multiple markets. It recognises the need to coordinate effectively between those markets, citing specifically the need to manage the inter-relationship between the distribution system and the wholesale market.

The Roadmap includes an 'independent market operator' (IMO) role supporting enhanced visibility, communication and co-ordination with the distribution system operator and therefore, implicitly, with other market participants.

TRANSITION recognised the importance of being able to stack the value that can accrue from enabling to distributed energy resources to be made available to different markets and both identify and manage value conflicts between market when they occur. The review of the Australian market therefore reinforces the need for TRANSITION to help inform decisions on the future British market design and the allocation of obligations between market roles.

California

Structurally California has a number of parallels with the British market. It sits within the Western Interconnector and is able to trade electricity across that interconnector in a similar way Britain is currently able to trade as part of the EU Internal Energy Market. The California Independent System Operator (CaISO) has a similar span of responsibilities to the National Grid ESO in Britain.

Unlike Britain, on the commercial side, distribution and supply of electricity is dominated by three Investor Owned Utilities (IOUs) with geographic monopolies. Recent policy changes have led to a huge increase in renewable energy being connected to the grid. Consumers are able to choose new energy options from new market participants, such as Consumer Choice Aggregators (CCAs) and Direct Access Providers (ESPs). This has triggered a reassessment of California's regulatory frameworks, which were developed for a utility being at the centre of the system. The growing decentralisation of the Californian system, with a potentially vastly increased number of actors, has brought into question whether the existing regulatory frameworks will be fit for purpose.

It is worth noting California suffered a substantial market failure in the early 2000s that required significant state intervention. This led to the recognition that California needed to establish suitable reimbursement mechanisms for IOUs to cover all reasonable expenditures on infrastructure and administration to enable demand response, as well as being provided with an incentive mechanism to encourage the best choices by consumers.

Despite this, PG&E (the largest IOU) filed for bankruptcy in January 2019. Whilst this was primarily due to the liabilities arising from the 2018 wildfires, PG&E have used their bankruptcy to 'reject' more than $30bn of long term power purchase agreements associated with renewable energy resources.

These PPAs created two issues for PG&E. Firstly, they were locked into higher costs associated with earlier generations of renewables. Secondly, whilst they were permitted to recover reasonable costs from customers, PG&E's financial challenge was compounded by the adoption of demand side PV installations removing a significant proportion of their profitable peak-demand revenue. However, increasing charges to their remaining customers simply caused those customers to move to 'direct access suppliers' or 'community choice aggregators'.

Clearly, the market rules and cost recovery mechanisms, particularly related to supporting early adoption of technologies, will be significant for both investor and consumer confidence.

The review of the Californian electricity market provides insights for TRANSITION around the implications of the energy transition on incumbent market actors and the potential for unintended consequences (such as the impacts on PG&E and the wider implications for investor confidence in renewables) arising from existing market rules and regulation. This learning will be taken forward in the TRANSITION trial design and learning objectives.

Germany

Energiewende (energy transition) in Germany is progressing. However, the research for this paper has not identified formal thinking about the implications of the energy transition on market structures nor about what needs

to happen to enable the trading of flexibility and value stacking across the different markets. Germany, whilst being unbundled, has approaching 900 DSOs, only 75 of which have more than 100,000 customers.

The analysis of the German market has demonstrated an understanding of the barriers to realising the full value of flexibility that exist in Germany's current market arrangements. These include:

- the pre-qualification requirements for energy resources and the potential for these to be discriminatory in favour of certain types of resource;
- the measurement requirements;
- charging mechanisms that do not enable incentivisation of making flexibility available to the system;
- the obligation for a third-party aggregator to get the bilateral agreement with its potential competitor, the balancing responsible party;
- the lack of a standardised role for third-party aggregators within the market model – requiring a multitude of contractual relationships between balance responsible parties, suppliers and the third-party aggregators;
- a lack of clarity on market rule on the obligations associated with different market roles;
- an energy market only approach is viewed as being less susceptible to market failure than capacity markets.

It is worth noting many of these barriers have been identified in the design of TRANSITION and are seeking to be understood through the trialling approach. For instance, the notification of third party actions that could affect the positions of other market participants that are not counterparties to the transactions is a mechanism to overcome the need for aggregators to establish bilateral relationships with the Balance Responsible Parties (BRPs), or the introduction of a neutral markets facilitation mechanism that reduces the need for a multitude of contractual relationships (so reducing the complexity associated to market entry).

Netherlands

The Netherlands is widely regarded as one of the leading territories in the energy transition and the DSOs have undertaken a number of innovation projects looking at how access to demand side flexibility can benefit market participants and, therefore, ultimately the consumer in a well-functioning market.

Like the GB market, the Dutch market was an early mover in the unbundling of supply, transmission, distribution and retail.

Whilst the Dutch market has a strong focus on decarbonising its energy system, it does not have the same practical pressures as the British market. The coal phase out in NL is not due to complete until 2029[1], compared with the 2025 emission limit for the UK and coal still contributed some 35% of production in 2016 compared to just 9% in the UK.

The Netherlands remains heavily dependent on thermal power generation, with it accounting for more than 70% of installed capacity in 2018. By 2030, gas generation is still expected to account for 30% of installed capacity, with the gap expecting to be filled by solar and wind reaching 60% of installed capacity[2].

This compares with almost 30GW of coal and gas generating capacity due to retire in Britain by 2025.

This presents Britain with an unparalleled opportunity to lead on the development of the market frameworks for flexibility because of the necessary rate of adoption of both low carbon generation and low carbon demand technologies.

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1 National coal phase-out announcements in Europe

2 'The Netherlands Power Market Outlook to 2030, Update 2019', GlobalData

Whilst the Dutch utilities have undertaken some significant innovation projects looking at how technology can enable access to demand side flexibility, the research for this paper has not identified formal thinking about the implications for market structures nor about market mechanisms and rules. Dutch utilities have taken leading roles in the development of the Universal Smart Energy Framework (USEF), but the application of that framework to FUSION appears to be the most significant to date. Therefore, TRANSITION will continue to monitor developments in the Dutch market.

Other Sectors

This report also reviews the opening up of access to data in other sectors to establish whether there is potential for analogous learning that could help inform approaches to data sharing in the electricity sector.

Open Banking

The implementation of Open Banking in the UK identified a number of parallels with the challenges facing the British electricity sector with the DNO to DSO transition. The intent of the Open Banking regulations was to improve competition and customer choice in the banking sector. Open Banking had to address structural barriers and open up the access to data, with the customers' interests at the heart of the market. This is analogous to the challenges faced by the British electricity system (and, more broadly, the energy system) as it transitions to a smart, flexible energy system; that is, providing appropriate access to the increasing volumes of data that are being created by the increasingly intelligent infrastructure and the smart, low carbon technologies that connect to it.

The background of the regulations driving the change in banking (the European Directive PSD2 and the CMA Retail Banking Market Investigation) could be seen as having parallels to the Third Energy Package[3] and the CMA Energy Market Investigation[4].

The approach to implementation of Open Banking and the mechanisms for opening up access to data provide some differences to the conventional approaches to facilitating access to data and market operations in the energy sector. The scope of the Open Banking Implementation Entity's (OBIE's) accountabilities are based around:

- the development and maintenance of Application Programming Interfaces (APIs),
- messaging and security standards for data exchange,
- enrolling regulated market participants (such as third party service providers (Account Information Service Providers (AISPs) and Payment Initiation Service Providers (PISPs)) and account providers (Account Servicing Payment Service Provider (ASPSPs))
- providing guidance on compliance and best practice for relevant governance requirements.

OBIE provides the framework to enable a well-functioning market for Open Banking services but does not provide that infrastructure.

Two other aspects worthy of consideration in the context of the facilitation of the emerging market in flexibility services are:

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3 DIRECTIVE 2009/72/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 concerning common rules for the internal market in electricity

4 Competition and Markets Authority - Energy Market Investigation

- The approach to funding OBIE – the established major market participants are responsible for funding OBIE
- Market participants are regulated.

The approach to data access by participants in TRANSITION, and more broadly for market design and data access by industry actors, can be informed by the learning from the review of Open Banking, especially in terms of the use of APIs and standards.

Open Banking's approach to funding of OBIE and regulation of industry actors are outside the primary focus of TRANSITION, but provide additional learning in the context of the overall DNO to DSO and energy system transition.

Transport for London

Whilst Open Banking was driven by regulation, TfL's justification for opening up access to its data was more strategic. TfL's open data approach demonstrates the potential for additional value to accrue to DSOs from opening up a broader set of DSO data.

Transport for London (TfL), being publicly owned, considered its data to be public data. Whilst in Britain the DNOs are in the private sector, arguments have been made that the data associated to DNO assets should be considered public data and the system data should be opened up for the public good. It has been estimated that establishing automated data sharing processes could raise utility companies' profits by 20-30%, and increase staff productivity by 15%[5].

The effective 'crowdsourcing of innovation' by TfL, based on access to its data, has enabled a new market for travel planning applications and services to develop. This empowers consumers to plan their journeys in the most effective way through the visibility of the performance of the transport infrastructure. In adopting this approach, TfL did not need to develop the skills or take on the risks associated with developing and supporting applications capable of working with a gamut of smart devices and operating systems.

Analogies can be drawn between TfL's decision to open up a wider range of data sets and the attempts of investors in low carbon technologies to identify and target areas of the distribution infrastructure with the greatest headroom to support a connection, or which could benefit most from the flexibility that such a resource (e/g a battery) could provide.

Unlike other examples of market facilitation and opening up access to data, TfL took a strategic decision to make its data accessible on an experimental basis, as it was unable to create a compelling investment case for opening up its data. By adopting this approach it was able to progressively build confidence in the value of incrementally opening up access to its data.

It is noted that both Open Banking and TfL achieved opening up access to their data through development and maintenance of APIs and implementing registration arrangements for developers.

5 Data for the Public Good

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1 DSO Learning | California

1.1 Market Context

California is the most populous state in the United States of America and the fifth largest economy in the world.[6] Energy is intrinsic to California's economic growth and meeting the everyday demands of consumers.

The US consists of three major interconnections. These are:

- The Western Interconnection covers the area from the Rockies to the Pacific coast, including adjacent Canadian provinces.
- The Eastern Interconnection, which covers the region east of the Rockies and includes adjacent Canadian provinces (except Quebec), and
- ERCOT (which covers most of Texas) [7]

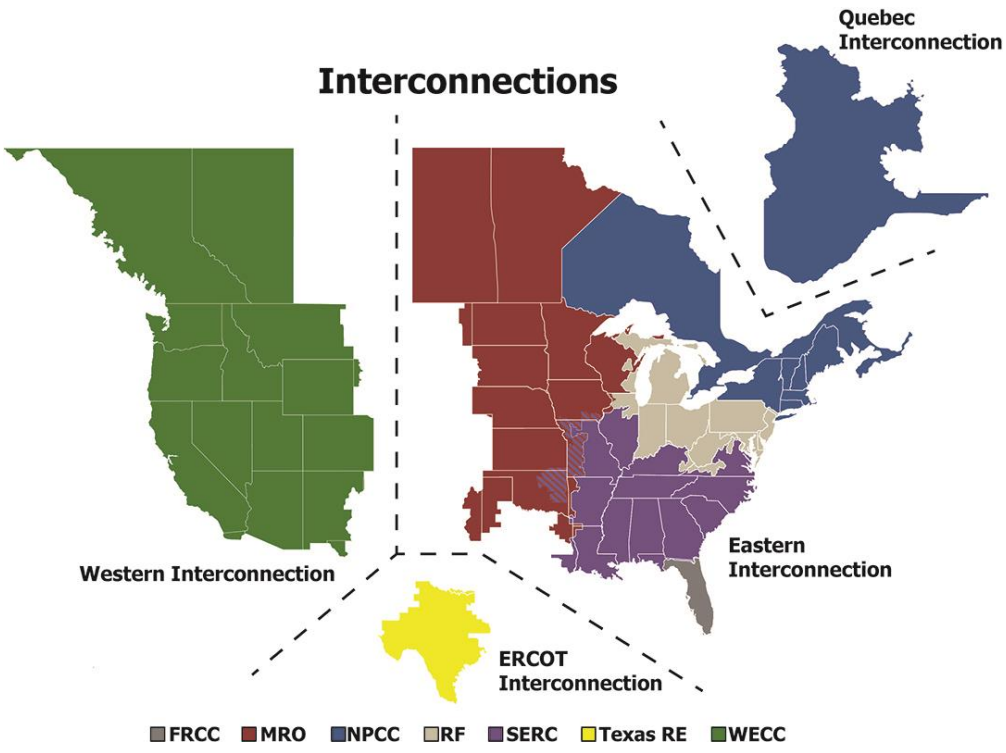

Figure 1.1a US energy system highlighting interconnections. Source NERC

6 Source: https://www.cbsnews.com/news/california-now-has-the-worlds-5th-largest-economy Accessed on 04/02/19

7 Lazar, J. Electricity Regulation in the US A Guide (2016). Available at: https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/

The North American Electricity Reliability Council (NERC) is responsible for ensuring the reliability, adequacy and security of the transmission system. The NERC is made up of 7 regional reliability councils (see figure 1.1b) who are collectively responsible for funding NERC.

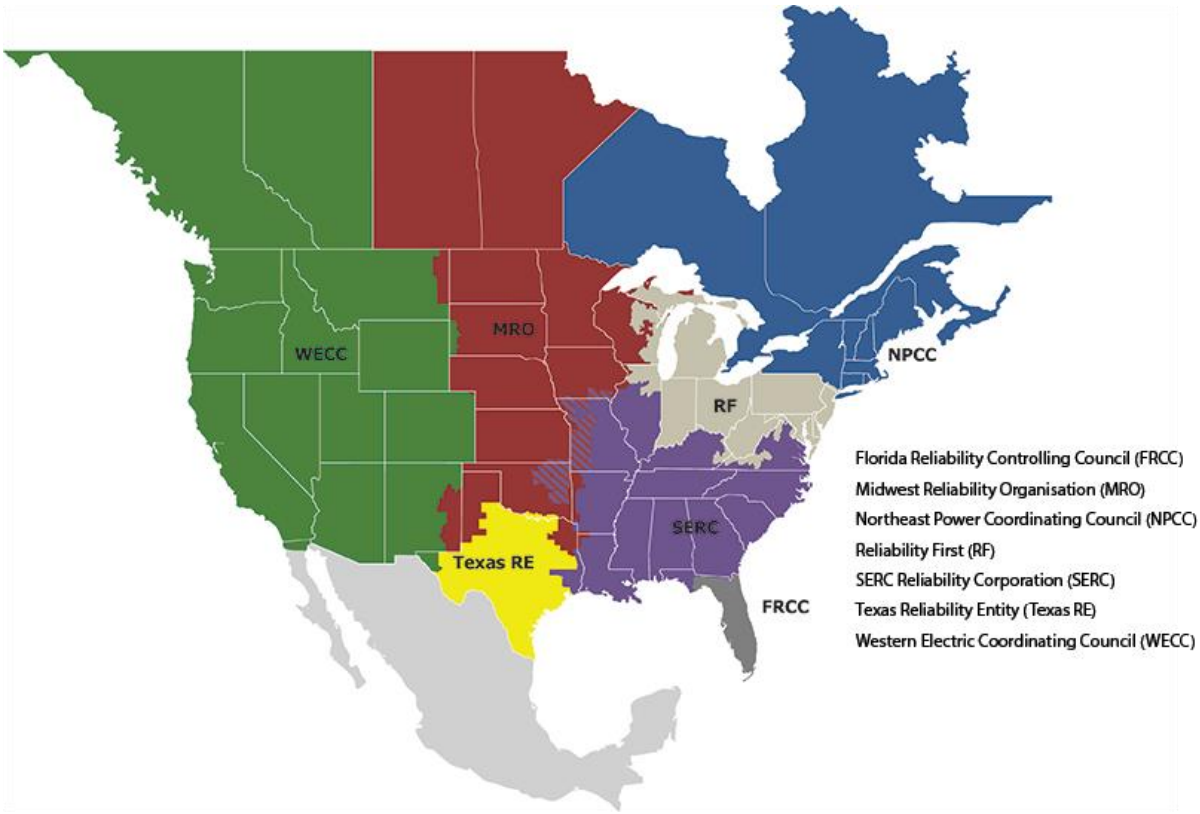

Figure 1.1b – NERC Regions. Source California Energy Commission

In turn, assessment areas are the primary operational entities that are subject to NERC and regional council standards for reliability. Each control area is a geographic region in which a single entity (known as Independent System Operator (ISO)) balances generation and loads in real time to maintain reliable operation.[8] The US electricity regulation guide states that an "An ISO controls and operates the transmission system independently of the local utilities that serve customers".

Regional Transmission Organisations (RTOs) control and manage the high-voltage flow of electricity over an area generally larger than the typical power company's service territory. RTOs include PJM, ISO-New England (ISO-NE), the Midwest Independent System Operator (MISO), the Southwest Power Pool (SPP), the New York ISO (NYISO), and the California ISO (CAISO).

The power system in California is physically part of the Western Interconnection and falls under the Western Electric Coordinating Council (WECC, one of NERC's regional reliability councils) in a sub-region (assessment area) known as the California-Mexico Power Area (CAMX).

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8 Lazar, J. Electricity Regulation in the US A Guide (2016). Available at: https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/

In 2017, total in-state system electric generation was 206TWh, with almost 30% of the electricity generated coming from renewable sources[9]. Figure 1.1c shows the breakdown for both in-state generation and energy mix.

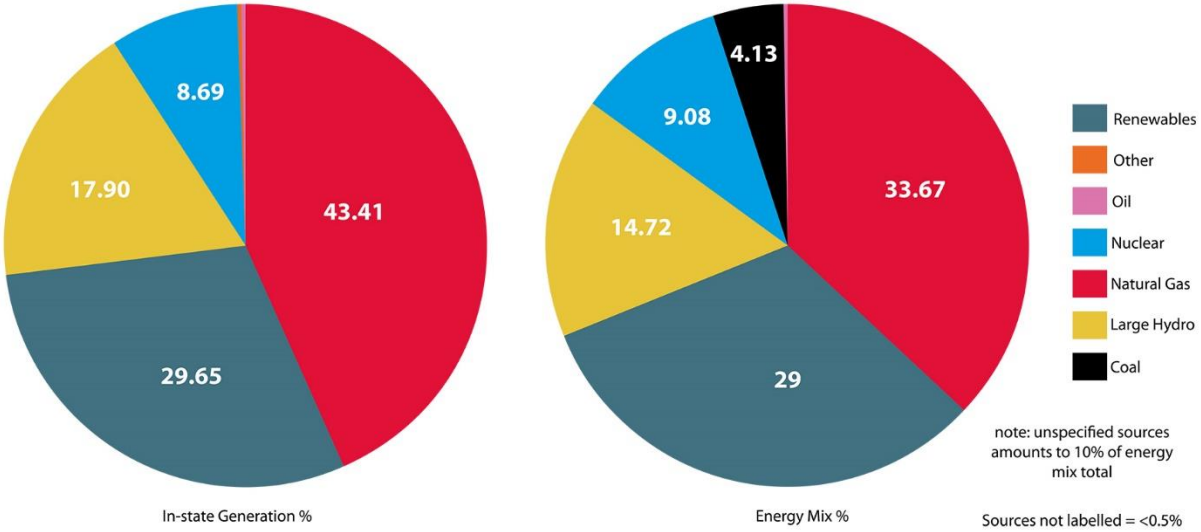

Figure 1.1c: California's Total Electricity System Generation, 2017

Figure 1.1d illustrates the location of the different power plants throughout California.

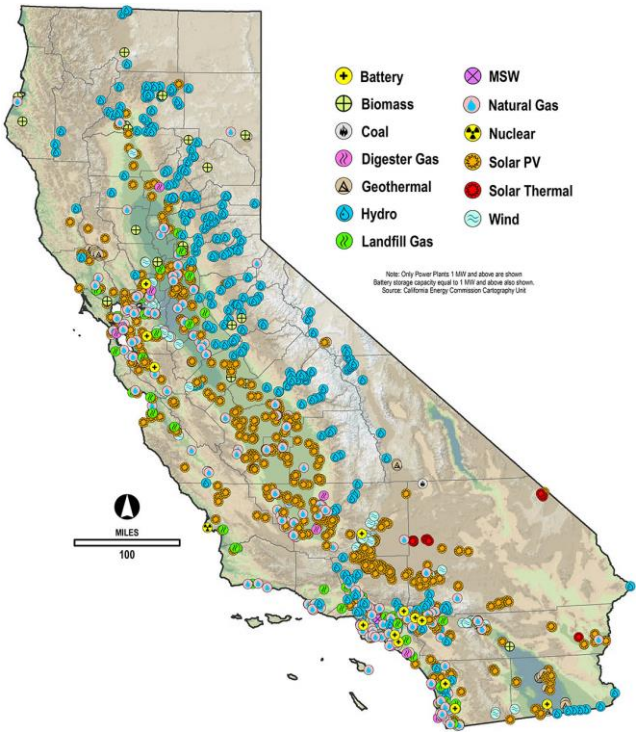

Figure 1.1d: California Operational Power Plants – May 2018

9 California Energy Commission. Source: https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html Accessed on 21/01/2019

Although California is the second largest user of electricity in the US, its actual per capita energy consumption ranks it at 48 out of the 50 states.[10]

1.2 Market Structure

1.2.1 CALIFORNIA'S ENERGY INSTITUTIONS

To ensure the state's energy is safe, affordable, reliable, and clean, California has established three governing institutions.

- The California Public Utilities Commission
- The California Energy Commission
- The California Independent System Operator

California Public Utilities Commission

The California Public Utilities Commission (CPUC) was established in 1911 as the Railroad Commission. In 1912, the state legislature passed the Public Utilities Act, expanding the agency's regulatory authority to include natural gas, electricity, telecommunication, and water companies, as well as railroads and marine transportation companies. In 1946, it was renamed the CPUC.

The CPUC primary role is to establish policies and rules for electricity and natural gas rates and services provided by private utilities in California. These include Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). These three investor-owned utilities (IOUs) serve approximately three quarters of California's electricity demand.[11] The remaining quarter is served by publicly owned utilities (POUs). The geographical span of all California's IOUs and POUs are highlighted in figure 1.2a.[12]

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10 California Energy Commission. Source: https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html Accessed on 21/01/2019

11 California Energy Commission. Source: https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html Accessed on 21/01/2019

12 Source California Energy Commission. Maps available at: https://www.energy.ca.gov/maps/

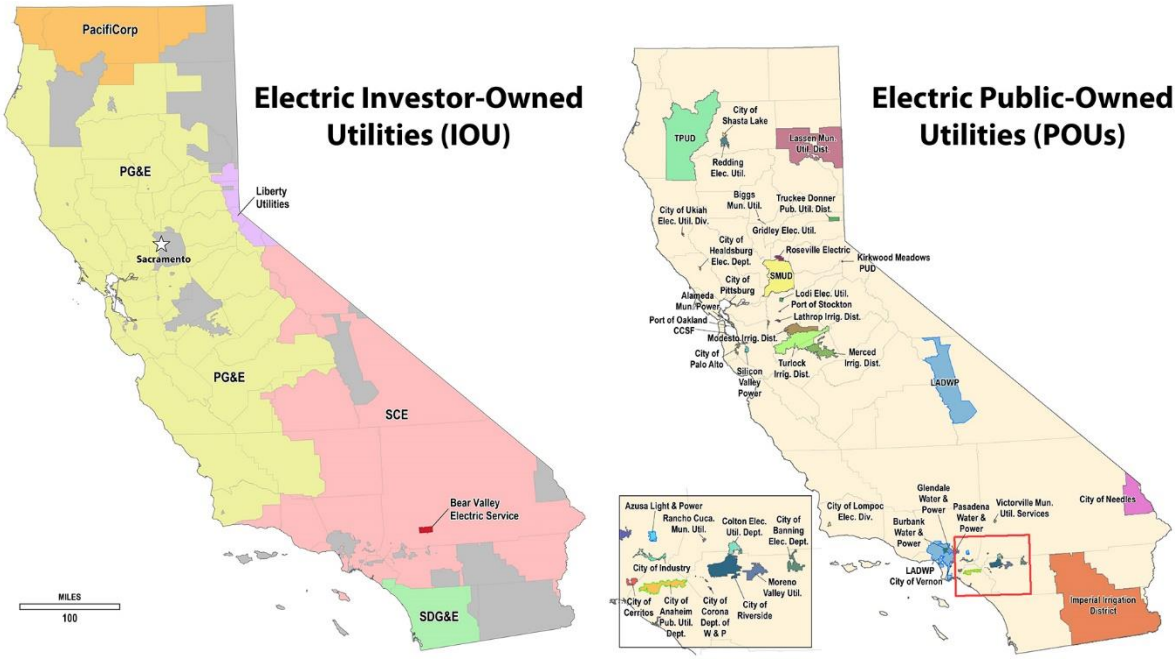

Figure 1.2a: California's IOUs and POUs geographical span

California Energy Commission

Established in 1974 in response to the energy crisis of the early 1970s and the state's unsustainable rate of growth in demand for energy, the California Energy Commission (CEC) has overall responsibility for the reduction of energy costs and the environmental impacts associated with energy use.

It has seven core responsibilities, including:

- advancing state energy policy;
- achieving energy efficiency;
- overseeing energy infrastructure of power plants greater than 50MW; and
- preparing for energy emergencies.

The commission also has specific and limited regulatory authority over publicly owned utilities that serve about 25% of the state's electricity demand. [13]

California Independent System Operator and Assembly Bill 1890

The California Independent System Operator (CAISO) was established in 1996 by Assembly Bill 1890 (AB 1890) and is an independent, non-profit public benefit corporation responsible for operating the high-voltage, long-distance electric transmission lines that make up 80 percent of California's and a small part of Nevada's electricity system. CAISO is also responsible for facilitating California's multi-billion dollar wholesale electric power

[13] Source: https://www.energy.ca.gov/commission/documents/2014-06_California_Energy_Commission_Strategic_Plan.pdf Accessed on 04/02/2019

markets.[14] CAISO is led by a five-member Board of Governors. Each member is appointed by the Governor and confirmed by the state Senate. It is regulated by the Federal Energy Regulatory Commission (FERC). CAISO is by far the biggest balancing authority in the State. Figure 1.2b highlights the geographical span of CAISO together with the other balancing authorities.[15]

Figure 1.2b: Balancing Authority Areas in California

14 *Policy report on AB 1890 renewables funding*, California Energy Commission. Renewables Program Committee. Available online: https://lccn.loc.gov/2010478089

15 California Energy Commission. Available at: https://www.energy.ca.gov/maps/

The implementation of AB 1890 marked a significant shift in energy policy in California. Following its implementation, the IOUs were required to transfer operational control (although they retained ownership) of the state's transmission system to CAISO in order to increase reliability as well as to open up the market to new power producers. All customers located within the service territories of the three IOUs were no longer restricted to buying their electricity from their local supplier.

AB 1890 did not alter ownership of local distribution lines, which continued to be operated by the existing electric utilities. But the IOUs were required to operate the distribution system in such a way that customers could be provided with direct access to any seller of electricity operating in their area.

Finally, the ISO has the responsibility to maintain overall electricity system reliability. The ISO will maintain reserve generators which can provide additional electricity in the event that a generator owned by an energy service provider fails to operate or cannot deliver the required amount of power[16].

Another important element of the restructured market created by AB 1890 was the creation of the power exchange (PX). Operating like a commodities market, the PX was a market where electricity generators compete to sell their electricity in response to bids submitted by buyers. The idea behind the PX was to create a "pool" or "spot market" where price information is publicly available. The creation of the PX, and its resulting manipulation, was a contributing factor in the blackouts which struck California in 2000 and 2001.

California Blackouts

In the first couple of years following the implementation of AB 1890, the restructuring was working well. Wholesale electricity prices declined, customers benefited from a 10% rate reduction. In addition, the IOUs benefited because they were able to pay off the costs of transitioning to a competitive environment.

However, in late spring of 2000 California's electricity market began to malfunction seriously. In June of that year, the price of electricity more than doubled and by January 2001 spiked at more than 300% compared with what it was when the new reforms were implemented. In the winter of 2000/2001, CAISO ordered blackouts 6 times in Northern California. On the worst day of the crisis, January 18, the equivalent of almost one million households lost electricity.[17] The reasons for this market failure were complex and included:

- a low rate of generation in preceding years making California dependent on imports of electricity;
- drought conditions resulting in lower than expected water runoff for hydropower generation;
- a rupture on a major pipeline supplier of natural gas, resulting in constrained generation capacity due to lack of primary fuel;
- strong economic growth in California leading to increased demand;
- unusually high temperatures (leading to increased demand from air conditioning) coupled with an increase in unplanned plant outages of older plants that were being run to meet increased demand;

[17] Weare, C. 'The California Electricity Crisis: Causes and Policy Options' (2003)

- Energy companies attempts to manipulate wholesale electric and gas markets[18].

The resulting fall-out led to recognition that the institutional structures governing the California electricity sector had not been fit for purpose. The PX went bankrupt and the state became more tightly involved in the electricity market than it had ever been before. The CAISO became highly politicised. The IOUs were no longer the main purchasers of power. Retail choice was curtailed, putting competition on hold. California was left in a position where it had to effectively rebuild its regulatory and market structure from scratch.[19]

In the wake of the crisis, the state legislature passed a number of Bills in order to regain control over the electricity sector. The Department of Water Resources became the default purchaser of electricity for the state, and the legislature created the California Power Authority with the stated mission of ensuring that the state has a sufficient supply of electricity at reasonable prices.

A notable outcome of the energy crisis was the Energy Action Plan.[20] The Action Plan envisioned a "loading order" of energy resources that would guide decisions made by California's agencies. First, the agencies were required to optimise all strategies for increasing conservation and energy efficiency to minimise increases in electricity and natural gas demand. Second, recognising that new generation was necessary, the agencies wanted to see these needs to be met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies would also support additional clean, fossil fuel, central-station generation.

In addition to the loading order, six actions came out of the Action Plan:

- Optimise Energy Conservation and Resource Efficiency through, inter alia, adopting a voluntary dynamic pricing system to reduce peak demand;
- Accelerate the State's Goal for Renewable Generation;
- Ensure Reliable, Affordable Electricity Generation;
- Upgrade and Expand the Electricity Transmission and Distribution Infrastructure;
- Promote Customer and Utility Owned Distributed Generation;
- Ensure Reliable Supply of Reasonably Priced Natural Gas.

In 2003, it published a paper entitled "Demand Resource: A Vision for the Future",[21] with the stated aim that by 2007 all Californian consumers should have the ability to increase value derived from their electricity expenditures

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18 Federal Energy Regulatory Commission (FERC) *The Western Energy Crisis, the Enron Bankruptcy, and FERC's Response.* (2005) Available online: https://www.ferc.gov/industries/electric/indus-act/wec/chron/chronology.pdf

19 Federal Energy Regulatory Commission (FERC) *The Western Energy Crisis, the Enron Bankruptcy, and FERC's Response.* (2005) Available online: https://www.ferc.gov/industries/electric/indus-act/wec/chron/chronology.pdf

20 Available online at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/2003%20Energy%20Action%20Plan.pdf Accessed on 06/02/2019.

21 Available at: https://www.caiso.com/Documents/OriginalCaliforniaDemandResponseVisionStatement_AdoptedbyCPUCin2003_.pdf

by choosing to adjust usage in response to price signals. To support this vision, consumers would be provided with smart meters capable of supporting time of use (TOU) tariffs. As a quid pro quo, IOUs would be reimbursed for all reasonable expenditures on infrastructure and administration to enable demand response, as well as being provided with an incentive mechanism to encourage the best choices by consumers.

California's Energy Vision

Today, in 2019, the CPUC, CEC and CAISO continue to rely on the loading order contained in the Energy Action Plan. In Senate Bill 32 (2016) California set itself on the path to reducing state-wide greenhouse gas emissions by 40% below 1990 levels by 2030. In 2015, the California state legislature passed Senate Bill 350 (SB 350, known as the Clean Energy and Pollution Reduction Act 2015) with the stated aim of increasing the amount of electricity generated per year from renewable energy sources to 50% by 2030.

SB 350 established the legislative framework for exploring the benefits of a regional energy market that would allow entities from outside California to join the ISO power grid as full Participating Transmission Owners (PTOs). The intent was for the market to create a coordinated electricity system across the West, using the ISO's infrastructure to develop one clean, reliable and efficient western states grid. This market would find the lowest-cost energy, typically renewable, through a larger geographic footprint with expanded resources. In order to realise this ambition, SB 350 provides for the transformation of the ISO into a regional organisation.

The California legislature was of the view that a regional energy market would allow California to take full advantage of its abundant renewable resources. Integrating renewable energy on a coordinated western grid allows for a broader mix of renewables across the western region and provides tangible economic benefits by allowing for the export of unused renewable power. A regional energy market would also help manage oversupply, as it could be sold to other states.

The premise of SB 350, that of an open regional energy market, marked an important milestone in the history of California's energy policy as it provided signals that it was again ready to explore the concept of an open market, which was the cornerstone of AB 1890. In some ways, though, SB 350 was simply the response to the wider, unprecedented changes brought about by a sequence of technological innovations as well as the introduction of new business models that were disrupting California's energy market. The proliferation of rooftop solar, Community Choice Aggregators (CCAs) and Direct Access Providers (ESPs), resulted in 25% of IOUs' retail electric demand being effectively unbundled and served by a non-IOU source as of the end of 2018. This share is set to grow quickly over the coming decade with some estimates that over 85% of retail demand will be served by sources other than the IOUs by the middle of the 2020s.[22]

The continued proliferation of the community choice aggregators together with the explosion in solar roof panels and the continued adoption of smart, digital technologies into the electricity grid is transforming California's once vertically-integrated market into one with increasingly fragmented responsibility. However, although California is on a path towards a competitive market for consumer electric services, there are an increasing number of policy groups that believe it is moving in that direction without a coherent plan to deal with all the associated challenges

22 Staff White Paper. Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework. (2017) California Public Utilities Commission

that competition poses, ranging from renewable procurement rules to reliability requirements and consumer protection.[23]

California's Future Policy Framework

The energy crisis of 2000-2001 significantly eroded California's faith in a deregulated energy market. The fallout from this crisis resulted in California making the conscious decision to return to the three IOUs as the dominant and monopoly providers of retail electricity services for most Californian consumers, while continuing to restrict the IOUs ownership of sources of electricity generation.[24]

However, policy changes introduced in the California energy market (including the Renewable Portfolio Standard (RPS), the California Solar Initiative and the Energy Storage Mandate) have led to a huge surge in renewable energy being placed on to the grid. This experience has empowered customers to choose new energy options and enabled the emergence of new market participants such as Consumer Choice Aggregators (CCA) and Direct Access Providers (ESPs). Consequently, California's regulatory bodies are now reassessing their frameworks; frameworks that were built on the notion of the electric utility at the centre of the system.

In a recent report,[25] Lawrence Berkeley National Laboratory (LBNL) depicted integrated demand side management (IDSM) solutions to include:

- Energy Efficiency (EE) – These are programs that incentivise deployment of EE technologies and behaviours whether upstream, midstream or downstream for equipment as well as other energy efficiency programs such as custom rebates, behaviour based programs, retro-commissioning and new construction.

- Demand Response (DR) – changing an end-user's load profile in response to system need for economic compensation.

- Distributed Generation (DG) – programs that offer rebates, incentives, and grants to utility customers that install DG technologies on site, such as PV solar, fuel cells, combined heat and power (CHP), and small wind turbines.

- Electric Vehicles (EV) – programs that provide incentives or rebates for deployment of EVs, EV chargers, grid-integrated EV smart chargers or offer time-based rates (TBR) to encourage specific charging behaviours.

- Storage – programs that incentivise customer deployment of storage technologies, such as Li-ion and other types of batteries, grid-integrated electric water heaters, commercial and residential thermal energy storage.

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23 Colvin, M. et al. "California Customer Choice. An evaluation of regulatory framework options for an Evolving Electricity Market". (2018) *California Public Utilities Commission*.

24 'Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework' (2017) *California Public Utilities Commission*.

25 Potter, J. *et al.* (2018) 'Barriers and Opportunities to Broader Adoption of Integrated Demand Side Management at Electric Utilities'. Lawrence Berkeley National Laboratory.

- Time-Based Rates – such as Time of Use (ToU), Critical Peak Pricing (CPP), Variable Peak Pricing (VPP) and Real-Time Pricing (RTP)

At present, there are very few true IDSM programs in operation in the United States (including California) electricity industry that fit within that definition. The reasons for this are many and varied, including market, policy and regulatory barriers. Market and policy barriers include:

- division of program funding and administration;
- misalignment of program cycles;
- inconsistent cost-effectiveness calculation methods; and
- DSM technologies acting as competitors rather than as complementary technologies.[26]

In relation to regulatory constraints, the present regulatory business model is looking increasingly unsuited to the regulation of a more decentralised energy system. The challenges of the existing approaches include:

a) borrowing large amounts of money to meet customer needs based on the expectation that IOUs will recover their investment through retail rates;
b) maintaining highly reliable service at all times and for all customers;
c) providing help to low income customers to ensure that everyone has access to basic electricity service; and
d) providing quality customer service among other more traditional services;

California's existing regulatory structure means most of the revenue to repay the borrowing by IOUs to invest in the energy infrastructure depends on a volumetric ($/kWh) tariff structure. However, the regulated IOUs are starting to lose their traditional revenue streams because of customers beginning to satisfy some of their own energy needs whilst continuing to rely on the grid for various services, and third party providers (like CCAs) are taking greater market share.

It was considered likely that some portion of the many costs other than electricity itself would shift to the ratepayers who remain fully bundled customers of the IOUs. PG&E filing for bankruptcy in January 2019 in some part was due to this very issue. The increasing costs being borne by bundled customers served to accelerate their move away from the IOUs, further adversely impacting the IOUs.

California, like all countries examined in this report, are facing issues with reliability as a result of distributed generation. The CPUC has sought to meet these issues with its Resource Adequacy (RA) program which covers all CPUC-jurisdictional Load Serving Entities (LSEs) including IOUs, CCAs and ESPs.[27] When there is a need for procurement in order to meet a reliability need or a state priority goal, the CPUC has ordered the three IOUs to procure capacity and allocate associated costs to all LSEs. However, where significant numbers of bundled customers move to non-Utility LSEs, entities like CCAs and ESPs, then such customers would make up the majority of the RA procurement requirement, which has the clear potential to create a whole new set of risks that are not addressed by existing regulation.

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26 For further detail see report *ibid*.

27 For further details see: http://www.cpuc.ca.gov/ra/

CCAs and ESPs, without the traditional tethers to state regulatory bodies and state-wide policy goals, might be less willing to use the RA program to advance dual reliability and public policy goals, particularly in emergency situations. This could create inequities across the body of consumers who benefit from and need to support the state's economic and environmental goals (as contained in SB 350 and similar legislation), and could disrupt RA assumptions that must be commonly shared by all consumers of electricity from the grid.[28]

1.3 Market Facilitation

Currently facilitation of the energy market is the responsibility of the California Independent System Operator. However, this is primarily related to the wholesale market for electricity generation.

With the accelerating adoption of renewable generation and new market participant roles such as Consumer Choice Aggregators (CCA) and Direct Access Providers (ESPs), California's energy regulators are evaluating appropriate regulation for a more decentralised market.

1.4 Lessons for the GB market

California provides some interesting parallels for the GB market, even though the market appears to be no more advanced that the GB market.

In its own right, California is the fifth largest economy in the world with an annual in-state generation of 206TWh (compared with 336TWh generation in UK during 2017). Structurally, California is part of the Western Interconnector and can trade energy across that interconnector in the same way that Britain is currently part of the European Union Internal Energy Market. The California Independent System Operator is responsible for operating 80% of California's transmission system and facilitating the wholesale electricity market, with clear parallels with the GB Electricity System Operator in terms of span of responsibility.

The distribution and supply of electricity is dominated by three Investor Owned Utilities with geographic monopolies for the provision of infrastructure and competition for the supply of energy.

A number of factors contributed to a market failure in the early 2000s leading to the California state becoming much more involved in the electricity market and rolling back many of the competitive elements that had been introduced.

California continues to rely on the loading order established by the Energy Action Plan, however, since 2015, the Clean Energy and Pollution Reduction Act established the legislative framework for exploring the benefits of a regional energy market. The intent was for the market to create a coordinated electricity system across the West Coast and would enable the market to determine the lowest-cost energy, typically renewable, through a larger geographic footprint with expanded resources.

The intent is to establish a regional energy market that enables California to take full advantage of its abundant renewable resources.

Policy changes introduced in the California energy market (including the Renewable Portfolio Standard (RPS), the California Solar Initiative and the Energy Storage Mandate) have led to a huge increase in renewable energy being placed on to the grid. This experience has enabled customers to choose new energy options and encouraged the emergence of new market participants such as Consumer Choice Aggregators (CCA) and Direct Access Providers (ESPs).

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[28] For a further discussion see: 'Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework' (2017) *California Public Utilities Commission*.

Consequently, California's regulatory bodies are now reassessing the regulatory frameworks, frameworks that are based on the electric utility being at the centre of the system, for their suitability in a more decentralised system. A system where there are potentially a vastly increased number of actors and $/kWh capital cost recovery mechanisms are becoming unfit for purpose as more consumers satisfy their energy needs beyond the meter.

California does not appear to provide any direct lessons for the GB market, other than an acknowledgement that it is facing many similar challenges for many of the same reasons as Britain.

Where California perhaps does provide some lessons is in the understanding of factors that can cause issues in the operation of the market. These include:

- Energy security;
- Infrastructural resilience;
- Decoupling of demand from economic growth;
- Impacts of climate change on demand (such as increasing adoption of air conditioning);
- Risks of manipulating electricity (and, by extension, flexibility services) and gas markets[29].

California has recognised the need for suitable reimbursement mechanisms for IOUs to cover all reasonable expenditures on infrastructure and administration to enable demand response, as well as being provided with an incentive mechanism to encourage the best choices by consumers.

At present, the United States (including California) has very few true Integrated Demand Side Management programs in operation. Britain can learn from the challenges California has faced, including market, policy and regulatory barriers. Regarding market and policy barriers, these include:

- division of program funding and administration;
- misalignment of program cycles;
- inconsistent cost-effectiveness calculation methods; and
- DSM technologies acting as competitors rather than being complementary.[30]

It is worth noting that in January 2019 PG&E, California's largest utility, filed for bankruptcy[31]. Whilst the immediate cause of the bankruptcy was cited as the liabilities arising from the wildfire damage alleged to have been caused by under-maintained transmission assets, PG&E used the bankruptcy to 'reject' more than $30bn of long term power purchase agreements (PPAs) for renewable energy. With the costs of renewable energy falling as the technologies improve and economies of scale are realised, PG&E found itself locked into high cost PPAs for energy from earlier generations of these technologies. The issue for PG&E was compounded by the adoption of demand side PV installations removing a significant proportion of their profitable peak-demand revenue. Increasing charges to their remaining customers simply caused those customers to move to 'direct access suppliers' or 'community choice aggregators'.

With this being the second time that PG&E have filed for bankruptcy (the first being in 2001), there are lessons for Britain to learn about the both the potential unintended consequences of market mechanisms and about the approach to the use of fiscal incentives to encourage adoption of innovative technologies versus the long term commercial implications for participants in a competitive market. Clearly, early investment in long-term PPAs for

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29 Federal Energy Regulatory Commission (FERC) *The Western Energy Crisis, the Enron Bankruptcy, and FERC's Response.* (2005) Available online: https://www.ferc.gov/industries/electric/indus-act/wec/chron/chronology.pdf

30 For further detail see report *ibid*.

31 See Financial Times article: https://www.ft.com/content/06d3fce8-d18f-3af8-a4dd-4f411644d591

early renewables meant that those commitments were locked into PG&E's cost base. Equally, PG&E's potential default on those commitments could have significant implications for investor confidence in other markets.

An increasing number of policy groups believe that California is on a path towards a competitive market for consumer electric services without having a coherent plan to deal with all the associated challenges that competition poses.[32] It may well be that, through the Smart Systems and Flexibility Plan and the Open Networks Project, Britain is already addressing some of these potential issues for Britain.

1.5 Relevance to TRANSITION

The similarities between the Californian market structure and its decarbonisation policies and the approaches being taken in Britain provides insights for TRANSITION. These insights include the implications of the energy transition on incumbent market actors and the potential for unintended consequences (such as the impacts on PG&E and the wider implications for investor confidence in renewables) arising from existing market rules and regulation.

This learning will be taken forward in the TRANSITION trial design and learning objectives.

TRANSITION will also maintain a watching brief on developments in the Californian market and assess the relevance of any emerging learning to TRANSITION's learning objectives.

[32] Colvin, M. et al. "California Customer Choice. An evaluation of regulatory framework options for an Evolving Electricity Market". (2018) *California Public Utilities Commission*.

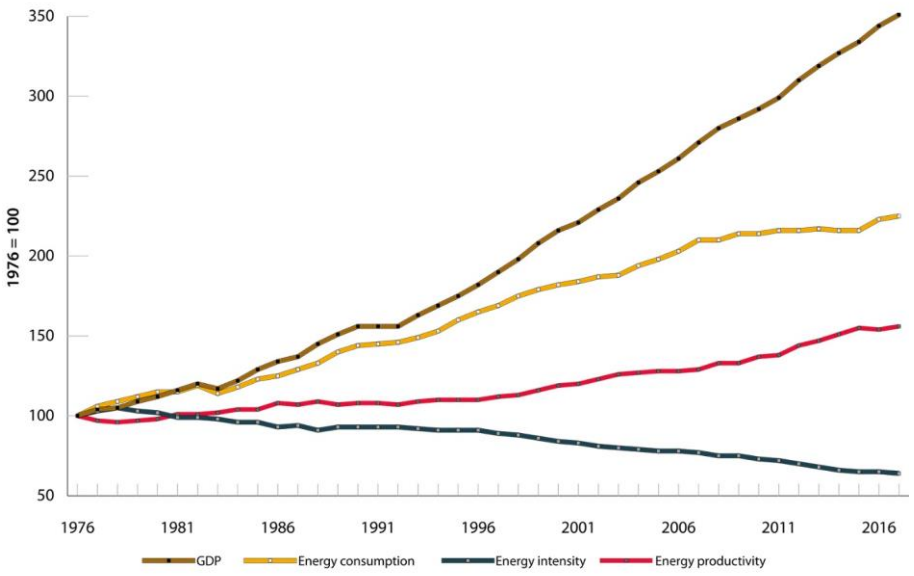
2 DSO Learning | Australia

2.1 Market Context

Australia has an abundance of indigenous energy resources and is key player in global energy markets. Like other electricity markets covered in this report, energy supply and use in Australia is changing rapidly as new technologies are adopted.

Extraction and export of fossil fuels is becoming increasingly important to the Australian economy and this is having an increasing effect on its domestic market. Energy represents nearly 40% of Australia's total export and is continuing to grow with demand from the emerging economies such as China and India. Net exports (exports minus imports) were equal to two-thirds of production in 2016–17.[33]

The Australian economy grew by 2% in 2016–17 to reach $1.7 trillion. Population grew by 1.7 per cent to reach 24.6 million people.[34] One of the key facets of the Australian economy is its low energy intensity. As depicted in figure 2.1a, economic growth has generally outpaced growth in energy consumption.[35] This trend reflects not only improvements in energy efficiency but a move away from highly energy intensive industries, such as manufacturing, and towards the service industry.



Source: Australian Energy Statistics – Table B

Figure 2.1a Comparison of Australian GDP growth with Energy Intensity and Energy Productivity[36]

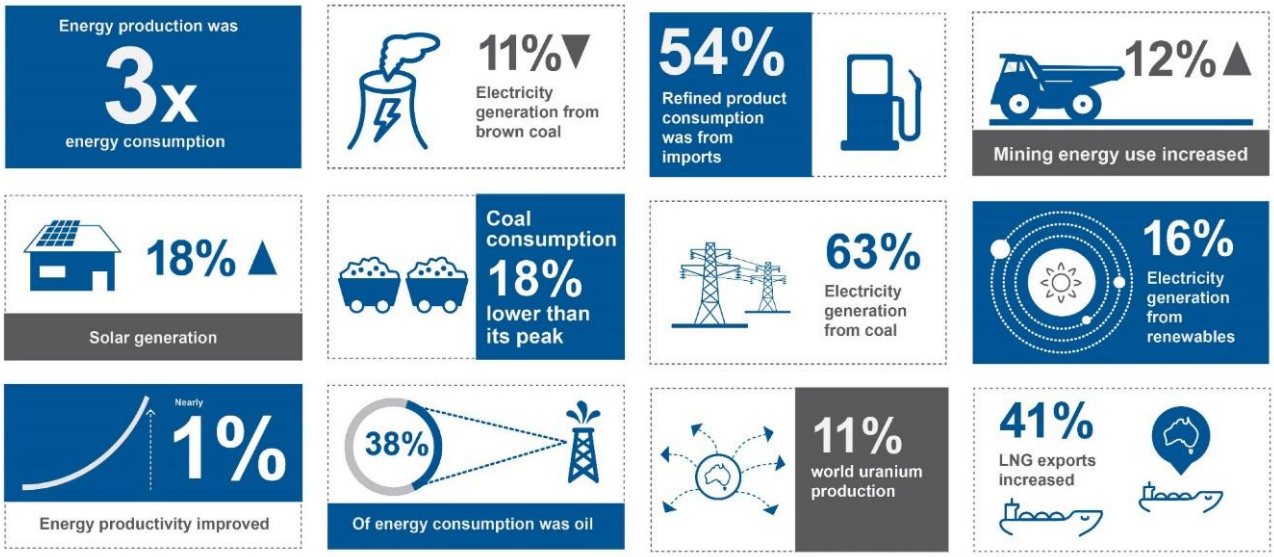
33 Australian Energy Statistics. Available at: https://www.energy.gov.au/government-priorities/energy-data/australian-energy-statistics

34 Australian Energy Update (2018) Available at: https://www.energy.gov.au/sites/default/files/australian_energy_update_2018.pdf

35 Available at: https://www.energy.gov.au/publications/australian-energy-update-2018

36 Source: Department of the Environment and Energy (2018) Australian Energy Statistics, Table B

A selection of key headline energy statistics can be seen in figure 2.1b. Particularly significant in the context of the energy transition is that nearly two thirds (63%) of electricity produced comes from coal with around a sixth (16%) coming from renewables.



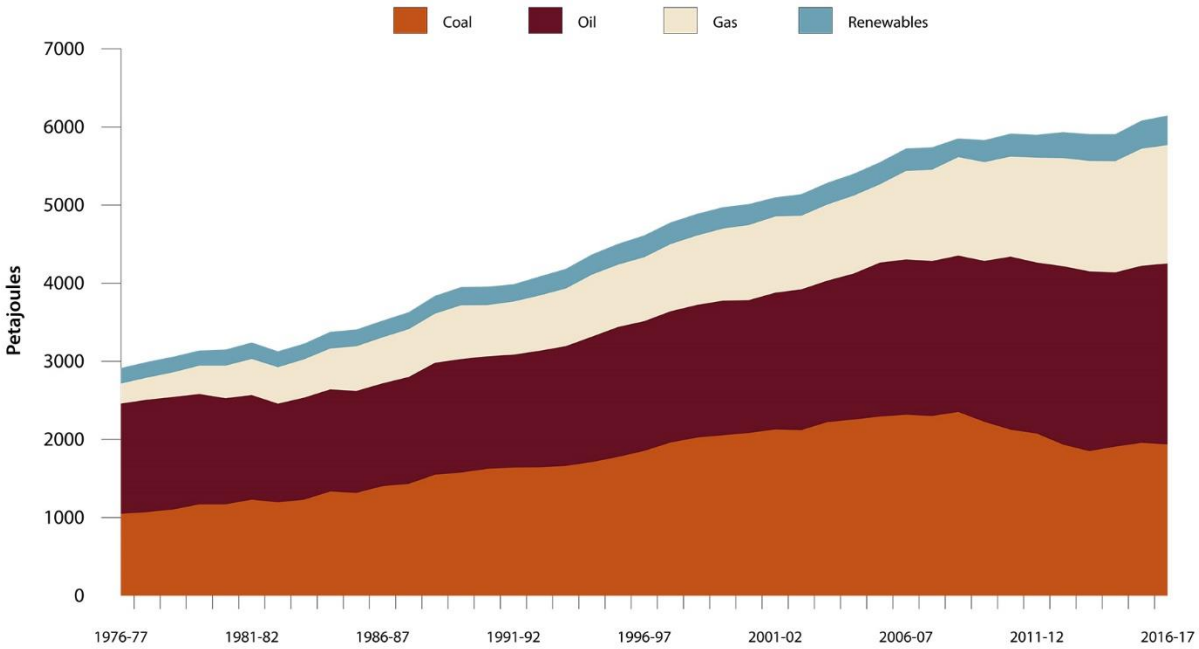
Source: Australian Government: Department of the Environment and Energy

Figure 2.1b: Australian Energy Statistics 2016-2017[37]

Electricity generation rose marginally in 2016–17 to 258 TWh; this figure includes around 12% beyond the meter generation by industry and households. Renewable generation accounted for 16% of total generation in 2016-2017, a 6% increase during that period. Most of this increase came from solar.

Figure 2.1c highlights how Australia's total energy mix has changed over the past 40 years, with an increase in the proportion of energy needs being met by gas and renewables.

[37] Australian Energy Update, August 2018



Source: Australian Energy Statistics – Table C

Figure 2.1c: Australian Energy (all uses) Consumption by Fuel Type

However, despite these figures illustrating a changing energy mix, Australia faces a number of challenges. Liberalisation and deregulation of the Australian electricity market are considered to have delivered many benefits. However, there are signs of underlying stress factors.

- Energy prices have remained consistently high against low levels of competition and low consumer choice, which is taken to indicate structural challenges in the market.
- Concerns have been raised that there may be a shortage in gas supplies in the east coast market as liquefied natural gas (LNG) exports ramp up in the period to 2022; this putting further upward pressure on power prices.

South Australia has the highest penetration of variable renewable energy in the National Electricity Market (see below for details). South Australia (SA) suffered a state-wide power outage (referred to as the 'SA region Black System event') on Wednesday, 28 September 2016. This prompted a review into their energy security. The review identified technical challenges created by the changing generation mix. Regulatory and market mechanisms that work effectively together to deliver least cost in the long-term interest of consumers were identified as key tools to reduce the risk of future 'Black System events'.

A number of the findings of the review[38] could provide significant learning for the British market:

- Access to accurate technical information about equipment connected to the grid is critical for system security;
- Processes around weather forecasts and changes to forecasts triggering reassessment of decisions as appropriate (this includes the potential for wind speed to exceed protection settings on wind turbines, leading to operation of 'over speed' cut outs and loss of generation from the system);
- From a system design perspective:

38 Black System South Australia 28 September 2016, AEMO report published March 2017

- Reduce the risk of islanding and, in the event of islanding, seek to increase the likelihood that the islanded grid remains stable;
- System inertia remains a significant factor in slowing the rate for frequency change and enabling automatic load shedding to happen and stabilise the system.

2.2 Market Structure

2.2.1 NATIONAL ELECTRICITY MARKET

Australia has two major electricity systems and wholesale markets: The National Electricity Market (NEM) with 47 GW of installed generation (in 2017) that serves the eastern and southern parts of the country, and the wholesale electricity market in Western Australia (WEM) with 5.8 GW for the South-West Interconnected System (SWIS). There is also a separate North West Interconnected System (NWIS) which does not have a wholesale market. The NWIS and SWIS are not physically connected to each other or to the NEM, but work is ongoing to harmonise the market rules and regulations with the NEM. Figure 2.2a illustrates these three power markets together with their generation mix.[39]

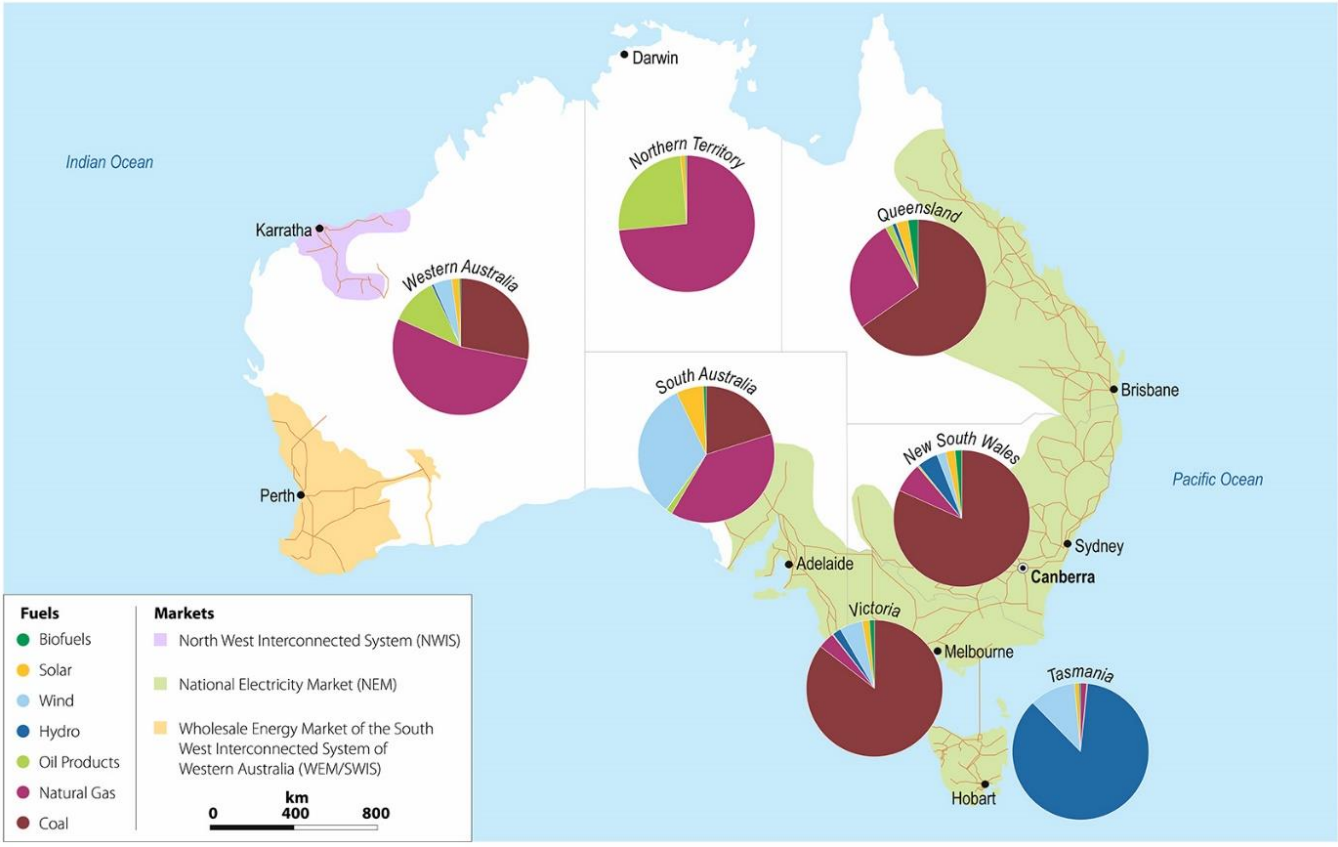


Figure 2.2a: Commonwealth of Australia Electricity Grid

39 Energy Policies of IEA Countries: Australia (2018). International Energy Agency

As illustrated in this figure, electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM), a wholesale spot market in which changes in supply and demand determine prices in real time. The NEM covers five regions – Queensland, New South Wales (NSW), Victoria, South Australia and Tasmania. In geographic span, the NEM is one of the world's longest interconnected power systems, stretching from Port Douglas in Queensland to Port Lincoln in South Australia, and across the Bass Strait to Tasmania. A detailed map highlighting the NEM and its five regions is depicted in Figure 2.2b below[40].

Each state or territory in the NEM has transmission network service providers (TNSPs) and a system control operator for the high-voltage electricity network within their jurisdiction. The role of TNSPs is to plan, develop and operate their respective electricity network. TNSPs in the NEM are AusNet Services (Victoria), ElectraNet (South Australia), Powerlink (Queensland), TransGrid (New South Wales) and TasNetworks (Tasmania). The TNSPs of the NEM are interconnected through six cross-border interconnectors.

The NEM works in a similar way to the British electricity market. A transmission grid carries this electricity along approximately 48,000 kilometres of high voltage power lines to industrial energy users and local distribution networks. Energy retailers purchase electricity from the NEM and package it, together with transmission and distribution network services, for sale to almost 10 million residential, commercial and industrial energy users. The electricity supply chain for the NEM is illustrated in Figure 2.2c.

Australia has 16 major electricity distribution networks,13 are located in the NEM. New South Wales, Victoria and Western Australia have multiple network companies that each have a geographically limited monopoly on their network. Queensland, South Australia and Tasmania have one DSO each. Figure 2.2b highlights the transmission networks and interconnectors in NEM.

40 State of the Energy Market 2018. Australian Energy Regulator

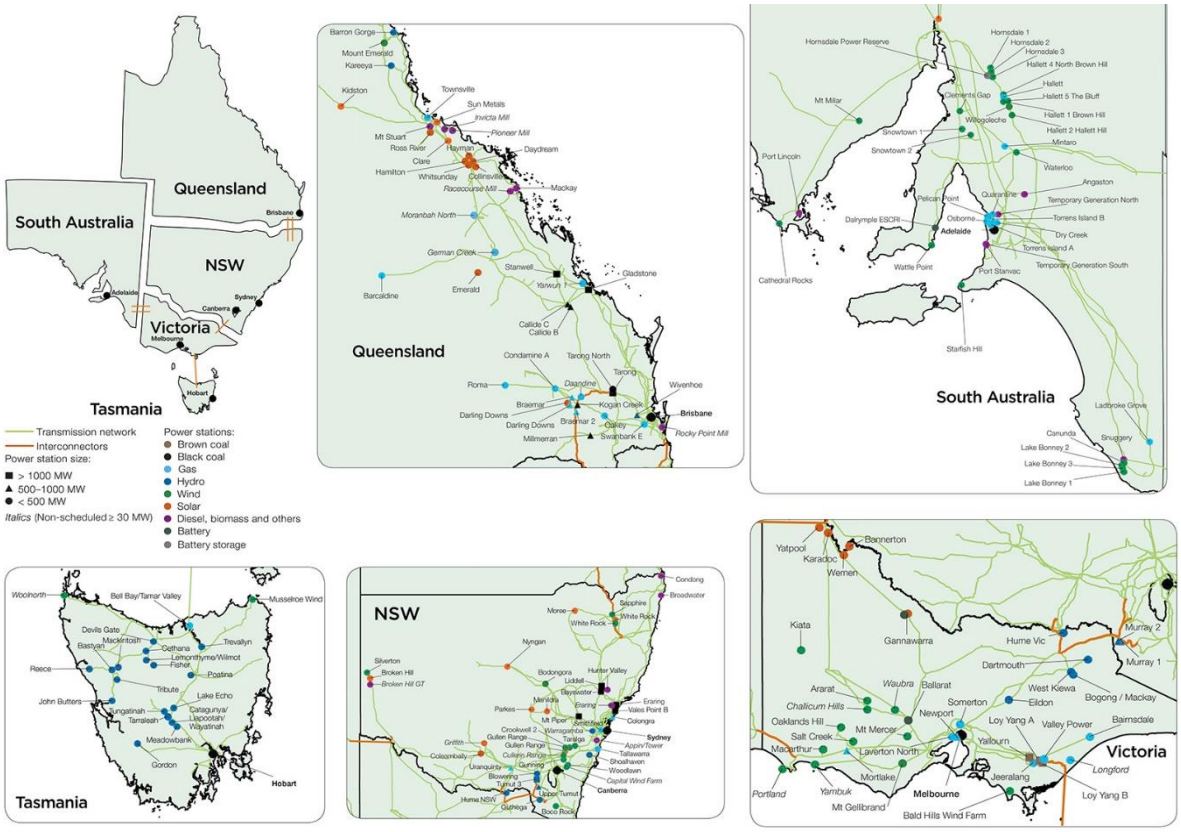


Figure 2.2b: Generators in the National Electricity Market (NEM)

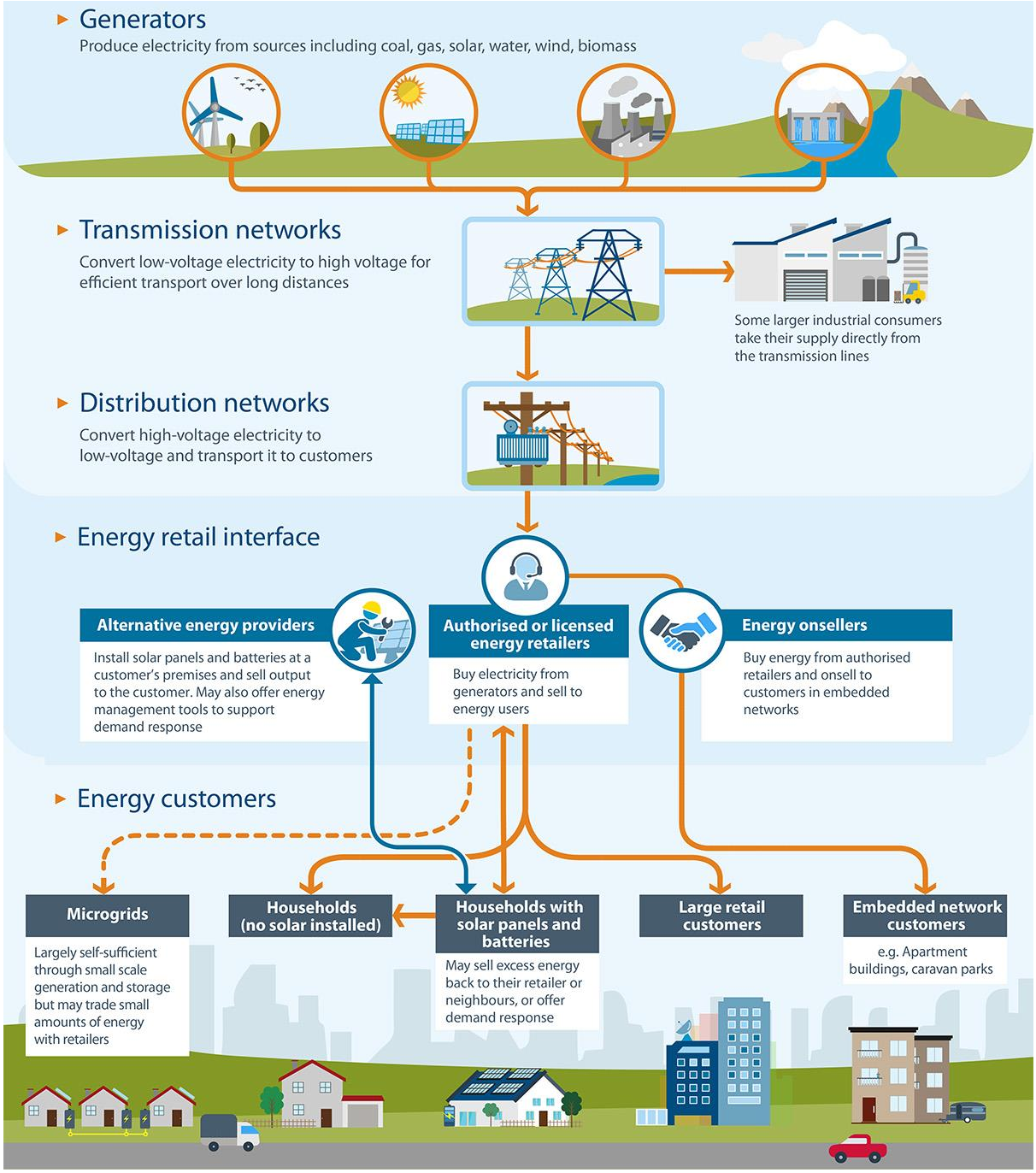


Figure 2.2c: Australia's Electricity Supply Chain. Source: AER

Traditionally, all electricity in NEM was produced by large scale registered generators and then sold through the NEM spot market. However, during the past decade almost two million households and businesses have installed solar PV systems to produce electricity, equating to 4% of the NEM's total electricity requirements in 2017-18.[41]

41 *ibid.*

The retail market is highly concentrated. As of March 2018, there were a total of 33 active retail electricity brands in the NEM, operated by 28 electricity companies. There has been a growing trend of retailers in the electricity market vertically integrating by acquiring generation assets. The retail arms of the three large 'gentailers' (generators and retailers) dominate supply to residential consumers. As of 2017, Origin Energy, AGL Energy and Energy Australia served 75% of national retail electricity customers and together owned 50% of generation in the NEM. The electricity retail ownership structure is depicted in Figure 2.2d.

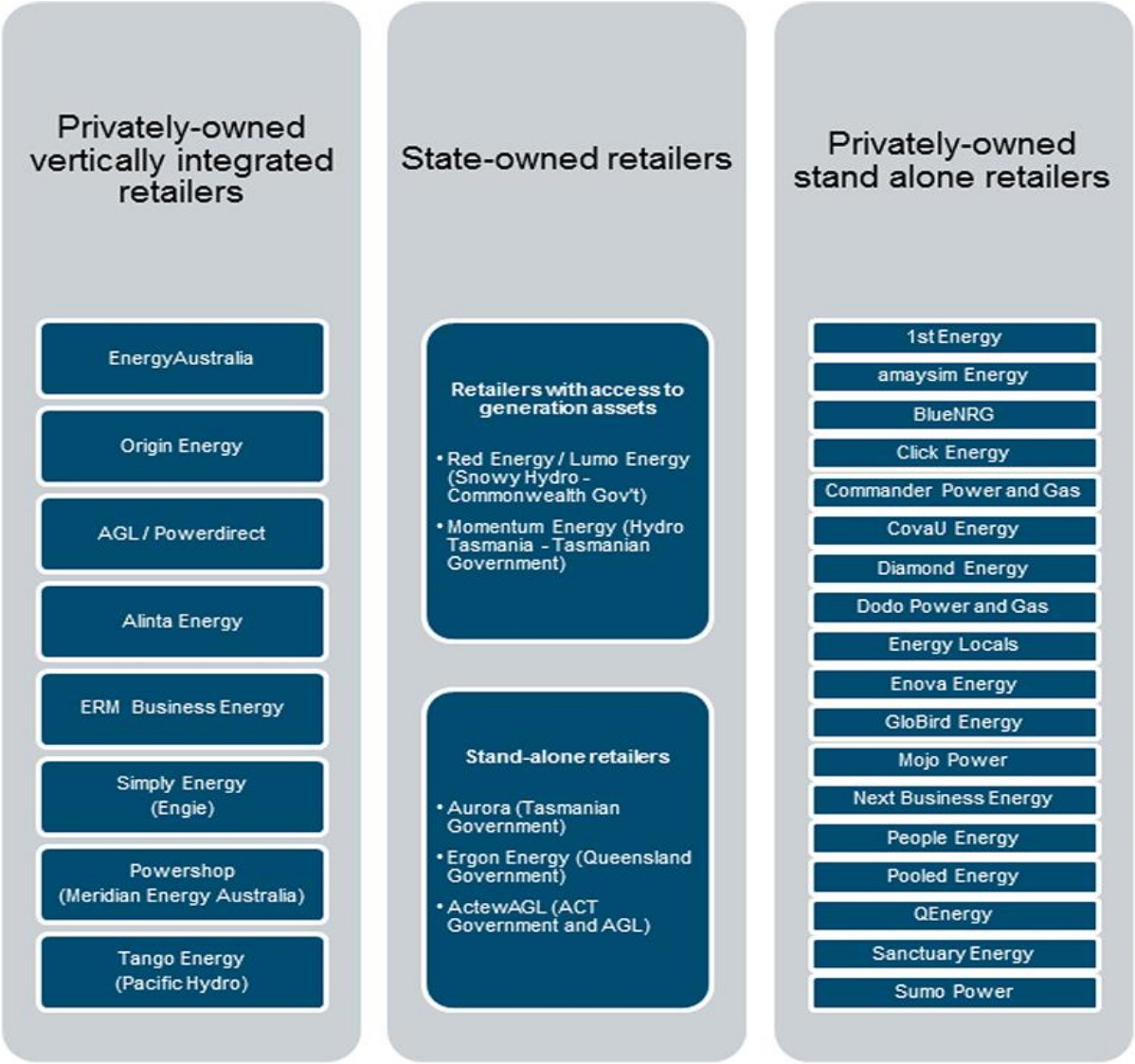


Figure 2.2d: Electricity Retail Ownership Structure. Source: AEMC

2.2.2 AUSTRALIAN ENERGY INSTITUTIONS

The National Energy Regime (NER) regulates the sale and supply of electricity and natural gas in Australia, with a focus primarily on competition and consumer protection. The NER is composed of three overlapping components:

- the National Gas Regime

- the National Electricity Regime
- the National Energy Customer Framework (NECF), which comprises the National Energy Retail Law and the National Energy Retail Rules

The objectives of the NER relate to promoting efficiency and the long term interest of consumers with respect to price, quality, safety, reliability and security of supply.

The principal NER legislation related to electricity is the National Electricity (South Australia) Act 1996 (as amended). Energy markets are overseen by three principal market authorities:

Australian Energy Regulator (AER): The AER is the key regulator in all jurisdictions other than Western Australia.[42] The AER's primary functions under the National Electricity Regime (NER) are contained in the 1996 Act. They include:

- Enforcing the laws for the National Energy Market (NEM);
- Protecting the interests of consumers by enforcing the Retail Law;
- Monitoring the conduct of authorised retailers, approving customer hardship policies and operating a scheme to protect consumers if a retailer fails;
- Setting the amount of revenue that network businesses can recover from customers for using the network.

The AER's work is guided by five strategic objectives:

- driving effective competition where feasible;
- providing effective regulation where competition is not feasible;
- equipping consumers to participate effectively in the market as well as protecting individuals who are unable to safeguard their own interests;
- inform debate about Australia's energy future;
- a long-term perspective whilst considering the impact on consumers today.[43]

Australian Energy Market Commission (AEMC): The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. The AEMC's primary function is to make and modify the Rules which apply under the National Electricity Law, the National Gas Law and the National Energy Retail Law. With limited exceptions, the AEMC does not initiate rule changes; instead, it manages the process by which rule changes are requested by others and ultimately deciding whether the changes should be accepted.

Australian Energy Market Operator (AEMO): The AEMO is the independent system and market operator, with the primary responsibility of managing and maintaining energy system security for all Australians. AEMO operates the NEM and the Wholesale Electricity Market (WEM) that covers the South West Interconnected System (SWIS) in Western Australia. It also manages the spot market as well as a number of the Australian gas markets.

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42 The Economic Regulation Authority Western Australia regulates the electricity market in Western Australia.

43 Australian Energy Regulator Strategic Statement. Available at: https://www.aer.gov.au/system/files/AER%20Strategic%20Statement%20August%202017.PDF

Similar to the UK transmission operator, AEMO may enter into contracts with generators or large customers to ensure back-up reserves are available. If system issues or an unexpected rise in demand pose a threat of unserved demand, AEMO can direct generators to provide additional supply, or may directly intervene as a last resort. AEMO procures ancillary services from market participants to keep the power system secure. If a serious power system threat cannot otherwise be avoided, AEMO may direct generators to provide additional supply. If, though, all other avenues have been exhausted, then AEMO can direct load shedding.

AEMO is 60% government-owned and 40% privately owned, but funded through fees. [44]

2.2.3 REFORM OF THE AUSTRALIAN ENERGY SYSTEM

In 2015, the Australian government published its national energy productivity plan to 2030.[45] Its stated goal was a reduction of 40% in greenhouse gas emissions from its 2015 levels. It laid out 34 measures in order to improve the transparency in the electricity system, including:

- reforming to network tariffs;
- incentivising investment;
- providing residential customers with greater choice.

In June 2016 the Australian Energy Market Commission (AEMC) released its 2016 Retail Competition Review.[46] It found:

- In electricity and gas markets across jurisdictions in the NEM, competition continued to be effective in most jurisdictions and is delivering benefits for customers.
- A need to increase customers' choice, particularly as new technology expands the range of options available in the market.
- In certain territories, particularly the Australian Capital Territory, competition was less effective.

Figure 2.2e shows the different stages of regulatory reform in retail energy markets of Australia at the time of that review.[47]

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44 Australian Energy Regulator (AER) Annual Report 2017. Available at: https://www.aer.gov.au/system/files/AER%20Annual%20Report%202016-17.pdf

45 "National Energy Productivity Plan 2015-2030. Boosting competitiveness, managing costs and reducing emissions". (2015). Australian Government. Available at: https://www.energy.gov.au/government-priorities/energy-productivity-and-energy-efficiency/national-energy-productivity-plan

46 Annual Report on the Performance of the Retail Energy Market 2015-2016. Australian Energy Regulator. Available at: https://www.aer.gov.au/system/files/201516%20AER%20Annual%20Report%20on%20the%20Performance%20of%20the%20Retail%20Energy%20Market_1.PDF

47 Annual Report on the Performance of the Retail Energy Market 2015-2016. Australian Energy Regulator. Available at: https://www.aer.gov.au/system/files/201516%20AER%20Annual%20Report%20on%20the%20Performance%20of%20the%20Retail%20Energy%20Market_1.PDF

Figure 2.2e: stages of regulatory reform in retail energy markets of Australia

In early February 2017, the east coast of Australia experienced severe heatwave conditions. These conditions led to an insecure operating state for the South Australian and New South Wales power systems and the AEMO intervened to restore security by directing load shedding in both states.
Not long after these blackouts, the Finkel report was published.[48] Its focus was on four key outcomes for the NEM:

- increased security;
- future reliability;
- rewarding consumers;
- stronger governance.

These outcomes were underpinned by three pillars of:

- an orderly transition;
- better system planning;
- stronger governance.

Security and Reliability: The Finkel report found these outcomes had been compromised by poor integration of variable renewable electricity generation, including wind and solar, into the system. The issues were further exacerbated by an unplanned withdrawal of older coal and gas-fired generators. In order to address these issues, Finkel recommended security should be strengthened through Security Obligations for new generators, including regionally determined minimum system inertia levels. Similarly, reliability should be reinforced through a Generator Reliability Obligation implemented by the AEMC and AEMO.

The report further recommended a Clean Energy Target as the mechanism for the electricity sector. As part of the orderly transition, generators would need to provide three years' notice of their intention to close, providing time for replacement capacity to be built. The report argued better system planning would see AEMO having a stronger role in planning the future transmission network, including through the development of a NEM-wide integrated grid

48 Finkel, A. Independent Review into the Future Security of the National Electricity Market. Blueprint for the Future (2017) Available at: https://www.energy.gov.au/sites/default/files/independent-review-future-nem-blueprint-for-the-future-2017.pdf

plan to inform future investment decisions. Similar to California's reform of CAISO, it argued investment decisions on interconnection between states should be based on the premise of a more distributed and complex energy system.

Rewarding Consumers – More attention should be paid to how the system can best reward consumers for demand management and their increasingly important role as prosumers. As the future grid will be more distributed, its security and affordability will be strengthened through smarter grids, meter data information and clear data ownership rules to promote new ways of trading, including the implementation of a demand response mechanism.

2.2.4 RESPONSE TO FINKEL

The Finkel review made in total 49 recommendations. A number of them have been implemented in the intervening two and a half years. In this report, we want to concentrate on the specific recommendations which touch on demand response and distributed energy. In late 2017, AEMC published its final report on a distribution market model.[49]

Similar to the EU market response, AMEC laid out a number of policy frameworks for an electricity model based on distributed energy. A summary of their findings included:

Market based approach: Regarding investment decisions, AMEC was of the view a fully market-based approach was better than centralised control over installation and use. Although it was recognised that centralised control had the benefit of making it easier for distribution network service providers (DNSPs) to manage their networks from a technical perspective, it was not considered to support consumer choice or maximise the value of all services that those resources are capable of providing. A centralised planning approach was considered likely to create a barrier to the considerable potential benefits of a well-functioning market and could result in trade-offs being made between different objectives by the Australian government on behalf of consumers. It was judged this would lead to consumers, not competitive businesses, bearing the costs of investment risk. AMEC concluded:

> Markets put consumers at the heart of decision making. Through markets, technologies and business models that promote value to consumers (as indicated by their individual consumption and investment decisions) will thrive, while those that do not will fail. Markets provide incentives for companies to innovate, either by reducing their costs and passing these savings to consumers in order to remain competitive, or by providing new and improved services that are valued by consumers.

Optimising Service: AMEC wanted to enhance consumers' ability to decide when the value of energy services to them is greater than the efficient costs of providing these services. A level playing field for the provision of optimising services would be created only if:

- The optimising service should be provided separately from the provision of regulated services to preclude the possibility of a party exerting market power or influence on the provision of those services;
- The optimising service is provided by a party who is exposed to financial incentives.

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49 Distribution Market Model (2017) AEMC. Available at: https://www.aemc.gov.au/sites/default/files/content/fcde7ff0-bf70-4d3f-bb09-610ecb59556b/Final-distribution-market-model-report-v2.PDF. The latest update on the AMEC website does not highlight what has happened since its publication.

A future energy system, where the penetration of distributed energy resources is high, where DNSPs provide optimising services was determined not to provide a level playing field for market participants.

Further, the AMEC argued, concerns about regulated DNSPs being able to exert control over the distributed energy resources and present a barrier to access to be a very high possibility. Therefore, if the DNSP was to offer an optimising service and be a purchaser of network services from distributed energy resources, then consumer choice would be weakened. This was because it was considered likely the DNSP would use the provision of the optimising service solely for network services, and so act in favour of itself, thereby negatively impacting on consumer choice and competition.

Network Tariffs: Similar to other jurisdictions covered in this report, tariffs are the means by which DNSPs recover the costs of providing network services from consumers. The issue in the Australian market is this approach results in the costs of providing network services being socialised across all consumers connected to that network. As a result, individual consumers do not directly incur the costs associated to supplying them with electricity at the network location to which they were connected at the times they consume the electricity. The report concluded all jurisdictions should allow the DNSPs to progress the implementation of cost-reflective network tariffs, including locational pricing.

2.2.5 ENERGY NETWORKS AUSTRALIA | ELECTRICITY NETWORK TRANSFORMATION ROADMAP

In April 2017 Energy Networks Australia published their 'Electricity Network Transformation Roadmap'[50].

The report follows a similar timeline to that discussed in relation to the British DSO Transition, with a foundation phase running to 2022 and implementation by 2027.

The report recognised that 'orchestration' is required to unlock the value of distributed energy resources. To achieve this, three recommendations are made for the full implementation:

- Networks pay for distributed energy resource orchestration to provide system support in the 'right place at right time';
- New network tariffs that provide beneficial incentives for stand-alone systems and micro-grids to stay connected to the grid;
- New and more adaptive regulatory approaches that are customer focused.

The Roadmap also recognises the role of market mechanisms in rewarding customers with distributed energy resources for providing network support services, orchestrated either directly or through other market actors. In order to support this, there are a number of Foundation phase and Implementation phase recommendations.

Laying the foundations include:

- establishing open standards and protocols to enable secure system operation, management and exchange of information and interoperability with distributed energy resources;
- networks enhancing their current system monitoring and models to inform advanced system planning;
- building distributed energy resource maps and feeder hosting analysis to support locational valuation of distributed energy based services.

[50] https://www.energynetworks.com.au/electricity-network-transformation-roadmap

The implementation phase is optimising the use of the distributed energy resources; recommendations include:

- establishing a new network optimisation market to procure distributed energy resources services for network support;
- networks provide a suite of grid intelligence and control architectures to incentivise distributed energy resource markets, as well as providing system security;
- implementing active network management to provide technical stability, enabling distributed energy resource markets and efficient optimisation.

2.3 Market Facilitation

In the context of this report, the operation of Australian National Electricity Market (NEM) is the responsibility of the Australian Energy Market Operator (AEMO) who act as the independent system and market operator. The AEMO role covers a range of market, operational, development and planning functions, primarily at the wholesale and transmission levels.

Australia's energy mix continues to be dominated by conventional, fossil fuel generation with 63% of electricity consumption being met from coal generation and just 16% from renewables. Australia has, however, already experienced a state wide power outage (the 'South Australia region Black System event' in September 2016), which led to a review of energy security.

One of the key findings of this review was that the regulatory and market mechanisms need to work effectively together to deliver least cost in the long-term interest of consumers and reduce the risk of future 'Black System events'.

The Australian Energy Commission is advocating that a fully market-based approach is better than centralised control over installation and use of new energy technologies. The well-functioning market-based approach is considered to incentivise innovative technologies and business models that deliver meaningful choices and value for consumers. More centralised models are seen as making it easier for distribution network service providers (DNSPs) to manage their networks from a technical perspective. Such centralised planning approaches are perceived to risk the need for greater intervention by the Australian government on behalf of consumers, with the potential to lead to consumers, not competitive businesses, bearing the costs of investment risk.

No decisions have been taken on the formal mechanisms for facilitation of the market, but there is clear precedent, through AEMO, for independent facilitation and there appears to be an apparent will to establish a well-functioning market for services, with perceived risks associated with DNSPs fulfilling such a role.

2.4 Lessons for the GB market

Although Australia is some way behind the British market in the transition to a low carbon energy system, it has already suffered from some of the perceived risks associated to greater penetration of intermittent, inflexible generation into its system, suffering from a significant blackout in September 2016.

Structurally, Australia has similarities to the British market in terms of unbundling, with the separation of transmission, distribution and retail, and many retailers having taken the strategic decision to have positions in generation as so called 'gentailers'.

A number of the findings from the review[51] of the South Australia Black System event provide learning for the British market. These include both market related and system design insights:

- Access to accurate technical information about equipment connected to the grid is critical for system security;
- Processes around weather forecasts and changes to forecasts triggering reassessment of system operational decisions as appropriate;
  - this includes the potential for situations where wind speed exceeds protection settings on wind turbines, leading to operation of 'over speed' cut outs and loss of generation from the system, triggering frequency excursions.
- From a system design perspective:
  - reduce the risk of islanding and, in the event of islanding, seek to increase the likelihood that the islanded grid remains stable
  - system inertia remains a significant factor in slowing the rate for frequency change and enabling automatic load shedding to happen and stabilise the system

The response to the Finkel report is setting a clear direction for a market based approach. This seems to be based on a desire to place consumer choice at the heart of decision making, empowering consumers' ability to decide when the value of energy services to them is greater than the efficient costs of providing these services.

Whilst it is recognised centralised control models have the benefit of simplifying the operation and management of the DNSPs' networks from a technical perspective, it seems to be considered consumer choice and maximising the value of all services that those resources are capable of providing will be best delivered via a well-functioning market. There also seems to be a concern the regulated DNSPs could use the provision of the optimising service solely for network services, and so act in favour of itself, thereby reducing consumer choice and competition in the market.

In terms of network cost recovery, there has been a conclusion that DNSPs should be allowed to implement cost-reflective network tariffs including locational pricing. This is judged to address the issue in the Australian market that current approaches result in the costs of providing network services being socialised across all consumers connected to that network. As a result, individual consumers do not directly incur the costs associated in supplying them with electricity at the network location to which they were connected at the times they consume the electricity.

The Energy Networks Australia's Electricity Network Transformation Roadmap also supports market mechanisms as part of the future electricity system. There is a clear direction that the distribution businesses should be responsible for funding the 'orchestration' of distributed energy resources to provide system support and the need to establish a 'network optimisation' market to enable the procurement of distributed energy resource services.

Whilst the Roadmap is clear about the distribution businesses' role in funding the 'orchestration' of distributed energy resources, it stops short of making recommendations about which market roles should have the obligation to facilitate the market. Indeed, the recommendation is that a cost benefit analysis of procuring such services via a 'digital market platform' should be undertaken. There is however discussion of the need for enhanced visibility, communication and coordination between an independent market operator (IMO) and the distribution system operator.

[51] Black System South Australia 28 September 2016, AEMO report published March 2017 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

The Roadmap recognises the value that could accrue from stacking value across the different markets that could benefit from access to the flexibility of distributed energy resources and recognises the need to effectively manage the inter-relationship between the distribution system and the wholesale market. The Roadmap sees a trigger for effective markets being a high level of distributed energy resource adoption.

2.5 Relevance to TRANSITION

The Australian market, and specifically the response to the Finkle review into the Future Security of the NEM has specific relevance to the objectives of TRANSITION. TRANSITION's focus is on understanding market-based approaches as a mechanism to support consumer choice and maximising the value that can accrue from energy resources being able to provide services across markets. Providing an evidential basis that can be used to inform decisions on the optimum market structure to enable value stacking across markets is that the heart of TRANSITION.

The response to Finkle also recognised the value to network businesses from being able to control the operation of their infrastructures, but judged that this should not outweigh the consumer choice. The importance of establishing a level playing field for services and ensuring the separation of the provision of regulated and optimising services. These elements play to the heart of TRANSITION, providing insight about how the future market can be most effectively neutrally facilitated and how industry actors gain equitable access to the markets.

TRANSITION will maintain a watching brief on developments in the Australian market and assess the relevance of any emerging learning to TRANSITION's learning objectives.

3 DSO Learning | Europe Union

3.1 Market Context

Europe consists of multiple energy markets, each with different structures, heritages, policy drivers and energy mixes. They operate within the Internal Electricity Market.

The power markets across Europe are continuing to evolve in response to the need to decarbonise to meet climate commitments. Combined with significant technological progress and the growth in innovative digital solutions, the sector is regarded as facing unparalleled opportunities and threats.

The European Union has recently begun to take a greater interest in energy policy. This opening section looks at the overarching legal and regulatory framework that governs EU energy policy.

Both the European Council[52] and the European Parliament[53] have repeatedly stressed a well-functioning, integrated energy market is the best tool to guarantee affordable energy prices, secure energy supplies and to facilitate the development of larger volumes of electricity produced from renewable sources in a cost efficient manner. Competitive energy prices are regarded as essential for achieving growth and consumer welfare in the European Union, and hence are at the heart of EU energy policy.

The EU's legal and regulatory frameworks are set out in the Lisbon Treaty and Directive 2009/72[54] (commonly known as the Third Energy Package, along with Directive 2009/73 covering gas) established common rules for the internal market in electricity. Article 194 of the Lisbon Treaty sets out four main aims of EU policy on energy:

- ensure the functioning of the energy market;
- ensure security of energy supply in the Union;
- promote energy efficiency and energy saving and the development of new and renewable forms of energy;
- promote the interconnection of energy networks.

A "well-functioning internal market" is defined in the preamble to the Third Energy Package as providing producers with appropriate incentives for investing in new power generation, including electricity from renewable energy sources. As well as providing consumers with adequate measures to promote the more efficient use of energy for which a secure supply of energy is a precondition. Article 41 requires the EU member states to ensure transparent retail markets, define with respect to contractual arrangements, commitment to customers, data exchange and settlement rules, data ownership and metering responsibility the roles and responsibilities of

52 Outcome of the Council Meeting 3429th Meeting, transport, Telecommunications and Energy, November 2015 14632/15. Outcome of the Council Meeting, 3472nd Meeting, Transport, Telecommunications and Energy, June 2016 9736/16.

53 European Parliament Resolution of 13 September 2016 on Towards a new Market Design (P8_T A(2016) 0333). Available online: http://www.europarl.europa.eu/sides/getDoc.do?pubRef=-//EP//TEXT+TA+P8-TA-2016-0333+0+DOC+XML+V0//EN

54 DIRECTIVE 2009/72/EC - common rules for the internal market in electricity: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=en

transmission system operators, distribution system operators, supply undertakings and customers and, if necessary, other market participants.

However, Article 194(2) provides an important caveat in that none of these measures shall “affect a Member State's right to determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply”.

The Third Energy Package represented the culmination of 10 years of work on the development of the internal electricity market with the stated aim of providing consumers with “real choice”. Although Directive 2003/54 made significant progress in developing common rules for the internal electricity market, the EU was of the view obstacles still existed to the sale of electricity on equal terms and without discrimination. In particular, non-discriminatory network access and an equally effective level of regulatory supervision in each Member State were judged not to be present.

Against a backdrop of increasing energy prices and the threat of global warming, the EU published a communication in 2007 entitled “An Energy Policy for Europe”. A real internal electricity market, they argued, could only be developed if an integrated approach was to be taken to competitiveness, sustainability and security of supply.[55] Without effective separation of networks from activities of generation and supply (effective unbundling), then an inherent risk of discrimination continued to exist, not only in the operation of the network but in the incentives for vertically integrated undertakings to invest adequately in their networks.

The Third Energy Package lays down a number of common rules, including those relating to:

- the generation, transmission, and distribution of electricity and consumer protection provisions;
- the organisation and functioning of the electricity market, open access to the market, the criteria and procedures applicable to calls for tenders and the granting of authorisations and the operation of systems;
- universal service obligations and the rights of electricity consumers, clarifying competition requirements.

Article 9 of the Directive, provides for unbundling of transmission systems and transmission system operators. Consequently, this person or these persons are neither allowed to exercise control over an undertaking performing any of the functions of generation or supply. Article 26 provides for similar unbundling for DSOs.

An independent body, the Agency for the Cooperation of Energy Regulators (ACER) was established under Regulation 713/2009 in order to fill the regulatory gap at Community level following the earlier formation of the European Regulators Group for Electricity and Gas (ERGEG). ACERs jurisdiction includes:

- Assisting National Regulatory authorities on the common rules for the internal electricity market.
- Providing an opinion or recommendation to the European Parliament, the Council and the Commission on any issues relating to the purpose for which it has been established.
- Monitoring regional cooperation between transmission system operators as well as the execution of the tasks of the European Network of Transmission System Operators for Electricity (ENTSO-e).

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- Providing an opinion, based on matters of fact, at the request of a regulatory authority or of the Commission, on whether a decision taken by a regulatory authority complies with the Guidelines referred to in the Third Energy Package.
- Decide on the conditions for access and operational security of cross-border infrastructure, including levying charges on users.

Overall, the Third Energy Package is regarded as having delivered tangible benefits for consumers. It has led to increased liquidity in European electricity markets and significantly increased cross-border trade. Consumers in many Member States are regarded as benefiting from more choice, and increased competition in wholesale markets has helped to keep wholesale prices in check.[56]

Since the Third Energy Package was passed, significant change has taken place across European Energy Markets. The share of electricity generated from renewable energy sources (RES) continues to increase. The physical nature of RES – more variable, less predictable and more distributed – is raising questions about whether the market and regulatory structures are fit for purpose for a decarbonised, decentralised electricity system based on high volumes of renewables. On the technological side, digital technologies and the rapid development of smart metering and low carbon technologies have enabled businesses and households to generate and store electricity, as well as participate in these markets via demand response solutions.

As the EU prepares for an electricity market characterised by more decentralised electricity production, greater volatility in both demand and supply and increasing interdependence between member states, in 2016 it published a proposal on the internal market for electricity.[57]

The rationale of the proposal was to deal with the shortcomings of the existing market arrangements, which the Commission felt were reducing the attractiveness of the energy sector for new investment. An adequately interconnected, market-based energy system in which prices follow market signals will, the Commission believe, stimulate the necessary investments into generation and transmission in an effective manner and ensure they are made where they are most needed by the market, thereby minimising the need for state-planned investments.

The proposal's overarching objective is to lay the groundwork to meet the obligations laid down in the climate and energy framework for 2030.[58] Its wide-ranging approach includes:

- setting fundamental principles for well-functioning, integrated electricity markets;

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56 Accompanying text (preamble) to the European Commission's "Proposal for a Regulation of the European Parliament and of the Council on the Internal Market for Electricity" 2016/0379 (COD).

57 European Commission "Proposal for a Regulation of the European Parliament and of the Council on the Internal Market for Electricity" 2016/0379 (COD).

58 'A policy framework for climate and energy in the period from 2020 to 2030' (2014). Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52014DC0015. For a detailed discussion see: 'Aligning the 2030 EU climate and energy policy framework to meet long-term climate goals. For a better coordination of climate and energy policies through the regulation on the Governance of the Energy Union' (2018). *Institute for Climate Economics and Enerdata (I4CE)*. Available at:

https://www.energinorge.no/contentassets/62daa99043024659a048974b38986b13/i4ce-enerdata_mind-the-gap-full-report-1.pdf

- ensuring non-discriminatory market access for all resource providers and electricity customers;
- empowering consumers;
- enabling demand response and energy efficiency;
- facilitating aggregation of distributed demand and supply;
- contributing to the decarbonisation of the economy by enabling market integration and market-based remuneration of electricity generated from renewable sources.

National market rules and state interventions hinder prices from reflecting when electricity is scarce. Furthermore, the Commission is of the view, that price zones do not always reflect actual scarcity if poorly configured and instead follow political borders. It was therefore considered any new market design must aim to improve price signals to drive investment in areas where it is needed most, reflecting grid constraints and demand centres, rather than national borders. Price signals were required to allow for adequate remuneration of flexible resources.

In most member states, consumers have little or no incentive to change their consumption in response to changing prices in the markets; this is based on real-time price signals not being passed on to final consumers. A new market design package is therefore considered to offer great energy saving potential for households. Additionally, it is considered that technological developments will mean appliances and systems can automatically follow price fluctuations and, on a large scale, offer a significant and flexible contribution to the electricity grid. It also recognised the role of aggregators in the system, although encouraged under existing EU law, has not been effective in removing the primary market barriers for those service providers to enter the market.[59]

3.2 Energy Mix Throughout the EU

As EU member states move away from fossil fuels the adoption of more renewable sources of energy continues to gain momentum. Figure 3.2a shows wind generation provides far the largest source of renewable generation and by 2017 had become second only to gas in terms of total generation.[60]

The EU's Renewable Energy Directive[61] sets a mandatory target of 20% of final energy consumption from renewable sources by 2020. This target will be achieved through the attainment of individual national targets. Article 3 required all member states to adopt a national renewable energy action plan detailing their targets from renewable sources. The renewable energy targets together with member states' progress to 2016 is highlighted in figure 3.2b.[62]

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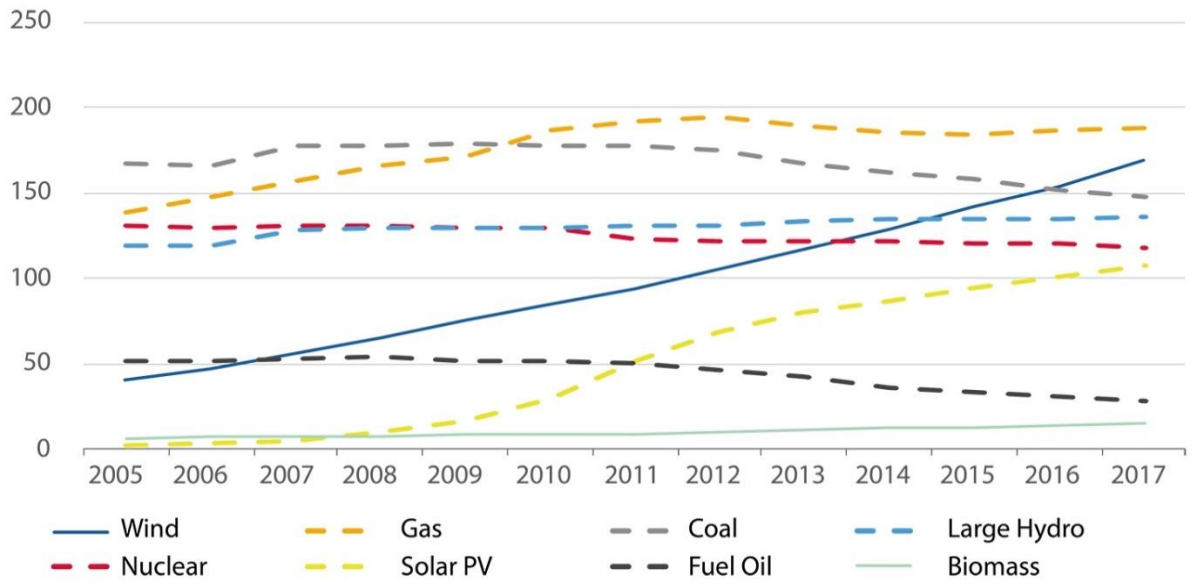
59 The relevant sections of this proposal are discussed in greater detail in subsequent sections.

60 "Wind in Power 2017 Annual combined onshore and offshore wind energy statistics". *Wind Europe*. Available at: https://windeurope.org/wp-content/uploads/files/about-wind/statistics/WindEurope-Annual-Statistics-2017.pdf

61 2009/28/EC – Renewable Energy Directive 2009, at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=EN

62 Source: https://ec.europa.eu/eurostat/statistics-explained/index.php/File:Figure_1-Share_of_energy_from_renewable_sources_2004-2016.png



Source: Wind in Power 2017

Figure 3.2a European Energy Mix

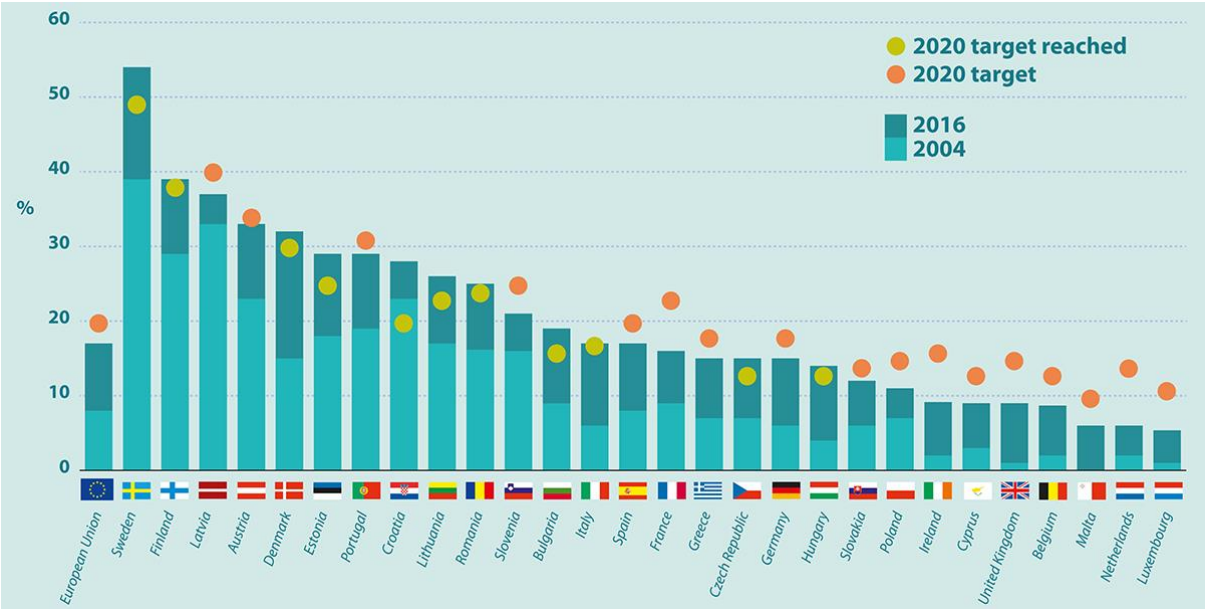


Figure 3.2b Member States' progress against Energy Action Plan

The trend toward decarbonisation will undoubtedly accelerate in the future. Recent reforms of the EU Emissions Trading System (EU ETS) have already seen the price of carbon allowances triple between 2017 and 2018 to €13.82 making them the world's best performing energy commodity in the last year.[63] Modelling work undertaken

63 https://www.carbontracker.org/eu-carbon-prices-could-double-by-2021-and-quadruple-by-2030/. Accessed on 25/01/2019

by Carbon Tracker estimates that the price could rise to €25 by 2020 and €55 by 2030.[64] If carbon allowances were to reach that price, then it is likely that coal and lignite power plants will become unprofitable.

3.3 Distribution System Operators (DSOs) obligations under EU Law

Traditionally, the regulation of electricity distribution operators is a national prerogative. However, EU legislation does provide an overarching framework. Article 2 of The Third Energy Package defines a DSO as a

> "natural or legal persons responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity"

Article 25 describes the tasks of a DSO. These include, inter alia:

- ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity;
- operating, maintaining and developing under economic conditions a secure, reliable and efficient electricity distribution system with due regard for the environment and energy efficiency;
- procuring the energy it uses to cover energy losses and reserve capacity in its system according to transparent, non-discriminatory and market based procedures.

Article 15 of The Energy Efficiency Directive (2012/27) places an obligation on Member States' DSOs and TSOs to

- guarantee the transmission and distribution of electricity from high-efficiency cogeneration;
- provide priority or guaranteed access to the grid of electricity from high-efficiency cogeneration;
- whilst dispatching electricity generating installations, provide priority dispatch of electricity from high-efficiency cogeneration in so far as the secure operation of the national electricity system permits.

Further, member states are required to remove incentives in transmission and distribution tariffs that are detrimental to the overall efficiency of the electricity system. They are required to address those that might hamper participation of demand response in balancing markets. Finally, the need to incentivise network operators to improve efficiency in infrastructure design and operation is recognised and tariffs should incentivise suppliers to improve consumer participation in system efficiency, including demand response.

In order to understand the distribution energy market's efficacy, in 2015[65] the EU published a consultation paper seeking views on the reforms that would be needed to meet changes in the energy market. These changes included:

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64 Lewis, M. (2018) "Carbon Clampdown. Closing the Gap to a Paris-Compliant EU-ETS". Available online at https://www.carbontracker.org/reports/carbon-clampdown.

65 Report available online: https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

- Adaptation of the grid to cope with increased local generation of variable renewable power.
- Procurement of flexibility services as a consequence of increased deployment of volatile energy sources such as wind and solar.
- Increased peak power demand in the distribution grid as a result of increased EVs and electrification of heat.
- The increasing importance of smart meters.

The responses to that consultation highlighted existing regulation of the distribution system is inadequate to address these challenges.

Following on from this consultation, the EU engaged in an impact assessment in order to understand the main regulatory weaknesses with the current system and evaluate different approaches for how those weaknesses could be addressed at an EU-wide level. Three overarching policy themes aimed at modernising EU regulation came out of the subsequent report.

- Improve DSOs' ability to operate the grid cost efficiently by acquiring flexibility from distributed energy resources.
- Enhance the framework for setting distribution tariffs.
- Ensure efficient data handling from new smart meters[66].

Each of these themes attracts a number of policy options which are expanded on in the section entitled "Future Role of DSOs in a Smart Grid".

In 2016[67], the EU published a proposal for the operation of the internal market for electricity. Article 51 of the proposed Directive outlines the tasks of a DSO which include, inter alia:

- coordinated operation and planning of transmission and distribution networks;
- integration of renewable energy resources, distributed generation and other resources embedded in the distribution network such as energy storage;
- development of demand response;
- digitalisation of distribution networks, including deployment of smart grids and intelligent metering systems.

It makes explicit the need for cooperation between TSOs and DSOs, particularly in relation to the exchange of necessary information and data regarding the performance of generation assets and demand side response, as well as the long-term planning of network investments.

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66 European Commission "*Impact assessment support study on: 'Policies for DSOs, Distribution Tariffs and Data Handling'*" (2016). Available online: https://ec.europa.eu/energy/en/studies/impact-assessment-support-study-policies-dsos-distribution-tariffs-and-data-handling

67 European Commission "Proposal for a Regulation of the European Parliament and of the Council on the Internal Market for Electricity" 2016/0379 (COD).

Much of the thinking behind the Commission's proposal was undoubtedly shaped by the three policy themes that were introduced above. Taking each of the three themes in turn:

3.3.1 FUTURE ROLE OF DSOS IN A SMART GRID

The increasing importance of variable, renewable resources and distributed energy is putting increased pressure on electricity infrastructure. Traditionally, DSOs will respond to bottlenecks by investing in the grid. However, this is not always the most economically effective solution as peak demand is transient. Harnessing flexibility from grid users may seem like the obvious way to alleviate bottlenecks; however, two significant challenges exist at an EU level.

- **The specific roles of DSOs are not well defined** – Article 25 of Third Energy Package (2009/72) describes the role of a DSO as limited to operating, maintaining and developing an efficient electricity distribution system. Although the Directive does make mention to DSOs giving priority to "generating installations using renewable energy sources", the lack of clarity as to whether DSOs can undertake such activities means that the default position is to maintain the status quo. Article 51 of the 2016 proposal on the Internal Market for Electricity may provide clarity, when it comes into force, in respect of prioritising demand response options, utilisation of system flexibility and generation options.

- **Remuneration schemes incentivising traditional grid expansion** – Across the EU, incentives are based on capital grid investments. If, as is expected, investments going forward will be based on a more distributed energy model then a new approach to incentives will be required. Any such scheme, however, will need to balance incentivising both a CAPEX and OPEX model. If the regulatory incentives do not provide DSOs with a reasonable return on investment then they will inevitably maintain their default, and potentially more expensive, approach of expanding their cable network.[68]

A key consideration in the approach to flexible grid operations is defining the conditions for how DSOs can make use of flexible energy resources – i.e. solely for grid operations or for other wider purposes. Specifically, where the DSO has the obligation to act as a neutral market facilitator, as provided for by the Third Energy Package, there is a risk the DSO has the potential to distort competition in commercial markets, particularly in markets where there are low levels of unbundling.

The need for investment in the electricity infrastructure will be driven by the adoption of the combination of distributed generation and new low carbon demand (such as electric vehicles, battery storage and heat pumps). Consequently, if generation and demand peaks can be managed, the need for grid investments can be reduced.

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68 European Commission "*Impact assessment support study on: 'Policies for DSOs, Distribution Tariffs and Data Handling'*" (2016). Available online: https://ec.europa.eu/energy/en/studies/impact-assessment-support-study-policies-dsos-distribution-tariffs-and-data-handling The policy document cites an example from Denmark highlighting that only about half of investments related to smart grid costs going forward are included in the regulated cost base. This implies that DSOs would not be able to cover its expenses related to such (otherwise cost efficient) activities, and consequently will opt for a solution which expands their physical network.

Therefore, modelling of costs on the distribution systems will be linked to the amount of flexibility in the system. Modelling work done at an EU level by Imperial College London[69] to understand the cost implications to the distribution grid from increased distributed generation and load growth conducted on behalf of the EU commission modelled the extra grid investment costs at an EU level based on scenarios underlining the EU energy roadmap 2050.[70]

Deploying similar techniques to California, the model uses a set of typical networks. It includes information on population density, typical network design policies and standards in different Member States. It captures voltage levels, network topologies and load densities (rural, suburban, urban), various load characteristics of different consumers (domestic, commercial, industrial) and specific devices such as heat pumps and EV's.

Imperial College modelled three scenarios for the increase in renewable energy sources (RES) by 2050.

- An optimistic scenario where RES accounts for 68% of electricity output.
- A middle scenario where RES accounts for 59% of electricity output.
- A pessimistic scenario where RES accounts for 51% of electricity output.

Figure 3.3a shows the evolution of the installed generation capacity for the whole of the EU. A number of conclusions can be drawn from these various modelling scenarios:

- A growing penetration of variable RES coincides with an increasing amount of installed generation capacity and an increasing volume of back up capacity;
- Whilst the volume of conventional generation capacity decreases over time, there are no significant differences between the three main scenarios; and
- The evolution of gas and coal-fired capacity varies substantially across the different scenarios.

The study estimated the additional reinforcement costs for the distribution network out to 2030 was likely to be as high as €10.8bn yearly. Interestingly, the simulations illustrate reinforcement costs are contingent on the correlation between load growth and distributed generation growth.

In a high RES scenario but with no growth in demand, annual extra reinforcement costs are estimated to be €4 billion until 2030.

In the reverse situation, with no extra distributed generation growth, but significant load growth, the annual extra reinforcement costs are significantly higher at €10.8 billion until 2030.

This suggests load growth is a more significant driver of grid reinforcement cost than distributed generation when looking across all EU distribution grids.

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69 Imperial College London and Nera Economic Consulting "Integration of Renewable Energy in Europe" (2014).

70 Available online: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/2050-energy-strategy

Not only is the specific distribution model deployed across member states going to be different, but it also hinges on where load and distributed energy growth is connected. The closer, in terms of proximity, that the distributed generation and load installations are, the less the likelihood is that grid reinforcement will be required in the wider distribution network.

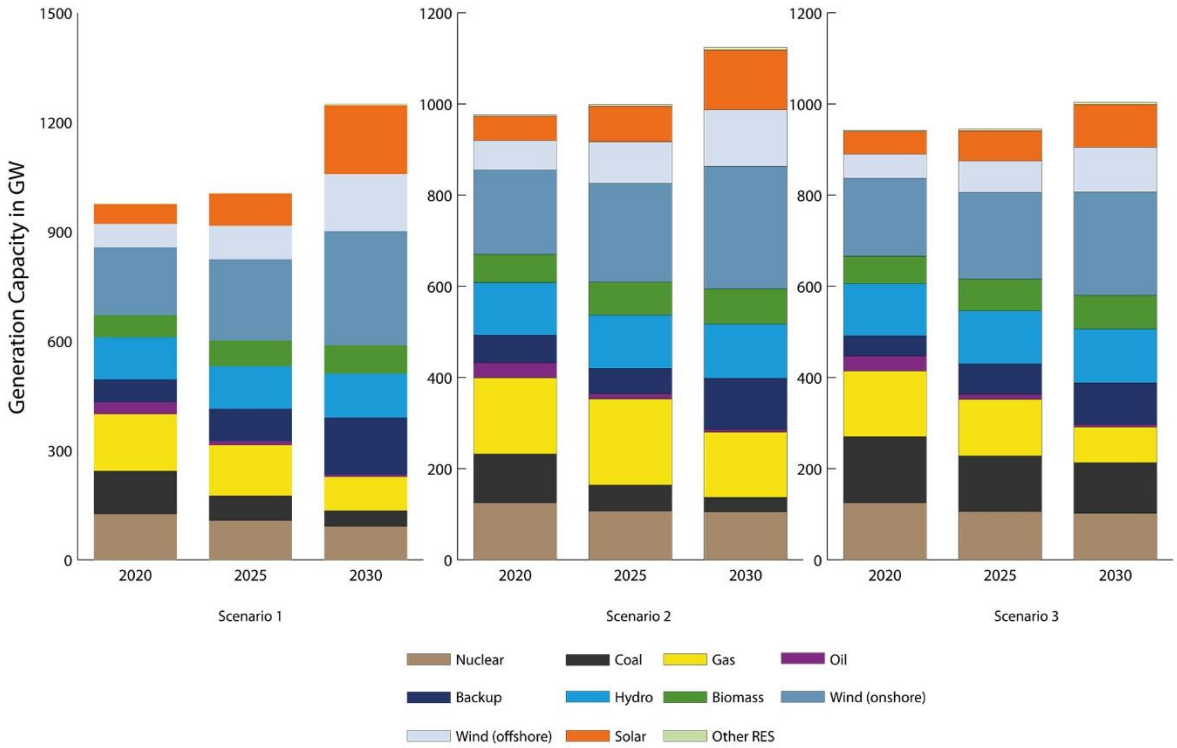

Figure 3.3a Evolution of EU Installed Generation Capacity

3.3.2 DISTRIBUTION TARIFFS

Article 15.4 of the Energy Efficiency Directive (2012/27) places an obligation on member states to remove incentives in the distribution tariff system that hamper participation in demand response. Across the EU, significant divergence exists as to the mechanism deployed by DSOs. In essence, there are four types of tariffs: volumetric; capacity-based; two part tariffs; and one of the above including system services.[71] Table 3.3a explains these tariffs in greater detail.

Network Tariff Type	Options Within This Approach
Volumetric Tariffs (€/kWh)	1. **Flat** (fixed price for a fixed amount of energy) 2. **Fixed** (fixed price per unit of energy/kWh) 3. **ToU** (price per kWh depends on time of consumption) 4. **Event driven including critical peak pricing** (higher prices if peak occurs)

71 Eurelectric (2013) "Network Tariff Structure for a Smart Energy System". Available online: http://www.elecpor.pt/pdf/20130409_network-tariffs-paper_final_to_publish.pdf

	5. **Dynamic including real time** (dynamic prices e.g. depending on wholesale prices)
Capacity Tariff (€/kW)	1. **Flat** (fixed price for a predefined capacity) 2. **Variable** – e.g. two capacity levels (different capacity levels defined, one price for each level) 3. **ToU** (price per kW depends on time of consumption)
Two Part Tariffs (€/kWh) + (€/kW)	**Combination of the above options** (for example ToU, event driven, dynamic options possible within the energy component)
One of the above + System Services Contract	**Interruptible tariff options** (e.g. lower network tariffs for giving the option to control a predefined amount of load)

Table 3.3a – Network Tariff Structure for a Smart Energy System – Source Eurelectric (2013)

Volumetric charges are by far the most common type of tariff. Although they have the advantage of being easy to understand they do not incentivise retail customers to reduce their peak consumption. Today, tariffs are calculated on the basis of the contribution of each customer group to peak demand. In Britain in 2019, the majority of households do not yet have a smart meter, therefore load profiles are applied to allocate consumption to every 30 minute settlement period based upon rules laid down in the Balancing and Settlement Code.

From a DSO perspective, capacity tariffs have the distinct advantage that they allow the DNO to recover their full costs. The introduction of prosumers, as well as increasing peak demand emanating from EV charging and electric heat pumps, means that the link between electricity distribution costs and consumed volume will be reduced. For example, if a consumer is close to becoming self-sufficient, their average consumed volume from the grid is likely to be low. However, provided the consumer remains connected to the grid, costs from this consumer will continue to exist because the grid will still have to support a connection that can support a peak demand when there is no generation behind the meter, or the reverse scenario where there is an abundance of behind the meter generation and the prosumer is exporting their excess electricity onto the grid (if they do not have storage).

The rapid rise of distributed energy has meant the EU is playing catch up when it comes to establishing a best practice approach to distribution tariffs. The problem is compounded by the fact member states will each have evolved different distribution systems, each presenting specific challenges. For example, a solution that relies on large volumes wind generation and lengthy distribution infrastructure is unlikely to work well in a country where there is an excess of sun and the distribution channel is short.

In light of these shortcomings, the EU recently published a proposal on the operation of the Internal Market for Electricity. Article 16(1) of the proposed Directive[72] states:

> "Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner. In particular, they shall be applied in a way which does not discriminate between production connected at the distribution level and production

[72] European Commission "Proposal for a Regulation of the European Parliament and of the Council on the Internal Market for Electricity" 2016/0379 (COD).

connected at the transmission level, either positively or negatively. They shall not discriminate against energy storage and shall not create disincentives for participation in demand response."

Additionally, Article 16(7) states that distribution tariffs must reflect the cost of use of the distribution network by system users, including active customers, and may be differentiated based on system users' consumption or generation profiles.

3.3.3 DATA HANDLING

Across the EU, 72% of all consumers are predicted to have a smart meter by 2020 as a result of wide-scale deployment.[73] Different approaches for handling data have emerged throughout member states which can be grouped into three categories: a) the DSO as facilitator; b) the central data hub; and c) Data Access Point Manager. Each has their own distinct advantages and disadvantages.

In their policy document, the EU discuss two options for dealing with the data handling issues which arise as a result of the role out of smart meters.

1) Update and strengthen EU rules relating to the access of consumer data in order to guarantee transparency, objectivity, non-discrimination and interoperability by any market actor currently responsible for handling data.
2) A specific data handling model in *each member state*, with uniform processes and access rules to the data.

Although option 2 has the distinct advantage of addressing existing risks, it has two major drawbacks. Firstly, the cost of building a new data handling model from scratch will be substantial and secondly, the one-size-fits-all solution means that member states will lose any flexibility in meeting their own specific needs. Consequently, the EU is of the view that option 1 is the preferred choice. By updating and strengthening existing rules on data handling, an appropriate framework will exist within which EU member states would be free to operate.

[73] European Commission "*Impact assessment support study on: 'Policies for DSOs, Distribution Tariffs and Data Handling'*" (2016). Available online: https://ec.europa.eu/energy/en/studies/impact-assessment-support-study-policies-dsos-distribution-tariffs-and-data-handling

4 Netherlands

4.1 Dutch Market Context

The Dutch market, like Britain, is a mature market. The reform of the Dutch Energy Market can be traced back to 1998,[74] when consumers were given the option to choose their own energy supplier. The unbundling of the electricity sector followed the second EU Energy Directive (2003/54), and the separation of the transmission and distribution of electricity from production, trading, metering and sales started. At the time the EU praised the Netherlands for being one of only two member states to have fully implemented that Directive within the timeframe specified.

The main goal of the 1998 Act was to diminish market power and to remove market entry barriers for new electricity producers, with the intention this would bring new technologies and energy sources to the electricity sector.

The reforms of 1998 can themselves be traced back to the Electricity Act 1989. That Act had taken steps toward creating competition by partly restructuring the sector (into generation and transmission on the one hand, and distribution and supply on the other) and establishing favourable rules for combined heat and power (CHP) production.[75]. Prior to the 1989 reforms, the Dutch market was characterised by vertically integrated local monopolies.

Pursuant to the 1989 Act, a network of four power generators controlled through SEP – the Dutch Electricity Generating Board (today the Transmission owner is Tennet) was formed. It was owned by the producing companies and was in charge of the capacity decisions in the Dutch electricity market. As a result, by 1999, 70% of electricity production was in the hands of large-scale producers.

Tennet remains the Netherlands's single national transmission system operator (responsible for voltages of 110kV and above). There are eight DSOs, but 90% of the distribution networks by connections are managed by four companies; Enexis, Liander, Delta and Stedin. The geographic footprints of the DSOs can be seen in Figure 4.1a.

74 The legislative framework being contained in the Electricity Act 1998.

75 "Country Studies. Netherlands Regulatory Reform in the Electricity Industry" (1998) OECD

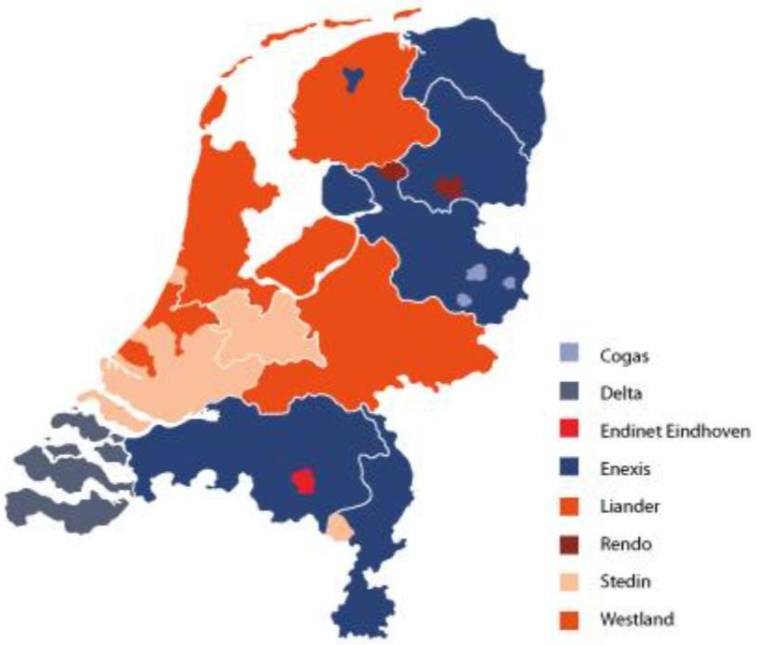

Figure 4.1a: Map of Dutch DSOs[76]

The reason why the reforms of 1989 failed to increase competition are complex and multi-faceted. However, it was widely attributed to the fact that generation and supply (both potentially competitive functions) were still tied in with transportation (which remained a natural monopoly). It had created further over-capacity problems by the way in which the CHP policies were implemented.[77]

The Electricity Act 1998 went considerably further than was required under the first Electricity Directive: the speed of liberalisation was quicker; full legal unbundling from activities in the supply market was required instead of just accounting separation (shares are held either directly or indirectly held by Dutch provinces and municipalities) and regulated third party access to the networks was insisted upon. Liberalisation occurred in stages. The largest 350 users, (annual demand of at least 100 GWh) gained freedom of supplier immediately; the middle segment as of 2002; and, finally, residential consumers in 2004.

4.2 Netherlands Energy Mix

The Netherlands' energy industry benefits from its unique location. The northern part of the country is rich in natural gas. Around 46% of Dutch electricity consumption was met by electricity generated from natural gas with

76 https://www.google.com/url?sa=i&rct=j&q=&esrc=s&source=images&cd=&ved=2ahUKEwj0-NDo9-rhAhWZRBUIHTlcAaMQjRx6BAgBEAQ&url=https%3A%2F%2Fwww.ru.nl%2Fpublish%2Fpages%2F769526%2Fz_maarten_bovy_scriptie.pdf&psig=AOvVaw2SvSY60rERf1_uCX9HQOSZ&ust=1556271107361944

77 van Damme, E. "Liberalizing the Dutch Energy Market: 1998-2004" (2005) Tilburg University

a further 35% coming from coal in 2016[78]. Only 13% of electricity comes from renewable sources. This was partly due to the absence of large-scale hydro generation, solar usage, and onshore wind (due to population density).

Electricity consumption in the Netherlands for the year to Feb 2018 was 120.7TWhs[79]. 18TWhs of this demand was met from renewable sources, which compared with 16.7TWhs in 2017 and 15 TWhs in 2016.

Of the renewable sources wind turbines, with a share of 55 percent, were the largest contributor. This was followed by biomass at 27 percent. Solar panels accounted for nearly 18 percent, against 13 percent in 2017. The share of hydropower in electricity production was limited to 0.5 percent.

The share of renewable electricity in total Dutch electricity consumption increased from 14 percent in 2017 to 15 percent in 2018.[80] Figure 4.2a highlights the changing share of renewables since 2010.[81]

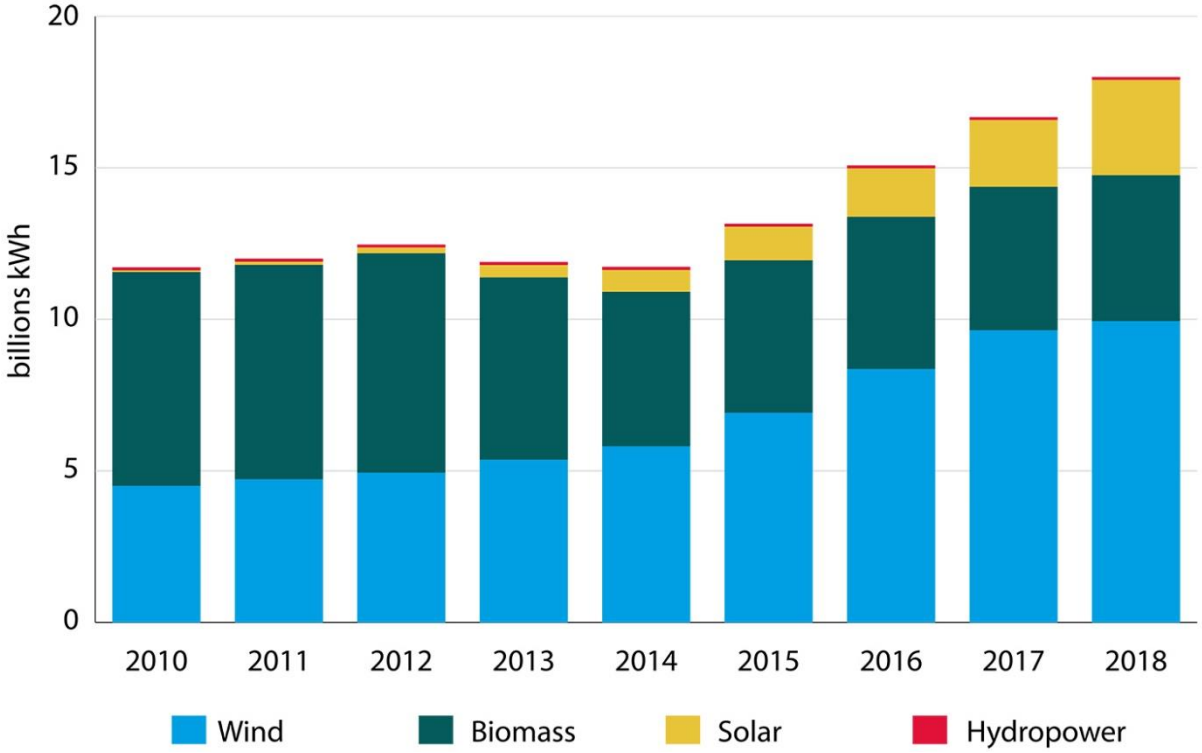

Figure 4.2a Total primary energy supply in the Netherlands between 2010 and 2018

78 https://www.export.gov/article?id=Netherlands-Energy

79 https://www.ceicdata.com/en/netherlands/electricity-supply-and-consumption/electricity-consumption

80 Official Netherlands statistics. Available at: https://www.cbs.nl/en-gb/news/2019/09/mainly-more-green-electricity-from-solar-power

81 Source: https://www.cbs.nl/en-gb/news/2019/09/mainly-more-green-electricity-from-solar-power

4.3 Reform of the Netherlands Energy Market

In 2011, the Dutch government published its energy report, in which it based its future energy policy on both international and economic policy.[82] In concrete terms this included: a) a modern industrial policy to strengthen the competitiveness of the Dutch energy market and b) expanding its renewable energy portfolio at the lowest possible cost through the Sustainable Energy Incentive Scheme.

In 2016, a further Energy Report provided the cabinet's integrated vision of the Netherlands' future energy supply. It was partly based on the recommendations provided in the document 'CO2-free nation: towards a renewable energy supply in 2050'. As with other countries, the primary consideration was meeting its obligations to reduce CO_2 emissions. However, there were other pressures that demanded new solutions, namely a series of earthquakes in the Groningen area (where the gas fields are located) and the increasing importance of variable renewable energy.

Recognising the energy market is in transition, the Dutch government's view in their report was to increase flexibility in the energy system in order to facilitate innovation and enable new entrants to join the market. In order to make this framework a reality, a number of key points needed to be addressed:

- a clear and consistent market framework that would assure the public and investors;
- implementation of goal-orientated regulations so that the regulator only indicates which interests must be served by a certain measure, instead of seeking to describe precisely how these interests should be safeguarded; and
- a market that facilitates new and innovative products and services, such as charging stations for electric vehicles, smart meters to encourage energy conservation and energy service companies (ESCOs) that provide energy to groups of users.

In 2016, a pilot of 203 homes was undertaken in the Municipality of Heerhugowaard and subsidised by the Dutch Ministry of Economic Affairs' Innovation Programme Intelligent Grids.[83] Of the sample, 183 had solar panels (with an average generation of 6.7 kWh per day), 95 households with a PV-switch, 49 households with a heat pump, 45 households with an electric boiler, and 14 households with a fuel cell. These appliances were controlled automatically – participants did not need to do anything themselves. Each participant was able to gain insight into the system via a user portal, a smart meter and a smart thermostat in the home.

During the pilot, the flexibility was traded on a flexibility market. The Universal Smart Energy Framework (USEF) market regulations were applied for this.[84] In summary, at the heart of the Framework was the aggregator whose role was to collect flexibility amongst prosumers and offer this as a service to the Balance Responsible Party (BRP) and DSO. The BRP then used the flexibility to manage the balance between electricity supply and demand.

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82 "Energy Report 2011". Ministry of Economic Affairs, Agriculture and Innovation.

83 Available online: http://www.edsoforsmartgrids.eu/wp-content/uploads/EnergieKoplopersEngels_FinalReport_2016_vs4.pdf

84 For further details see https://www.usef.energy

The project focused on four key market participants:

- **Prosumer** – The study found that an aggregator needed to offer a compelling value proposition to prosumers. This included both a compelling story and a value proposition that was easy to understand. Automatic control was another key facet with 72% of participants reporting that they found this highly convenient. The prosumer also valued receiving a fixed flexibility fee over dynamic tariffs.

- **DSO** – The pilot demonstrated that flexibility had the potential to prevent serious congestion on the network. However, above the congestion limit of 200kW there were still a number of peaks that were not resolved – mainly because the flexibility had already been sold to the BRP.

- **BRP** – The adoption of flexibility was of value to the BRP. The BRP was able to increase the value of its portfolio through flexibility in the imbalance market. However, on the down side, the portfolio was exposed to more risks mainly because the aggregator was unable to stick completely to its agreed plan.

- **Aggregator** – On average, the aggregator delivered 2/3 of the sold flexibility. Although the supply of flexibility is primarily achieved through control of the smart appliances, other factors also proved to be important. These included unforeseen changes in a household's electricity consumption or appliances that did not function properly.

The pilot study demonstrated the successful trading of flexibility through a market mechanism. However, in order to adopt such a market approach on a national scale the report highlighted a number of barriers that needed to be overcome.

From a DSO perspective, the key issue is perceived to be providing grid operators with the opportunity to use flexibility as an alternative to grid reinforcement. Currently, the DSO is regulatorily obliged to reinforce their infrastructure if there is a peak load that is too high for the current network. In doing so, the DSO may not be able to deliver the best societal or most economic outcome because they are unable to use the alternative options that are now being created. Consequently, legislative change will be needed to enable this and to ensure a flexibility market is an equal alternative to conventional options such as grid reinforcement.

Another key area the pilot highlighted, and one which has been a recurring theme across a number of geographies, is how to apportion risk in a flexibility market. One of the key tenets of a flexibility market is forecasting potential issues and there is an inherent risk that forecasts could turn out be incorrect. An unusual feature of this Study was that the risk was borne exclusively by the aggregator, which might well (at least partly) explain why the aggregator only delivered 2/3 of the sold flexibility. It is important to remember, however, that the model used, USEF, was developed within the Netherlands and may not be fit for all purposes and across all geographies.

4.4 Market Facilitation

TenneT, as the Transmission System Operator, is responsible for maintaining the system in balance and procurement of suitable ancillary services to enable this.

There does not yet appear to be any clarity on the scope of any obligations surrounding facilitation of new markets or related to the scope of those obligations.

Innovation projects such as Enexis's Jouw Energie Moment have begun to establish the technical potential for the use of mass market demand side flexibility from low carbon technologies to help satisfy system needs. Both Stedin and Alliander (as the parent of Liander) have been partners in the development of the Universal Smart Energy Framework and the associated market rules.

4.5 Lessons for the GB market

The Netherlands is widely regarded as one of the leading territories in the energy transition and the Dutch DSOs have undertaken a number of innovation projects looking at how access to demand side flexibility can benefit market participants and, therefore, ultimately the consumer in a well-functioning market.

Like the GB market, the Dutch market was an early mover in the unbundling of supply, transmission, distribution and retail.

Whilst the Dutch market has a strong focus on decarbonising its energy system it does not have the same practical pressures as the British market. The coal phase out in NL is not due to complete until 2029[85], compared with the 2025 emission limit for the UK and coal still contributed some 35% of production in 2016 compared to just 9% in the UK. Three of the Netherland's five coal plants were commissioned in 2015 and 2016, so will retire less than half way through their life.

The Netherlands remains heavily dependent on thermal power generation, with it accounting for more than 70% of installed capacity in 2018. By 2030, gas generation is still expected to account for 30% of installed capacity, with the gap expecting to be filled by solar and wind reaching 60% of installed capacity[86].

This compares with almost 30GW of coal and gas generating capacity due to retire in Britain by 2025.

This presents Britain with an unparalleled opportunity to lead on the development of the market frameworks for flexibility because of the necessary rate of adoption of both low carbon generation and low carbon demand technologies.

4.6 Relevance to TRANSITION

The Dutch DSOs have undertaken a number of technical feasibility projects with respect to understanding the value of alternative sources of flexibility and some of the DSOs have collaborated on the development of the Universal Smart Energy Framework. However, this review did not identify significant activity looking at market mechanisms that would allow flexibility from distributed energy resources to be accessed by different market actors for different purposes.

TRANSITION will maintain a watching brief on developments in the Dutch market and assess the relevance of any emerging learning to TRANSITION's learning objectives.

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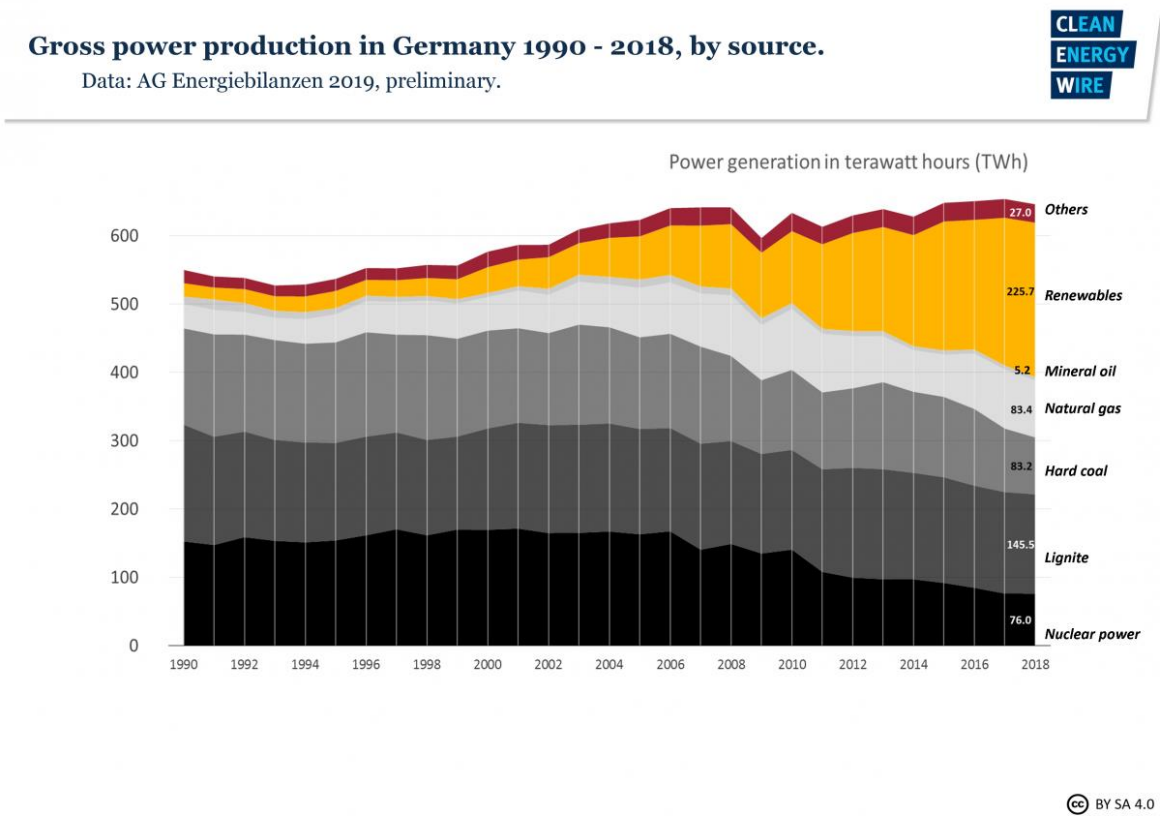
85 https://beyond-coal.eu/wp-content/uploads/2018/11/Overview-of-national-coal-phase-out-announcements-Europe-Beyond-Coal-November-2018.pdf

86 'The Netherlands Power Market Outlook to 2030, Update 2019', GlobalData

5 Germany

5.1 German Market Context

Germany is the largest power market in Europe with a gross electricity production of 646TWhs as of 2017.[87] The fuel mix is predominantly based on fossil fuels with 36% being accounted for by coal and oil and 13% by natural gas. The level of energy supplied from nuclear continues to decline down to 11.7% in 2018 from 14.2% in 2015. In terms of renewable generation, wind power accounts for the largest amount standing at 17.3% of total generation. Photovoltaic accounts for 7.2%.[88] After only a slight increase in renewable electricity generation in 2016, there was a substantial increase of 24.6TWhs in 2017, with renewable electricity generation being equivalent to 35% of gross electricity consumption in 2018. Germany's changing energy mix is illustrated in Figure 5.1a.



87 Genesis online databank. Available at: https://www-genesis.destatis.de/genesis/online/data;sid=E3CC7A1994468DDFF5F2FC34A7AC7D01.GO_1_1

88 Federal Statistics Office, Gross Electricity Production in Germany from 2015 to 2017 (Available at: https://www.destatis.de/EN/FactsFigures/EconomicSectors/Energy/Production/Tables/GrossElectricityProduction.html

Figure 5.1a[89]

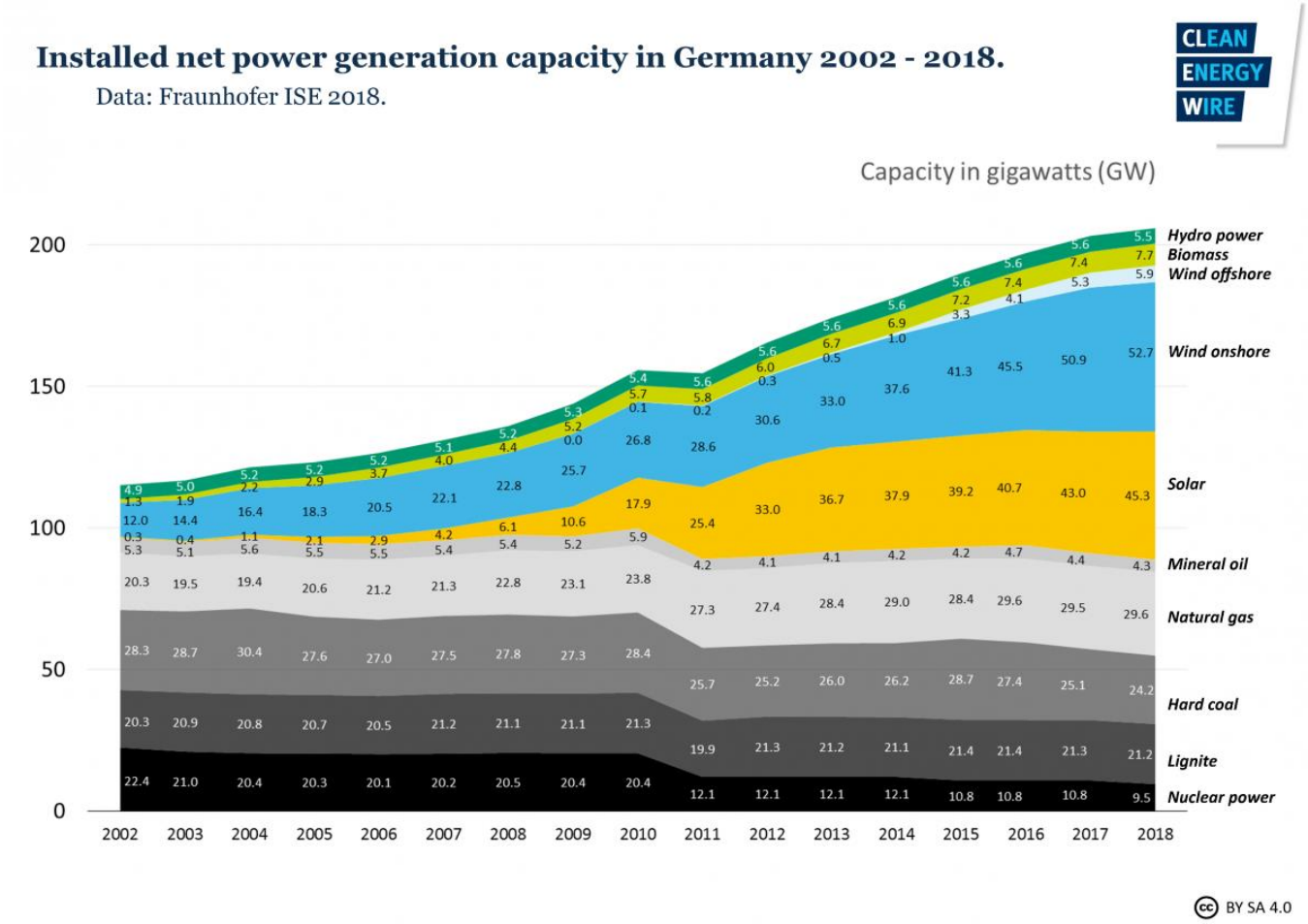


Figure 5.1b[90]

Germany has 206GW of installed generating capacity of which 24% is coal and oil, with a further 14% from natural gas. Renewables account for 57% of installed capacity, almost doubling since the decision to phase out nuclear following the Fukushima disaster in 2011. Germany's generation mix is illustrated in Figure 5.1b.

The transformation in Germany's fuel mix can be traced back to the Energy Act of 2011. Referred to as the "energy package", it consists of eight legal acts which significantly amend various areas of German energy law. Apart from implementing the provisions of the EU Third Energy Package, they lay the groundwork for the intended nuclear power phase-out in Germany by 31 December 2022, which was precipitated by the nuclear incident at Fukushima.[91]

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89 https://www.cleanenergywire.org/sites/default/files/styles/paragraph_text_image/public/paragraphs/images/fig2-gross-power-production-germany-1990-2018-1.png?itok=glXOK-fm

90 https://www.cleanenergywire.org/sites/default/files/styles/paragraph_text_image/public/fig1_installed_net_power_generation_capacity_in_germany_2002_2018.png?itok=dpkm8Ja9

91 "Changes to European Electricity and Gas Markets" (2012) 5th Edition. Allen & Overy

Germany's domestic electricity market was fully liberalized in 1998. Although there are currently over 800 individual providers, the majority of the country's electricity is still generated by four big energy companies: E.ON, RWE, Vattenfall and EnBW. The grid is operated by four TSOs who historically were owned by the four big energy generators. Through unbundling the four TSOs, or control areas, are operated by Amprion, TenneT, TransnetBW and 50Hertz. Their geographic footprints are shown in Figure 5.1c.

Figure 5.1c: German TSOs' geographic coverage.

In 2013 Germany had 880 DSOs, 75 of which had more than 100,000 customers.

Although Germany's power market is being deregulated it remains highly structured. Its geographic position at the centre of Europe has led to the potential for integration and interconnection with neighbouring markets. Germany has interconnectors with nine countries. The key stakeholders, regulators and power market participants are laid out in table 5.1a.[92]

National Regulatory Authority	Federal Network Agency (Bundesnetzagentur)
Unbundling Regime	Full Ownership Unbundling (FOU), Independent System Operator (ISO); Independent Transmission Operator (ITO)
Principal Electricity Generators	EnBW, RWE, Vattenfall, and municipality owned companies (Stadtwerke)
TSOs	50Hertz Transmission, Amprion, EnBW Transportnetz, TenneT TSO
Electricity Distributors	Approximately 880, 75 of which have more than 100,000 customers more than 700 have <30,000 customers

92 Source: The European Energy Handbook 2015. Available at: https://www.cobalt.legal/files/bundleNewsPost/2308/European_Energy_Handbook_2015.pdf

Principal Electricity Suppliers	EnBW, RWE, Vattenfall, and municipality owned utilities (Stadtwerke)
Interconnections	Austria, Switzerland, France, Luxembourg, Belgium, Netherlands, Denmark, Poland, Czech Republic

Table 5.1a

However, change continues in the German energy market. In 2018, the "big four" utilities fell out of the list of the country's 100 largest companies.[93] This has not been due to any single disruptive change but rather a continuous transition, which can be divided into 2 main phases: liberalisation and energy transition (Energiewende).

Liberalisation – The cornerstone of the 1998 German Energy Act was the end of regional monopolies, enabling consumers to choose their electricity supplier. It also provided third party access to the grid allowing electricity suppliers for the first time to sell power directly to a consumer. "Wheeling" fees, for access to the distribution grid, were initially negotiated directly, however in 2005 an amendment meant that the Federal Network Agency would regulate fees. This also led to unbundling of production, transmission and distribution.[94]

Energiewende (Energy Transition) – Germany is increasingly moving away from centralised production and distribution of power from fossil fuels and nuclear energy. It is transitioning towards a decentralised low-carbon model based on renewable energy. In addition to phasing out nuclear generation by 2022, the commitment is to increase the percentage of renewable energy from 12% in 2011, through to 18% in 2020 and 60% in 2050.

Renewable energy (RE) has been promoted for more than a decade in Germany. After the introduction of a Feed-in Tariff (FiT) scheme in 1991 (the first worldwide), the RE Act amendment of 2000 introduced the RE levy, through which the costs of the FiT are passed on to all power consumers. Since 2009, the government has sought to reduce the costs of RE roll-out when the FiT was reduced.

In 2012, the RE generating companies gained the option to sell RE power on the electricity markets. The market price has been topped up by a 'market premium', calculated as the difference between the market price and a hypothetical FiT. Since 2014, this direct marketing of RE power on the electricity market is mandatory. This had become necessary because of the rising costs associated with RE promotion schemes. Eventually, in 2016 the complete FiT was replaced by competitive tendering with specifically allocated bidding windows, which has resulted in bringing down the costs further.[95]

The price of energy generation decreased sharply as a result of the regulatory changes opening up the market and because of the increasing share of renewable energies. This increase of self-generation began to threaten the classic business models of municipalities of selling electricity. Directly after liberalisation, the prices for end consumers dropped by as much as 40%. However, this effect soon reversed, mainly due to the renewable energy levy. Figure 5.1d shows the power tariffs for households doubled between 2000 and 2016: from 13.94 to 28.69 EUR cents per kWh. This increase can mostly be attributed to the RE levy which made up 22% of the total tariff in 2016, compared to 1.4% in 2000, accounting for almost half the increase.

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93 https://www.cleanenergywire.org/news/renewables-overtake-coal-sino-german-cooperation/big-four-german-utilities-drop-out-top-100-company-list Accessed on 25/02/2019.

94 New Business Models for Municipalities in the Electricity and Energy Sector (2017). Available at: http://www.cityenergy.org.za/uploads/resource_406.pdf

95 New Business Models for Municipalities in the Electricity and Energy Sector (2017). Available at: http://www.cityenergy.org.za/uploads/resource_406.pdf

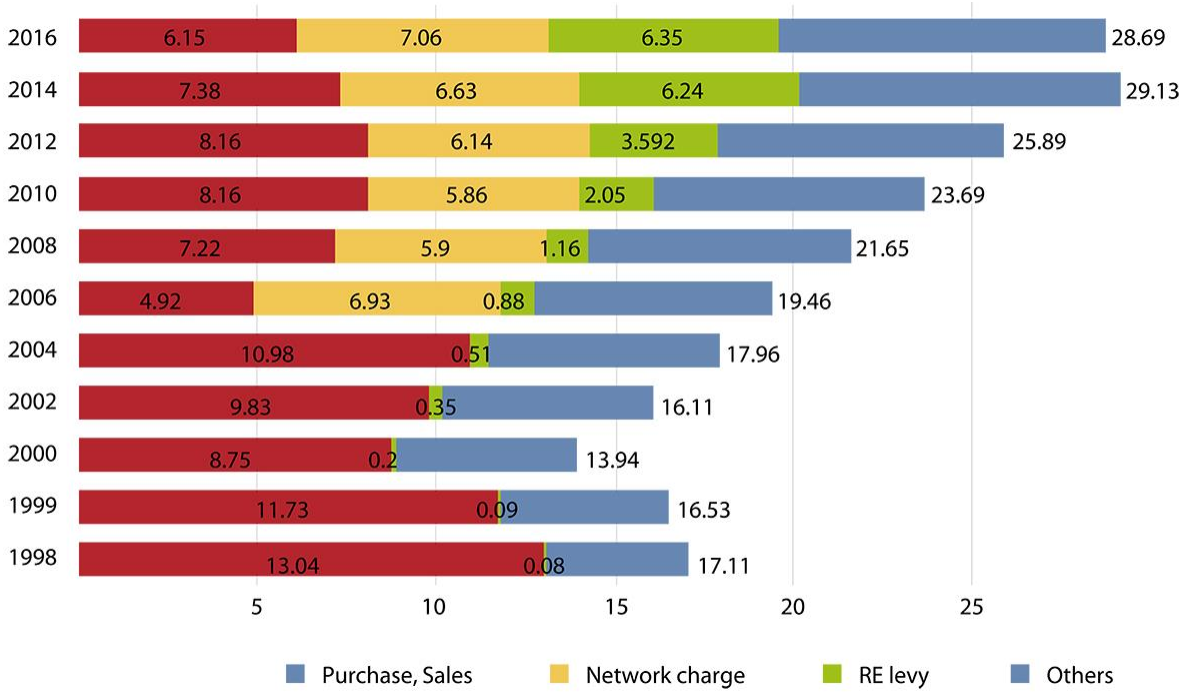

Figure 5.1d – Development and Structure of the Power Tariff

5.2 Demand Response in Germany

Today, a significant portion of demand-side flexibility in Germany remains untapped as a result of a number of barriers including:

- the amount of pre-qualification requirements at the asset level (rather than exclusively at a pooled level);
- the measurement requirements;
- the complex generation-centred programme requirements (e.g. minimum bid size, length in time of products);
- network fees that are designed to incentivise a flat consumption pattern, hence penalise those who provide flexibility to the system;
- the obligation for a third-party aggregator to get the bilateral agreement from its potential competitor, the balancing responsible party;
- the lack of a standardised role for third-party aggregators within the market model – requiring a multitude of contractual relationships between balance responsible parties, Suppliers and the third-party aggregators;
- no single standard, market roles not clearly defined, pooling across balancing zones.[96]

In order to address these challenges, in 2015 the German government published a white paper entitled “an electricity market for Germany’s energy transition”.[97] On the fundamental question of whether Germany should

96 Smart Energy Demand Coalition (SEDC). Mapping Demand Response in Europe Today. Smart Energy Demand Coalition. Available at: http://www.smarten.eu/wp-content/uploads/2015/09/Mapping-Demand-Response-in-Europe-Today-2015.pdf

install a capacity market or whether an energy-only market "2.0" would be sufficient, the decision was taken not to introduce a capacity market, but instead to further develop the energy-only market and complement it with a capacity reserve for the transition period ahead. It was felt that capacity markets are more susceptible to regulatory failure and therefore make it more difficult to transform the energy system. On the other hand, an electricity market 2.0 did not require any intervention in the market mechanism and was thus judged to be less susceptible to regulatory failure.

In total, 20 measures were suggested in order to implement the Electricity Market 2.0. These include:

- **Revising the special grid charges to allow for greater demand side flexibility.** As wind and solar power become the norm, the more important it is deemed to be for consumers to respond flexibly to market price signals. If suitable large-scale consumers are to utilise their potential for flexibility, they should be able to take account of the price signals of the electricity market in their decisions with as little distortion as possible.

- **Continuing to develop the grid charge system.** This measure is not only about reducing costs but also about them being distributed transparently and fairly. The level of grid charges varies considerably from region to region in Germany. The grid costs that accrue in a grid area are currently basically paid for by the final consumers in that grid area.

- **Clarifying rules for the aggregation of flexible electricity consumers.** At present, the market for demand side management is dominated by large consumers. The aggregation of medium-sized and small flexible electricity consumers can efficiently leverage unutilised potential. However, third-party aggregation is currently very difficult in Germany, due to regulatory barriers that require aggregators to ask the bilateral permission of multiple parties – including the consumer's balancing responsible party (BRP), a potential competitor – prior to offering a consumer's flexibility into the market. That is why the report identified the need to simplify the energy market to allow for aggregators to enter the balancing market.

5.3 Lessons for the GB market

Whilst the energy transition, Energiewende, in Germany is progressing, the research for this paper has not established formal thinking on the market structures to enable the trading of flexibility and value stacking across the different markets.

That said, the analysis of the German market has demonstrated an understanding of the barriers to realising the full value of flexibility that exist in Germany's current market arrangements. These include:

- the pre-qualification requirements for energy resources and the potential for these to be discriminatory in favour of certain types of resource;
- the measurement requirements;
- charging mechanisms that do not enable incentivisation of making flexibility available to the system;
- the obligation for a third-party aggregator to get the bilateral agreement with its potential competitor, the balancing responsible party;

97 Available at http://bccg.de/bild/webseite/fachartikel_57.pdf

- the lack of a standardised role for third-party aggregators within the market model – requiring a multitude of contractual relationships between balance responsible parties, suppliers and the third-party aggregators;
- a lack of clarity on market rule on the obligations associated with different market roles;
- an energy market only approach is viewed as being less susceptible to market failure than capacity markets.

5.4 Relevance to TRANSITION

It is worth noting that many of the barriers to accessing the flexibility of energy resources in the German market have been identified in the design of TRANSITION and are seeking to be understood through the trialling approach.

For instance, the notification of third party actions that could affect the positions of other market participants that are not counterparties to the transactions provides a mechanism to overcome the need for aggregators to establish bilateral relationships with the BRPs. Or the introduction of a neutral markets facilitation mechanism that reduces the need for a multitude of contractual relationships (so reducing the complexity associated to market entry).

TRANSITION will maintain a watching brief on developments in the German market and assess the relevance of any emerging learning to TRANSITION's learning objectives.

6 Sectoral Learning | Open Banking

6.1 Sectoral Context

Open Banking is a series of reforms on how banks deal with customer financial information, called for by competition watchdog the Competition and Markets Authority (CMA). The objective was to improve competition and customer choice in the banking sector by addressing structural barriers and opening up the access to data. Open Banking transferred ownership of customer account information from the banks to the customers themselves. The goal was to provide a mechanism that would enable customers that chose to opt in to Open Banking, to share their transactional data with other banks and third parties.

In addition, the new rules aim to promote the development and use of innovative online and mobile payments through Open Banking. For example, customers could connect their bank account to an app that would analyse their spending and recommend new products, such as a credit card or savings account that better matched the customer's needs, or enable customers to sign up to an aggregator that displays all of the customer's accounts with multiple banks in one place, enabling them to have a single view of their finances.

The European Parliament adopted a revised Payment Services Directive[98], known as PSD2, in October 2015. Following the conclusion of its Retail Banking Market Investigation[99] that ran between June 2013 and February 2017, in August 2016 the UK's Competition and Markets Authority (CMA), the a non-ministerial government department in the United Kingdom responsible for strengthening business competition and preventing and reducing anti-competitive activities, issued an order[100] that required the nine-biggest UK banks (HSBC, Barclays, RBS, Santander, Bank of Ireland, Allied Irish Bank, Danske Bank, Lloyds and Nationwide) had to allow direct access to their customers' data down to the level of transactions relating to current accounts (also referred to as 'transaction accounts').

These moves were regarded by some as the start of a revolution in banking[101], while other commentators were concerned about the potential dangers of sharing data. According to a survey by Which?[102] in late 2017, 92% of people were unaware of the imminent introduction of Open Banking from January 2018.

The Open Banking regulations came into force on January 13, 2018. The CMA created Open Banking Ltd (the Open Banking Implementation Entity (OBIE), a non-profit body) to establish and maintain software standards and industry guidelines that would drive competition and innovation in UK retail banking[103]. Enforcement powers

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98 DIRECTIVE (EU) 2015/2366 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 25 November 2015 on payment services in the internal market https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015L2366&from=EN

99 CMA Retail Banking Market Investigation https://www.gov.uk/cma-cases/review-of-banking-for-small-and-medium-sized-businesses-smes-in-the-uk

100 Retail Banking Market Investigation Order 2017 https://www.gov.uk/government/publications/retail-banking-market-investigation-order-2017

101 "Shake-up for UK bank accounts comes into force" https://www.ft.com/content/3930bbd2-f619-11e7-8715-e94187b3017e

102 Open banking: 92% of the public in the dark https://www.which.co.uk/news/2017/10/open-banking-92-of-the-public-in-the-dark/?utm_source=webgains&utm_medium=affiliates&utm_content=22278&source_code=314AGJ

103 Open Banking Ltd website: https://www.openbanking.org.uk/about-us/

remain with the CMA. Protection for consumers is the responsibility of the banks (for payments) or the Information Commissioner's Office (for data).

Open Banking was not universally supported. Concerns have been expressed by the UK Financial Inclusion Centre[104] that the benefits of Open Banking would accrue mainly to the techy-savvy and could lead to more financial exclusion for those on low incomes. The concerns seemed to surround consumers' ability to own their financial data and be able to determine the best deals that would meet their need from banks or from new market entrants. The exploitation of customers, either by businesses offering new types of expensive payday loans, or targeted marketing through the misuse of data and personal information that people have revealed in places such as social media, were perceived as risks.

The shifts in attitudes towards the issue of data ownership illustrated by regulations such as GDPR and concepts such as the Open Data movement are viewed as underpinning the move to Open Banking. Concepts such as Open Innovation[105] are also seen as important in realising the benefits of the move to Open Banking.

6.2 Market Facilitation

The Open Banking Implementation Entity (OBIE) plays a key role in opening up the market in financial services.

Open Banking is built on three principles:

1. The use of open application programmable interfaces (APIs) that enable third-party developers to build applications and services around the financial institution.
2. Greater financial transparency options for account holders ranging from open data to private data.
3. The use of open-source technology to achieve the aims.

OBIE is responsible for working with the UK's largest banks and building societies as well as challenger banks, financial technology companies, third party providers (such as 'aggregators') and consumer groups in order to:

- create and maintain security[106] and messaging standards;
- design and maintain the specifications for the APIs[107] that banks and building societies use to securely deliver Open Banking;
- manage the Open Banking Directory[108], which allows regulated participants like banks, building societies and third party providers to enrol in Open Banking;
- produce guidelines for participants in the Open Banking ecosystem, including guidelines on customer experience[109] that set out what people should reasonably expect from established banks and building societies, new challenger banks and third party providers and operational guidance[110];

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104 Financial Inclusion Centre: http://inclusioncentre.co.uk/wordpress29/

105 Open Innovation: https://en.wikipedia.org/wiki/Open_innovation

106 Open Banking Security Profile: https://openbanking.atlassian.net/wiki/spaces/DZ/pages/937820526/Security+Profile

107 Open Banking API specification: https://openbanking.atlassian.net/wiki/spaces/DZ/pages/23363964/Read+Write+Data+API+Specifications

108 Open Banking Directory https://www.openbanking.org.uk/providers/directory/

109 Open Banking Customer Experience Guidelines: https://www.openbanking.org.uk/wp-content/uploads/Customer-Experience-Guidelines-V1.3.0.pdf

- support regulated third party providers, such as 'aggregators', and banks and building societies to use the Open Banking standards;
- set out the process for managing disputes and complaints.

OBIE is funded by the UK's nine largest banks and building societies.

It is governed by the CMA, who retains the statutory enforcement powers. The guidance published by OBIE provides financial institutions, such as Account Servicing Payment Service Providers (ASPSPs), with recommendations on compliance with the regulatory requirements for a dedicated interface, as set out in PSD2[111], Regulatory Technical Standards (RTS)[112], European Banking Authority (EBA) Guidelines[113] and Financial Conduct Authority (FCA) Approach [114]documents. These documents provide recommendations on best practice in supporting the design of effective and high-performing API interfaces.

6.3 Lessons for the GB flexibility services market

The context of the implementation of Open Banking in the UK has a number of allegories for the DNO to DSO transition and the neutral facilitation of the markets for flexibility services and value stacking across those markets.

The intent of the Open Banking regulations to improve competition and customer choice in the banking sector has parallels to the policy and regulatory direction in energy to address barriers to customer choice and improve the functioning of the energy markets. Access to the increasing volumes of data that are becoming available as Britain transitions to a smart, flexible energy system is analogous to Open Banking addressing structural barriers and opening up the access to data and placing the customer at the heart of the market. Even the background of the European Directive PSD2 and the CMA Retail Banking Market Investigation could be seen as having parallels to the Third Energy Package[115] and the CMA Energy Market Investigation[116].

The approach to implementation of Open Banking and the mechanisms for opening up access to data provide some differences to the conventional approaches to facilitating access to data and market operations in the energy sector. The scope of the Open Banking Implementation Entity's (OBIE's) accountabilities are based around the development and maintenance of API, messaging and security standards for data exchange, enrolling

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110 Open Banking Operational Guidelines: https://www.openbanking.org.uk/wp-content/uploads/Operational-Guidelines-v1.1.0-master-01.05.2019.pdf

111 DIRECTIVE (EU) 2015/2366 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 25 November 2015 on payment services in the internal market https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015L2366&from=EN

112 Regulatory Technical Standards on strong customer authentication and secure communication under PSD2 https://eba.europa.eu/regulation-and-policy/payment-services-and-electronic-money/regulatory-technical-standards-on-strong-customer-authentication-and-secure-communication-under-psd2

113 EBA guidance on implementation of technical standards on strong customer authentication and common and secure communication under the PSD2 https://eba.europa.eu/-/eba-provides-clarity-to-market-participants-for-the-implementation-of-the-technical-standards-on-strong-customer-authentication-and-common-and-secure-

114 Comment on FCA guidance https://www.linklaters.com/en/insights/blogs/fintechlinks/2018/december/new-guidance-on-account-providers-open-banking-obligations-in-latest-fca-psd2-policy-statement

115 DIRECTIVE 2009/72/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 concerning common rules for the internal market in electricity https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=en

116 CMA Energy Market Investigation https://www.gov.uk/cma-cases/energy-market-investigation

regulated market participants (such as third party service providers (AISPs and PISPs) and account providers (ASPSPs)) and providing guidance on compliance with and best practice for relevant governance requirements.

OBIE provides the framework that enables a well-functioning market for Open Banking services but does not provide that infrastructure.

Two other aspects that are worthy of consideration in the context of the facilitation of the emerging market in flexibility services are:

- The approach to funding OBIE – the established major market participants are responsible for funding OBIE
- Market participants are regulated.

6.4 Relevance to TRANSITION

Open Banking's approach to opening access to data is being considered in TRANSITION's requirements for exchange of data between industry actors in order to facilitate trading in flexibility services and optimisation of decision making.

7 Sectoral Learning | Transport for London

7.1 Sectoral Context

Transport for London (TfL) is part of the Greater London Authority (GLA) and is publicly owned. It is the local government body responsible for implementing transport strategy and managing transport services across the UK capital.

It oversees almost all aspects of transport in London, managing London's buses, the Tube network, Docklands Light Railway, Overground, Tramlink, the cycle hire scheme, River Services, coach stations and the Emirates Air Line cable cars that cross the River Thames. It controls traffic flow on London's 580km network of main roads via 6,000 traffic lights. TfL also runs the London's Congestion Charge scheme and regulates the taxis and private hire vehicles. All of this transport infrastructure enables 31 million journeys to be made each day.[117] [118]

TfL was regarded as being cautious in its approach to opening up access to its data in 2011, although the roots of its journey can be traced back to 2009. By 2016, access to TfL's open data sets, or more precisely the apps built on the back of the use of this data, were being accessed by millions of London transport users every day. The benefit in terms of convenience for TfL's users in informing their transport choices and their time savings has been monetised to deliver tens of millions savings to its core customer base, all for comparatively low investment.

TfL's original decision to open its data was initially based on adopting an experimental approach as they had been unable to model a business case for open data. With the growing adoption of smart devices giving TfL's customers access to a wide variety of data and services, they knew their customers also wanted access to information about transport services to be able to plan their journeys.

TfL judged that in-house development of apps for all the different smart devices and operating systems would be complex and expensive. This was a key factor in the decision to open their data. Through this approach TfL was able to establish the benefits of an open data policy whilst managing the expense and risk of developing the necessary skills themselves.

By 2019, over 11,000 developers have registered to access and make use of TfL's open data. There are over 650 travel apps in the UK and over 46% of Londoners regularly use apps accessing the 80 separate datasets TfL makes accessible via a standard Application Programming Interface (API). These include real-time feeds (such as Tube departure boards, live traffic disruption, live bus arrivals, and TfL's Journey Planner API), fixed datasets (such as timetables, station locations, and station facilities) and transparency-oriented datasets (detailing operational performance).[119] [120]

This has also led to a cultural shift within TfL, with 'Open Data thinking' now "embedded" across the organisation. TfL's experience with open data has also acted as a reference that has enabled other transport authorities to justify opening up their data sets.

In October 2017, TfL established that open access to their data provides the following benefits[121]:

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117 Transport for London Get Set, Go! http://odimpact.org/files/case-studies-transport-for-london.pdf

118 https://www.intelligenttransport.com/transport-articles/65404/opening-data-full-capacity-transport/

119 https://tfl.gov.uk/info-for/media/press-releases/2017/october/tfl-s-free-open-data-boosts-london-s-economy

120 https://www.intelligenttransport.com/transport-articles/65404/opening-data-full-capacity-transport/

121 https://tfl.gov.uk/info-for/media/press-releases/2017/october/tfl-s-free-open-data-boosts-london-s-economy

- Saved time for passengers. TfL's customers are better able to plan journeys using apps with real-time information and advice on their best journey options. Estimated benefit of between £70m and £90m per year.
- Better information to plan journeys, travel more easily and take more journeys. Customers can use apps to better plan journeys, enabling them to use TfL services more regularly and access other services. Conservatively, the value of these journeys is estimated at up to £20m per year.
- Creating commercial opportunities for third party developers. A wide range of companies now use TfL's open data commercially to help generate revenue. Having free and up-to-date access to this data increases the 'Gross Value Add' (analogous to GDP) that these companies contribute to the London economy, both directly and across the supply chain and wider economy, estimated to be between £12m and £15m per year.
- Leveraging value and savings from partnerships with major customer facing technology platform owners. TfL receives back significant data on areas it does not itself collect data (e.g. crowdsourced traffic data). This allows TfL to get an even better understanding of journeys in London and improve its operations.

TfL recognises that, as a public body, the data they collect is publicly owned. By opening up access to the data TfL is effectively crowdsourcing innovation through enabling thousands of developers to work on designing and building applications, services and tools with the data and APIs. Data is made available as XML wherever possible.

The GLA has built on TfL's experience through the London Infrastructure Mapping Application[122], a new platform that allows utilities, boroughs, the Mayor of London and TfL to share information relevant to infrastructure investment and planning. By bringing together a range of data, the Infrastructure Mapping Application facilitates collaboration, improves approaches to construction and design, and enables identification of future demand and potential capacity constraints. The project has provided evidence that investment can be better aligned with objectives – such as reducing disruption throughout London by enabling projects such as roadworks to be timed better and cost savings to be realised through coordination of construction (e.g. joint ducting of utility cables and pipes). Analysis by the GLA found that £4.2m could be saved in avoided delays, significantly exceeding the cost of developing the Application.

7.2 Market Facilitation

TfL's approach to opening up its data does not directly enable a market in transport services. It has, however, enabled a market for transport information and journey planning services to be established. Indirectly this visibility of London's transport system performance is facilitating a form of demand management based on TfL users being able to plan their quickest or most convenient route at any given time.

Transport for London has, in effect, outsourced the delivery of transport information and journey planning to the 11,000 registered developers who are offering TfL's customers choices about how they plan their travel. Innovative business models are developing around the provision of the apps that provide travellers with access to the information they require.

TfL's approach to opening up their data is straight forward, simply requiring developers to register to make use of the standard API that enables access to the 80 datasets TfL has so far made open.

7.3 Lessons for the GB flexibility services market

122 Data for the Public Good https://www.nic.org.uk/wp-content/uploads/Data-for-the-Public-Good-NIC-Report.pdf

The context of TfL opening access to its data has a number of allegories for the DNO to DSO transition and the neutral facilitation of the markets for flexibility services and value stacking across those markets. The potential for additional value to accrue to DSOs from opening up a broader set of DSO data is also highlighted.

TfL, being publicly owned, considered its data to be public data. Whilst in Britain the DNOs are in the private sector, arguments have been made the data associated to DNO assets should be considered public data and the system data should be opened up for the public good. It has been estimated that establishing automated data sharing processes could raise utility companies' profits by 20-30%, and increase staff productivity by 15%[123].

The effective 'crowdsourcing of innovation' has enabled a new market for travel planning applications and services to develop, empowering consumers to plan their journeys in the most effective way through the visibility of the performance of the transport infrastructure. Analogies could be seen here with the potential for investors in low carbon technologies to identify and target areas of the distribution infrastructure that have the greatest headroom to support a connection, or could benefit the most from the flexibility that such a resource (e.g. a battery) could provide.

Unlike other examples of market facilitation and opening up access to data, TfL took the decision itself to make its data available on an experimental basis. The experimental approach was chosen because TfL was unable to create a compelling investment case for opening access to its data. By adopting this approach it was able to progressively build confidence in the value of incrementally opening up access to its data.

TfL achieved opening up access to its data through development and maintenance of an API and implementing registration arrangements for developers.

7.4 Relevance to TRANSITION

TfL's approach to opening access to data is being considered in TRANSITION's requirements for exchange of data between industry actors in order to facilitate trading in flexibility services and optimisation of decision making.

[123] Data for the Public Good https://www.nic.org.uk/wp-content/uploads/Data-for-the-Public-Good-NIC-Report.pdf

8 Summary of Learning for TRANSITION

This section summarises the key learning from the review of market facilitation in different territories for DSO and from different sectors. It seeks to identify learning points that will be taken forward and used to inform the approach that will be taken by TRANSITION to deliver the project's learning objectives.

The overall conclusion of this review was that TRANSITION's scope and focus seeks to address the challenges that remain outstanding in other territories. As such, TRANSITION is both timely and presents an opportunity for the British market to take a leading position in the facilitation of markets in decentralised, low carbon electricity systems.

8.1 Market Rules and Industry Actor Roles & Responsibilities

When reviewing electricity markets in other territories, the importance of market structure and the roles and responsibilities assigned to the different industry actors became clear.

California experienced market failure in the early 2000s and PG&E filed for bankruptcy again in early 2019. The obligations placed on vertically integrated, geographic monopoly investor owned utilities did not appear to have been addressed with the emergence of new market participants such as Consumer Choice Aggregators (CCA) and Direct Access Providers (ESPs), and hence the associated changing profile of risk.

Equally, there did not appear to be a formalised mechanism that enabled accessibility of data that would provide industry actors with visibility of third party actions that could impact the positions (such as operation of the distribution system or wholesale portfolio optimisation) of industry actors fulfilling other industry roles. Nor was a formal mechanism identified that would enable value stacking by facilitating flexible energy resources to be traded across different markets.

California's regulatory bodies are reassessing the current regulatory frameworks with respect to their suitability for a more decentralised system.

The learning from the review of California will be taken forward in the development of the market rules that will be trialled in TRANSITION with learning objectives relating to the obligations placed on the different industry actor roles, the alignment of risks and the visibility of the data required to manage those risks effectively.

TRANSITION will maintain a watching brief on California in respect of the review of their regulatory frameworks and the relevance to the British market context.

The significant finding from the review of the Australian market was from the Finkle review, which was the importance of establishing a level playing field for services and ensuring the separation of the provision of regulated and optimising services. This was based on a judgement that value created from consumer choice should not be outweighed by the value accruing to network businesses from being able to control the operation of their infrastructures.

The review of the German market identified the importance of visibility of third party actions that could affect the positions of other market participants that are not counterparties to the transactions. This requirement delivers a mechanism to overcome the need for aggregators to establish bilateral relationships with the BRPs. Or the introduction of a neutral markets facilitation mechanism that reduces the need for a multitude of contractual relationships (so reducing the complexity associated to market entry).

The separation of regulated and optimising services and the need for mechanisms to provide visibility of third party actions were already within the TRANSITION design. As such, the review provides validation of the TRANSITION learning objectives.

Overall, the learning from the review of these territories validated the need for TRANSITION. Its focus is on understanding market-based approaches as a mechanism to support consumer choice and maximising the value that can accrue from energy resources when they are accessible and able to provide services across markets. TRANSITION will deliver an evidential basis that can be used to inform decision on the optimum market structure, appropriate allocation of obligations to industry actors and enable value stacking across markets.

8.2 Approaches to Market Facilitation and Data Sharing

Whilst the review of approaches to utility market facilitation in other territories validated the need for projects such as TRANSITION to inform market design, the review of approaches in other sectors gave insights as to how this might be achieved.

Open Banking illustrated how accessibility of data can deliver new choices for consumers by addressing barriers to development of new services. The review of Transport for London's approach illustrated how making their data openly available effectively enabled them to 'outsource innovation'; simultaneously enabling travellers to be offered new services and also helping manage demand on the transport infrastructure.

In both cases, the approach to making data accessible was via publishing APIs (Application Programming Interfaces) and getting organisations or people to sign up to access the data.

TRANSITION is, at the time of publication of this report, developing the requirements for the trials phase. The emerging learning from this review has been fed into the development of those requirements. The API approach to delivering the requirements is being considered in the context of value for money for the trials and delivering the learning objectives versus the appropriateness for facilitating the final market design.

Appendix A

Research Methods

This review was conducted as a desk top review of available, public-domain literature with some limited structured discussions with contacts in the relevant areas. The main purpose of these discussions was to confirm the identified literature sources or to gain access to relevant literature for review.

The objective of the review was to identify what was happening in the target markets and understand the drivers for the various initiatives. Factors such as energy security challenges, electricity mix, the remaining lives of their existing generating capacity, the plans for its retirement, the policies that promote a move to a low carbon electricity system and market structure (including the obligations of the different industry actors) were sought to be identified. These were used to assess the relevance of learning from a market and how that learning might apply in the British market context, specifically to the objectives of TRANSITION and how the learning could help inform the approach to the TRANSITION trials phase.

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Appendix B

Glossary of Terms

Acronym	Definition
AB	Assembly Bill (of the state of California)
ACER	Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AISP	Account Information Service Provider: a market player using a customer's account information to build new advisory and information services for customers following the introduction of Open Banking.
API	Application programming interface: a set of functions and procedures allowing the creation of applications that access the features or data of an operating system, application, or other service.
ASPSP	Account Servicing Payment Service Provider: any financial institution that offers a payment account with online access.
BRP	Balance Responsible Party: a market participant or its chosen representative responsible for its imbalances[124].
CCA	Community Choice Aggregator
CAISO	California Independent System Operator
CEC	California Energy Commission
COAG	Council of Australian Governments
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
DB	Distribution Business (Australia)
DER	Distributed Energy Resource
DG	Distributed Generation
DNO	Distribution Network Operator (Britain)
DNSP	Distribution Network Service Provider (Australia)
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution System Operator (Europe)
EC	European Commission
EE	Energy Efficiency
ENTSO-e	European Network of Transmission System Operators - Electricity
ERGEG	European Regulators' Group for Electricity and Gas
ESCo	Energy Services Company
EU	European Union
EUETS	European Union Emissions Trading Scheme
EV	Electric Vehicle
ESP	Direct Access Provider (California)
FIT	Feed in Tariff
FOU	Full Ownership Unbundling
IDSM	Integrated Demand Side Management

[124] COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, Article 2(7)

IOU	Investor Owned Utility
ISO	Independent System Operator
ITO	Independent Transmission Operator
LBNL	Lawrence Berkeley National Laboratory
LSE	Load Serving Entity
NECF	National Energy Customer Framework (Australia)
NERC	North American Electricity Reliability Council
NEM	National Energy Market (Australia)
NER	National Energy Regime
OBIE	Open Banking Implementation Entity
PISP	Payment Initiation Service Provider: a service provider who can initiate a payment transaction on behalf of the customer, meaning they are able to withdraw the money directly from the customer's account where the customer has given consent following the introduction of Open Banking.
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PTO	Participating Transmission Owners
RE	Renewable Energy
RES	Renewable Energy Sources
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organisation (North America)
RTP	Real Time Pricing
SB	Senate Bill (in California)
TfL	Transport for London
TBR	Time Based Rate
TNSP	Transmission Network Service Provider (Australia)
TOU	Time of Use
USEF	Universal Smart Energy Framework
VPP	Variable Peak Pricing (when related to tariffs and pricing)
VPP	Virtual Power Plant (when related to the aggregation of distributed power plant and distributed energy resources)

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