DEMOCRASI project

Work Package 1: Policy comparison and review

Report (final draft)

Photo credit: British Solar Renewables

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2. About Regen

Regen[1] is an independent centre of energy expertise, market insight and analysis, dedicated to transforming the energy system for a zero carbon future. We are a team of energy system and zero carbon technology experts, using detailed analysis and evidence-based research to underpin all aspects of our work.

Regen works with a wide range of industry and public-sector clients. Our mission-led approach has enabled us to work in collaboration with public and private organisations that are at the forefront of the energy system transformation, helping them to shape future policy, develop new markets and business opportunities and to exploit technological innovation.

Our work covers a wide spectrum of energy related capabilities including:

- Energy strategy development and decarbonisation pathway analysis.
- Future energy scenario planning (Distribution Future Energy Scenarios).
- Energy system modelling.
- GIS and spatial analysis of energy and related demographic data.
- Policy and market analysis.
- Economic and financial assessment and feasibility studies.
- Community energy and community stakeholder engagement.
- Customer engagement, including DNO sponsored community and customer forums.
- Communications, including animations, podcasts and our energy art programme.
- Policy and position papers, most recently in areas such as energy networks, energy storage, local energy markets and electric vehicles.
- Several innovation and pilot projects ranging from network innovation to smart energy systems to energy efficiency.

[1] Regen https://www.regen.co.uk/

3. Executive Summary

This report looks at the DEMOCRASI (Dispatchable Energy Market Optimized Constraint Real-time Aggregated System Interface) project, a leading smart grid innovation project based in Ontario, Canada. This project gives greater visibility of the behaviour of Distributed Energy Resources (DERs) to the main actors that are responsible for the operation of the electricity system. The project outputs include a joint product solution (combining Opus One Solutions and KiwiPower products), a pilot of this solution in Ontario and UK, and a Cost Benefit Analysis of these pilots under various scenarios.

This report compares the UK and Canadian electricity systems, with a focus on Great Britain (GB)[2]and Ontario. Some similarities are found, particularly in the generation sector. However, there are less similarities evident in other sectors, such as in electricity retail (Table 1). A list of key differences are identified, including, but not limited to:

- **Energy policy context** - The UK has a strong centralised decarbonisation policy framework in the legally binding Climate Change Act. Canada has an overarching framework and pricing scheme, but policies and implementation vary by province.

- **Networks** - Distribution Network Operators (DNOs) in the UK are privately-owned, regulated monopolies based on location and are separate entities to the electricity suppliers. In Ontario, there are currently 60 Local Distribution Companies (LDCs)[3] who act as both network operator and customer utility based on location, and they are a mix of municipally owned and privately-owned companies.

- **Status of flexibility markets** - Both jurisdictions are undergoing a transition in their electricity systems and significant reforms to their respective markets and services. In GB the National Grid ESO is replacing and reforming services and DNO-led local flexibility market auctions are increasing in size. In Ontario the Independent Electricity System Operator (IESO) is also reviewing the markets and services available but no LDC-led local flexibility markets are active.

Further analysis is available in Section 5.

[2] Northern Ireland (NI) is part of the UK, but not part of the Great Britain (GB). There are considerable differences between NI and GB in terms of governance, regulation and system operation
[3] Local Distribution Company (LDC) in Canada or Distribution Network Operator (DNO) in UK refer to the same type of organisation.

Table 1: Brief overview of similarity between GB and Ontario electricity systems per sector

Sector	Similarity rating (with RAG)	Summary
Energy policy context	**Medium**	The governance structure shares some similarities with overarching decisions coming from government but regulated independently.
Networks	**Medium**	Networks are split into high-voltage transmission and low-voltage distribution. However, there is more competition between network operators in Ontario than the UK.
Generation	**High**	Strong shift away from coal generation and towards renewable energy.
Retail	**Low**	Smart metering and fixed time of use tariffs are already in place with relatively low levels of competition in Ontario. In contrast, the smart meter rollout in the UK has been slow, but there is more competition between suppliers. Both markets are liberalised.
Energy system operation and markets	**Medium**	An electricity system operator operates markets to manage the power system. Regarding the markets, similar focus on DSR, capacity markets and flexibility.

The report then discusses the potential for applying the DEMOCRASI project to the UK, focused on GB. We conclude there are no hard barriers for delivery of DEMOCRASI project in the UK market, but there are a set of softer barriers, or potential challenges, to delivery that are set out in Table 2. Further detail is provided in Section 6.1.

Table 2: List of barriers for adoption of the DEMOCRASI project in the UK

Barrier type	Summary
Market access	• The existing markets and services for flexibility are changing, making it difficult to make a business case for aggregators and DER deployment. • Structure of markets, services, and governance in the UK is still weighted towards incumbent centralised energy utilities. • Lack of value for low carbon DERs in current markets and services. • Barriers for DER entry to certain markets and services remain. • Limited value and access in DNO local flexibility markets.
Data and network monitoring	• Poor progress on smart metering. • Metered data access restrictions. • Challenges in accessing network data. • Distribution network monitoring is limited, particularly at Low Voltage (LV) level.
DER deployment	• Revenue support schemes for renewable energy capacity do not support flexibility services. • Retail market reform has been proposed but not delivered in any meaningful way. • Lack of electrified heat DERs in the UK market. • Existing network capacity is focused in industrial areas and power station sites.
Competition for DEMOCRASI	• Competition from other similar models and products active in the market. • A more complex set of market actors to navigate due to market privatisation and liberalisation.

We also highlight a number of opportunities for the DEMOCRASI project associated with future value streams and services outlined in detail in Section 6.2. This includes an analysis of the different services procured by National Grid ESO and DNOs currently available and their level of DER liquidity and market stability. Overall, while there are some services that have good levels of DER liquidity, offer some market certainty, and align well with some DER technologies, the majority do not. A selection of the future opportunities are summarised in Figure 1.

Figure 1: A selection of the future value opportunities for the DEMOCRASI project

ESO services

- A changing set of service requirements including new reserve and frequency response services are set out in the National Grid ESO Market roadmap to 2025.
- More focus on whole system and locational aspects to new services with emerging regional constraint management markets, including voltage, reactive power, stability and inertia services.

Network charging

- There is likely to be changes that reduce the upfront connection costs for new DER projects, particularly in areas of network constraint that could increase deployment. The overall net impact on DERs will vary across the country and depend on how the methodologies are developed and applied.
- More investment by DNOs in network monitoring, internal capabilities and local flexibility markets will be needed in order to implement the changes.

DNO services

- Local flexibility markets are growing in scale and importance under the new business plans being developed. Including a 'flexibility first' approach to network investment decisions.

Sale of energy (wholesale and retail)

- New opportunities are emerging for DERs to access the wholesale electricity markets without going via a licenced supplier - improving market access.
- Changes to the electricity retail market are likely to be implemented that will help improve local energy offers and propositions.

The report then highlights lessons learnt from the UK that could apply to Ontario, which include:

- **Retail liberalisation** - Competition and liberalisation in the retail market means that there is an opportunity for new entrants and innovative models to enter the market.
- **Data availability and standardisation** - Requirements for all network operators to produce Digitalisation Strategies that meet minimum requirements set by the regulator and enable a move towards more open source data and greater innovation.
- **DSO model** – The energy regulator has required DNOs become Distribution System Operators (DSOs), taking a proactive approach to develop and use their networks more efficiently and identify flexible alternatives to network reinforcement.

Further detail is provided in Section 7.

In Section 8, we outline the changes being implemented in the EU Clean Energy for all Europeans Package (CEP) and identify three countries with different characteristics, and discuss the potential for DEMOCRASI entering those markets. France, Portugal and the Netherlands all present an opportunity for the DEMOCRASI project and we recommend closer examination of all three. Portugal is the market with significant potential as it more of an emerging market, with high renewable energy deployment, as well as growing levels of DER uptake.

Finally, we provide a set of recommendations for the DEMOCRASI project in Section 9. These include the following:

- **Continue to build relationships and engage with DNOs.** We recommend contacting each DNO to discuss the DEMOCRASI products and outputs, and opportunities to work together, whether through trials or rolling out as business as usual.
- **Identify and develop market opportunities**, including: capitalise on the maturing local flexibility markets in GB; engage in the formation of new regional constraint management markets; and closely monitor new services being developed by National Grid ESO.
- **Engage with the network companies on their Digitalisation Strategies**. Put pressure on DNOs to provide CIM standard network data and support them to identify use cases for other datasets.
- **Provide more content that communicates the DEMOCRASI project to a wider audience.** Additional non-technical content on a webpage defining the project outputs and sharing the latest updates, would help increase awareness and credibility**.** The webinar planned for September 2021 is a good opportunity for further project dissemination.

4. Background

4.1. The DEMOCRASI project

DEMOCRASI - Dispatchable Energy Market Optimized Constraint Real-time Aggregated System Interface, is a project partially funded under the Power Forward Challenge[4], a Canada-UK joint competition on Smart Energy Systems, funded by Natural Resources Canada (NRCan) and the Department for Business, Energy and Industrial Strategy (BEIS).

The £2.3 million smart grid project is based in Parry Sound, Ontario, Canada, where Bracebridge Generation, the owner and operator of assets, work with Lakeland Power Distribution, the network operator, under the same parent company - Lakeland Holdings Ltd.

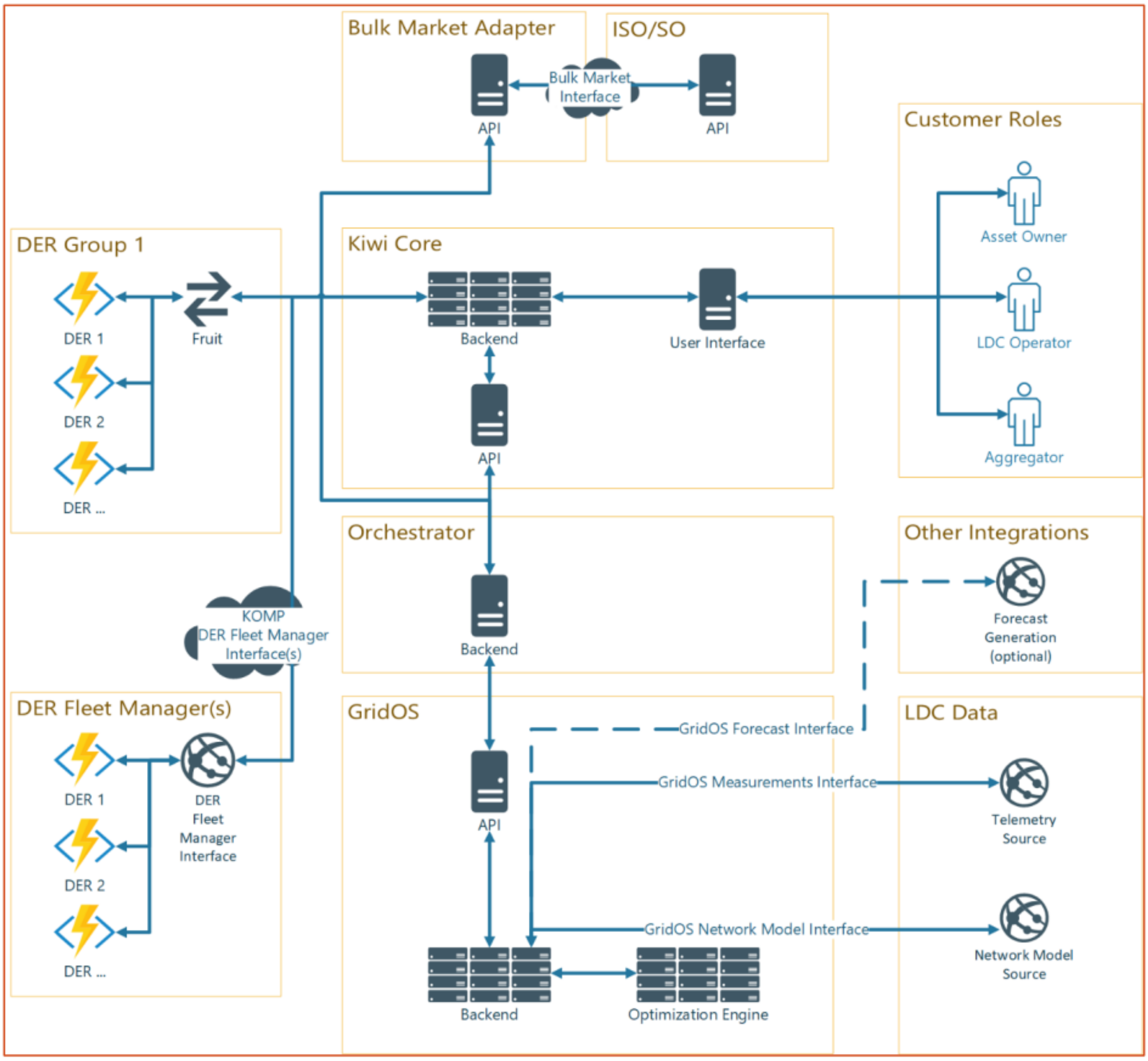
The problem that this project is looking to solve, is the need for increased visibility of aggregated DERs to the LDC. At present, dispatch of DERs is normally done without taking into account the distribution network limitations and wider system impacts, which can lead to asset degradation and costs to consumers.

This project gives greater visibility of the behaviour of DERs to the main actors that are responsible for the operation of the electricity system. The key output of the project is the design of a joint product solution, by combining services from Opus One Solutions (based in Canada) and Kiwi Power (based in the UK), to optimise and dispatch DERs in multiple markets, from the system operator and LDC, while taking into account the local distribution network limitations (power capacity, voltage, impedance, losses, and power factors). Figure 2 provides an overview of the joint product architecture. This joint product provides enhanced DER optimisation, visibility, and control that benefits the distribution network, focusing on system operator markets and including localised flexibility services where possible.

A further output of the project is to pilot the joint product solution in Parry Sound, Ontario via simulations into the Capacity Auction market run by the IESO. In addition, the project will deliver a separate pilot, simulating the use of assets in the UK Short Term Operating Reserve (STOR) service from National Grid Electricity System Operator (ESO)[5]. The final aspect of the project is to provide a Cost Benefit Analysis of the joint product solution from both pilots and assess outputs under various scenarios.

[4] NRCan, 2021 *Power Forward Challenge* https://impact.canada.ca/en/challenges/power-forward
[5] NB. – this is to be carried out using the STOR market characteristics before the changes to day-ahead tenders that are due to be implemented on 1 April 2021.

Figure 2: Graphic of the DEMOCRASI joint product solution architecture[6]. The Grid OS software is owned by Opus One Solutions, KIWI Core and Komp[7] are owned by Kiwi Power.



The DEMOCRASI project is working alongside the £5.5 million Smart, Proactive, Enabled, Energy Distribution – Intelligently, Efficiently and Responsive - SPEEDIER project[8] that is led by Bracebridge Generation, based in same area - Parry Sound, Ontario. This project aims to deploy flexible assets such as a large scale battery (1.25 MW/2.5 MWh), 10 residential batteries (5 kW/13.5 kWh each), 50 hot water tank controllers, alongside 500 kW of solar PV. These assets are to be used in the DEMOCRASI project pilot output.

[6] Opus One, 2020 *1.5 Joint Product Specification Document* Link N/A
[7] Kiwi Core and Kiwi Komp are separate software products from Kiwi Power.
[8] Bracebridge Generation, 2021 *SPEEDIER project* https://www.speedier.ca/

4.2. Introduction

This document provides a high-level policy review, summarising the opportunities and barriers to implementation for the DEMOCRASI project in the UK. We review the key aspects of the DEMOCRASI project and comment on their applicability for the UK energy market. We also examine the value drivers for both Ontario and the UK and summarise the key differences between the two energy markets.

Regen has extensive energy policy knowledge and experience. We are well respected in UK policy circles as a constructive and solutions-focused organisation. As such, we have extensive relationships across the industry and have drawn upon the following information sources to inform this project:

- Ofgem's guidance for the current price control for Distribution Network Operators in the UK (RIIO-ED2).
- The work of the Energy Networks Association "Open Networks" project which is a collaborative project of all UK energy networks to identify and address barriers to Distribution Network Operators becoming Distribution System Operators.
- The work of the BEIS/Ofgem Smart Systems Forum that addresses the policy and regulatory issues in shifting to a smart, flexible decentralised energy system – on which Regen is represented by its Chief Executive, Merlin Hyman OBE.
- Regen's work as a partner in two Innovate UK funded detailed local energy system design projects, including the Zero Carbon Rugeley project.
- Regen's extensive relationships across the UK energy sector.

This report is structured around the following three key areas in the proposal document:

- The key differences between the Ontario and UK energy markets.
- The applicability and value of the DEMOCRASI project in the UK, especially in relation to RIIO-ED2.
- The policy and regulations that have been (or will be) implemented in the UK, and other international examples, that could be considered in Ontario to enable a smart, flexible energy system.

5. Comparison between the UK and Canadian electricity sectors

The key areas of interest for the DEMOCRASI project include, but are not limited to:

- Uptake of DERs – including solar PV, electricity storage, Electric Vehicles (EVs), heat pumps, refrigeration, smart immersion and hot water heaters, smart appliances and others.
- The system operation mechanisms and markets that are available to flexibility providers, such as DERs and aggregators.
- The level of rollout of network control and monitoring systems.
- Availability of detailed data on the electricity network characteristics (ideally in Common Information Model (CIM) format).
- A willing partnership with the local DSO.

These areas are crucial factors for the success of projects like DEMOCRASI. They are also fundamental aspects of decentralised and decarbonised electricity systems. This section of the report provides a comparison of the UK, focused on GB, and the Canadian, focused on Ontario, electricity systems. We summarise the themes that have emerged, comment on the similarity per area and list the main differences.

For more detailed analysis and background regarding the GB and Ontario electricity sectors please refer to the Appendix, Section 10.1 and Section 10.2.

5.1. Overview of UK electricity sector

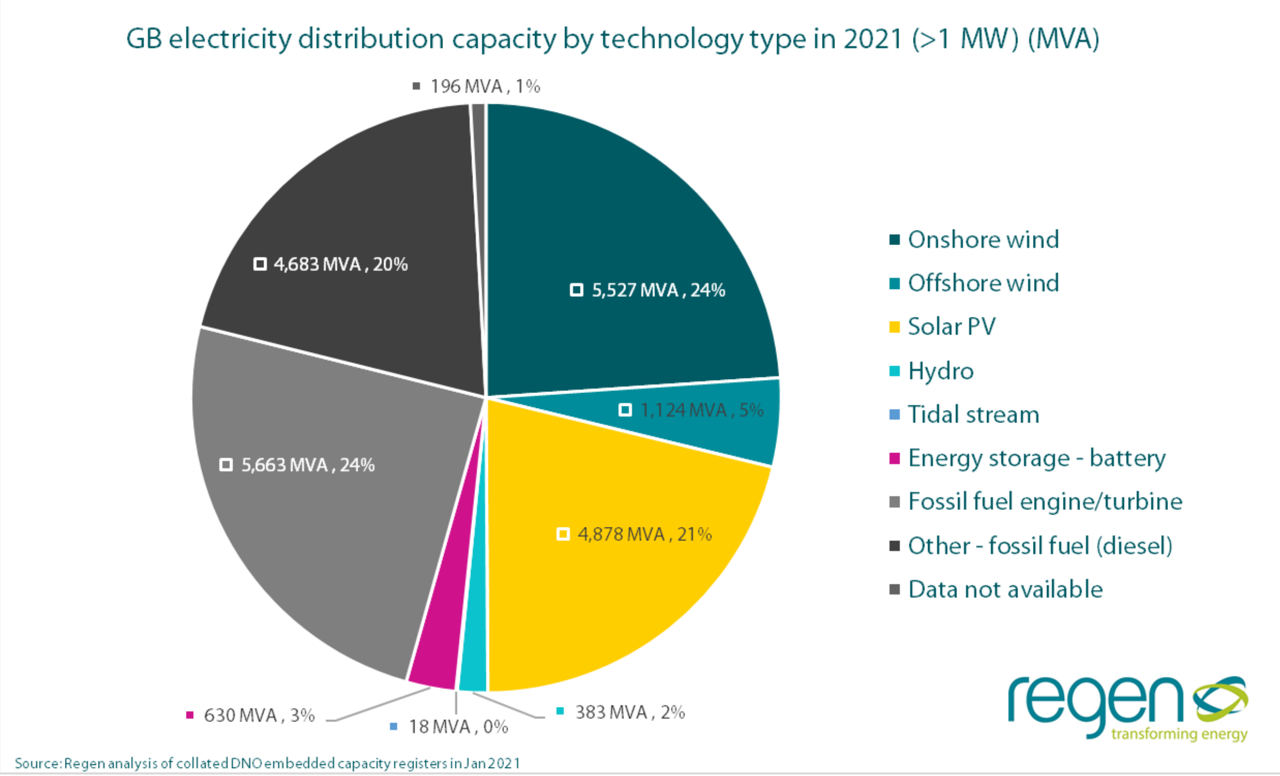
The UK is made up four countries, England, Wales, Scotland and Northern Ireland. GB, which excludes Northern Ireland, has a specific integrated electricity system, regulator (Ofgem), government department (BEIS), and system operator (National Grid ESO). Northern Ireland has a separate governance structure as energy policy is a devolved matter. The UK has a strong policy focus on decarbonisation with a legally binding net zero target, or 100% reduction in greenhouse gas emissions by 2050, from 1990 levels[9].

The UK has shown considerable growth in the deployment of DERs in recent years, due to revenue support schemes, technology development, and cost reductions. There were close to 870,000 installations under the Feed-in Tariff up to the end of 2019, the majority of which were solar PV on domestic buildings. Solar PV represents 21% of the connected generation capacity above 1 MW at the distribution level (Figure 3), and there is a 14 GW pipeline of subsidy-free sites with accepted connection offers. There is an estimated 1 GW of battery storage installed in the UK, the majority of which is connected at the distribution level (Figure 3). There is a further 5 GW pipeline of projects with accepted network connection offers. The amount of domestic energy storage is less well known. One company, Social Energy, claims to have 6,400 residential homes with batteries under a virtual power plant in the UK, that is bidding into frequency

[9] UK government, 2021 https://www.gov.uk/government/publications/the-uks-nationally-determined-contribution-communication-to-the-unfccc

response markets. See Appendices section 10.1.3 for more background on the UK electricity generation sector.

Figure 3: Pie chart showing the distribution connected generation capacity (above 1 MW) by technology type



There is a set of commercial flexibility services available from the system operator (National Grid ESO) including frequency response and reserve markets, with some restrictions in place that stop or limit DER and aggregator inclusion. Many of the services are still dominated by fossil fuel assets, however there is considerable change underway in the requirements and procurement of these services, due to reforms. For more detail refer to section 6.2.

In addition, local flexibility markets are used by DNOs to help manage the network in certain areas and there is a new flexibility first approach to network reinforcement. The distribution networks are managed by six DNOs that are privately owned regulated monopolies.

Smart meter rollout has been very slow, with only 36% of the targeted domestic and small non-domestic properties with a smart meter installed and operating in smart mode at the end of 2020, after eight years of the programme. Data access for third parties is restricted and network data has also been very difficult to access over recent years. However, the impact of the Energy Data Taskforce and requirement for all network operators to produce Digitalisation Strategies has started to change the sector. Some DNOs have started to provide their detailed network characteristic data in a Common Information Model (CIM) format and DNOs are very active in developing new processes and systems to help the integration of DERs and aggregators.

5.2. Overview of Canadian electricity sector

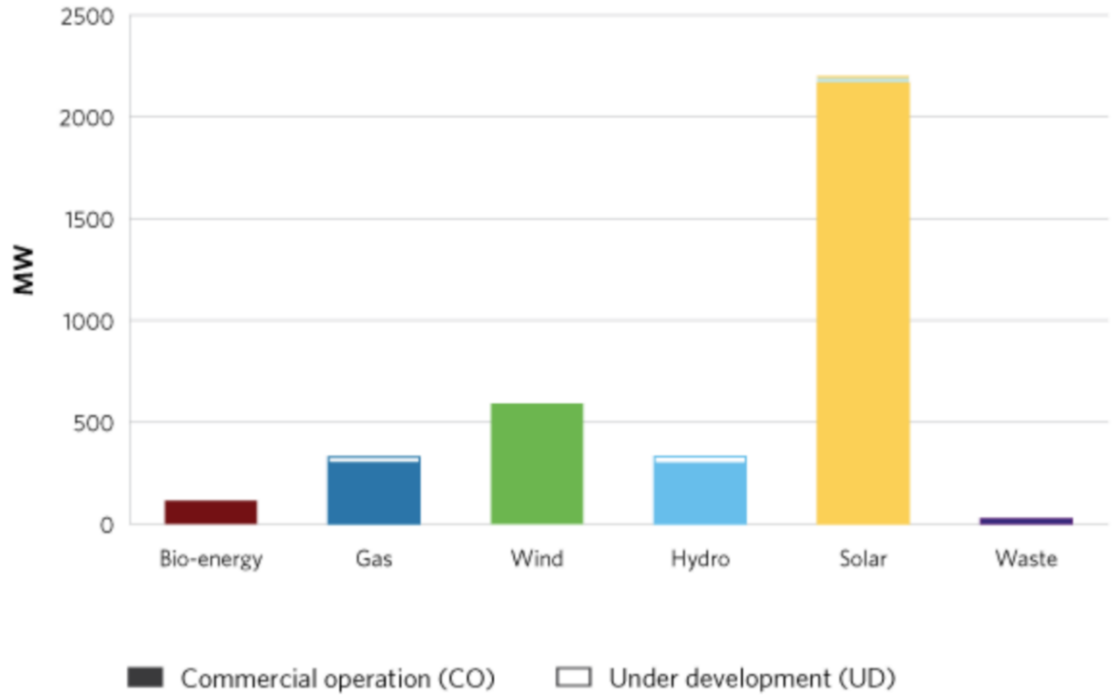
The Canadian electricity sector is characterised by decentralised and provincial energy governance, with Ontario having a separate regulator and independent ESO. The IESO is central to the heart of Ontario's power system, delivering key services across the electricity sector including; managing the power system in real-time, planning for Ontario's future energy needs, and enabling conservation and efficiency in the system.

The uptake of DERs in Ontario is encouraging, with more than 2 GW of solar PV connected to the distribution grid, followed by wind at just over 500 MW, and then gas at over 250 MW (see Figure 4). This does not include load control, behind-the-meter energy storage and demand response capacity, for which there are several pilot projects. The IESO has been active in promoting storage DERs through the POWER.HOUSE project in the York region and is also undergoing two phases of energy storage procurement. Numerous pilot projects are being funded under the Innovation Fund on topics like behind-the-meter energy storage (NRStor), locational price signals (Opus One Solutions) and Local Achievable Potential Studies to assist LDCs in meeting capacity needs through DERs, to name a few.

Ontario has 60 LDCs currently that can be municipally owned corporations or privately-operated entities. Several markets exist with opportunities for aggregated DERs, including the Capacity Market, which has replaced the Demand Response Market, and the Ancillary Services Market. The Real-Time Energy Market uses the Day-Ahead Commitment Process (DACP) to secure bids and offers and has integrated DERs in recent years. The Operating Reserves market requires participants to put as much energy into the Real-Time market, inherently raising the capacity needed to participate. Many processes are changing under the Market Renewal program, which will most likely introduce new DSR reforms, such as make-whole prices.

Data on energy flows is recorded at five-minute intervals, and settlements are received daily by market participants. The balancing process for the Day Ahead market includes bids and offers in the morning, with data validation and dispatch towards the end of the day. Smart metering has been rolled out and almost all residential properties have an operational smart meter.

Figure 4: Bar chart showing the distribution connected generation capacity by technology type in Ontario for 2020 Q3 [10]



[10] IESO, 2020 *Progress Report on Contracted Electricity Supply.* Available from https://www.ieso.ca/en/learn/ontario-power-system/a-smarter-grid/distributed-energy-resources

5.3. Comparison summary

Following the brief overview of Ontario and GB electricity systems, we have provided an analysis of the similarity, and listed the key differences per sector in Table 3. Overall, we have found that:

- The generation sectors show the most similarity due to a shift away from coal-fired generation and towards renewable energy.
- The energy policy context has some parallels, with dedicated government departments for energy. The provincial governance system in Canada provides more control over policies and implementation, compared to the national centralised policy frameworks in the UK.
- The network sectors share some characteristics, however the network operators are privately-owned regulated monopolies in the UK, and in Ontario they are privately or municipally owned.
- The electricity system operation and markets again share some key features. But there are differences in the services and market structures. For example, Ontario has a publicly owned independent system operator, whereas in GB the system operator is privately-owned commercial company.
- In contrast the retail sector comparison shows the lowest level of similarity due to different electricity tariff structures, and levels of competition for consumers.

Table 3: Overview of similarity and differences between GB and Ontario electricity systems per sector

Sector	GB and Ontario electricity system comparison	
	Similarity rating (with RAG rating)	List of main differences
Energy policy context	**Medium** – The governance structure shares some similarities with overarching decisions coming from government but regulated independently.	• The UK has a strong centralised decarbonisation policy framework in the legally binding Climate Change Act. Canada has an overarching framework and pricing scheme but policies and implementation vary by province. • Both have government departments dedicated to energy (BEIS in the UK and Ministry of Energy, Northern Development and Mines in Ontario). However, the UK has more initiatives for renewable generation revenue support and provides considerably more policy support for decarbonisation than its Ontarian equivalent. • GB has one energy regulator (Ofgem) for all market participants, whereas Canada has both a pan-Canadian regulator that regulates pipelines, powerlines, energy development, and trade, as well as dedicated provincial regulators that deal with electricity and gas distribution and generation licences. • The Ontario Energy Board (OEB) aims to stimulate development, productivity, and innovation in the sector, while Ofgem's function is mainly to guarantee that the distribution companies can fulfil the requirements established by law or contract[11]. • Both areas have a regulatory sandbox for energy innovation projects to use.
Networks	**Medium –** Networks are split into high-voltage transmission and low-voltage distribution. However, there is more competition between network operators in Ontario than the UK.	• Distribution network operators in the UK are based on location and are separate entities to the suppliers. In Ontario, there are currently 60 LDCs, who act as both network operator and customer utility. • The UK network operators are regulated monopolies, while Ontario's LDCs are either municipally owned or privately-operated entities. • Privatisation in the UK has reduced vertical integration of utility companies, separating network operators from electricity retailers/suppliers. • Network charges make up a much smaller proportion of the consumer electricity bill in Ontario.

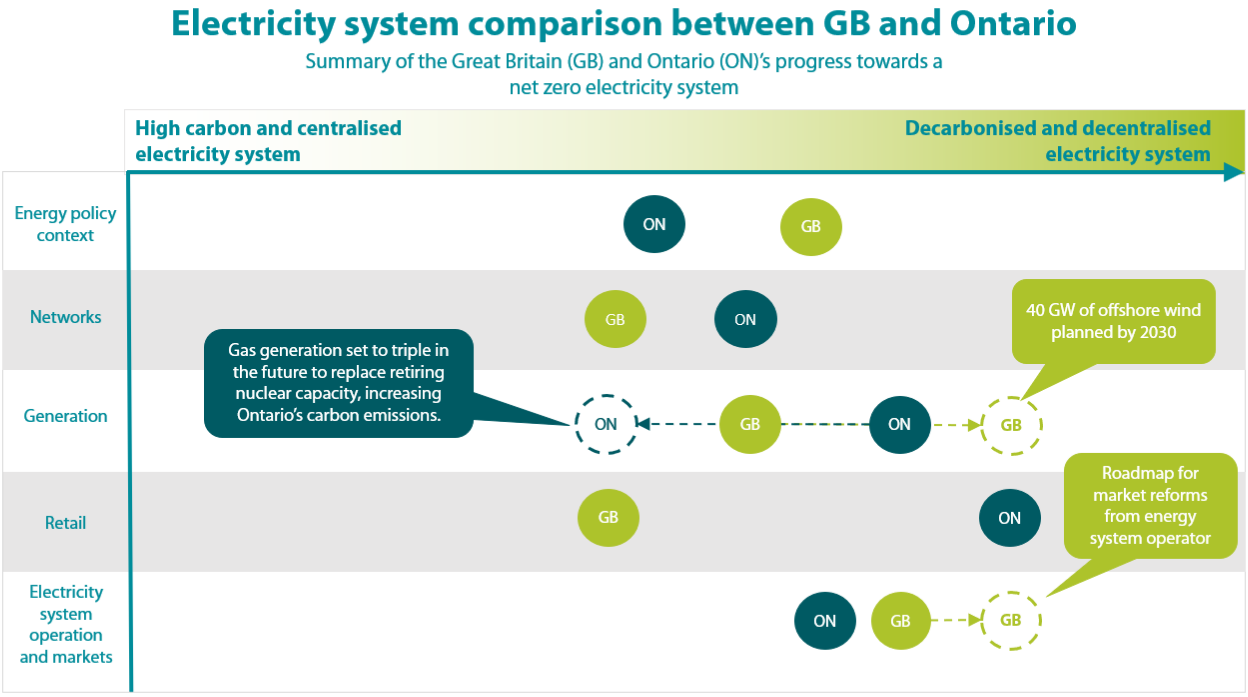
[11] Braga, K. et al., 2016 *Financial Regulation of the Electricity Distributors: Necessity and Feasibility* https://www.sciencedirect.com/science/article/pii/S187661021631671X/pdf?md5=f726ff805879025f93eebc2a59c42693&pid=1-s2.0-S187661021631671X-main.pdf

Generation	**High** – Strong shift away from coal generation and towards renewable energy, with future shift to fossil gas in Ontario.	• The UK has a stronger focus on offshore wind as a key source of renewable energy generation, compared to Ontario. • Nuclear makes up a much larger proportion of electricity generation in Ontario, while fossil gas makes up a much larger proportion of electricity generation in the UK. Fossil gas in Ontario is set to increase in coming years to replace retiring nuclear power plants. • Large hydropower makes up much of Canadian renewables generation capacity, but makes up much less of Ontario's provincial generation. Ontario's hydropower installed generation capacity is double that of the UK. • There is limited policy support to enable the building of renewable generation in Ontario.
Retail	**Low** – Smart metering and fixed time of use tariffs are already in place with relatively low levels of competition in Ontario. Both markets are liberalised.	• Market competition in the GB retail market has increased dramatically in recent years, particularly in the domestic retail market. Whereas Ontario's retail market is more stable, with 95% of customers opting for the local utility. • Time of use tariffs are the default option in Ontario, with off-peak, mid-peak and on-peak rates per kWh, determined by the Ontario Electricity Board. Very few time of use tariffs are available in the UK for domestic consumers, with the exception of Economy7/10 (cheaper overnight) and some dynamic time of use tariffs that track the wholesale market price. • There is seasonal pricing in Ontario for domestic consumers, whereas domestic consumers in the UK do not have any seasonal element to their final bill. • Customers in Ontario are offered the choice of a tiered pricing regime that has a higher rate when you go over a certain kWh limit, incentivising consumers to use less electricity. • Smart meters are mandatory in Ontario, and there has been a much higher uptake in comparison with the UK rollout for domestic and small non-domestic consumers. • Third party access to anonymous smart meter data is possible in Ontario, whereas the UK requires explicit customer consent.
Energy system operation and markets	**Medium** – An electricity system operator operates markets to manage the power system. Regarding the markets, similar focus on DSR, capacity	• Flexibility is provided by fossil gas power stations in Ontario and the UK. With plans for further gas power stations in both countries. However, the UK is more reliant on fossil gas at present. • Interconnectors play a bigger role in UK electricity markets and system operation in comparison with Ontario. With impacts on system operation when interconnectors are not available. • There are calls for the UK to create an independent system operator, as it is currently the role of the privately owned National Grid ESO. Ontario has had a publicly owned independent system operator since 1998.

	markets and flexibility.	• The settlement process happens in real time in Ontario, and half hourly in the UK. Data in Ontario is recorded at five-minute intervals before undergoing validation, and bids are settled every five minutes. • The current DACP settlement process in Ontario is a reliability process rather than a market process like that in the UK, and does not calculate imbalance charges. This is likely to change under the Market Renewal reforms. • Both GB and Ontario are undergoing reform, but the direction of this reform is different for each: Ontario's regulator is currently transitioning to a corporate ownership structure, whereas the UK regulator remains a governmental department. • Ontario's capacity market was introduced only recently to replace the demand auction, whereas the UK retains both.

Figure 5 compares the progress of each sector in GB and Ontario towards a decarbonised and decentralised electricity system. This shows a mixed picture per sector, with each jurisdiction showing different levels of progress. For example, in the electricity generation sector, Ontario is ahead of GB due to low carbon capacity currently operational. However, future plans for further fossil gas power stations are due to reverse this progress. Whereas in GB, significant new renewable energy capacity is planned, particularly offshore wind.

Figure 5: Electricity system comparison between GB and Ontario, based on progress towards a decentralised and decarbonised electricity system.



While both the GB and Ontario have some sectors that are similar and have made some progress towards a decentralised and decarbonised electricity system, there are some key differences that should be underlined. The following key differences have been identified from our analysis.

For a reminder for background information regarding the GB and Ontario electricity systems, please review section 10.

Policy

While the UK and Canada both have government departments dedicated to energy, the Canadian governance is more decentralised and differs from province to province. The Ontario electricity policy framework is loosely defined and favours short-term planning. The current system is a hybrid model with both market-based mechanisms and some vertical governance approaches. System planning decisions are made on a political level, and thus subject to change following new election cycles, and long-term energy plans are not subject to rigorous regulatory oversight or approval.

In contrast, the UK energy governance system follows a strong regulatory framework approach with significant oversight from the energy regulator.

Comparing revenue support schemes in the UK and Ontario reveals more support has been available for renewable energy generation capacity in the UK, than in Ontario.

Distribution networks

In GB, there are six DNOs, whereas in Ontario there are currently 60 LDCs present in the market. Distribution networks in the UK are privately-owned regulated monopolies, whereas the Ontarian market contains a mix of municipally owned and privately-owned companies.

Retail market

The retail market in Ontario is generally more established and stable than in the UK, where recent trends in privatisation have added complexity to the market. Competition for consumers in Ontario is recent in comparison. So while both markets are liberalised, the UK market has greater levels of competition.

Status of flexibility markets

Both jurisdictions are undergoing a transition in their electricity systems and significant reforms to their respective markets and services. The UK hosts DNO-led local flexibility market auctions in specified locations. These locations, or Constraint Management Zones (CMZs), have variable levels of value available to DERs (see section 6.2). Local flexibility services from DNOs are not active in Ontario. In addition, Ontario recently cancelled the demand response auction and aims for the capacity auction to be able to act as a balancing mechanism by 2026.

Differences in connected DER generation capacity

The types of DERs available in Ontario include participants that can regulate their consumption levels[12]. Ontario has 4 GW of DERs that were contracted over the past 10 years. The majority of distributed generation is provided by solar PV, making up just over half of all distribution-connected capacity, followed by wind at just over 500 MW (Figure 4). In the UK, distribution-connected generation capacity is led by onshore wind and fossil fuel generation at 24% each, followed by solar PV at 20% (Figure 3).

Availability of metering data

In regard to the availability of metering data, some key differences stand out between the two electricity systems. In the UK the smart meter rollout has been slow, reaching less than half of domestic and small non-domestic consumers. By contrast, Ontario has a much higher uptake of smart metering. The availability of data in the UK is hampered by a stricter data security framework for third parties that requires written customer consent, and allows the customer to 'opt out.' In Ontario, customer data is anonymised which gives third parties more freedom of access while respecting consumer privacy.

Differing settlement processes

The current DACP process in Ontario does not generate prices and related schedules, and acts as a reliability process rather than a market process. It delivers a detailed breakdown of all financial calculations performed by IESO concerning market participation activity, or dispatch data[13]. Uniform Ontario prices, schedules and other settlement ready data are sent on the pre-dispatch real time market through the Market Interface System. This is in contrast to the UK system, where imbalance charges are calculated for situations in which a party finds itself out of

[12] IESO, 2020 *Progress Report on Contracted Electricity Supply* https://www.ieso.ca/en/learn/ontario-power-system/a-smarter-grid/distributed-energy-resources

[13] IESO, 2021 *Energy Stream Detailed Design – Market Settlement* https://ieso.ca/en/Market-Renewal/Energy-Stream-Designs/Detailed-Design

balance. These prices reflect the costs of balancing the Transmission System for that Settlement Period and depend on the system's overall imbalance.

The Ontario market is currently undergoing the Market Renewal process, where many real time prices and schedules, as well as day ahead markets prices and schedules, are to be introduced. This includes make-whole payments which will operate outside of the first and second settlement system to ensure financial neutrality[13].

Changes to network charging

Until recently, a key incentive for demand side flexibility in the UK has been the Triad benefit, which incentivised demand reduction to avoid charges during specific peak demand periods. However, Ofgem has reformed the network charging regime, removing the Triad benefit, and instead has introduced charges based on maximum capacity. The result of this reform is the removal of a strong demand side flexibility incentive to avoid periods of peak demand, replaced with a focus on energy efficiency improvements and charges based on maximum capacity. This reduces the incentive for demand side flexibility and could potentially increase peak demand. With further forward looking network charge changes planned, the impacts on DERs will depend on how they are implemented and the location of the asset. See further discussion on network charges in Section 6.2.10. In Ontario, the incorporation of demand-side incentives has primarily been through time-of-use rates on electricity tariffs.

Aggregators

Aggregation services in the UK face a number of barriers to entry in each market. Notably, an aggregator must obtain a supply licence, and thus faces significant administrative processes and costs. In addition, DERs are at a disadvantage within the Balancing Mechanism (BM), since National Grid ESO has faced operational issues with dispatch of small power plants. The Capacity Market is undergoing reform following an EU court order to minimise discrimination against DSR.

Conversely in Ontario, aggregators are able to participate fully in the equivalent capacity, wholesale and balancing markets without requiring an electricity supply licence or partnering with an organisation which has one.

Non-independent system operator

As it stands, there is no independent systems operation entity in the UK as there is in Ontario. There are calls for the UK to create an Independent System Operator (ISO), as it is currently the role of the privately-owned National Grid ESO. Ontario has had a publicly owned IESO since 1998.

While there are some significant similarities in some sectors of the GB and Ontario electricity systems, there are clearly also significant differences which will impact any potential application of the DEMOCRASI project to the UK. We discuss this topic in further detail in the next section.

6. Feasibility of applying the DEMOCRASI project to the UK electricity sector

This section outlines how the DEMOCRASI project can be applied in the UK, focused on the GB electricity sector.

The DEMOCRASI project has assessed the potential for use of the joint product solution in the UK market, through a market simulation using the STOR service from National Grid ESO. The changes to the STOR market in 2021 (see section 10.1.5) have caused some complications in the delivery of this pilot simulation. Therefore, the previous STOR service specification has been used (prior to 1 April 2021 changes).

Certain aspects of the DEMOCRASI project are already being tested in the UK market. Opus One Solutions is involved in a number of innovation projects, including the five-year Ofgem-funded innovation project TRANSITION with SSEN[14] and Innovate UK funded Zero Carbon Rugeley[15]. These projects harness the Opus One Solutions GridOS platform that the DEMOCRASI project also uses.

Overall, following adaptations to the joint product solution, and using the knowledge gained by project partners in the market simulations, there are not any hard barriers to applying the DEMOCRASI project in the UK. However, there are a number of barriers that would make the project more challenging to deliver. We summarise these barriers in the next section of the report, then move on to discuss the opportunities for potential future value streams in the UK market.

6.1. Barriers to adoption in the UK

Many of the barriers, or challenges, outlined in this section are a result of the original electricity system design in the UK which was built around centralised fossil fuel generation. This creates a bias against projects such as DEMOCRASI. There are ongoing efforts to reform the electricity system through changes to the various policy, governance, industry codes, and services available. So despite there being no hard barriers to the DEMOCRASI project, it is taking time for policies and regulations to be rolled out and for markets to evolve that will support the DEMOCRASI business model.

Some of the specific barriers for adoption of the DEMOCRASI project in the UK include:

Market access

- **The existing markets and services for flexibility are changing, making it difficult to make a business case for aggregators and DER deployment.** For example, recent changes to the network charging regime and STOR market have removed the value available to a proportion of flexible assets. We discuss this in more detail in Section 6.2. The reduction of value streams undermines business models and investor confidence, reducing overall DER deployment.

[14] SSEN, 2021 *TRANSITION project* https://ssen-transition.com/
[15] Engie, 2021 *Zero Carbon Rugeley project* http://www.rugeleypower.com/zero-carbon-rugeley-project/

- **Structure of markets, services, and governance in the UK is still weighted towards incumbent centralised energy utilities**. For example, the industry code modification processes are split between several organisations, are overly complex, and are mainly resourced by those large utility actors that are protecting the status quo, rather than new entrants that want change towards a decentralised system. There have been some improvements evident in the last few years as services have been opened up to new participants. For example, the Virtual Lead Party (VLP) model that allows access to the BM for aggregators and other parties that do not have an electricity supply licence[16].
- **Lack of value for low carbon DERs in current markets and services.** There is an absence of adequate value reward for low carbon DERs in current markets and services available, that remain dominated by fossil fuel actors. The technology neutral approach and focus on keeping costs low for the consumer does not value low carbon flexibility ahead of high carbon flexibility. There are a number of reforms occurring, but the pace is slow and there remains a lack of value for low carbon flexibility solutions, such as energy storage and DSR. This has limited the uptake of DERs.
- **Barriers for DER entry to certain markets and services remain.** There is no direct access for independent aggregators to the wholesale electricity markets without applying for a supply licence or entering into a bilateral agreement with a supplier. This places small, embedded aggregators at a disadvantage to large generation assets. Even then, they may only bid on generation and not on DSR to the wholesale electricity markets[17]. This has led many aggregators currently operating in the market to obtain a supply licence, which adds considerable costs and risks.
- **Limited value and access in DNO local flexibility markets.** DERs and aggregators must operate within highly defined geographical areas, which do not readily align with where available and controllable DER capacity is located. The value available in each market is highly variable and often not enough to make a significant impact on the stack of revenues available in a business case.

Data and network monitoring

- **Poor progress on smart metering.** Poor performance of the rollout scheme led by electricity suppliers, has led to inferior electricity system outcomes and less visibility of the LV system for network operators and other actors. It has also slowed the rollout of smart tariffs, such as time of use tariffs, which can support the uptake of DERs.
- **Metered data access restrictions.** Strict data privacy requirements for proven written consent from the consumer before metering data can be accessed by third parties. This limits the scale of a key dataset to assess power flows on the network.
- **Challenges in accessing network data.** Detailed network characteristic data for the UK distribution networks is not always available in a usable format. WPD is the first DNO to provide their network data in the CIM format, which is the international standard. However, this is not currently available from other DNOs and their licence areas.
- **Distribution network monitoring is limited.** The DNOs are investing in network monitoring equipment to increase visibility and active management of power flows.

[16] Elexon, 2021 *Becoming a Virtual Lead Party* https://www.elexon.co.uk/reference/market-entry/market-entry-virtual-lead-party/

[17] University of Exeter Energy Policy Group, 2019 *Barriers to Independent Aggregators in Europe* https://ore.exeter.ac.uk/repository/bitstream/handle/10871/40134/Barriers%20to%20Independent%20Aggregators%20in%20Europe.pdf?sequence=1

However, this tends to be limited to the higher voltage levels and Constraint Managed Zones (CMZs) at present. Increasing the coverage of monitoring and the granularity of data will support the growth in local flexibility markets.

DER deployment

- **Revenue support schemes for renewable energy capacity do not support flexibility services**. Agreements under CfD, RO, and FIT revenue support schemes can pose barriers to co-location of energy storage alongside renewables. These schemes are designed to maximise generation rather than provide flexibility via DERs. Therefore, there are challenges when retrofitting energy storage, or trying to provide flexibility from existing DERs.
- **Retail market reform has been proposed but not delivered in any meaningful way.** This has led to fewer consumers, particularly domestic, getting effective price signals via their electricity bill. Therefore, removing the incentive for DER deployment.
- **Lack of electrified heat DERs in the UK market.** The electrification of heat has been slow in the UK and there is a significant cost distortion in the market that favours natural gas for heating applications over electricity, due to higher environmental levies payable on electricity in comparison to fossil gas. This acts as a barrier to flexible electrified heating services, such as heat pumps, in the UK. This flexible load is an important opportunity for DER flexibility.
- **Existing network capacity is focused in industrial areas and power station sites.** This does not align with the location of renewable energy resources, such as areas of high wind speed, where co-location of energy storage may be the optimal solution, or where domestic DERs are due to be deployed. This has significant implications for network charging and some of the forward-looking changes proposed (section 6.2.10)

Competition

- **Competition from other models**. Existing models and innovation projects are already in place in the UK that provide some, if not all, of the capabilities included in the DEMOCRASI project (e.g. Cornwall Local Energy Market[18]). Therefore, the project is competing with other product solutions provided for utilities by other organisations.
- **A more complex set of market actors**. More market liberalisation in the UK electricity markets has increased competition and the number of actors that need to engage in a project like DEMOCRASI, for it to be successful, in comparison with Ontario.

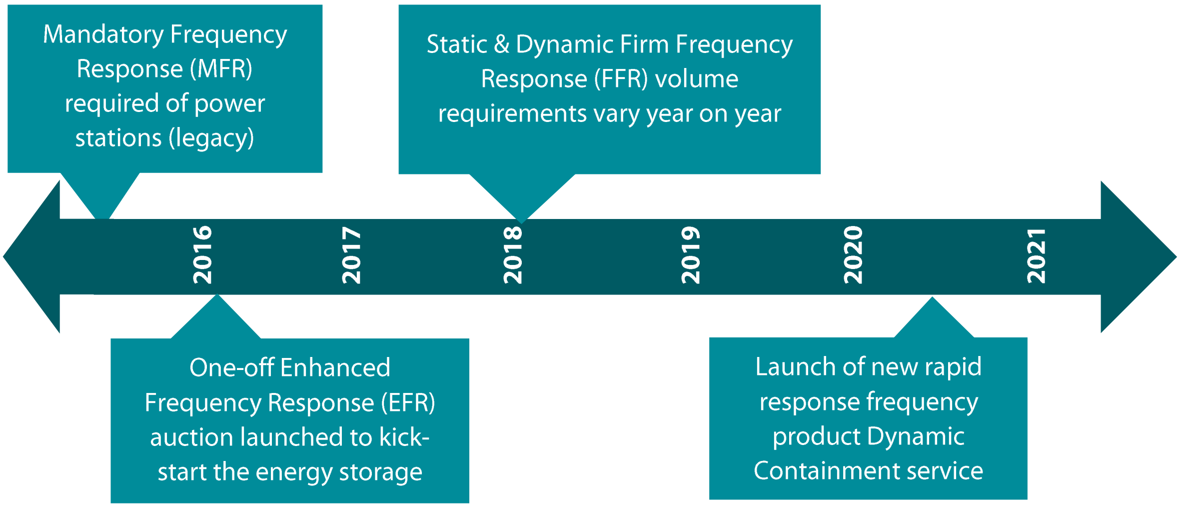
[18] Centrica, 2021 *Cornwall Local Energy Market* https://www.centrica.com/innovation/cornwall-local-energy-market

6.2. Future value streams and services

The systemic transformation of UK energy production and use will undoubtedly require reforms to existing electricity markets, as well as the creation of brand new markets and services, and closure/removal of legacy markets and services that are incompatible with net zero targets.

The UK has already been through one Electricity Market Reform process19, seeing the creation of the CM mechanism and a suite of commercial system balancing and ancillary services (see Table 4) As described in the previous section, these commercial services are under constant review and naturally evolve to meet the needs of our changing electricity system. Frequency response is a prime example of how systemic reform and evolutions in the energy sector causes markets to adapt and evolve in a relatively short space of time (Figure 6).

Figure 6: Illustrative timeline of recent changes to frequency response services in GB.



Is there liquidity and stability in the current services and markets?

GB electricity markets can principally be split into two distinct areas:

- **Base commodity markets** – e.g. Wholesale, day-head, intra-day and retail markets
- **Commercial flexibility markets** – System balancing, ancillary, restoration, and local network flexibility markets

Focussing initially on **commodity markets**, in 2019 Ofgem commissioned *NERA Economic Consulting* to assess the liquidity of GB's wholesale electricity market[20]. In this report NERA concluded that the GB wholesale market is less liquid than equivalents in Continental Europe, but stated that "low liquidity is not a market failure that in itself would justify intervention to increase it and may instead be an efficient response to market conditions."

The GB commodity markets have evolved in recent years, with the rise of many new entrants to the electricity retail supply sector, essentially eroding the market dominance of the so-called 'big six' energy supply companies[21]. In addition to this, an ever-increasing capacity of distributed

[19] See Ofgem EMR overview: https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform-emr
[20] See *GB Wholesale Power Market Liquidity: Options Assessment* (Dec 2019, NEA Economic Consulting): https://www.ofgem.gov.uk/system/files/docs/2020/01/nera_report.pdf
[21] See *Small Energy Companies vs The Big Six* article (Mar 2019, Money Supermarket): https://www.moneysupermarket.com/money-made-easy/small-energy-companies-vs-the-big-six/

generation with more dynamic power purchase agreements is coming forward[22]. Therefore, presence of liquidity is potentially more difficult to track.

Ofgem state three liquidity objectives for the electricity market:

- "Ensure the availability of a range of longer-term products to support hedging of risk of exposure to large changes to prices (hedging refers to the ability to buy power over different timescales at set prices to manage risk of exposure to changes in price).
- Support robust reference prices that that are widely available to market participants (reference prices are prices reflective of a product's real market value based on underlying economic conditions).
- Promote an effective near-term market which enables all companies to buy the power they need for their customers."

In respect to **commercial flexibility markets**, specifically the procured services of National Grid ESO and the regional DSOs, the liquidity of these markets is a different consideration. By definition, flexibility markets and flexibility needs are reactionary in nature and the market for these services is dynamic, with needs and bidding parties changing regularly.

Competition in these markets is also a different consideration to wholesale commodity markets, with entry requirements, entry capacity thresholds and fundamental dispatch requirements of the services being aligned more to some technologies over others. The ESO and Ofgem state that technology neutrality is a core principle of flexibility markets, but the reality of the system needs, response times, the operation of flexibility dispatches and response durations do essentially favour some technologies in some markets over others:

- Rapid response services such as Dynamic Containment (DC) or other frequency regulation markets are naturally suited to rapid response technologies such as battery storage, supercapacitors, instantly switchable Demand Side Response offerings and potentially some modular inverter-controlled generation assets. Larger, less responsive assets and technologies will not necessarily be able to respond quick enough to provide frequency divergence support services.
- Conversely, longer duration reserve and system integrity services such as Short Term Operating Reserve (STOR), and CM System Stress Event dispatching, are less directly suited to rapid response battery storage assets, due to the fact that a proportion of the deployed battery storage plants in the UK do not have sufficient energy storage capacity to sustain charge-up or discharge at their max (or declared) MW rating for several hours as the rollout so far has been focused on low capacity installations. These markets are therefore principally being targeted by gas peaking plants and other forms of dispatchable thermal generation, and some Demand Side Response proponents.
- Other than the geographical variability of local flexibility requirements, the fundamental nature of the services required are tailored to dispatchable generation, DSR companies that have some inherent flexibility in their processes to enable them to respond potentially at any time, and medium duration energy storage technologies. One simple restriction of note is that some of the services require flexibility services to support the network in managing winter evening peak demand periods, thus meaning that solar

[22] See *Number of Renewable PPAs on the Rise* article, (July 2020, Windfair): https://w3.windfair.net/wind-energy/news/35031-ppa-power-purchase-agreement-renewable-energy-cornwall-insight

generation is unable to participate by default without multi-hour capacity co-located electricity storage.

Table 4 summarises the liquidity and stability of some of the key flexibility markets and services currently procured in GB. In summary, while there are some services that have good levels of DER liquidity, are generally stable as a market, and align well with some DER technologies, the majority do not. This is due to the design of these services and the fact that there are significant changes planned in services procured by National Grid ESO. This increases uncertainty and risk for DER operators in GB, and could undermine the impact of projects like DEMOCRASI.

Table 4: A list of current services and markets that are particularly relevant to the DEMOCRASI project, with DER liquidity and service stability assessments.

Service name	DER liquidity	Stability level
Dynamic Containment (DC)	**High** – Level of uptake by market participants has been lower than National Grid ESO has asked for due to challenging technical requirements. However, the service parameters are designed for battery storage capabilities and other rapid-response technologies and thus have been the only technology that has been successful in securing contracts so far. Prices have remained high – close to the current market cap of £17/MW/h - due to undersupply in the market.	**Medium** – new service with good feedback from the market participants. Still in "soft launch" phase so there may be updates to the service specifications and requirements.
Firm Frequency response (FFR)	**High** – A good market for DERs with energy storage and DSR taking the majority of the monthly Dynamic FFR contract volume in 2020. Static FFR remains dominated by fossil fuel generation. Prices for Dynamic FFR averages £10-12/MW/hr. Whereas Static FFR was much lower (under £1/MW/hr). The weekly FFR market showed more variation in pricing (£9 to £4/MW/hr) depending on the time of year.	**Low** – Frequency response services are moving to a new suite of response products including DC above in 2022 and a transition away from this service in 2023.
Short Term Operating Reserve (STOR)	**Medium** – STOR procurement had been paused since December 2019 and has now restarted on a day ahead basis in line with the EU CEP. The service historically has been dominated by fossil fuel thermal generation assets, and that has not changed since the restart of procurement on a day-ahead basis. There is high competition for the service with almost double the capacity volume submitted for 1,300 MW daily requirement.	**Low** – Move to new day-ahead tender arrangements from 1 April 2021. As well as new quick reserve and slow reserve services announced and being consulted on. A transition away from existing reserve services is planned by the end of 2023.

Optional Downward Flexibility Management (ODFM)	**Medium** – The service dispatch was dominated by wind (76%) and solar PV (16%) in 2020. Prices were variable due to the varying marginal costs of power. The average price to turn down generation for wind was £88/MW/h and £144/MW/h for solar PV. Although the amount of dispatch was relatively low in 2020.	**Low** – This service was set up in record time for Spring 2020 and the record low demand periods caused by COVID-19. The service has been restarted for 2021 (Apr to Oct) but is unlikely to be dispatched due to a focus on other services and recovering demand. Other reserve products are due to replace this type of service in 2022.
Capacity Market (CM)	**Low** – The CM is dominated by existing and new centralised fossil gas generation, securing 66% of the awarded capacity in the most recent long term (T-4) auction. DSR secured just over 1 GW or 2%, and battery storage 250 MW or 0.6% of the awarded capacity in the same auction. DSR, battery storage and renewable generation performed better in the recent short term (T-1) auction that hit a record price of £45/kW/year. With 240 MW (11%), 114 MW (5%) and 101 MW (5%) respectively of capacity awarded. However, successive auctions over recent years have had much lower proportions of DERs and lower value available.	**Medium** – This service now offers contracts of up to 15 years and some significant changes in favour of DERs. Although de-rating factors keep the value available low. In 2021 BEIS are consulting on 10 potentially significant improvements to the Capacity Market[23], these are discussed in more detail in section 1.1.1.
Local flexibility markets	**Medium** – A lack of DER resources in the areas which services are sought has limited these services. However, services are focused on delivery from DERs and some auctions have shown good level of innovative portfolios, such as smart EV chargers.	**High** – Ofgem is pushing for a "flexibility first" approach and there was five times as much contracted capacity in 2020 in comparison to 2019. However, value available is highly variable and only in specific CMZs.

[23] See *Capacity market 2021: proposals for improvements* (BEIS, March 2021): https://www.gov.uk/government/consultations/capacity-market-2021-proposals-for-improvements

6.2.1. Markets roadmap to 2025 from National Grid ESO

The National Grid ESO has set out the future product roadmap up to 2025 for specific services including market deep-dives in to some sectors[24]. This is part of the commitment from National Grid ESO to put in place the right markets and services in order to be able to "operate a zero carbon electricity system by 2025" in GB. The following areas are particularly relevant to the DEMOCRASI project:

- **Reform of the reserve markets.** A set of new services is being consulted on that will be implemented in 2022 and replace the existing set in 2023. The new services proposed include:

  - **Quick Reserve** – a fast acting reserve product looking to fill the gap between frequency response and reserve services. Response time is full delivery within 30 secs for delivery in one minute blocks, extendable up to a maximum of 20 minutes.

  - **Slow Reserve** – a slower acting manual reserve product to help the transition from frequency response and BM timescales. Response time is full delivery within 15 minutes and delivery for one minute blocks extendable to 240 minutes (4 hours).

  Slow Reserve is more suited to assets that are already providing STOR and so will be particularly relevant for DEMOCRASI project partners. Both slow reserve and quick reserve are to have a 1 MW minimum capacity and be procured in a day ahead auction (in line with CEP requirements).

  In addition, the National Grid ESO has been undertaking a trial to assess the potential for energy storage to provide reserve services in the BM with Arenko, Flexitricity and Habitat Energy[25]. The results of the trial have been very positive and are feeding into the design of future reserve services.

- **Additional frequency response services.** In addition to the successful DC service, the National Grid ESO is planning to rollout to further frequency response services in 2022 and transitioning away from existing products in 2023. They will use the same platform and day ahead auction procurement. The new services include:

  - **Dynamic Moderation** (DM) – technical specifications are yet to be confirmed but a response time of one second is planned.

  - **Dynamic Regulation** (DR) – a slightly slower response time of around 10 seconds is planned.

  These new services align closely with the reserve services and are aimed at DER technologies. The DEMOCRASI project should ensure it monitors the development of these new services. Further details of these services will be available in an industry consultation in 2021.

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[24] National Grid ESO, 2021 *Electricity System Operator: Markets Roadmap to 2025* https://www.nationalgrideso.com/document/188666/download

[25] National Grid ESO, 2021 *Reserve from storage trial in BM* https://data.nationalgrideso.com/backend/dataset/b3c55e31-7819-4dc7-bf01-3950dccbe3c5/resource/3efdf448-e5c2-4e41-98fe-ca0c98aa1af8/download/reserve-from-storage-trial-in-the-bm-phase-3-review-20210210.pdf

- **Focus on whole system approach.** The National Grid ESO now has a whole set of Regional Development Programmes, working with DNOs to take a more whole system approach to network operation and "maximise the opportunities for more efficient deployment of distributed resources". There are a number of different pieces of work taking place across all DNOs.
- **A greater focus on location.** A decentralised, zero carbon energy system brings locational concerns to the fore for the National Grid ESO in way that hasn't been so relevant in the past. The market developments are increasingly locationally focussed – particularly around thermal constraint management, stability (inertia), voltage management, and even the Balancing Mechanism. **There could therefore be an opportunity for projects like DEMOCRASI to tailor outputs to address these needs and derive value.**
- **Barriers to access for small participants.** Whilst all the above provide opportunities for DERs, there are still a number of barriers which prevent smaller participants from accessing these markets – for example, minimum capacity requirements, difficulty in using ESO technology and accessing the control room, and the ability to participate in multiple services. The ESO recognises these barriers and is working to overcome them (e.g. using a single markets platform to act as a one-stop-shop for balancing services), but these are long term pieces of work with no immediate resolution. In particular, a shift in culture and attitude is needed across the ESO to become more comfortable with smaller assets. The ESO recognises this, but it will take some time to transition.

Other key areas of content in the product roadmap are discussed in more detail below.

Constraint management

The COVID-19 lockdown circumstances have led to demand out-turn being up to 20% lower than predicted and caused problems in managing the level of generation versus demand on the electricity system. With particularly high levels of solar and wind generation in the summer of 2020, forcing National Grid ESO to contract with Sizewell B to reduce output for that period, spend much higher amounts on constraint payments via the BM (£400 million and 3 TWh of wind reduction in 2020), to create a new flexibility product – ODFM, and to formalise a way of disconnecting DG, (initially Gride Code 0143, then Grid Code 0147)[26].

As discussed in Section 10.1.5, ODFM has been very successful in accessing flexibility from generation assets and DSR that are not part of the BM or any other flexibility service. National Grid ESO is looking to take this learning and apply it to future services. The final option, DG disconnection, is a last resort after other levers are used. The new frameworks set out in Grid Code 0147 have not been used. If it is used the generation will not be compensated as they would be if they were connected to the transmission network. The code modification was initially developed as an emergency measure but has been confirmed as permanent, this change could reduce the value of flexibility if it starts to be used by the National Grid ESO.

The constraint management pathfinder project by National Grid ESO is looking at new ways of managing constraints in areas of the network that are congested[27]. Specifically, the thermal constraints that are currently an issue at the English and Scottish border ahead of a new link

[26] National Grid ESO, 2021 *GC0147* https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0147-last-resort-disconnection-embedded
[27] National Grid ESO, 2021 *NOA constraint management pathfinder* https://www.nationalgrideso.com/future-of-energy/projects/pathfinders/constraint-management

being built (Eastern HVDC link). This will include automatic intertripping hardware on generation and demand sites that can relieve constraints, without the need for more expensive balancing actions via the BM in anticipation of any fault.

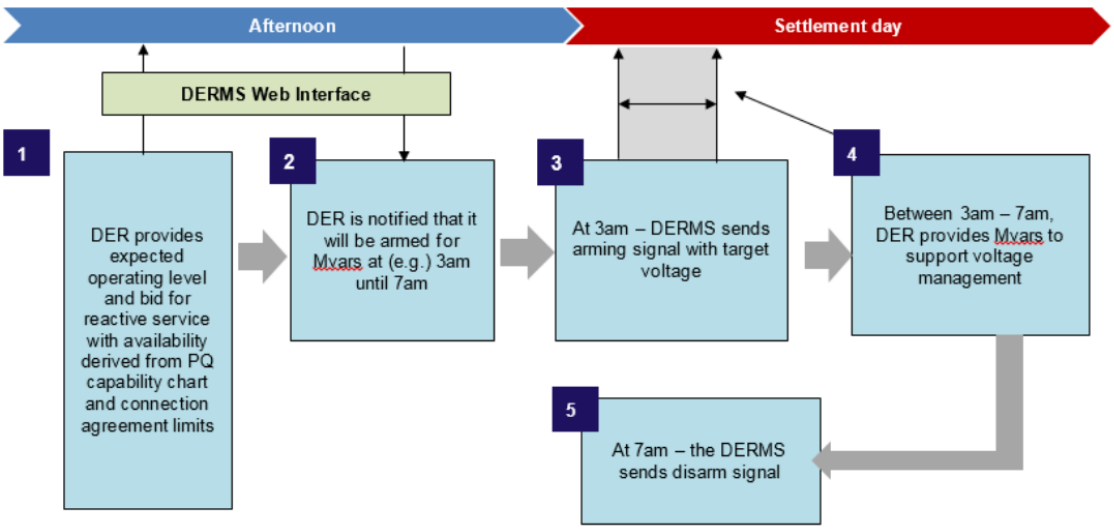
There are also Regional Development Programmes that bring together DNOs and National Grid ESO to work through constraints on the network in specific areas[28]. These projects include regional constraint markets and solutions, an example of which we discuss below.

In total, transmission constraint payments were £600 million in 2020. National Grid ESO is expecting these costs to increase over the coming years. The DEMOCRASI project provides additional situational awareness of any constraints on the network and can be used to identify further opportunities for DERs to feed into regional constraint management services.

Reactive power

One aspect of constraint management is the use of reactive power. Historically, voltage management services on the transmission systems have been provided by larger power stations and power electronics, in 2020 this market was dominated by fossil fuel fired generators. There is no competitive market for reactive power procurement in the UK. However, the Power Potential innovation project is looking at DERs providing reactive power services to National Grid ESO via the DNO UK Power Networks in specific areas. The project has completed site specific trials and is entering a wider commercial market pilot phase. This has provided some insight into what a competitive reactive power market may look like in the future and the tendering process[29] (see Figure 7).

Figure 7: Power Potential innovation project reactive power service tendering process (Source: National Grid ESO, 2021[29])



[28] National Grid ESO, 2021 *Regional Development Programmes (RDPs)* https://www.nationalgrideso.com/research-publications/regional-development-programmes
[29] National Grid ESO, 2020 *Power Potential market procedures* https://www.nationalgrideso.com/document/178061/download

National Grid ESO has recently tendered for reactive power services in specific areas and as part of a pathfinder project. A recent example saw Zenobe Energy win a contract and they are developing a 100 MW/100 MWh battery storage project that can be used to absorb reactive power on the transmission system, due to be operational in April 2022[30].

The National Grid ESO is developing this service and plans to explore a new wider competitive market solution for reactive power in 2022/2023[31]. There are challenges to the delivery of a functional market as the requirements are very locational, so there may not be a market-based solution that can effectively meet the needs of the system. Yet this remains a potential option that could impact the future value to DERs and product solutions that can access them, such as those developed in the DEMOCRASI project.

Stability and inertia services

The need for inertia services is increasing as large power stations are removed from the electricity system. These stations have traditionally been the providers of inertia via large rotating equipment such as power station turbines. National Grid ESO have also used the BM to procure further stability if needed in certain locations. The Accelerated Loss of Mains project has been working to increase the resilience of DG to fluctuations in power quality by changing the Loss of Mains settings at sites, making them less likely to automatically disconnect in response to a disturbance, such as frequency deviation. This has been achieved by National Grid ESO paying generators a fixed fee to upgrade their sites, with the DNO as the local delivery actor. Compliance with the new specifications for DG sites is needed by September 2022.

There has been an ongoing Stability Pathfinder project to look at solutions using assets in BM and synchronous compensators[32]. Long term and short term stability markets are planned using the knowledge gained from this pathfinder project. A procurement in 2020 gave six-year contracts to a number of market actors, including new battery storage projects from Statkraft[33].

A grid code change is being progressed (GC0137)[34] that will lower the barrier of entry to stability markets by confirming the specifications of Virtual Synchronous Machines (VSMs). This will allow other DERs such as solar PV and wind to provide inertia services.

This is a new area of market and service development for National Grid ESO. However, the growing need for inertia services as more renewable energy capacity is deployed and large power stations close down, will increase the size and value of these services in the next few years.

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[30] Energy Storage News, 2021 *First grid scale battery in the world to absorb reactive power* https://www.energy-storage.news/news/first-grid-scale-battery-in-world-to-absorb-reactive-power-announced-by-zen

[31] National Grid ESO, 2021 *Future of reactive power* https://www.nationalgrideso.com/document/189661/download

[32] Defined as a synchronous motor such as large electric motor or generator which has a shaft that is not connected to any output and spins freely. This means that instead of converting electric power to mechanical power it can adjust the conditions on the electricity network by generating or absorbing reactive power, to adjust voltage and power factors.

[33] Energyst, 2020 *Drax, Welsh Power, Statkraft, Triton, Uniper land £328m inertia contracts* https://theenergyst.com/drax-rassau-grid-welsh-power-statkraft-triton-uniper-national-grid-inertia/

[34] National Grid ESO, 2021 *GC0137* https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0137-minimum-specification-required

Balancing Mechanism

The BM has a large value potential with £1,080 million of balancing payments made in 2020. Developments in the market are planned to reduce barriers to entry and include a new IT interface with an API communication facility, enabling more real-time connection with assets.

The creation of the Virtual Lead Party (VLP) model has provided a new route to market for those aggregators without an electricity supply licence. A critical code modification to the BSC, p375, for allowing wider access to the BM has been approved for implementation by Ofgem. The modification was proposed by Flexitricity, an aggregator and licenced supplier in UK, and allows secondary meters beyond the current boundary point to be used for BM services. The modification had been approved by the panel at Elexon in late 2020 and was sent to Ofgem for approval. This approval has now been given and moves to an implementation phase, which is expected to end by 23 June 2022. Approval was passed unanimously and without the need for a costly impact assessment, which often delays the code modification progress.

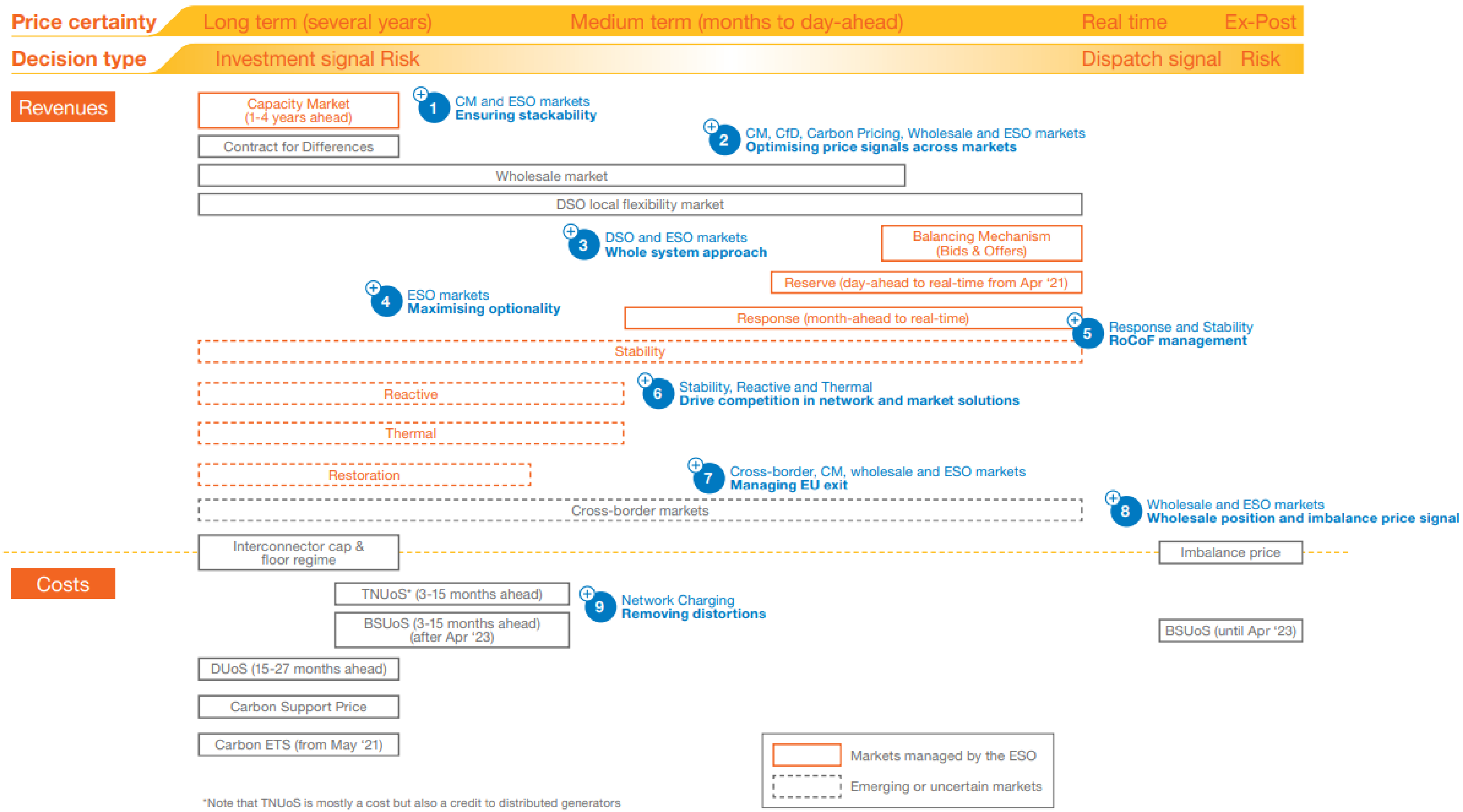
This change is particularly important for the VLP model used by some aggregators, where access to the BM is permitted without a supply licence. However, it will also enable those with a supplier licence to access and accurately meter assets behind the current boundary point.

Once this change has been implemented, DER assets that are behind the meter, will be easier to enter into the BM. This will help increase the value available to DERs and be crucial for projects like DEMOCRASI.

Market interactions

Arguably the most useful graphic in the National Grid ESO product roadmap is Figure 8, which provides an overview of the various market interactions, with reference to timeframes, revenues available, and cost signals. **This graphic can be used by the DEMOCRASI project partners to view new services and revenue opportunities, that are already or are soon to become available.**

Figure 8: Market interaction graphic in the National Grid ESO markets roadmap 2025 (Source: National Grid, 2021[24])



6.2.2. Changes to the Capacity Market

BEIS is currently consulting on changes to the Capacity Market (CM) in GB[35]. The proposals are focussed on making incremental technical modifications to the entry requirements, operations, secondary trading, and other areas.

The proposed changes can be summarised as:

- Require all Capacity Market Units (CMUs) to be registered as Balancing Mechanism Units (BMUs).
- Make changes to certain formulae and clarifications to the legislation relating to Emissions Limits in the CM.
- Give the CM Delivery Body greater flexibility to consider information which corrects administrative or clerical errors in prequalification applications.
- Prevent certain secondary trades from being rendered ineffective when the transferor's Capacity Agreement is terminated.
- Review the existing COVID-19 easements.
- Extend the deadline for meeting the Extended Years Criteria so that it aligns with the requirement to provide Evidence of Total Project Spend, and make the sanction for breaching both (a reduction in agreement length) subject to the Secretary of State's discretion.
- Allow refurbishing plant to have the same Long-Stop Date as new build plant.
- Disable the net welfare algorithm for T-1 auctions that are held only to meet the 50% set-aside commitment.
- Maintain the minimum capacity threshold at 1 MW.
- Other minor corrections to the legislation.

These changes have linkages with a number of other UK energy policy areas, from interactions with the UK Balancing and Settlement Code, to the adoption of Carbon Capture and Storage, secondary trading markets and aggregation.

The decision to retain a 1 MW entry threshold is of particular interest to demand side response proponents, as the potential for aggregation of small individual units is something being explored in several trial projects and flexibility market feasibility studies. Smaller commercial and domestic flexibility simply cannot enter the CM directly and the aggregation of many properties would be needed before a guarantee of service could be reached. The potential for aggregated portfolios entering the CM is however an opportunity that remains, and aggregators will continue to be able to bid into the T-1 and T-4 auctions. The proposal to require assets looking to pre-qualify to register in the BM as a BMU could also have impacts on DER assets or aggregators.

[35] BEIS, 2021 *Capacity Market 2021: proposals for improvements* https://www.gov.uk/government/consultations/capacity-market-2021-proposals-for-improvements

6.2.3. Shift to an Independent System Operator

As stated in the Energy White Paper in December 2020, Ofgem and BEIS have identified a need to make changes to the system operator role and governance. This has been formalised in a detailed report from Ofgem that outlines the case for a fully separated, ISO of the UK energy system with enhanced functions to help deliver net zero[36]. New responsibilities could include:

- "Taking a more proactive role in the balancing of supply and demand across both local and national electricity networks, which could include creating new opportunities to reward consumers and generators for being flexible in the way they use electricity."
- "Coordinating the planning of the GB electricity network."
- "Making recommendations on the future capability requirements of existing assets."
- "Facilitating an integrating approach to the development of networks across the energy system and with other areas including heat and transport."
- "Providing trusted policy advice on the costs and trade-offs of different low carbon pathways to government"[36].

The governance and commercial model is also being assessed by Ofgem, with strong hints that privately-owned options may not be optimal. The funding of the ISO is assumed to remain as via Ofgem, through BSUoS charges. This report is part of a wider review and consultation of energy system governance being carried out by BEIS and Ofgem, including a further consultation on reforming the energy industry codes due in 2021. A full consultation on the system operation, including the ISO role is also due in 2021.

The role of the DSO is also still being developed in the UK, this has been evident in the recent DSO strategies released by DNOs and the draft RIIO-ED2 business plans. Ofgem is incentivising DNOs to more efficiently develop and use their networks by taking into account flexible alternatives to network reinforcement.

The overall ambition is for a more coordinated and whole-system approach that drives innovation and competition across all aspects of the energy system. An ISO would be required to have a strategic and proactive approach to flexibility market facilitation, potentially across both transmission and distribution. For example, enabling DERs to participate in national markets and dispatching DERs on behalf of DSOs.

If the ISO role is adopted in the GB electricity system, it would have wide-ranging impacts on governance, markets, services and system operation. DEMOCRASI project partners should ensure they monitor this area of policy closely.

6.2.4. Local flexibility markets and RIIO-ED2

As discussed in section 10.1.5, the UK is a leading country in the development of DNO-led local flexibility markets. Commercial services have been procured since 2018, and in 2020 there was a marked increase in the amount of capacity tendered. In addition, new aggregated portfolios of technologies have started to contract with DNOs to provide services, including aggregated smart EV chargers, as well as the first procurement of reactive power services via a DNO in the

[36] Ofgem, 2021 *Ofgem recommends an independent body to help lead Britain's green transformation* https://www.ofgem.gov.uk/publications-and-updates/ofgem-recommends-independent-body-help-lead-britain-s-green-transformation

Power Potential project[37]. The importance of local flexibility markets is likely to continue to increase, as they are a crucial part of the DNOs RIIO-ED2 business plans that are currently being consulted on.

Revenue price control changes in RIIO-ED2

The revenues of network operators and the system operator in GB are controlled via the Revenue = Incentives + Innovation + Outputs or RIIO periodic investment, price and revenue review process.

For DNOs, business plans are being developed for the next price control period, which begins on 1 April 2023, whereas for the transmission network operators, system operators and gas distribution companies, the new price and revenue control process came into force on 1 April 2021. In early 2021, a number of transmission network operators submitted appeals to Ofgem regarding their business plans decisions and the matter is due to be referred to the Competitions and Markets Authority (e.g. National Grid ET[38]). This will delay the process until at least Autumn 2021.

We focus here on the DNO RIIO-ED2 process, as this will have the biggest impact on DER uptake and projects such as DEMOCRASI.

Ofgem has set out baseline expectations to DNOs for so called DSO functions in RIIO-ED2[39], which are to:

- "Plan efficiently in the context of uncertainty, taking account of whole system outcomes, and promote planning data availability.
- Promote operational network visibility and data availability.
- Facilitate efficient dispatch of distribution flexibility services.
- Provide accurate, user-friendly, and comprehensive market information.
- Embed simple, fair, and transparent rules and processes for procuring distribution flexibility services."

All investment decisions will need to consider 'flexibility first' and there is clear guidance from Ofgem that DSOs should be taking a more proactive approach to stimulating local flexibility markets as a neutral market facilitator. Only if the commercial market cannot provide a viable solution can the DSO look at other options. Ofgem state in relation to the CBA process that DSOs need to evidence, "why a market solution could not, or should not, be utilised to deliver the activity, and that all options have been considered on a level playing field"[40].

In addition, Ofgem is introducing a new licence condition on DNOs to 'promote the uptake of energy efficiency measures where this cost effectively alleviates the need to upgrade or replace electricity capacity'[39]. This will take effect by the end of 2021 and should be considered alongside other flexibility options. This could open local flexibility markets to new entrants, increasing competition with DERs. However, research suggests that flexibility and energy efficiency deliver

[37] UKPN, 2021 *Power Potential* https://innovation.ukpowernetworks.co.uk/projects/power-potential/
[38] National Grid ET, 2021 *Response to RIIO-ED2 draft determination* https://www.nationalgrid.com/uk/electricity-transmission/document/134556/download
[39] Ofgem, 2020 *RIIO-ED2 Methodology Decision: overview* https://www.ofgem.gov.uk/system/files/docs/2020/12/ed2_ssmd_overview.pdf
[40] Ofgem, 2021 *RIIO-ED2 Business Plan Guidance* https://www.ofgem.gov.uk/system/files/docs/2021/02/ed2_business_plan_guidance_-_published_1_february_2021.pdf

different outcomes: flexibility is best for curbing peak loads and energy efficiency is best suited to reduce the impact of the electrification of heat[41].

A further aspect of RIIO-ED2 is the investment in monitoring and control systems on the distribution network. This issue is particularly important at the LV level as the anticipated increase in heat and transport electrification put additional pressures on the network. Historically, different DNOs have taken different approaches to this investment, with some investing more than others. What is clear is that in RIIO-ED2 all DNOs will be investing in further control and monitoring systems to enable more local flexibility markets. For example, WPD state in the second draft of their business plan[42] that they will be investing in the following hardware:

- DER SCADA monitoring systems retrofitted to customer points of connection.
- Power flow monitoring equipment at all primary substations (11kV and higher voltages).
- Additional EHV and LV monitoring,
- Further power quality monitoring.

This investment will increase the visibility of the system and power flows for DNOs. Allowing them to make best use of the current network assets installed. Additionally, they will be able to better identify and respond to areas that have constraints.

Overall, local flexibility markets and their continued development under RIIO-ED2 represent a significant opportunity for the DEMOCRASI project. Products and services that provide solutions to enable the rollout of local flexibility markets will be able to compete for new value streams.

6.2.5. Customer Load Active System Service (CLASS)

Customer Load Active System Services (CLASS) is the use of remote voltage management at substations, remotely managing transformers and circuit breakers at primary substations. CLASS was developed by an Electricity North West innovation project. CLASS can "reduce or increase effective electricity demand and absorb reactive power". At present DNOs are allowed to sell these services to National Grid ESO. Electricity North West are the only DNO that have invested in CLASS on their primary substations and have provided services to National Grid ESO via FFR and Fast Reserve services.

Ofgem issued a consultation in February 2020 which supported the view, a minded-to position, that DNOs should continue to be able to offer voltage management services in competition with other providers to National Grid ESO under RIIO-ED2[43]. The argument being that DNOs are the only actor that can provide CLASS services and that consumers would benefit from sharing in

[41] Sustainability First, 2021, *RIIO-ED2 SSM – Note to Ofgem on DNO energy efficiency.* https://www.sustainabilityfirst.org.uk/consultation-submissions/246-riio-ed2-ssm
[42] WPD, 2021 *Second draft of WPD RIIO-ED2 business plan* https://yourpowerfuture.westernpower.co.uk/second-draft-business-plan
[43] Ofgem, 2020 *Regulatory treatment of CLASS as a balancing service in RIIO-ED2 network price control* https://www.ofgem.gov.uk/publications-and-updates/regulatory-treatment-class-balancing-service-riio-ed2-network-price-control

any profits. This is in contrast with other areas, where Ofgem has been clear that "DNOs cannot operate storage or act as commercial aggregators", except in very specific circumstances[44].

The inclusion of CLASS from regulated monopolies in competitive procurement for National Grid ESO services, is an area of debate that is likely to continue, with the wider industry seeing this as a threat and Ofgem focusing on the system benefits. Other DNOs are likely to wait for a final decision before following Electricity North West along the CLASS route. The outcome of the consultation mentioned above will provide an opportunity for clarity. The DEMOCRASI project partners should monitor this area closely as there could be much wider impacts on markets and services if other DNOs start investing in CLASS type assets on their substations.

6.2.6. Security of supply

Following on from the outage event on 9 August 2019, security of supply has risen in importance at Ofgem and BEIS. Previously there had been calls to reduce the security of supply requirements in some areas, due to a considerable period of no major incidents, however this mentality has now changed, particularly in the light of COVID-19. The role of embedded generation in making the frequency lag worse during the outage on 9 August 2019 has heightened concern that this would occur again.

This increase in importance of security of supply is an opportunity for the DEMOCRASI project. The situational awareness provided by the products of Opus One Solutions and GridOS, provide benefits to DNOs and other market actors, as they will increase the reliability and visibility of network assets, improving security of supply.

6.2.7. Increased volatility and wider access to wholesale electricity markets

As we discuss in Section 10.1.5, there is an increase in volatility in some of the wholesale electricity market prices due to Brexit and the shift away from a centralised electricity system. This has led to generally higher pricing and much greater price peaks (e.g. £4,000/MWh on 8 January 2021)[45]. If DERs can access this price volatility, they can improve their returns (e.g. via price arbitrage).

In addition, a new Balancing and Settlement Code modification (P415) proposed by Enel X, could help increase access to wholesale markets for DERs[46]. At present some actors are restricted from accessing wholesale energy markets and must act through their electricity supplier. This modification will allow access via a VLP, creating more opportunities for actors without a

[44] Ofgem, 2017 *Enabling the competitive deployment of storage in a flexible energy system: changes to the electricity distribution licence* https://www.ofgem.gov.uk/system/files/docs/2017/10/storage_ownership_publications_policy_consultation_final.pdf
[45] EnAppsSys, 2021 *Q1 2021* https://www.enappsys.com/free-reports/
[46] Elexon, 2021 *Mod proposal p415* https://www.elexon.co.uk/mod-proposal/p415/

supplier licence, such as some aggregators. It also allows smaller assets to access these opportunities.

If DERs and aggregators can access the wholesale electricity markets, including the increased price volatility, more easily and at a lower cost, then this will increase DER uptake. Therefore, improving the liquidity of DERs available for projects like DEMOCRASI.

6.2.8. Changes to the retail market

There is yet to be significant policy change in electricity supply or retail markets in the UK despite a number of significant policy reviews and consultations recognising the need for change (as discussed in Section 10.1.4). It is likely we will see innovation within the current supplier hub arrangements. However, it is possible that BEIS and Ofgem will open up the market by granting supply licences for specific geographic areas, by expanding the licence exemption regime and/or by removing the universal service obligation on suppliers that want to focus on local offerings. These more radical changes will only be introduced if they can guarantee consumer choice, healthy competition, and appropriate safeguards for consumers.

If these changes are made, it could help open up more opportunities for local energy markets and market platforms, such as those that have been investigated and designed in the DEMOCRASI project.

6.2.9. Implementation of the Clean Energy Package

One of the main benefits of the Clean Energy for All Europeans package is the integration of several rules regarding free and non-discriminatory inclusion of DERs into the wider electricity market[47]. This is to be the case with respect to balancing responsibility, access to wholesale markets, access to data, switching processes and billing regimes and, where applicable, licensing. Specific articles outline the conditions for inclusion of community energy projects as well as aggregators and small-scale renewables and self-producing entities.

Under the package, retailers/suppliers will be required to offer dynamic electricity price contracts. Smart meters will be installed so long as a cost-benefit analysis is validated. In the case that the cost-benefit analysis is unsuccessful, customers are still entitled to a smart meter and may demand a smart meter at a cost to themselves. Member states are to organise the management of metering data, and procedures for attaining data will be easy with procedures for obtaining access made publicly available.

According to the Electricity Directive, "distribution system operators shall cooperate with transmission system operators for the effective participation of market participants connected to their grid in retail, wholesale and balancing markets"[51]. In addition, Member States are to ensure access to electricity markets through aggregation for citizen energy communities and ensure that active customers are entitled to operate through aggregation or directly. Through an aggregation contract, all customers may freely purchase and sell electricity services, including through aggregation, independently from their electricity supply contract.

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[47] European Commission, 2019 *Clean Energy for All Europeans: Commission welcomes European Parliament's adoption of new electricity market design proposals* https://ec.europa.eu/commission/presscorner/detail/en/IP_19_1836

Alongside measures to promote access to the market for flexibility services are several provisions pertaining to security of supply and redispatching, which includes load curtailment. Redispatching is to be minimised as much as possible by TSOs and DSOs while optimizing the interests of reliability and safety of the grid and generation from renewable energy sources or high-efficiency cogeneration. In addition, any non-market-based downward dispatching will be subject to financial compensation by the system operator. This is known as constraint payments in the UK and applies to transmission connected assets, but not to those at the distribution level.

While the UK is no longer bound legally to abide by EU-level regulation as of the end of the implementation period, it is also barred from certain markets like TERRE or MARI unless some of these CEP rules are adopted, thus creating the need for policy equivalence between the EU and GB. In this sense, the package has influenced certain policies, either postponing, altering or cancelling them altogether.

The DEMOCRASI project should be aware of the further impact and implementation of the CEP on the range of services from National Grid ESO and DNOs, as well as wider system changes. These changes will cause uncertainty initially but benefit aggregators and DERs overall, opening up further opportunities over the coming years. While the UK is no longer legally bound to meet the CEP requirements, it could adopt them following further negotiations and decision-making regarding implementation of TERRE and MARI in the UK. National Grid is due to start a CBA on this decision as part of its reserve services reform.

6.2.10. Changes to network charging

In the last few years Ofgem has undertaken a series of reviews of how customers pay for our electricity networks, which account for around a third of a typical electricity bill in the UK. A key part of Ofgem's review is that electricity bills could become more reflective of the costs of running and improving the electricity network where consumers are connected. A bill may also vary depending on the amount of generation and demand connected locally. These changes can remove or add value to DERs connected, or due to connect in the future, fundamentally impacting the operation and behaviour of new and existing customers on the distribution network. Therefore, they are a crucial part of the policy and regulatory environment in the UK.

These reforms have included the following two main parts:

- **Targeted Charging Review (TCR)** – focused on how network customers pay for the residual or fixed costs of running the network.

  Ofgem had concerns that some customers were able to avoid paying for their 'fair share' of the fixed costs of the network. For example, by avoiding peak charge periods. As a result, they wanted to update the charging methodology to ensure that the 'fixed' network charges were 'fairly' distributed and more accurately reflected each customer's contribution.

  The TCR review outcome was announced in December 2019 and the main changes will be implemented from April 2022. A key change will be to significantly increase the proportion of network costs which are recovered as a fixed network charge paid by demand customers. The objective of this is that these are therefore unavoidable, whatever the profile of your demand.

A key impact is likely to be a reduction in the variable time-of-use price signal (the peak time charge), which may reduce the incentives for customers to turn down demand during peak periods.

As part of the TCR Ofgem is also going ahead with the removal of two embedded benefits (or beneficial credits). The Balancing Services Use of System (BSUoS) embedded benefit is being removed from distributed generators as is Transmission Network Use of System (TNUoS) generation residual from transmission generators (which is currently a credit) entirely from April 2021 onwards. The change to BSUoS removes a revenue stream from distribution generation (estimated to be c. £2.50 MWh),further impacting the profitability of new distribution generation.

- **Access and forward-looking charges Significant Code Review (SCR)** – focused on forward-looking costs and how new distribution customers pay to connect to the network.

  In starting the SCR, Ofgem stated they had concerns about the following:
    - Whether the locational and time of use signals, and the overall distribution use of system network charging methodology (the DUoS tariffs), reflected the true cost of the fixed and variable cost of running the distribution network.
    - The level of credits and exemption from TNUoS costs for distribution connected generators, particularly in areas that regularly experienced "reverse flows" exporting energy back onto the transmission network via Grid Supply Points (GSPs).
    - The definition and choice of access rights for distribution network customers (e.g. through Active Network Management and limited connection contracts) and whether more choice and better solutions could be provided.

  Ofgem also mentioned working to reduce the discrepancy between connection methodologies for distribution and transmission and the resulting potential market distortion:
    - At present the distribution connection boundary is 'shallow-ish', where new distribution customers are expected to pay a proportion of reinforcement upgrades needed to the network's upstream infrastructure as a result of their connection at their connection voltage and one voltage above.
    - This is in contrast to transmission where there is a 'shallow' transmission connection boundary, where new transmission network customers only pay for their sole use connection assets.
    - This SCR is still in progress and is at the stage where several shortlisted options are under consideration. Ofgem indicated that it will publish a "minded-to" position on SCR policy changes in November 2020, but there have been delays and a decision has not yet been published.
    - The latest information on network charging decisions in the SCR from the Charging Future Challenge group, includes a preferred decision to decouple the DUoS review on locational charges with the shallow charge for new

connections. This will mean new connections costs are likely to be shallow for demand. For new generation connections the costs will be shallow at EHV in England, and shallower at LV and HV (only their voltage level).

It is beyond the scope of this document to go through each of the SCR changes in detail. However, we have provided a high-level list of the current proposed impacts and how the changes will support or detract from decarbonisation and net zero goals (Table 5).

Overall, some of the changes are likely to be positive and increase DER uptake - decreasing costs to connect to the network through shallow or shallower connection boundaries and more flexible access and connection options will help support growth in DER deployment. This means that new connections might be expected to pay less, or possibly none, of the network reinforcement costs associated with their connection. However, the overall benefit will depend on the level of ongoing network costs, which are likely to be higher in generation-dominated zones and lower in demand dominated zones. Therefore, it is difficult to make an overall judgement at this stage as it will depend on how these locational charge changes are implemented.

The decision to decouple the DUoS review on locational charges (generation and demand dominated zones) and shallow connection charges, will speed up the process of decision making and implementation of the shallow connection charges aspect of the SCR. It will also allow for the government and regulator to claim they support the net zero ambition, as the lower connection costs will help new DER projects get deployed, particularly in areas of current network constraint that have high reinforcement costs at present.

Table 5: Analysis of the SCR changes and whether or not they support decarbonisation and net zero goals

Will the changes support decarbonisation and achieving net zero?		
Network charging change	Impacts	RAG rating
Higher fixed charges for demand customers	• Enhances uptake of low carbon DERs by benefitting those with higher electricity usage for example EVs and heat pumps and electrification of processes.	
	• Reduces cost of electricity unit but also energy efficiency signal.	
	• Reduces the business case for behind-the-meter generation, however most impact on plants that run at peak which is likely to be diesel engines and other fossil fuel.	
Locational charges and price signals	• Potential political consequences of the different zones may conflict with delivery of local net zero plans.	
	• Locational charges in generation dominated areas may dissuade new renewable generators from connecting in areas with good wind and solar resources.	

	• Encourages flexibility and local matching of demand and generation, reducing losses.	
	• Fossil generators likely to find it easier to capture locational DUoS benefits than renewable generators.	
Shallower distribution connection boundary	• Increase in renewable generation in areas of good resource.	
	• Supports electrification of heat, transport and processes by not requiring recharge of high cost upgrades.	
	• Potentially facilitates more strategic investment in key areas of the network.	
	• Potential reduction of incentive for new home and commercial developments to be energy efficient but also means fewer barriers to electrification (or heat and transport) in new demand sites.	
Flexible access and connection options	• Increase the utilisation of the existing electricity network and allowing more connections at a lower cost.	
	• Could support the development of network monitoring and flexibility markets.	
	• Could support greater electrification and renewable generation at lower network cost.	

One of the key problems is that of timing, as the TCR changes have been or are in the process of being implemented. Whereas the SCR changes are still uncertain and not confirmed. The TCR has in effect removed value from those who were providing flexibility, particularly those behind-the-meter, without setting the future framework in the SCR. The SCR changes may provide value back to DERs, providing an overall net positive impact, but many of the changes are still yet to be confirmed, with delays to published timeline from Ofgem exacerbating the issue.

Taking an overall look at the net impact of the TCR and SCR changes in their current form Table 6 provides a summary by user type. Taken together the changes will help new projects connecting to the network the most. Some existing user types will lose value, particularly those with generation assets behind the meter and commercial users with low capacity-factors. However, the actual gross change will depend on a consumers relative utilisation of capacity, the extent to which they previously avoided Triad network charges, and their ability to respond to new forward-looking signals. Generation in Scotland will be significantly impacted by the TNUoS changes in their current form.

Table 6: Summary of distribution network customer cost impacts from the network charging options (TCR and SCR) developed or being considered by Ofgem.

Charging key impact areas		Residual fixed charges for demand customers (TCR)			Locational DUoS and forward price signals				New connection options		
Cost of options developed or being considered		TNUoS residual fixed charge	DUoS residual fixed charge	BSUoS volumetric for domestic only	EHV Customers moving to long run marginal cost	Locational forward DUoS - demand area	Locational forward DUoS - generation area	Additional TNUoS on distributed generation	Fully shallow connection boundary	Shallower connection boundary	New flexible capped connections
Existing demand customers	Average domestic	⇨	⇨	⇘		⇨	⇗		⇘	⇨	
	High usage domestic	⇗	⇗	⇘		⇨	⇗		⇘	⇨	
	Commercial - low capacity factor	⇩	⇩	⇘	?	⇨	⇗		⇘	⇨	
	Commercial - high capacity factor	⇘	⇘	⇘	?	⇨	⇗		⇘	⇨	
Existing generation customers	Scottish generation				?	⇨	⇘	⇩	⇘	⇨	
	Other generation				?	⇨	⇘	?	⇘	⇨	
	Behind the meter generation	⇘	⇘	⇘		⇗	⇨				
New customers	New renewable generation				⇨	⇨	⇘	⇘	⇧	⇗	⇧
	Dispatchable & fossil generation				⇨	⇗	⇗	⇗	⇧	⇗	⇧
	New demand	⇨	⇨	⇘		⇨	⇗		⇧	⇗	

Generally, the proposed changes will have mixed and uncertain impacts for DERs. The net final impact will vary across the country and depend on how the methodologies are developed and applied. What is clear, is that these network charging changes are going to require further investment by DNOs in physical assets, network monitoring, processes, and capability to support net zero, new connections and local flexibility markets. These are key factors to enable DER uptake and projects such as DEMOCRASI.

7. Lessons learnt from the UK

In this section of the report, we look at some of the key regulatory arrangements in the UK that are relevant to the DEMOCRASI project. We highlight the policy and regulations that have been (or will be) implemented that could be considered in Ontario to enable a smart, flexible energy system (see Table 7).

While we recognise that Ontario has its own regulatory strengths, the purpose of this section is to show how knowledge and benefits could be leveraged by learning from the UK approach. We have included programmes and certain decisions that have been instrumental in helping to accelerate the uptake of DERs, in terms of structure of the retail market, data accessibility, and distribution system operation and national system operation.

Table 7: An overview of the main lessons learnt from the UK electricity market that could apply to Ontario

Part of Energy System	Key Policy / Action / Programme	Impact	Implications for Ontario
Retail	Liberalisation of the Retail Market	In the UK, competition and liberalisation in the retail market means that there is an opportunity for new entrants and innovative models to enter the market. Full market competition facilitates innovation and creates a space for flexibility services to operate.	95% of Ontarians choose to buy electricity from their local utility, signalling that more could be done in Ontario to facilitate competition in the retail sector. More competition would also help to lower electricity prices and address fuel poverty.
Data Availability and Standardisation	Energy Data Task Force (EDTF) and the Modernising Energy Data programme	Requirements for all network operators to produce Digitalisation Strategies that meet minimum requirements set by the regulator. Providing support to help DSOs gain recognition and establish standards and best practices between one another, helping to learn as they go along.	In doing the same, Ontario could ensure that the digitalisation of the energy sector happens in a standardised way that supports transparency, accessibility and innovation.
	Embedded Capacity Registers	The Embedded Capacity Registers are a centralised data format required to be published by DNOs, that allows for public access to installed and pipeline distribution assets. This is a step in the right direction for further transparency with DSO reporting data and could	Improving data and transparency for distribution connected assets would help market actors in the Ontario energy market who wish to map progress towards connection of distributed assets in each LDC distribution area.

		lead to further access in the future.	
	API interface for the Balancing Mechanism	Developments in the market are planned to reduce barriers to entry for DERs and aggregators, including a new IT interface with an API communication facility, enabling more real-time connection with assets.	More API compatibility in the Ontarian market mechanisms should bring about similar benefits and allow for real-time asset management.
Distribution System Operation	Move to DSO	Ofgem has required that all DNOs become DSOs, taking a proactive approach to develop and use their networks more efficiently and identify flexible alternatives to network reinforcement. Furthermore, new requirements under RIIO 2, like the Digitalisation Strategy & Action Plan (DSAP), will facilitate their digital transformation.	This model could be followed by Ontario's LDCs which currently do not contract for any local flexibility services, as system operation is still largely the role of the IESO. The Ontarian distribution system is already evolving, but distribution system operation is not encouraged in the current Market Renewal plans, which sees less alteration to the roles of the main energy sector actors.
	"Open Networks Project", Energy Networks Association	This brings all the network operators together to take a coordinated approach to making the connections process for DERs as easy as possible. It has provided visibility by creating a list of flexibility tenders across all network operators to facilitate DER market entry. Through the project, products have been integrated and customer experiences standardised.	A similar system connecting flexibility tenders from different operators would add visibility to DERs in Ontario and improve the standardization process.
	Whole system approaches to flexibility markets	Ofgem has required the networks to take a whole systems approach to network operation. This means greater coordination between the national and distribution flexibility markets going forward. An example is the South Coast Regional Development Programme, run by UK Power Networks and National Grid ESO. It trials a new system that will directly connect the local network operator's control room with the control room at the national system operator, giving them more visibility	Similar programs initiated by the IESO in Ontario could be invoked to nurture system operation capability within the distribution networks. Additionally, by drawing from the UK "trial by doing" approach to distribution system operation, Ontario's LDCs could unlock DER connections in the same way through balancing system operations.

		and control to keep the system balanced.	
National System Operation	Virtual Lead Party	Through the creation of the Virtual Lead Party, the UK has addressed barriers to accessing balancing services for aggregators through the creation of a new type of participant. This enables aggregators to participate without having to attain a supplier licencing and enables recognition for distributed assets of at least 1 MW.	In Ontario, aggregators are not recognised as a distinct class of market participants, and aggregators could benefit from such a distinction and bringing more efficiency to data submission to the ESO and smaller aggregated market units.
	NG ESO Markets Roadmap	The Markets Roadmap provides a summary of ESO market activity and plans to enable a completely carbon free market by 2025.	Creating a policy roadmap for decarbonising networks could give Ontario a vision and game plan to action. Such a plan could be informed by the ongoing Framework for Energy Innovation: Distributed Resources and Utility Incentives consultation process.
	Dynamic Containment (DC)	Frequency regulation markets can assist response technologies such as battery storage, supercapacitors, instantly switch-able Demand Side Response offerings and potentially some modular inverter-controlled generation assets. The DC service is primarily aimed at battery storage due to the technical requirements.	Following a DER Impact Study, Ontario identified the need for the ability to dynamically adjust DER settings to respond to local system conditions, and to explore options for further flexible grid operations[48]. The rollout of DC would provide a good example of a dynamic fast-response service for Ontario. The service requirements are such that battery storage is the only technology that has got a contract in GB.

[48] IFC, 2021 *Ontario Distributed Energy Resources (DER) Impact Study* https://www.oeb.ca/industry/policy-initiatives-and-consultations/responding-distributed-energy-resources-ders

8. Other countries where the DEMOCRASI project could be applied

In this section we discuss some of the key changes in the CEP and briefly comment on whether the DEMOCRASI project could be applied within three other countries in the EU (France, Portugal and the Netherlands).

Impact of the Clean Energy for all Europeans Package

The EU's adoption in 2019 of the new market design rules as part of the CEP included opening European electricity markets not only to renewables and storage, but also imposed harmonized and stricter rules for capacity mechanisms to demand response[49]. This follows the creation of a new Electricity Regulation in 2016 that opened up the EU to renewables, energy storage and demand response. If the UK is to remain an active player in EU flexibility markets, then it will need to abide by these rules, and markets will have similar constraints and practices to those elsewhere in Europe. A map of the different capacity markets and plans for the future can be seen in Figure 9.

Part of the new Energy for all package is centred around demand-side response and making the consumer a key player in the energy system. This move has opened the opportunity for innovation in capacity markets and flexible grid management within member states, with security of supply and emissions reductions in mind. Consumers are encouraged to play an active role in and benefit from decentralised and digitalised energy systems. One of the main takeaways from these new rules include the phase out of capacity subsidies for more than 550 gCO_2/kWh, a change which has been implemented in the GB Capacity Market. EU market design rules as part of the CEP with implications for DERs and flexibility services include, but are not limited to:

- **Revised electricity market regulation (In force January 1 2020):**
    - Granting priority for dispatch of renewable sources from small power-generating facilities via a specific priority order in the dispatching methodology or via legal or regulatory requirements for market operators to provide this electricity on the market.
    - Efficient and non-distortive price formation for balancing markets, requiring that balancing capacity contracts do not set the price for balancing energy.
    - Facilitation of day-ahead and intraday markets and balancing as close as possible to real time, including a requirement for operators to provide products for minimum bid sizes of 500 kW or less to allow for participation of demand-side response, energy storage and small-scale renewables.
    - Unification of settlement periods to 15 minutes by January 1 2021, unless a derogation is given. Derogations may be granted only until December 31 2024, and shall not exceed 30 minutes regardless of derogation by January 1 2025.

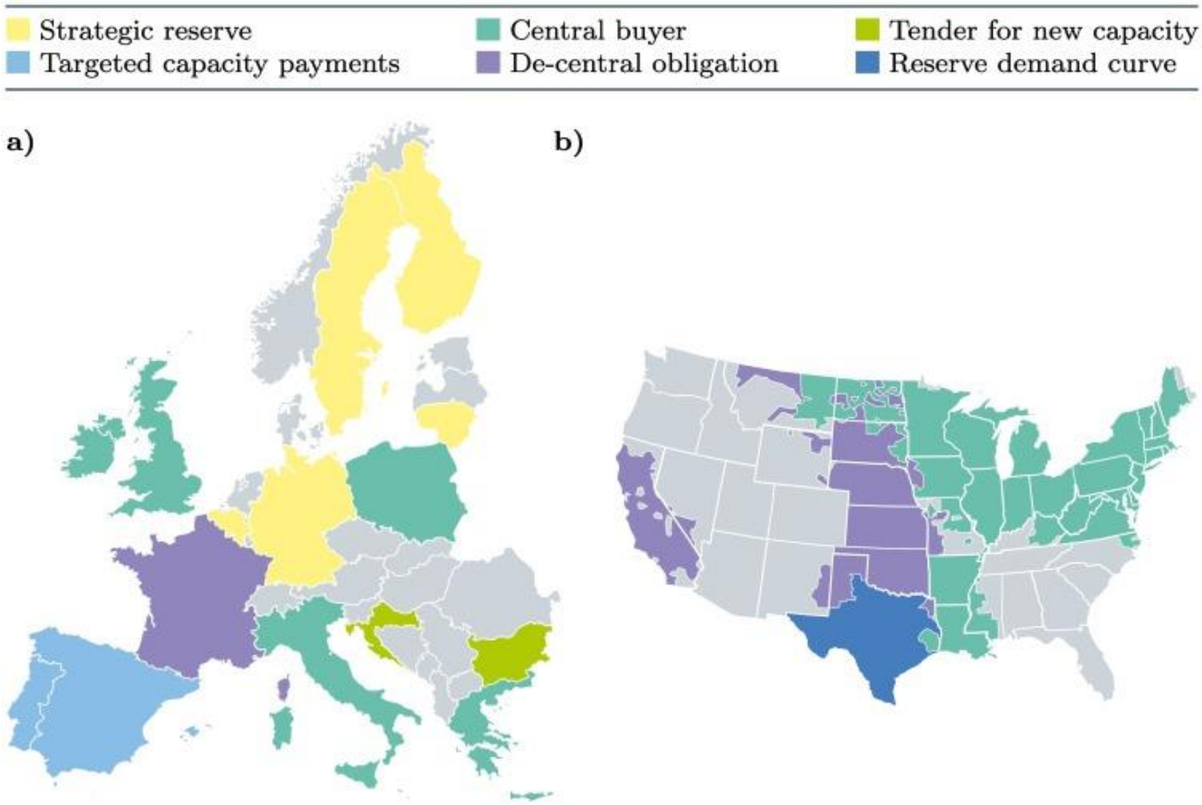
[49] European Commission, 2019 *Clean Energy for All Europeans: Commission welcomes European Parliament's adoption of new electricity market design proposals* https://ec.europa.eu/commission/presscorner/detail/en/IP_19_1836

  - Priority given to dispatching renewables with a capacity of less than 400 kW or demonstration projects for innovative technologies that have been approved by the regulatory authority.
  - Non-discriminatory criteria for redispatching demand response.
  - Establishment of an EU DSO entity to safeguard fair and proportionate treatment of its members, facilitate demand side flexibility, contribute to digitalisation of distribution systems.
  - Design principles for capacity mechanisms, as well as a contingency to introducing capacity markets where Member States must identify a resource adequacy concern[50].
- **Revised electricity market directive (In force January 1 2021)**:
  - Article 11 on the entitlement to a dynamic electricity price contract.
  - Article 13 on aggregation contracts, ensuring all customers the freedom to purchase and sell electricity services, independently from their electricity supply contract.
  - Article 15 relative to the right of active customers to operate, to sell self-generated electricity, to participate in flexibility scheme, and to delegate management to a third party.
  - Article 16 on the rights of citizen energy communities to be treated as active customers and participants in aggregation services.
  - Article 17 on market access for demand response through aggregation in a non-discriminatory manner.
  - Article 19 relative to the deployment of smart metering system, subject to a cost-benefit analysis.
  - Article 20 relative to the required functionalities of smart metering systems.
  - Article 32 on incentives of the use of flexibility in distribution networks.
  - Article 33 on the integration of electromobility into the electricity network[51].
- **New risk-preparedness regulation**, including common rules on how to prepare for electricity crises and ensure cross-border cooperation, common rules for the management of crisis situations (the role of TSOs and DSOs to reduce supply and minimize risk), common methods to assess risks related to security of supply, a common framework for evaluation and monitoring of security of supply, and a required national framework for manual load shedding;
- **Enhanced role of Agency for the Cooperation of Energy Regulators (ACER),** which will enhance coordination between energy regulators to the benefit of EU citizens.

[50] PE/9/2019/REV/1 *Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity* https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0054.01.ENG&toc=OJ:L:2019:158:TOC

[51] PE/10/2019/REV/1 *Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU* https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0125.01.ENG&toc=OJ:L:2019:158:TOC

Figure 9: Overview of future planned Capacity Remuneration Mechanisms (CRMs) in Europe and the USA (Source: Bublitz et al. 2019[52])



As for demand side flexibility, according to the EU Market Monitor 2019, "France, Great Britain, and Ireland are the highest-ranking countries for market activity, followed by Germany, Finland, Belgium and the Netherlands"[53]. Another EU-level policy to take note of is Article 11 of the Electricity Directive, which states that consumers should be entitled to dynamic pricing contracts[54]. Like in the UK, the implementation of CIM in Europe by utilities is very new and at the early stages.

In this section we have selected three European markets that are of interest for the DEMOCRASI project. These three countries are France, Portugal and Netherlands. We selected them because each one is a unique case in how flexibility services can be applied to the market, and each of these three examples show a good amount of progress towards implementing the infrastructure that is necessary for flexibility services to operate. This includes a significant level of DER deployment, plans for further DER and renewable energy deployment, and an existing set of flexibility and ancillary services available.

Many similarities can be drawn between Spain and Portugal, as the energy system on the Iberian Peninsula consists of similar market actors and structure. It is also interesting to note that Poland's capacity market is modelled largely after that of the UK. Furthermore, the

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[52] Bublitz, A. et al., 2019 *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms* https://doi.org/10.1016/j.eneco.2019.01.030
[53] Delta EE & smarten, 2019, *EU market monitor for demand side flexibility* https://www.delta-ee.com/downloads/1-research-downloads/40-system-flexibility-research/2379-the-2019-eu-market-monitor-for-demand-side-flexibility.html#form-content
[54] Article 11 of the Electricity Directive 2019/944

abovementioned CEP will apply to all countries within the European Economic Area, which will alleviate some of the national-level barriers once these changes are implemented on a national level. The deadline for Member States to transpose the Electricity Directive into national law was December 31 2020. The Electricity Regulation does not need to be transposed into national law, and is in force as of January 1 2020.

8.1.1. France

France was the first European country to authorise the sale of electricity consumption reductions on the market through calls for tender to an operator without having to obtain prior approval from their supplier. The capacity mechanism was inaugurated in January 2017, following a green light by the European Commission in November 2016. The recent policy atmosphere in France continues to be favourable towards demand side response and flexibility markets, as shown by the recent adoption of a new energy plan, the Programmation pluriannuelle de l'énergie (PPE) 2019. Major market actors within the French flexibility market contributed to the PPE, advocating for the importance of flexible energy systems to facilitate renewables integration in the energy mix. In many ways, the French energy plan mimics the goals of the new European market design rules in that it puts in place measures to accelerate the development of intelligent consumption techniques.

Markets

France has several different electricity markets (futures, daily, intra-daily, and market for differences), and prices of electricity fluctuate throughout the day based on peak and availability or not of non-dispatchable sources. The futures market that allows buyers to buy at a fixed price for a pre-determined time in the future. There is also a "spot" market that operates on an hourly basis or for a day ahead, that consists either of purchase through mutual agreement or through grants. Then, there is the intra-day market, that allows for the purchase of energy up to five minutes before delivery. Finally, there is a market of differences, that determines an additional price for an amount of electricity that it under or over consumed, for a client that has consumed more energy than expected. This last market is intended to motivate energy providers to maintain market equilibrium.

Of these four electricity markets, the "spot" market is a crucial indicator of supply and demand, and each day at 12:40pm a new fixed price (between EUR -500/MWh and EUR 3,000/MWh) for a 24-hour period is published, and offers for sale and purchase can be made until 12:00pm. The market auctions are organized by EPEX Spot.

France operates its flexibility market based on negative balancing services, providing lower generation or higher consumption. In place of a capacity market, the country has a dedicated strategic oil reserve that is detached from the market and operates separately. This reserve is sized at several months of consumption for emergency use. In 2020, France also introduced a low-emissions capacity market auction, which contracted 253 MW of energy storage.

Market actors

Compared to the UK and Canada, France's networks are much more consolidated. The sole national transmission system operator is RTE, while Enedis manages 95% of the electricity distribution network. GRDF is the main DSO for the gas distribution network. The transmission networks for gas are GRTgaz and TIGF.

There are two main types of DERs in France: 1) electricity producers and 2) "load shedding" clients, who have the ability to voluntarily restrict their consumption, or to carry it over to other periods. Certain market actors have emerged (including Kiwi power) in the past ten years to increase flexibility and demand side response of markets in France. Centrales Next is a "virtual power plant" service that surveys market fluctuations every 30 minutes, or 48 times per day, and sells aggregated services in the market. EnerDigit is a flexibility market operator (DER aggregator), that engages with businesses and industry actors and offers contracts for energy reductions operator. Other DER aggregators ("opérateurs d'effacement") like EnerDigit can sell in private contracts or on the energy stock exchange one day ahead or several times per day.

As of 2018, 2.7 GW of DERs with the ability to reduce their power consumption were certified in France, falling short of the 5 GW objective outlined in the energy plan PPE 2016. According to the French Energy Regulatory Commission, DERs are mobilised in France by price signals on the market offers, or by regulated rates, and thus by system operators that are operate independently to the DER to comply with European competition laws.

Smart Grids

The National Regulatory Authority (CRE) is responsible for defining deployment targets for electricity and gas smart meters. DSOs are in charge of meter ownership and the incurred costs, installation and data collection, as well as its storage and transmission to third parties. Data is then centralised and made available to third parties by a common entity called Agence ORE[55]. Third parties are required to attain consent from consumers to access metering data via written approval validated by DSO or central party, a delegated third-party supplier as part of a service contract, or via an app or website with secured access. One of the advantages is integration of decentralised energy resources with flexible access, load shedding, and infeed curtailment.

As of 2019, 21 million smart meters were already installed, which is around 60% of the total number of meters. Up to 175,000 are installed each week and by the end of 2021, it is expected that this number will rise to 35 million, according to Enedis[56]. Consumers are not able to refuse installation and do not have access to in-home displays for the moment. This has largely been enabled by the centralization of the French rollout program, which is organized by the DSO and not the supplier, greatly facilitating the process compared to the UK rollout process.

RTE is introducing initiatives to provide ancillary services to demand response at lower voltage levels. Equally, Enedis is offering advanced distribution network services such as legal opportunities to valorise storage flexibility, legal framework for local energy communities and self-consumption, support for RES hosting capacity in the form of quicker and cheaper connection charges, and flexibility services procurement for DSOs as an incentive framework and CAPEX reductions.

According to the European Network of Transmission System Operators for Electricity (ENTSO-E) registry, RTE is conformant to the Common Grid Model Exchange Specification (CGMES) requirements since 2014, which is essentially a set of standards for CIM integration into network

[55] European Union Directorate General for Energy, 2020 *Supporting country fiches accompanying the report Benchmarking smart metering deployment in the EU-28* https://op.europa.eu/en/publication-detail/-/publication/09ca8b61-698f-11ea-b735-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search

[56] ENEDIS, 2021 *Le compteur Linky, un grand projet industriel français* https://www.enedis.fr/le-compteur-linky-un-grand-projet-industriel-francais

operators[57]. Another company registered in France included in the ENTSO-E registry is ALSTOM Grid SAS.

Pricing

Consumers either pay a tariff on their electricity bills that is dedicated to the capacity mechanism or economise by reducing their energy consumption during peak hours. Large industries can earn between EUR 10,000 and EUR 18,500 on the capacity market by selling its capacity on the capacity market, and are eligible for additional renumeration under calls for tender organized by the energy system operator, RTE.

In the context of the recent sanitary crisis, the price of calls for tender for flexibility services has risen in 2021 compared to 2020, with prices in some circumstances tripling, making the market in France increasingly attractive for DERs[58]. The reason for this increase in prices is a necessity, since maintenance of certain nuclear reactors in France has been pushed back due to the sanitary crisis, and therefore more need for flexibility to make up the demand.

The CRE has introduced a new distribution tariff structure called TURPE which allows consumers to benefit from demand response during peak times using a mobile peak timeframe. This differs from a previous scheme that was based on predetermined day/night timeframes.

Market mechanisms

The French capacity mechanism serves to provide additional capacity in the event of peak loads, usually in winter. Its role is to introduce a remuneration to the means of production and load-shedding to ensure their maintenance and possible emergence if they are useful to the security of supply in the medium term. By de-central obligation, each electricity supplier is required to have a certain amount of capacity guarantees depending on the electricity consumption of its customers. These guarantees, certified by RTE, can be purchased from generation or load shedding capacity operators, who commit to the availability of their means during peak periods.

The load-shedding mechanism in France is controlled by RTE and called NEBEF, which translates to Notification of Exchanges of Load Shedding Units. This is the mechanism that allows an enterprise to be remunerated for the activation of supply during a determined time frame. RTE signs contracts with flexibility system operators to use the mechanism, while the operators in turn sign contacts with certified DERs. Energy providers are renumerated for the block of energy that would have been produced at the DER that has agreed to reduce electricity consumption at that period.

In addition to this, two short-term flexibility mechanisms are in place, which are also operated by RTE. These are the “adjustment mechanism,” which is activated manually and controls the tertiary reserve to respond within around one hour, and the “system services” that control the primary and secondary reserves operate instantaneously with automatic activation to respond to 15-minute dispatch signals.

Level of Demand Side Response

The current levels of smart meters deployment are a key enabling factor for demand side response. Furthermore, citizen energy projects are well-developed and support mechanisms are

[57] ENTSO-E, n.d. *Common Information Model* https://www.entsoe.eu/digital/common-information-model/#developing-cim-standards
[58] EnerDigit, 2010 *Le prix de l’appel d’offres effacement : en très forte hausse !* https://enerdigit.fr/coefficient-aoe/

in place. A significant part of the French flexibility market is reliant on load shedding. When the electricity grid is heavily burdened, market participants will be asked to reduce their consumption to re-establish equilibrium via the NEBEF mechanism.

In France, ancillary services, the capacity mechanism, and the wholesale markets are all open to demand side flexibility. However, some barriers exist, such as a poor business case for independent players due to compensation rules, and difficulties entering the secondary reserves market.

Considerations for DEMOCRASI project

France's system works quite differently from Ontario and the UK in that its flexibility market has a focus on load shedding. This means that DERs are paid to reduce their consumption at a given time, rather than increase it. Thus, a new joint product solution may be needed to operate in this way. Kiwi Power has already engaged in the French market, has a collaborative relationship with Engie, and can benefit from its existing connections.

There is existing market competition for grid flexibility services in France, and aggregators are already established. Finding a niche in the market would be necessary and a full stakeholder mapping could accomplish this and better determine the demand for a joint product solution like the one proposed by DEMOCRASI.

Another big plus is the availability of metering data to third parties by a centralised agency. Third parties are still required to attain consent from consumers to access data. Smart metering has also enabled self-consumption schemes for community-based and localised generation and sharing schemes. Furthermore, both the transmission and distribution system operators are extending provision of ancillary services to demand response at local voltage levels.

8.1.2. Portugal

One market that has been studied in the context of markets and flexibility, and is of interest to investors in flexibility services is Portugal. Following a study by Catapult of 31 European markets, Portugal was selected as one of the final six to be evaluated for a project called *Towards a Smarter and More Flexible European Energy System*[60]. Portugal has a higher-than-average penetration of renewables, making up 71.6 % of domestic primary energy production as of May 2020. Much of this comes from hydro and wind, followed by bioenergy and solar, with solar projected to soon bypass bioenergy. The country also aims to decommission it's two coal-fired plants by 2023, and is looking towards hydrogen to repurpose the remaining coal-fired infrastructure.

Several clear opportunities exist, such as a presence of grid-connected storage resources. And pre-existing smart grids.

Markets

In Portugal, there has been a transition into an unregulated market system. In 2019, the unregulated market reached 5.2 million consumers, and experienced a 2.8% growth rate. 1.3 million consumers remained in the regulated market. Portugal's capacity market operated under a targeted capacity payment, where a central body sets a fixed price paid only to eligible capacity, e.g., selected technology types or newly built capacity.

Market actors

REN is the operator of the national transmission grid, or RNT, and operates under a concession agreement with the Portuguese state. Together, these two entities manage extra high voltage transmission. REN has seven million euros set aside for grid expansion to the southern part of the country. RNT delivery points feed into the distribution network. Distribution grids operate under concessions contracts between municipalities and distributors. Electricity supply companies are responsible for managing relations with customers, such as billing and customer services.

The energy regulator Entidade Reguladora dos Serviços Energéticos, ERSE, oversees setting up tariffs for the regulated market on a yearly basis. The regulated tariffs were intended to be discontinued in 2019, but a government announcement has extended the use of regulated tariffs for three more years. As a result, a hybrid system is in place during the transition to unregulated tariffs.

Rede Elétrica Nacional, REN, and REN Gasodutos are the electricity and gas Transmission System Operators (TSOs) respectively.

EDP, Energias de Portugal, is the main energy stakeholder and has built an international presence in the past 40 years. It is the country's largest supplier, distributor and producer.

EDP Distribuição is the distribution network operator in the mainland of Portugal. EDP Serviço Universal runs the regulated market, with tariffs set by ERSE, while the unregulated market is lead by EDP Comercial.

Smart grids

EDP Distribuição has been pioneering smart grids through various projects. As of July 2020, 2.5 million smart meters were installed in the country, leaving 2/3 of customers not served by smart metering. The expectation is that by 2025 all six million customers will be using a smart meter. Although charging infrastructure is largely present, vehicle-to-grid trials are less present than in other European economies. All meters have a measuring interval of 15 minutes.

Pricing and auctions

Household electricity bills are divided as follows: 30 % for the network component, 30 % for the energy component, and the remaining covering VAT, taxes, levies and RES subsidies. For most industrial consumers, network tariffs are 27 % excluding VAT, and the energy component represents 26 %. There is also an option for industrial tariff focused on capacity term.

In accordance with EU law, suppliers will be expected to offer dynamic pricing contracts to reflect variance in sport markets, at interval equal to the settlement frequency. This means that the energy component of the tariffs will no longer be regulated in the future.

Energy storage auctions were to be organized for first time in 2020 to manage the annual 800-1200 GWh surplus in RE expected for the same year. There were plans for 50-100 MW of storage capacity for dispatchable renewables, but these plans were never realised. Instead, the Portuguese solar auction held in 2020 included an option to add energy storage to project proposals, which successfully contracted 670 MW of solar at record low prices, including 483 MW with an energy storage component[59].

Capacity mechanism

In 2017, the Capacity Renumeration Mechanism (CRM) markets in Spain and Portugal were suspended and the market is in standstill until an assessment can be made by the European Commission. This means that revenue stacking for businesses for large scale storage is reduced.

Level of demand side response

While storage capacity that is connected to networks is a plus, there are some barriers to aggregating these resources that should be considered. Currently, aggregators cannot access balancing markets or ancillary services, although the EU requirements are likely to unlock access to aggregators soon. Lacking CRM points to a limited opportunity to stack revenues. Several aggregators are looking into the Iberian Peninsula aggregator market, including EDP Commercial and Red Eléctrica de España.

Industrial scale response is made possible by the Replacement Reserve market.

For the moment, the lack of aggregation-friendly policy slows down the demand side response market, as well as relatively low levels of solar, despite recent acceleration of solar uptake. However, this is changing, and the access to aggregated DSRs may look more positive in the near future.

Considerations for DEMOCRASI Project

The fact the Portugal is so reliant on renewables and increasing its investment in solar in the coming years flags a possible need for distribution and flexibility services. However, the lack of a supportive policy framework to reward flexibility and grid services is a drawback.

The saturated market may be difficult to enter, especially concerning EDP Energias and its sister companies throughout the energy supply chain, as they are less willing to incorporate new technologies. In addressing this problem, a study by Energy Systems Catapult advised engaging with "tier 2" companies, since the pre-qualification for tenders is simpler[60]. These companies include: Eurico Ferreira, efacec, cme, EIP group, Conduril, Telcabo, Viatel, Somitel Grupo, Motaengil, Painhas, Somague and Sotencnica.

One thing to consider concerning metering data access is the lack of a defined data management strategy. In theory this data is available with limited barriers to access, and further investigation would be required to determine ease of access given the non-defined nature of data security.

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[59] Institute for Economic Analysis and financial analysis, 2020 *Record-low solar price of $13.16/MWh set in latest Portuguese capacity auction* https://ieefa.org/record-low-solar-price-of-13-16-mwh-set-in-latest-portuguese-capacity-auction/

[60] Foreign Commonwealth Office and Catapult, 2020 *Towards a smarter and more flexible European energy system* https://es.catapult.org.uk/reports/europe-smart-energy-and-flexibility-market-study/

8.1.3. The Netherlands

The Netherlands has made strides towards removing fossil fuels, as is shown with the symbolic closure of the Groningen oil field. In 2028 Coal is expected to be phased out and gas will be reduced by 55%, signalling an uptake in variable renewable resources, for which a need for flexibility services will follow. Furthermore, the price signals in the Netherlands are such that the electrification of heat is more incentivised compared to other EU markets, as price distortions in the market between natural gas and electricity are minimal. There have also been heavy investments in EV infrastructure, signalling flexibility opportunities in the future from electric transport. The Netherlands energy market is characterised by generation dominated by multinationals and a government-owned transmission system operator.

Several renewable support schemes are in place, including net metering, a premium tariff offered to renewable energy generators, tax reductions for consumers of self-generated renewables, and tax credits for companies for solar PV investments.

Markets

The retail market is made up of 45 different suppliers, flexibility markets in the Netherlands are seeing growth that is expected to continue in the coming years. The aggregation market is established and there are strong price signals for industrial and commercial customers to provide flexibility services.

Several big players in the European smart heat services market have a strong presence in the Netherlands, such as Eneco. This is an emerging market with new electric heating a real possibility in the country's future.

The wholesale market plays a big role, since the Netherlands do not have a dedicated capacity market. DSR participates in the ancillary service markets, but require an aggregator to establish a contract with the relevant balancing responsible party. Aggregators are allowed access but only one balancing service provider is allowed per pool of resources. The minimum size for bidding is 1 MW. Activation time is 15 minutes, and 10 minutes or less for manual frequency restoration reserves, with a minimum of 20 MW.

Market actors

TenneT is the government-owned transmissions system operator. There are eight DNOs with Enexis and Liander being responsible for most new connections. These DNOs are independently owned by provincial and local governments.

Smart grids

Under the National Agenda on Charging Infrastructure, there Is a statement of intent on enabling smart grids, charging infrastructure for logistics, and innovation in EV charging. A pilot project by Vandebron and TenneT is experimenting with the interruption of car charging sessions by the TSO to help manage network frequency. Other vehicle-to-grid projects exist in Utrecht and Amsterdam.

The smart metering rollout has just exceeded the levels of the UK, with 47 % of the population having access to a smart meter in 2018.

Pricing and auctions

A typical household bill is split between energy component (36%), network component (31%) and the remaining on taxes, VAT and RES. Contrarily, the industrial electricity bill is made up of

53% by the energy component, with network charges taking up 25%. Time of Use (ToU) tariffs for the moment are limited to large industrial consumers. Network tariffs for transmission-connected parties are based on a unit price per kWh, and can be higher or lower depending on hours of grid utilisation. Distribution tariffs are divided into customer type: residential, small industrial and large industrial. DERs in the Netherlands do not pay for use-of-system.

Household tariffs in the Netherlands differ from other EU tariffs in that they are based on connection capacity, rather than volumetric consumption. In the past, household retail electricity contracts would last for one year or more, or be based on tariffs that are variable, and change twice a year. Some market-based pricing experiments that are linked to wholesale prices are underway in the market following the rollout of smart meters. Suppliers that offer variable pricing include NieuweStroom, Eneco, Powerhouse (part of Essent) and Qurrent. Net metering for solar is set to phase out starting from 2023 to 2031, when it will decrease by 9% year on year, thus consumers are incentivised to install solar sooner rather than later to benefit from the scheme before it runs out.

Capacity mechanism

The Netherlands does not currently operate a capacity mechanism, and, like Germany, has an 'energy-only' market.

Level of demand side response

As previously stated, heating and EVs are promising markets for the future of demand side response in the Netherlands. The need for data services, optimisation, aggregation and trading is on the rise in multiple sectors, especially in electric mobility.

Large consumers of over 50 GWh/year can benefit from off-peak consumption via the "volumecorrectie," so long as their annual off-peak consumption is 65% of all annual off-peak hours. Distributed generation is exempt from distribution network charges for excess energy export, batteries are charged, however, as normal energy consumers.

Considerations for DEMOCRASI Project

Since domestic users use a capacity-based tariff rather than a volumetric one, there is no true price signal to incentivise demand side response. This is a barrier to be taken into consideration for residential demand side response. However, the opportunity for mobilising EV connected smart grids is a significant opportunity. The presence of smart heating and an expected increase in electrification indicates a strong need for flexibility services in the future with relative certainty.

Kiwi Power has already engaged in the Netherlands market, and can benefit from its existing connections.

9. Summary of recommendations

In this section we provide a list of recommendations for DEMOCRASI project partners based on our analysis in this report.

- **Engage with other DNOs in GB to share learning.** We recommend making contact with each DNO to discuss the DEMOCRASI products and outputs, and opportunities to work together, whether through trials or rolling out as business as usual.
- **Provide more content that communicates the DEMOCRASI project to a wider audience.** Additional non-technical content on a webpage defining the project outputs and sharing the latest updates, would help increase awareness and credibility**.** The webinar planned for September 2021 is a good opportunity for further project dissemination.

Market opportunities

- **Monitor changes that are allowing further market access for DERs and aggregators.** While there remain barriers to accessing some markets and services, there are changes underway which will allow better access for DERs and aggregators. A good example is the code modification P375 to the BSC, as discussed in section 6.2.1. Changes like these will help increase DER uptake once they are implemented.
- **Closely monitor new services being developed by National Grid ESO.** The GB electricity system is in a state of transition to allow for a zero-carbon operation by 2025. New services to monitor from the National Grid ESO are the Slow Reserve and Quick Reserve services, as well as new frequency response services Dynamic Regulation and Dynamic Moderation. Other system stability markets are also likely for reactive power and inertia services. These are all opportunity areas for DER and solutions that enable them.
- **Capitalise on the maturing local flexibility markets in GB.** The DEMOCRASI partners should monitor the new DSO Strategies under RIIO-ED2 as well as the development of local flexibility markets on the Flexible Power website[61]. As these functions become more mainstream, products like DEMOCRASI will be enabled to compete for new value streams to provide their solution to the rollout of local flexibility markets.
- **Engage in the formation of new regional constraint management markets.** Regional constraint management markets and services are starting to be developed in GB and they present a significant opportunity for the DEMOCRASI project capabilities.
- **Input to ISO development in GB**. Ofgem has confirmed a shift to an ISO model for GB and the DEMOCRASI project partners are well-placed to share their experience from working with the IESO in Ontario. This change will have far-reaching implications for electricity system governance and operation in GB. Being a part of shaping how the development of the ISO model in GB progresses, by feeding into consultations and meeting with relevant officials, will raise the profile of DEMOCRASI project partners with BEIS and Ofgem.
- **Take time to understand the changes to network charging in GB.** The network charging regime decides how we pay for our electricity networks and can significantly impact the viability, scale and choice of location for energy generation, storage and

[61] https://www.flexiblepower.co.uk/locations

flexibility projects. Therefore, DEMOCRASI project partners need to comprehend the implications for DERs and the wider electricity system when the Access and Forward-Looking Charging Significant Code Review 'minded-to decision' is published later this year.

- **Watch for further policy changes driven by the EU CEP.** While no longer legally bound, the UK is likely to adopt policies in line with those put forward in the CEP in order to retain access to European energy markets. In addition, other countries in the EU will be reforming their national markets and services to comply. The DEMOCRASI partners should monitor these policy changes, as they have implications for further benefits to DERs.

Data

- **Put pressure on DNOs to provide CIM standard network data.** The CIM model is a universal standard that can greatly facilitate the integration of digital services. Putting pressure on DNOs to adopt this model would help to spread this methodology further. DNOs can also be directed towards useful resources for developing their own CIM.
- **Encourage the availability of DER and network data.** The advent of the UK's Embedded Capacity Registers has greatly improved planning and tracking of DER deployment and on the distribution networks. The DEMOCRASI partners could ask for further datasets to be shared to help understand DER uptake. The DNOs are going through a process of identifying use cases for network data to determine which datasets to surface and make available to stakeholders. There is an opportunity to work with them to support this process.

Replicability in other countries

- **France is the only country with a system operator that has certified conformity with CIM model standards in Europe.** The market for aggregation is already established in the country, and further stakeholder and competitor mapping is advised to assess the demand for a DEMOCRASI project solution in the current market.
- **Portugal is an emerging market for DERs, and it is high in renewable energy generation.** The overall electricity market is competitive, while the saturation of the flexibility services market is less evident. This poses an advantage for new market players in flexibility services seeking to be the first to provide unique services. However, the subsequent lack of data or system preparedness may equally pose significant barriers for market entry, until such improvements are made. The DEMOCRASI partners are encouraged to watch the growth of this market strategically over the upcoming years.
- **The Netherlands has mature EV and energy storage markets.** There is also a move towards heating electrification. The market for aggregators is already established, with a focus on industrial and commercial customers. DERs require aggregator services to participate in the ancillary services market. Again, DEMOCRASI project partners should investigate this country as a potential candidate for market entry.

10. Appendix

This section of the report provides a summary of the electricity sectors of both the UK (focused on GB) and the Canada (focused on Ontario), so that we can make informed comparisons between the two. This includes the energy policy context, the electricity networks, how electricity is generated, the retail market for electricity, the main markets, and how electricity system is operated.

10.1. Overview of UK (focused on GB) electricity sector

The UK energy system is undergoing a period of significant reform and transitional change, requiring significant investments in infrastructure, to accommodate:

- A rapid, significant and widespread increase in electricity demand from the electrification of transport and some sources of heat demand.
- The next phase of decarbonisation of electricity generation, potentially seeing GWs of additional renewable electricity generation capacity (including significant amounts of offshore wind[62]) coming online across the UK.
- A rapid and significant deployment of electricity storage and other sources of electricity flexibility, connecting at both distribution and transmission voltages[63].
- The repurposing (and potential shrinkage) of the UK gas network to enable the production, storage, transportation and use of hydrogen[64].
- Almost one million prosumers generating renewable energy.
- A sharp reduction in coal generation.

There is a strong policy on decarbonisation via a net zero target for 2050 and political focus ahead of the UN climate change conference, COP 26, to be hosted in Glasgow November 2021.

The UK is made up of four separate countries, England, Scotland, Wales and Northern Ireland. From a UK perspective, Northern Ireland has a separate governance structure as energy policy is a devolved matter governed by the Department for the Economy in the Northern Ireland Executive[65]. Northern Ireland is part of a separate electricity market - and capacity mechanism - covering the Republic of Ireland and Northern Ireland. However, there is close relationship between the two structures due to interconnected energy markets and support mechanisms. In this document we will focus on the electricity system in Great Britain (GB).

From a nationalised electricity network system created in the early 20th century, the GB energy system was privatised and reformed during 1980s and 1990s. This process culminated in the Energy Act (and subsequent amendments)[66], which integrated the electricity systems of England, Scotland and Wales and set out the framework under which generating, transmitting,

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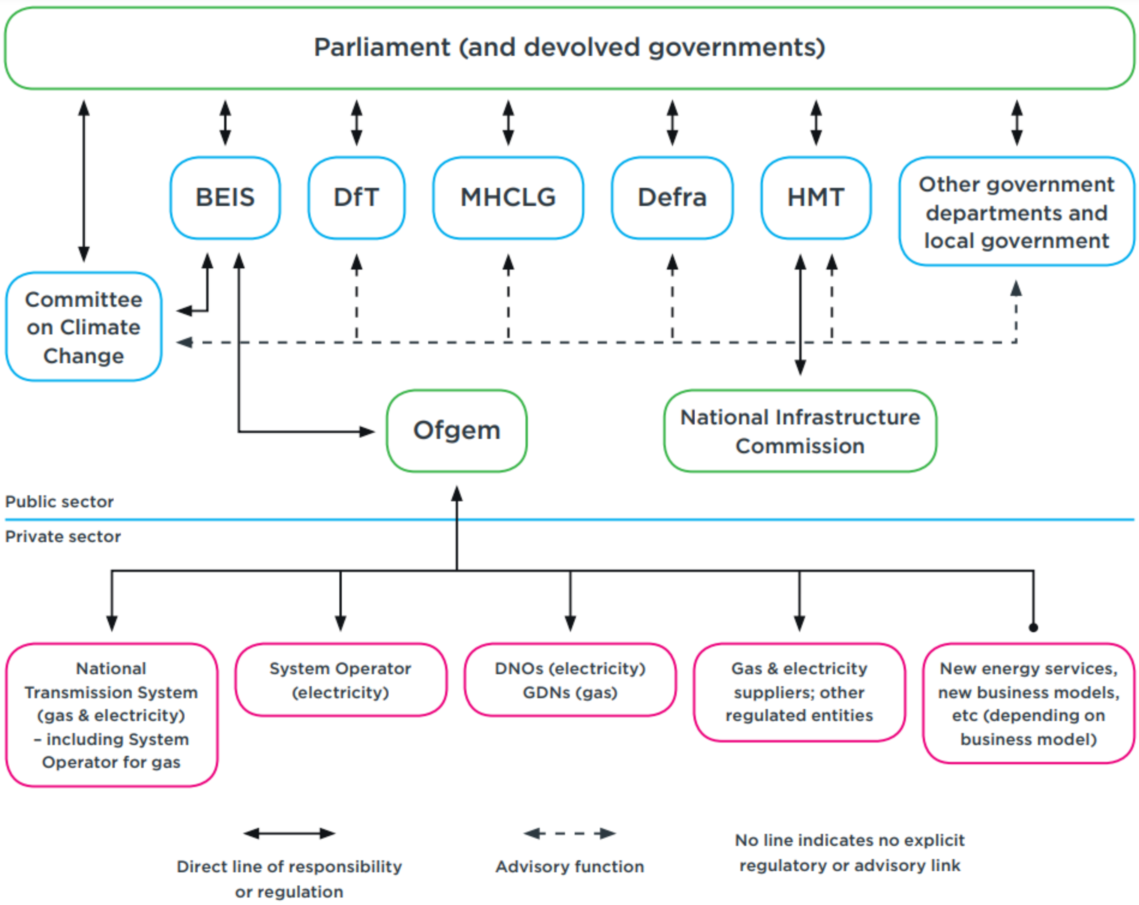
[62] Regen, 2021 *Big oil raises the stakes in UK offshore wind market* https://www.regen.co.uk/big-oil-raises-the-stakes-in-uk-offshore-wind-market/
[63] Regen, 2020 *Electricity Storage: Pathways to a Net Zero Future* https://www.regen.co.uk/publications/electricity-storage-pathways-to-a-net-zero-future/
[64] Regen, 2020 *Hy to Hydrogen* https://www.regen.co.uk/hy-to-hydrogen/
[65] UK government, 2017 *Northern Ireland Affairs committee – Electricity sector in Northern Ireland* https://publications.parliament.uk/pa/cm201617/cmselect/cmniaf/51/5104.htm#_idTextAnchor005
[66] UK government, 2004 *Energy Act* https://www.legislation.gov.uk/ukpga/2004/20/contents

distributing, and supplying power requires a license, regulated by Ofgem.

There are several important roles for the public sector in the governance of the electricity sector., a high-level overview of the various roles in the GB energy system is shown in Figure 10. The UK government (and devolved administrations) through the various departments, particularly the Department for Business, Energy and Industrial Strategy (BEIS), work with the energy regulator Ofgem. Ofgem is responsible for regulating the energy network companies, the system operator, the functioning of the wholesale market and the energy suppliers. BEIS was formed in 2016 and is responsible for energy policy and meeting the UK's statutory targets for reducing greenhouse gas emissions. The strategic objectives include:

- Ensure the UK's energy system is reliable and secure.
- Deliver affordable energy for households and businesses.
- Support clean growth and promote global action to tackle climate change[67].

Figure 10: Governance framework for GB (Source: IGov[68])



Ofgem is the energy regulator and BEIS is the government department setting the policy and regulatory framework. The relationship framework document states that, "Ofgem is the

[67] NAO, 2019 *Departmental overview 2019* https://www.nao.org.uk/wp-content/uploads/2019/09/Departmental-Overview-BEIS-2019.pdf

[68] University of Exeter, 2019 *IGov – enabling the transformation of the energy system* http://projects.exeter.ac.uk/igov/wp-content/uploads/2019/04/IGov-Enabling-the-transformation-of-the-energy-system-Sept2019.pdf

independent regulator for the gas and electricity sectors in Great Britain. Classified as a non-Ministerial government department."[69] Again note that Ofgem's remit does not cover Northern Ireland.

The principal objective of Ofgem under the Gas Act 1986 and the Electricity Act 1989 is to "protect the interests of existing and future gas and electricity consumers"[69].

Key documents that control the aims and strategy of Ofgem, and that are deliberated by Ofgem's Board (the Gas and Electricity Markets Authority, or the Authority) include:

- Strategy and policy statement – The Energy White Paper published on 14 December 2020 by the UK government included an action to develop a new Strategic and Policy Statement for Ofgem in 2021[70].
- Ofgem's decarbonisation action plan – a set of actions that describe the trade-offs taken into account to get to net zero[71].
- Forward work programme – published annually, this lists the projects that are to be delivered over the coming year and the expected expenditure. The latest version has been published and outlines a new focus on full-chain flexibility, retail reform, and reviewing energy system governance[72].

While Ofgem contends that they have a duty to serve current and future customer's needs, many have argued that in recent years current customers have taken precedent, at the cost of zero carbon actions. Growing pressure has led to a change in rhetoric, this is one of the reasons the strategy and policy statement is due to be updated in 2021.

The licensing framework is regulated by Ofgem and separate standard licence conditions apply to distribution network operators, transmission network operators, suppliers, generators and interconnectors on the electricity system[73]. There are a set of exemptions that have mainly been used by commercial and housing developments to help instigate opportunities for local energy generation and supply. BEIS has just closed a call for evidence on licence exemptions and there are likely to be further consultations and policy changes in this area. Regen responded to this call for evidence, with a set of recommendations[74].

There is a complex mix of organisations responsible for the governance and management of the nine industry codes that govern the GB electricity sector (see Table 8). The process of code change involves Ofgem receiving a recommendation from a code panel before making a decision on whether to approve a modification. Fragmentation, lack of consistency, poor transparency, slow rate of change, and limited accessibility of this process have been

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[69] For more details see Ofgem, 2019 *Framework document final publication* https://www.ofgem.gov.uk/system/files/docs/2019/12/framework_document_final_publication_version_december_2019.pdf
[70] BEIS, 2020 *Energy White paper* https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[71] Ofgem, 2020 Ofgem's decarbonisation action plan https://www.ofgem.gov.uk/publications-and-updates/ofgem-s-decarbonisation-action-plan
[72] Ofgem, 2021 *Forward work programme 2021-22* https://www.ofgem.gov.uk/publications-and-updates/forward-work-programme-202122
[73] Ofgem, 2021 *Licence conditions* https://www.ofgem.gov.uk/licences-industry-codes-and-standards/licences/licence-conditions
[74] Regen, 2021 Response from Regen and Electricity Storage Network https://www.regen.co.uk/wp-content/uploads/BEIS-call-for-evidence-licence-exemptions-Regen-ESN-response.pdf

highlighted by various organisations over a number of years. There are plans to reform the energy industry codes in 2021, that will also consider responses from a consultation on the matter that ended in in 2019[75]. EU network codes also have an impact on UK electricity industry codes as the markets need to maintain equivalence, regardless of Brexit.

Table 8: Electricity sector industry codes in GB[76]

Area	Code title	Managed by	Brief description
Electricity distribution	Distribution Code (D-Code)	Energy Networks Association (ENA)	Technical rules for the use and planning of the distribution networks.
	Distribution Connection and Use of System Agreement (DCUSA)	Electralink	Arrangements for how the connections and use of system charges are applied to the distribution networks (related to CUSC).
Electricity transmission	Connection and Use of System Code (CUSC)	National Grid ESO	Focused on the connection and use of system charges for the distribution network (related to DCUSA)
	Grid Code		Covers the connections, operation, and use of the electricity transmission networks.
	System Operator/Transmission Code (STC)		Dictates the working relationship between the system operator (National Grid ESO) and the electricity transmission network operators.
Balancing	Balancing and Settlement Code (BSC)	Elexon	Governs the Balancing Mechanism[77] delivery and the settling of any imbalances between parties.
Smart metering	Smart Energy Code (SEC)	Gemserv	Governs the use of smart meters on the electricity and gas systems
Electricity retailing	Master Registration Agreement (MRA)	Gemserv	Covers the retail market rules including switching suppliers and meter administration.
	Retail Energy Code (REC)	Retail Energy Code Company	New codes consolidating the MRA and other arrangements into a new framework that covers electricity and gas suppliers.

The industry network codes impact different actors in the energy system. Table 9 provides an overview of which codes apply to specific organisation types.

[75] BEIS, 2021 *Reforming the energy industry codes* https://www.gov.uk/government/consultations/reforming-the-energy-industry-codes
[76] University of Exeter, 2015 *Innovation and energy industry codes in Great Britain* http://projects.exeter.ac.uk/igov/wp-content/uploads/2015/12/ML-Innovation-energy-industry-codes-in-GB1.pdf
[77] See Electricity system operation and markets

Table 9: Industry network code compliance per organisation type.

Organisation type	Associated codes								
	D-Code	DCUSA	CUSC	Grid Code	STC	BSC	SEC	MRA	REC
Distribution network operators									
Transmission network operators									
Interconnectors									
Connected generators									
Suppliers/retailers									

10.1.1. Energy policy context

Several UK government policy changes have had an impact on the electricity sector in the UK in the last ten years including, but not limited to:

- **Climate Change Act 2008**[78] and update in 2019, that sets a legally binding reduction in greenhouse gas emissions to net zero, or 100% reduction from 1990 levels, by 2050. The updated Nationally Determined Contribution (NDC) in late 2020, confirmed ambition "for at least 68% reduction in greenhouse gas emissions by the end of the decade (2030), compared to 1990 levels"[79]. This brought the policy in line with 2015 UN Paris Agreement. The government updated their ambition further in April 2021, committing in law to “cut emissions by 78% by 2035 compared to 1990 levels” and incorporating the UK’s share of international aviation and shipping emissions for the first time in the sixth carbon budget[80].
- **Electricity Market Reform** programme through the Energy Act 2013, that among other changes created the Capacity Market and Contracts for Difference framework.
- **Clean Growth Strategy[81],** released in 2017, set out the green ambitions under a new Industrial Strategy framework, focusing on progress against the fourth and fifth carbon budgets.
- **Ten Point Plan**[82] announced by the UK Prime Minister in November 2020 and the closely related **Energy White Paper**[83] in December 2020, that sets out a number of actions and the scale of change needed in the energy system to help meet the net zero target by 2050**.**

The new net zero target and updated NDC, alongside the Ten Point Plan and Energy White Paper have provided strong impetus to the energy policy landscape, increasing ambition and confirming the direction of travel. However major gaps in policy remain, particularly in relation to the decarbonisation of heat and buildings, the new Heat and Building Strategy, due for release in May 2021, is expected to address these.

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[78] UK government, 2019 *Climate Change Act 2008* https://www.legislation.gov.uk/ukpga/2008/27/contents
[79] UK government, 2020 https://www.gov.uk/government/publications/the-uks-nationally-determined-contribution-communication-to-the-unfccc
[80] UK government, 2021 *UK enshrines new target in law to slash emissions by 78% by 2035* https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035
[81] UK Government, 2017 *Clean Growth Strategy* https://www.gov.uk/government/publications/clean-growth-strategy
[82] UK government, 2020 *Ten Point Plan* https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution
[83] UK government, 2020 *Energy White Paper* https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

10.1.2. Networks

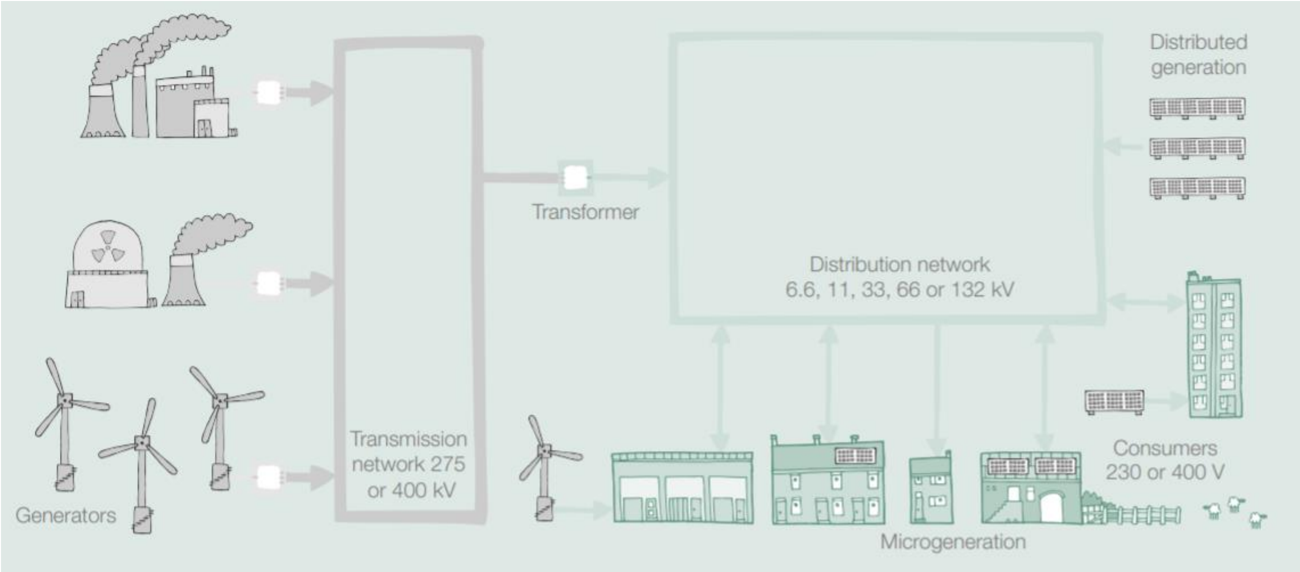
In the conventional centralised model of the GB energy system, electricity flows from the large power stations into the transmission network, which transports electricity over long distances at a high voltage (275 kV or 400 kV in England and Wales, 132 kV, 275 kV or 400 kV in Scotland) (Figure 11). There are three transmission network operators that own and maintain the network in specific areas of GB[84].

Electricity then flows to the distribution network, run by Distribution Network Operators (DNOs), to users, such as homes and businesses. The voltage is reduced in the distribution network to be able to supply electricity ready for use in consumers' homes; from 132 kV down to 230 V in England and Wales, and from 33 kV down to 230 V in Scotland. There are 14 licenced areas managed by six DNOs in GB[85].

In recent years, the nature of the energy system in GB has changed as more generation, including renewable energy technologies such as solar farms, connects at a local level directly to the distribution network. This is referred to as distributed generation or DG. This change has led to more two-way flows of electricity, with some licence areas of the distribution network exporting electricity back up to the transmission network at certain times, particularly in the summer when solar generation is higher. New disruptive demand technologies such as heat pumps and electric vehicles (with the associated charging infrastructure), are due to connect in large numbers, as the heat and transport sectors decarbonise rapidly over the coming years. The UK government confirmed ambitions for 600,000 heat pump installations per year by 2030 and an effective ban on the sale of internal combustion cars and vans in 2030 in the Ten Point Plan[82], further accelerating the pace of change. This will have significant impacts, particularly at the Low Voltage (LV)[86] level of the distribution network, requiring investment in monitoring, network reinforcement to increase capacity, and smart system management through flexibility enabled by markets at the local and national scale.

[84] Scottish and Southern Electricity Networks – Transmission (Scottish Hydro-Electric Transmission), SP Energy Networks, National Grid Electricity Transmission.
[85] Scottish and Southern Electricity Networks, SP Energy Networks, Electricity North West, Northern Powergrid, Western Power Distribution, UK Power Networks
[86] Less than 1 kV networks, i.e. 230/400 V

Figure 11: Simplified illustration of the electricity network in the UK



All the network operator companies are privately-owned, regulated monopolies. The revenues are controlled via the Revenue = Incentives + Innovation + Outputs or RIIO periodic investment, price and revenue review process[87]. The DNOs are currently preparing their business plans for the next price control period, to begin on 1 April 2023. Whereas for the transmission network operators, system operators, and gas distribution companies, the new price and revenue control process began on 1 April 2021. However, a number of companies have already submitted appeals and the matter is due to be referred to the Competitions and Markets Authority (e.g. National Grid ET[88]). An outcome is due in Autumn 2021. We discuss this crucial area of change in Section 6.2.4.

Since privatisation, competition has been increasing, particularly at the distribution network level, with the introduction of competition in connections reform, allowing Independent Distribution Network Operators (IDNOs)[89] and Independent Connection Providers (ICPs)[90]. These organisations are licenced by Ofgem and accredited with National Electricity Registration Scheme (NERS)[91] respectively, providing alternatives to consumers looking to connect to the network in comparison with the DNOs.

[87] Further details available here – Ofgem, 2017 *Guide to RIIO-ED1* https://www.ofgem.gov.uk/system/files/docs/2017/01/guide_to_riioed1.pdf
[88] National Grid ET, 2021 *Response to RIIO-ED2 draft determination* https://www.nationalgrid.com/uk/electricity-transmission/document/134556/download
[89] Independent Distribution Network Operators (IDNOs) are separate organisation that can develop and operate the distribution network and mainly provide services to housing developments or commercial industrial estates.
[90] Independent Connection Providers (ICPs) are companies that provide certain contestable aspects of connections process.
[91] NERS, 2021 *Lloyds Register* https://www.lr.org/en-gb/utilities/ners/

Network charges

Network charges are 22.3% of the average domestic electricity bill[92] and can vary depending on the type of consumer. They can significantly impact the viability, scale and choice of location for energy generation, storage and flexibility projects, impacting the operational behaviour of users connected to the electricity system. Network charges include four charges that are calculated using two industry codes (Table 8 and Table 9):

- Connection charge – distribution DCUSA, transmission CUSC.
- Distribution Use of System charge (DUoS) – set by DCUSA.
- Transmission Network Use of System charge (TNUoS) – set by CUSC.
- Balancing Services Use of System charge (BSUoS) – set by CUSC.

The network charges include:

- Forward looking components that can allow customers to affect their charges through behaviour.
- Residual or fixed components for revenue recovery of the overall cost of the electricity network.

Ofgem has had concerns that some consumers were able to avoid paying for their 'fair share' of the fixed costs of the network and wanted to send better price signals. For example, by avoiding peak charge periods. There are some substantial changes proposed and being implemented to the network charging framework in the Targeted Charging Review (TCR) and Access and Forward Looking Charges Significant Code Review (SCR). The decisions in the TCR have been confirmed and are in the process of being implemented, whereas the SCR is yet to be finalised (a minded to decision is due in 2021). There is still uncertainty regarding the SCR impacts, we discuss this in more detail in the section 6.2.10.

Network data

Network organizations in the UK have undertaken several initiatives in recent years to open-up their data for use by energy network stakeholders and third parties. The rise of data and digitalisation strategies has greatly facilitated this process. For example, the Energy Data Taskforce, commissioned by the UK Government, Ofgem and Innovate UK, put out a report outlining expectations and recommendations[93]. The approach includes data visibility, infrastructure and asset visibility, operational optimisation, open markets, and agile regulation. The report outlines five key recommendations, all of which have seen uptake and impact throughout the Industry[94].

Through the RIIO-2 price control, Ofgem has introduced the requirement for all network and system operators to regularly publish a Digitalisation Strategy & Action Plan (DSAP) and to use data in a way that meets the expectations of Data Best Practice guidance.[95]

Western Power Distribution (WPD), a DNO, has made some recent advancements in this realm

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[92] Ofgem, 2021 *Breakdown of electricity bill* https://www.ofgem.gov.uk/consumers/household-gas-and-electricity-guide/understand-your-gas-and-electricity-bills

[93] Catapult, 2019 *Energy Data Taskforce: A Strategy for a Modern Digitalised Energy System* https://es.catapult.org.uk/reports/energy-data-taskforce-report/

[94] For a list of the five recommendations and of the impact of these recommendations, visit: https://es.catapult.org.uk/case-studies/energy-data-taskforce/#:~:text=The%20Energy%20Data%20Taskforce%20(EDTF,for%20the%20benefit%20of%20consumers.

[95] Ofgem, 2020 *RIIO-ED2 Methodology Decision: Overview.* https://www.ofgem.gov.uk/system/files/docs/2020/12/ed2_ssmd_overview.pdf

with its digitalisation strategy, focusing on improved data management, increased network insight and operation and presumed open data[96]. According to the WPD strategy, the current visibility of infrastructure and assets is ad hoc, but by the end of RIIO-ED-2 (in 2028) asset and infrastructure data will operate on a differentiating basis, in coordination with similar organizations "to create new markets and common investment decisions"[96]. The Presumed Open Data (POD) project with WPD aimed to maximize data visibility, make data more discoverable, and establish standardised metadata. It also aimed to maximize the value of data and employ common structures and interfaces[97].

The Open Networks Project is an initiative between gas and electricity industry licence operators that seeks to accelerate smart technology uptake in the UK. Another key player in the data availability space is Flexr, led by Electralink, which provides transparent data access between all energy market-participants via a controlled open platform. There also exists a Data Working Group (DWG) on combined gas and electricity data and digitalisation, working to meet the five EDTF report recommendations.

DNOs to DSOs

The DNOs in the UK have been required to change their role from network operators to Distribution System Operators (DSOs) this means taking a proactive approach to develop and use their network more efficiently, and identify flexible alternatives to network reinforcement. The RIIO-ED2 price control framework sets out a new DSO incentive that requires DNOs to produce DSO strategies that deliver against a set of baseline requirements, which are listed in Table 10:[98]

Table 10: DSO roles in RIIO-ED2 business plan guidance from Ofgem (Source: Ofgem, 2020[98])

Role	Activity
Role 1: Planning and network development	1.1. Plan efficiently in the context of uncertainty, taking account of whole system outcomes, and promote planning data availability
Role 2: network operation	2.1. Promote operational network visibility and data availability
	2.2. Facilitate efficient dispatch of distribution flexibility services
Role 3: Market development	3.1. Provide accurate, user-friendly, and comprehensive market information
	3.2. Embed simple, fair, and transparent rules and processes for procuring distribution flexibility services

[96] WPD, 2020 *Digitalisation Strategy* https://www.westernpower.co.uk/downloads-view-reciteme/171166
[97] Western Power Distribution, n.d. *Presumed Open Data (POD)* https://www.westernpower.co.uk/innovation/projects/presumed-open-data-pod
[98] Ofgem, December 2020, RIIO-ED2 Methodology Decision: Overview. https://www.ofgem.gov.uk/system/files/docs/2020/12/ed2_ssmd_overview.pdf

The Business Plan Guidance expands on the market development role and states:

> "DNOs should set out how they will adaptively enable third parties to provide market support services and platform services, taking account of market conditions. DNOs should set out the measures they will take to promote coordination of distribution flexibility services across third party platforms, for example through APIs rather than proprietary systems whilst promoting and enabling competition between third party platform providers"[99].

Ofgem has decided not to separate the DSO role from the DNO for the next price control, but will keep this under review.

10.1.3. Generation

There has been extraordinary progress in decarbonising the electricity sector in the UK over the last 10 years. Renewable energy generation has grown six-fold in the last decade, helping the UK to cut its electricity generation carbon intensity by 58%. This is double the reduction seen in other major economies over the same period. This was mainly due to a shift away from coal to renewable energy (e.g. offshore wind) and fossil gas for electricity generation. Generation from coal fell from 30% in 2010 to 5% in 2018 (Figure 15) and just 2% of power produced over 2020. This was primarily driven by a carbon price support policy that was set at £4.94 per tonne of CO_2e initially and increased in 2015 to £18 per tonne[100]. This is levied on top of the EU's Emissions Trading Scheme (EU ETS) carbon price making coal generation much more expensive and reducing levels of generation. The future of carbon pricing in the UK post Brexit is still to be decided. However, it is likely to be intricately linked to the EU ETS model and could be part of a wider reform to the tax landscape[101].

Generation from renewable energy has been rising at the same time; from 8% in 2010, to 23% in 2018 (Figure 15), and 42% of the country's electricity supply in 2020. There were other records broken in 2020, including:

- Renewable energy generated more electricity than fossil fuels over the year for the first time[102].
- Record low average carbon intensity of electricity network – 181 gCO_2/kWh[103]
- Electricity demand fell by 6% compared to the previous year, primarily due to COVID-19.

Some of these changes are illustrated in the historic data on electricity generation in the UK (Figure 12 and Figure 13) and the projected changes outlined in an ambitious Leading the Way scenario in the National Grid ESO Future Energy Scenarios for 2025 (Figure 14). The continued

[99] Ofgem, February 2021, RIIO-ED2 Business Plan Guidance. Available at https://www.ofgem.gov.uk/system/files/docs/2021/02/ed2_business_plan_guidance_-_published_1_february_2021.pdf

[100] This level of carbon price support £18 per tonne of CO_2e has been frozen for 2022/23 in the Budget 2021 by HM Treasury.

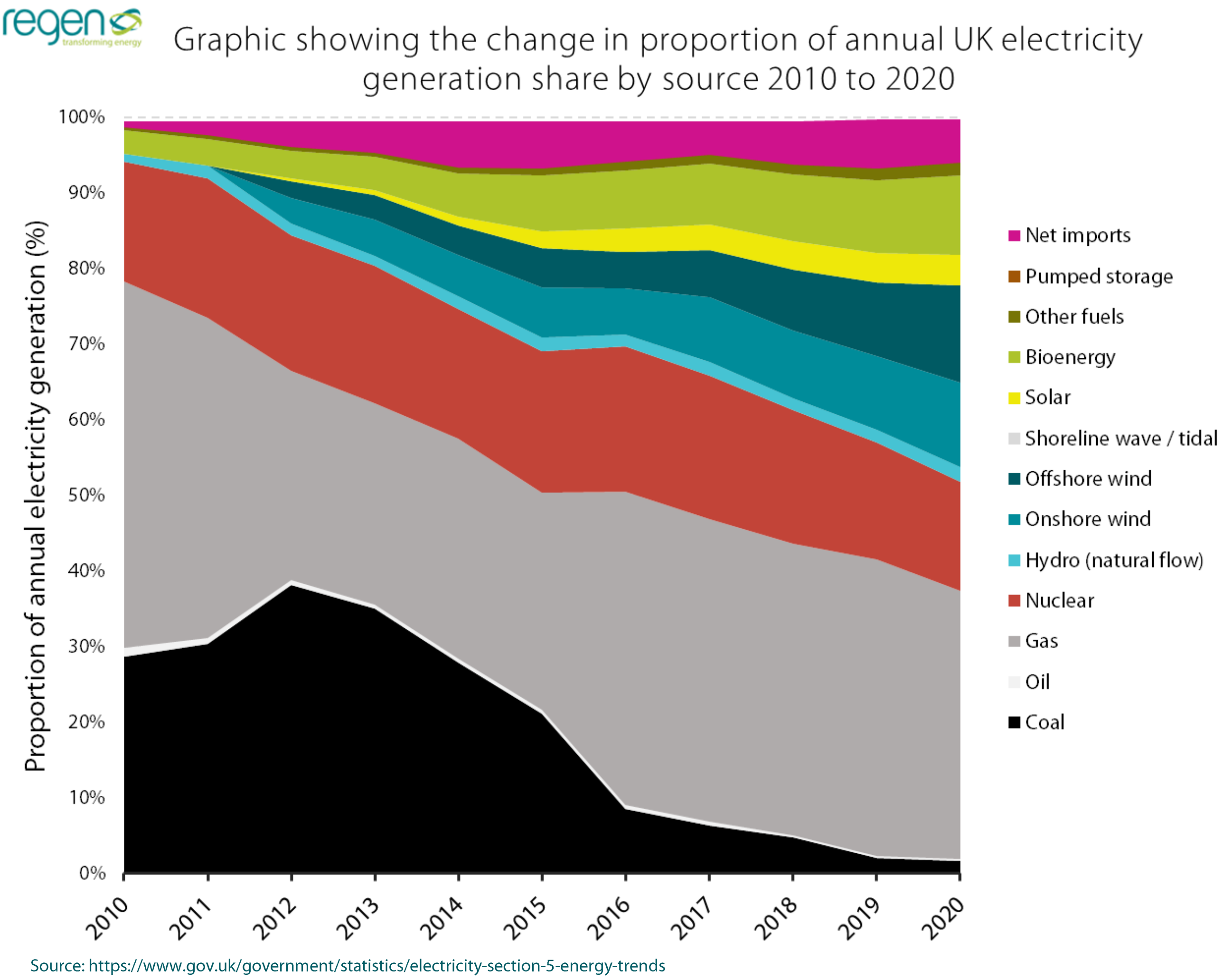
[101] LSE, 2021 *UK carbon pricing needs to be part of comprehensive tax reform* https://www.lse.ac.uk/granthaminstitute/news/uk-carbon-pricing-needs-to-be-part-of-comprehensive-tax-reform/

[102] Carbon Brief, 2021 *Analysis: UK is halfway to meeting its 'net-zero emission' target* https://www.carbonbrief.org/analysis-uk-is-now-halfway-to-meeting-its-net-zero-emissions-target

[103] National Grid ESO, 2021 *Record breaking 2020* https://www.nationalgrideso.com/news/record-breaking-2020-becomes-greenest-year-britains-electricity

shift away from coal and fossil fuels is a clear trend. The generation market share is replaced by renewable energy generation, particularly wind.

Figure 12: Graphic illustrating the change in proportion of annual UK electricity generation by source



In terms of installed generation capacity in UK, there was a total of 103.7 GW connected to the system at the end of 2019[104]. The majority of that capacity is combined cycle gas turbines (32.7 GW or 32%), with the remaining technologies in ascending order; onshore wind (14.1 GW or 14%), offshore wind (10 GW or 10%), and solar PV (13.3 GW or 13%), all with a share above 10% of total installed capacity[104]. Coal (7.9 GW or 8%), bioenergy via converted coal power stations (7.5 GW or 7%) and nuclear (8.9 GW or 9%) also have significant installed capacity on the system.

[104] BEIS, 2020 *DUKES* https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Figure 13: Pie chart of UK electricity generation by fuel type in 2018

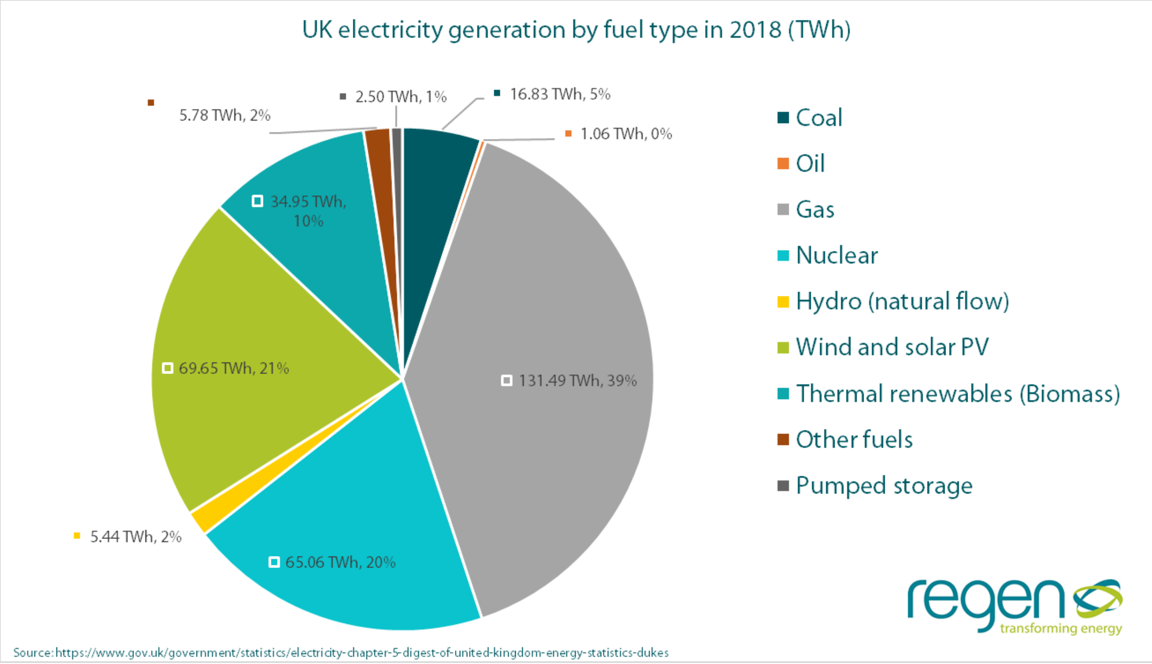
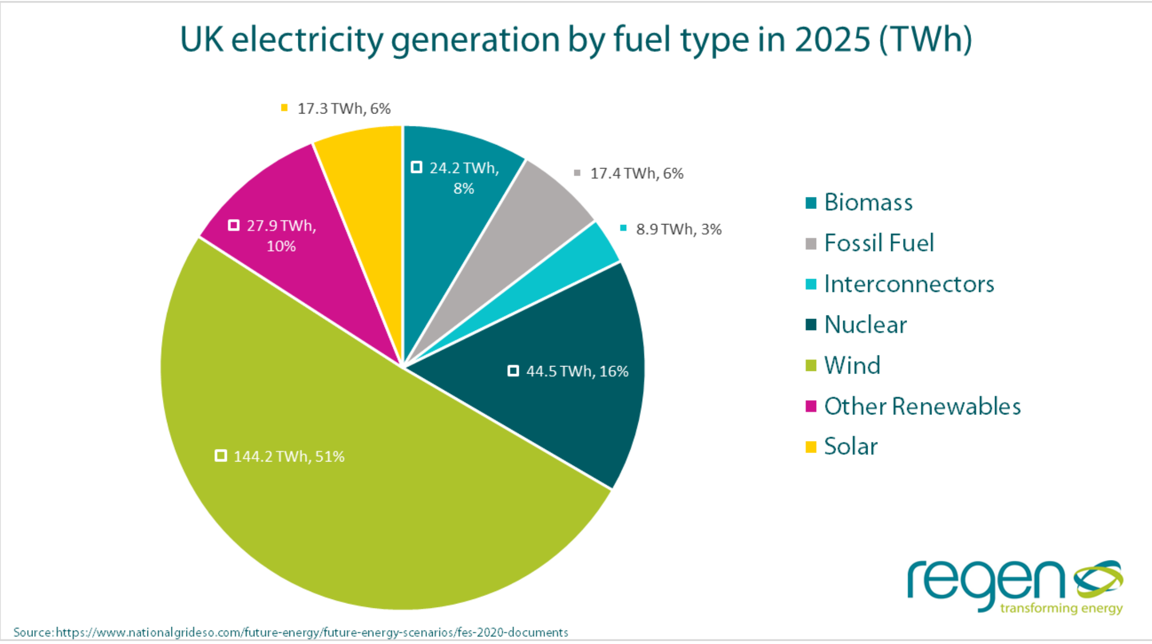


Figure 14: Pie chart of UK electricity generation by fuel type in 2025 in the Leading the Way scenario from National Grid ESO[105]



There has been strong revenue support for renewable energy generation in the UK, initially from the Renewables Obligation (RO). The RO was open to new applicants from 2002 to 2017 for large scale projects and supported 35.4 GW of installed capacity. Following this the Feed-in Tariff (FIT) for smaller scale projects (up to 5 MW scale) was open to new applicants from 2010 to 2019, and

[105] National Grid ESO, 2021 *Future Energy Scenarios 2020* https://www.nationalgrideso.com/future-energy/future-energy-scenarios

supported 6.4 GW installed capacity, 80% of which is solar PV[106]. There have been almost 870,000 FIT accreditations overall, largely on domestic buildings. The Smart Export Guarantee (SEG) is the replacement for the FIT and has been available since 1 January 2020. However, the SEG rates (p/kWh) provided are much lower (needing to be above 0p/kWh is the main limitation) due to them being set by electricity suppliers (see section 10.1.4), are not government backed, and there is no minimum contract length like the FIT.

The Contracts for Difference (CfD) revenue support mechanism was launched in 2014 and remains the main government support mechanism for low carbon electricity generation. It is run by one private limited company, the Low Carbon Contracts Company, wholly owned by BEIS, with National Grid ESO as a delivery partner. Projects enter a competitive tender process or round to get a CfD and are "paid a flat (indexed) rate for the electricity they produce over a 15-year period; the difference between the 'strike price' (a price for electricity reflecting the cost of investing in a particular low carbon technology) and the 'reference price' (a measure of the average market price for electricity in the GB market)"[107]. Crucially the funding pots are allocated ahead of each round, aiming support at specific technologies. Support has been mainly limited to offshore wind projects, up to now with 4.7 GW or 69% of installed capacity in the current portfolio. This is set to continue with another 8.1 GW of offshore wind allocated funding and due to deployed up to 2026 and an overall government target of 40 GW installed capacity by 2030[82]. The costs of offshore wind have fallen by two thirds in the last five years. Notably, one new nuclear power station has received support under the CfD framework at a high strike price compared to other technologies[108]. The government has announced a new allocation round of funding for 2021, targeting 12 GW of renewable generation that will include a wider range of technologies, including floating offshore wind, onshore wind and ground-mounted solar PV[109].

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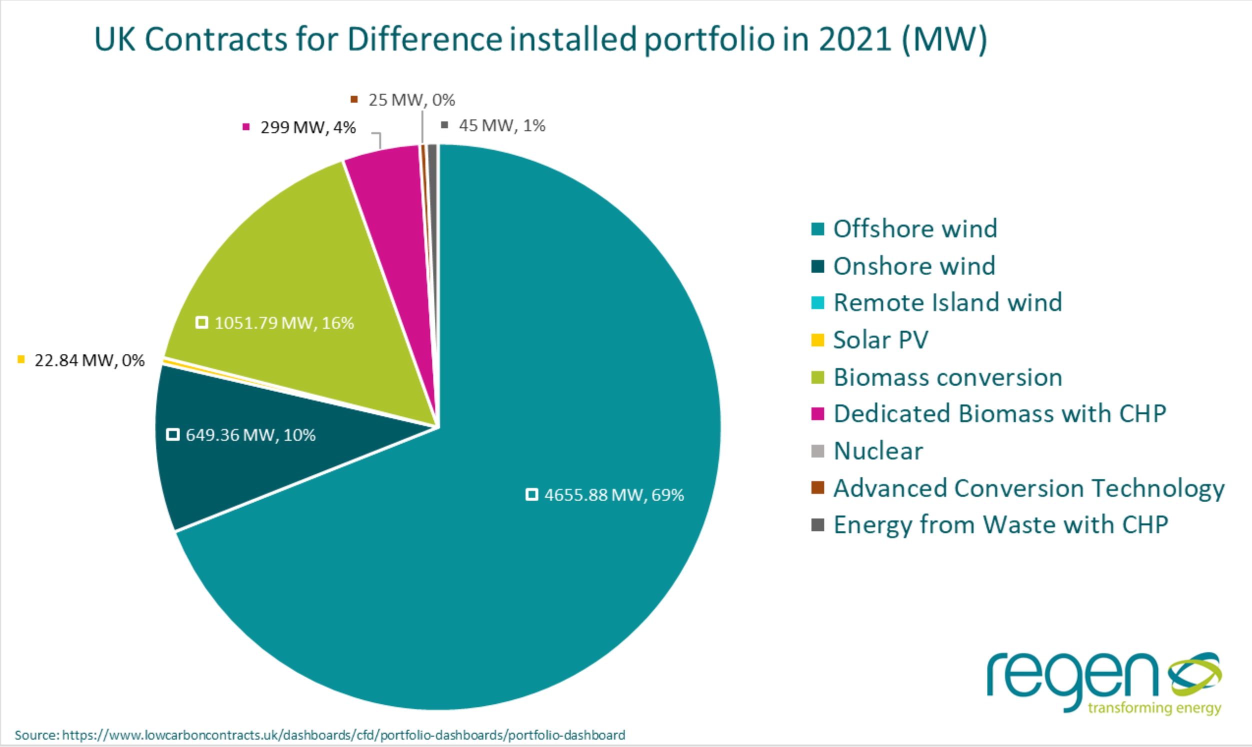
[106] Ofgem, 2021 *Feed-in tariffs: quarterly statistics* https://www.ofgem.gov.uk/environmental-programmes/fit/contacts-guidance-and-resources/public-reports-and-data-fit/feed-tariffs-quarterly-statistics

[107] BEIS, 2021 *Contracts for Difference* https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference

[108] LCCC, 2021 *Hinkley Point C* https://www.lowcarboncontracts.uk/cfds/hinkley-point-c#:~:text=Project%20Information&text=The%20Initial%20Strike%20Price%20is,MWh%20to%20%C2%A392.50%20MWh.

[109] BEIS, 2021 *CfD allocation round 4* https://www.gov.uk/government/collections/contracts-for-difference-cfd-allocation-round-4

Figure 15: Pie chart of installed capacity (MW) by technology in the current Contracts for Difference portfolio



10.1.4. Retail

In order to supply electricity in the UK using the public network, you must have a supply licence and comply with multiple industry codes and regulatory obligations to ensure that the system is safe and consumers are protected. BEIS and Ofgem have recognised that the retail electricity market is in need of reform and there have been the following recent policy discussions:

- July 2019, BEIS and Ofgem published a consultation on Flexible and responsive energy retail markets, the status of which is "closed, awaiting decision"[110].
- July 2020, Ofgem published a consultation - Supporting retail innovation: Policy consultation on ability to provide derogations from certain standard licence conditions; and, granting supply licences for specific geographic areas or premises types. This is also "closed, awaiting decision"[111].
- December 2020, BEIS published its Energy White Paper, which reiterated its commitment to assessing the retail regulatory framework. A formal consultation is due in 2021.

Despite all this activity, we are yet to see any substantive regulatory or policy change to reform the existing retail market model. See Section 6.2 for further information.

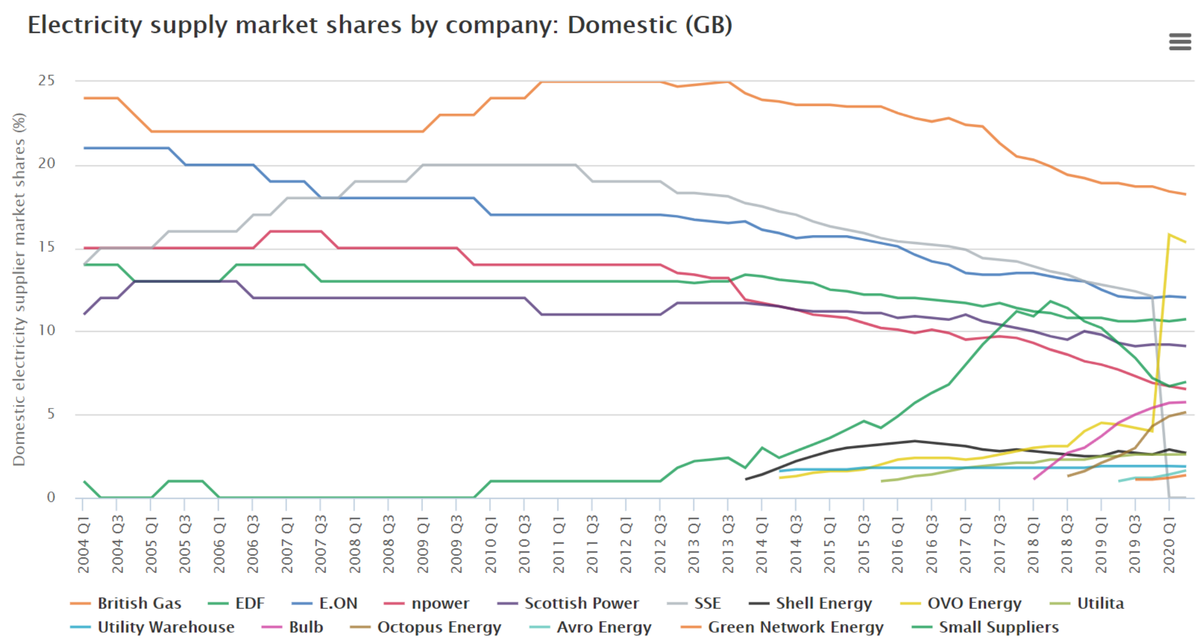
[110] Ofgem, 2019 *Flexible and Responsive Energy Retail Markets* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819624/flexible-responsive-energy-retail-markets-consultation.pdf
[111] Ofgem, 2020 *Supporting retail innovation* https://www.ofgem.gov.uk/publications-and-updates/supporting-retail-innovation-policy-consultation-ability-provide-derogations-certain-standard-licence-conditions-and-granting-supply-licences-specific-geographic-areas-or-premises-types

Market review

Competition in the UK electricity retail market started in 1999 and in 2004 there were six major utility companies, British Gas, EDF, E.ON, npower, Scottish Power, and SSE - collectively known as the "big six", representing 100% of retail market share. This has changed over time as competition from new entrants, increased switching, and a period of acquisitions has occurred in the domestic sector[112] (Figure 16). The "big six" now only represent 55% of the domestic retail market, with the likes of Ovo Energy, Bulb Energy and Octopus Energy on the rise. Consequently, Ofgem has now changed its classification structure, defining large suppliers as those with 5% or more market share.

A default tariff cap[113] was implemented in January 2019 to provide better value for 11 million domestic consumers that were not switching away from their electricity suppliers or going past the periods of cheaper fixed term tariffs[114]. Changes have been made to the level of the cap due to market changes and COVID-19. The latest change was a 9% increase, due to the added costs associated with worsening economic situation and recovery of payments from consumers.

Figure 16: Market share of domestic consumers per electricity supplier (2004 to 2020)[115]



The non-domestic retail market has remained more competitive and less concentrated. With a larger number of companies and brokers involved. Other companies such as Opus One, Haven

[112] For example, Ovo Energy purchasing SSE, increasing market share from 4% to 15% https://sse.co.uk/sse-and-ovo

[113] The default or standard tariff is the price paid per kWh of electricity (or gas) by consumers to the energy supplier. They are typically more expensive than other fixed-term tariffs that consumers switch to for better value and allow existing suppliers to make a higher margin on these less engaged consumers.

[114] Ofgem 2021 *Default tariff cap* https://www.ofgem.gov.uk/gas/retail-market/market-review-and-reform/default-tariff-cap

[115] Ofgem, 2021 *Retail energy market indicators* https://www.ofgem.gov.uk/data-portal/retail-market-indicators

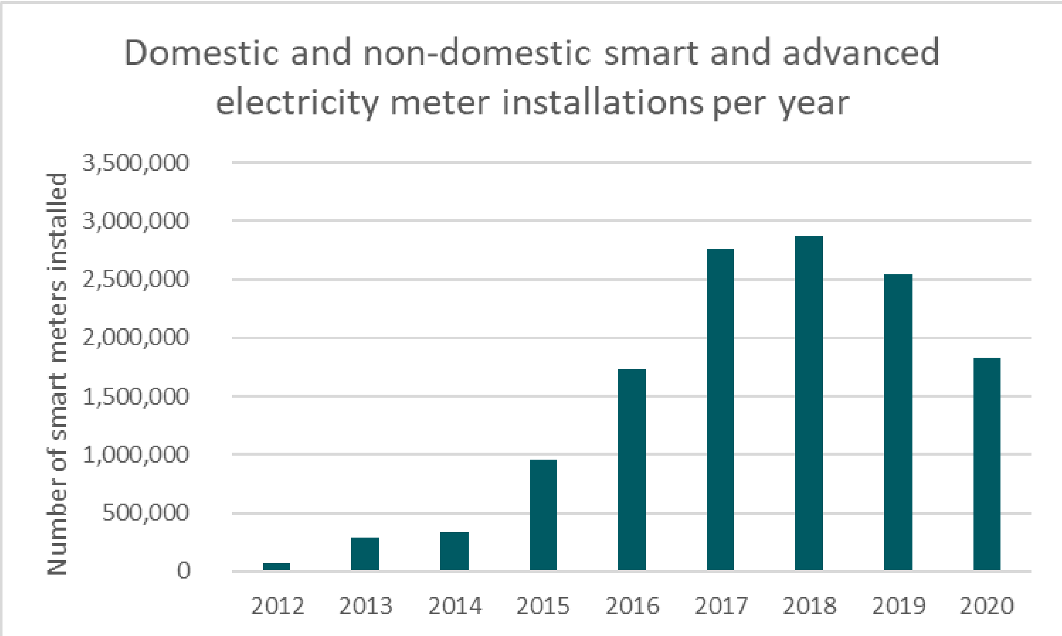
Power, Smartest Energy and Total Gas and Power are significant players in the market, in addition to the original "big six"[116].

At present environmental levies are almost entirely levied on top of electricity charges and currently make up make a very significant 20.4% of the typical electricity bill compared to only 1.6% of the typical gas bill[117]. This distortion has had a big impact on the uptake of low carbon heat technologies, such as heat pumps. Reducing the incentive to make the switch away from gas for heating purposes.

Smart meters

Smart meters enable the near real time measurement and settlement of energy consumption. The rollout is being led by energy suppliers which are required to offer a smart meter to all their domestic and small business customers. At the end of December 2020, only 36% of the targeted properties had a smart meter installed and operating in smart mode, after eight years of the smart meter rollout programme[118]. Further delays due to COVID-19 have caused a 28% reduction in smart meter installations in 2020 compared to 2019[118]. However, this continues a downward trend of installation numbers from a peak in 2018 (Figure 17). The UK government has introduced a new smart meter obligation on suppliers, to start in July 2021, with annual installation targets.

Figure 17: Chart showing the number of domestic and non-domestic smart meter installations 2012 to 2020[118]



Data privacy is a key concern for UK consumers in the conversation on smart meters, it was with this concern in mind that the UK developed the Data Access and Privacy Framework to complement existing General Data Protection Regulation (GDPR) protocol. Domestic customers

[116] Ofgem, 2019 *State of the energy market 2019* https://www.ofgem.gov.uk/system/files/docs/2019/11/20191030_state_of_energy_market_revised.pdf
[117] Regen, 2020 *Decarbonisation of heat* https://www.regen.co.uk/publications/decarbonisation-of-heat/
[118] BEIS, 2021 *Smart Meter Statistics in Great Britain* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/968356/Q4_2020_Smart_Meters_Statistics_Reportv2.pdf

have the right to opt-out of their data being collected and must give their explicit consent in order for an energy supplier to gain access to consumption data. The one exception is that energy suppliers can access less granular data on a monthly basis without consumer consent. As laid out by the Smart Energy Code (Section I), third parties are required to put procedures in place to obtain and verify consumer consent. This is then subject to an independently conducted assurance regime. Both suppliers and third parties are required to inform consumers on granularity of data collected, purpose of collection, and inform the consumer of right to object or withdraw consent.

Market-wide half-hourly settlement

Market-wide half-hourly (HH) settlement will move those consumers that are not settled on a HH basis, which are domestic and small business consumers as it stands, to this process. It will use more granular data from smart meters and remove the need for profiling (estimates). Other customer segments are already settled HH. Exposing the full cost of supplying customers to the supplier per HH period, improved system outcomes and incentivising suppliers to help consumers manage their consumption. HH settlement is an enabler for flexibility, demand side response and new tariffs/business models.

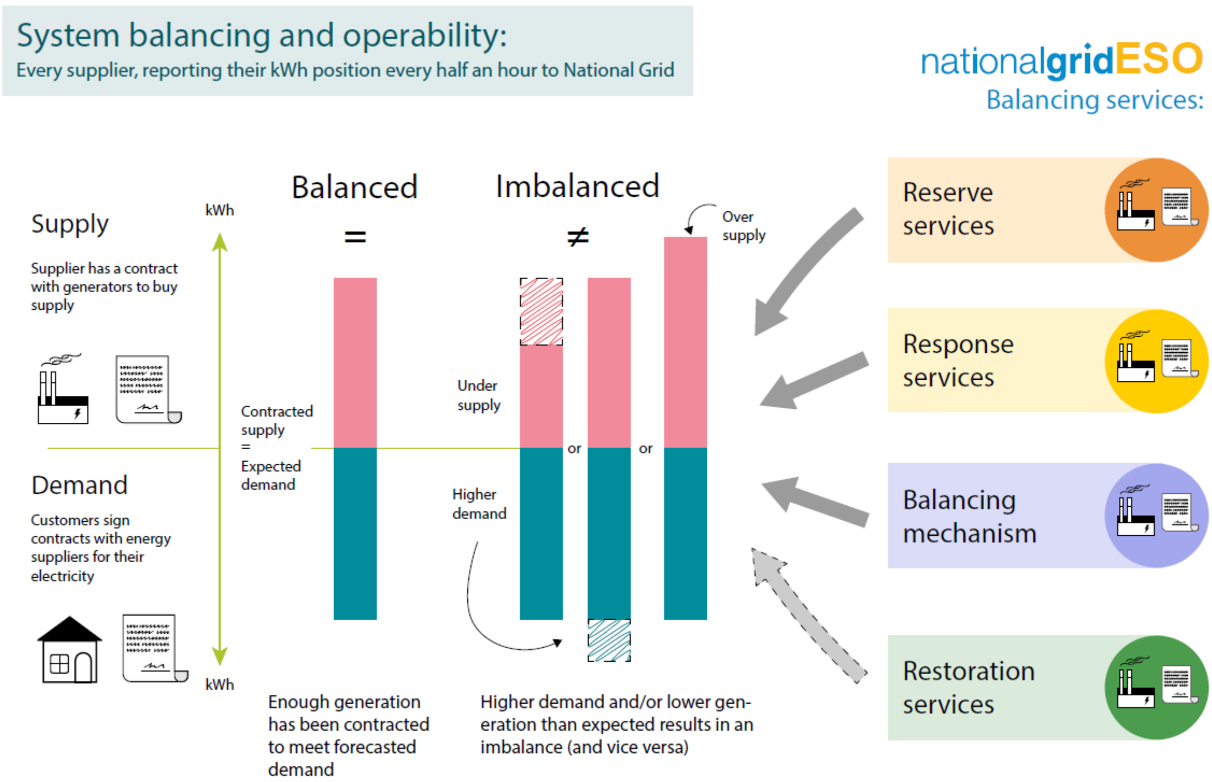
The progress of market-wide Half-Hourly (HH) settlement has been delayed due to COVID-19. Suppliers can choose to voluntarily use HH settlement for consumers at present but are unlikely to do so. Initial timelines were for all consumers to be migrated by the end of 2024. However, the four-year transition period has not yet started and Ofgem is currently reviewing the project timelines ahead of the final business case publication in Spring 2021. Therefore, the implementation timeframes are uncertain, but will be delayed beyond the end of 2024.

10.1.5. Electricity system operation and markets

National Grid ESO is the organisation responsible for balancing supply and demand of electricity in GB (Figure 18), as well as maintaining specific conditions on the network that is set out in the Security and Quality of Supply Standard (SQSS)[119] and other licence conditions. There are several markets, and commercial services that National Grid ESO run to achieve this, using different 'ramp up' periods and offering different payments. It is National Grid ESOs role to balance the system at the lowest cost, using the range of services and assets at its disposal. The System Operator functions were legally separated into National Grid ESO in April 2019. Before then it was managed under the same company. There are plans to develop an Independent System Operator with additional functions (see Section 1.1.1).

[119] National Grid ESO, 2021 *SQSS Code Documents* https://www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standards/code-documents

Figure 18: Simplified graphic of the balancing role provided by National Grid ESO



Most of the current flexibility in the system is provided by fossil gas power stations and interconnectors. GB has consistently been a net importer of energy via interconnectors due to price differentials between the power markets on the continent and in GB. In 2019, interconnectors supplied 8% (25 TWh) of total electricity consumption in Great Britain, an estimated 66% of this energy came from zero-carbon sources. The capacity of interconnectors is due to rise from 6 GW in 2020 to 9.8GW by 2024[120]. New interconnectors to Norway (North Sea Link, 1.4 GW) and France (ElecLink, 1 GW) are due to be completed in 2021.

Skip rates and dispatch

One aspect of the National Grid ESO operations that has received recent interest from the sector is the decision-making process for the dispatch of assets via the various markets and levers available to the National Grid ESO. There have been calls for greater dispatch transparency, following complaints regarding skip rates, where certain assets are not dispatched and "skipped" over in favour of others, often the conventional fossil fuelled generators. National Grid ESO has created a new tool, publishing data on dispatch transparency, and already has a dedicated webpage[121]. The data has been published from March 2021 and shows that there is more than one thousand actions taken per day by National Grid ESO and that the most common dispatch reason is the merit order (price and other factors) and system (e.g. maintaining frequency with set parameters).

[120] National Grid, 2021 *What are interconnectors* https://www.nationalgrid.com/stories/energy-explained/what-are-electricity-interconnectors
[121] https://data.nationalgrideso.com/balancing/dispatch-transparency

Impact of COVID-19

The COVID-19 pandemic has had a significant impact on the GB electricity markets in 2020 and 2021. Record low demand levels were logged alongside high renewable energy generation, leading to system operation challenges. Overnight on June 28 2020 there were high levels of wind generation and only 13.4 GW demand on the system. This example led to high balancing costs and is reflected over the year where balancing costs were 44% higher in 2020 in comparison to 2019. These balancing costs are charged back to consumers via BSUoS[122]. The main causes of this increase have been more constraint payments via the BM (paying wind to reduced generation output), the Optional Downward Flexibility Management (ODFM) service, and a bilateral contract to curtail output of Sizewell B nuclear power station. Curtailment costs doubled in 2020 from the previous year, to over £282 million (3.8 TWh of lost generation)[102]. Various actions have been taken to limit the financial impact of these increased balancing costs on consumers, suppliers and generators, including a network charge deferral scheme[123].

Further changes that have become apparent in the extraordinary circumstances, are the need for more frequency regulation due to lower system inertia, caused by less large coal and gas power stations operating. This requires services to act faster, to catch any change in frequency earlier, rather than later.

What is clear is that COVID-19 accelerated changes in the system and the way that it is managed, that were already underway.

Wholesale electricity market

On April 1 2005, changes to harmonise electricity trading across GB came into effect with the introduction of a single set of arrangements known as BETTA (British Electricity Trading and Transmission Arrangements)[124]. BETTA is based on bilateral trading between generators, suppliers, customers and traders, and participants self-dispatch rather than being dispatched centrally. Under BETTA, contracts for electricity are agreed in forward and futures markets from several years up to 24 hours ahead of a given half hour delivery period. Short-term power exchanges and energy brokers give participants the opportunity to fine tune their contract positions from one to 24 hours before delivery, known as the day-ahead markets an intra-day markets. All the deals are bilateral and are settled at the price registered on the power exchange or agreed bilaterally or through a broker (Figure 19).

As far as opportunities for small generators in the wholesale market go, there are two main options: Central Volume Allocation (CVA) and Supplier Volume Allocation (SVA). The former option, CVA, is an agreement that allows generators to access the market directly, whereas the latter, SVA, are agreements that involve partnering with a licenced supplier indirectly via a PPA.

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[122] BEIS, 2020 *Statutory Security of Supply report 2020* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945297/statutory-security-of-supply-report-2020.pdf

[123] Ofgem, 2020 *Network Charge Deferral scheme update* https://www.ofgem.gov.uk/publications-and-updates/network-charge-deferral-update-0

[124] Ofgem, 2005 *BETTA User Guide* https://www.ofgem.gov.uk/publications-and-updates/betta-user-guide-summary-new-british-electricity-trading-and-transmission-arrangements-betta-and-high-level-guide-key-activities-required-implement-new-arrangements-and-run-pre-betta-arrangements

The CVA is less desirable for small, unaggregated generators as the volumes required for entry pose a barrier, as do electricity licencing codes[17].

The GB market has left the EU internal energy market, including the day ahead market coupling arrangements since the start of 2021. This has led to more price volatility caused by less power flowing via the interconnectors to France, the Netherlands, Belgium, and Ireland. This is due to there being less liquidity and less efficient dispatch of the capacity of the interconnectors in the new market arrangements. Power flows to the UK from the continent are happening at higher prices, resulting in more extreme pricing when the system is under stress (e.g. evening peak with low wind output).

The new Trade and Cooperation Agreement between the UK and the EU includes some sort of loose market coupling at the day-ahead with markets adjacent to GB. However, this is not going to be implemented until April 2022 at the earliest. Until then extreme prices and higher balancing costs are likely to continue[125].

Balancing Mechanism

The Balancing Mechanism (BM) is one of the main tools used by National Grid ESO to balance demand and supply of electricity and represented over £1 billion worth of balancing services in 2020. When there is a difference between supply and demand, the ESO looks to accept a bid or offer from a BM market participant (or BM Units/BMUs) to increase or decrease generation or demand (consumption). By doing so, National Grid ESO balance the supply and demand of electricity in each half hour trading period of every day. Most electricity trading happens in the wholesale energy market (Figure 19), which can be years in advance. Generators contract with electricity suppliers for every half hour of every day. Trading occurs up to one hour before each delivery half hour period. This milestone is called gate closure. Generators must publish details of their activity to Elexon. Following gate closure, the BM is active ensuring that the supply and demand of electricity is balanced, by accepting bids and offers from BMUs and instructing generators (via Bid Offer Acceptances or BOAs). BMUs must then deliver the required service to avoid imbalance and penalties (imbalance settlement) (Figure 19). An important distinction between the BM and whole energy market is that the BM is a pay as bid system, whereas, the wholesale energy market is not.

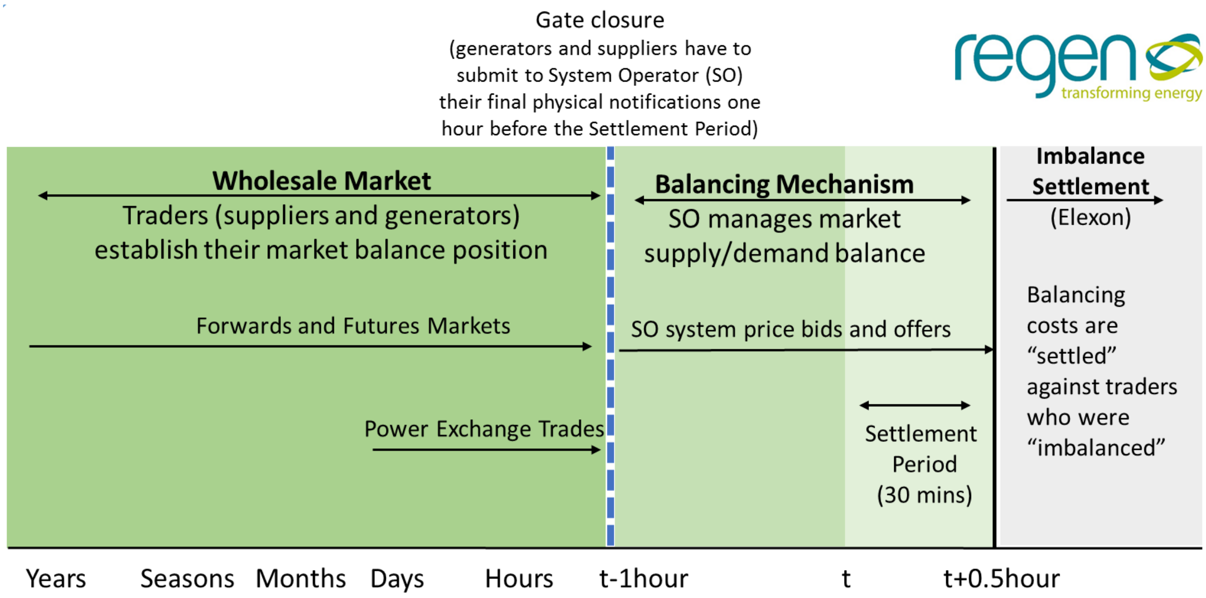
Historically the BM has been dominated by existing fossil fuel power stations, however there have been efforts to widen access and increase DER involvement. Until recently, the only way for a flexible asset to access the BM was through a licensed electricity supplier or by gaining a generator licence. A new model introduced by modification P344 called the Virtual Lead Party (VLP) was developed, to help aggregators (and their DER assets) without an electricity supply licence access the BM. There has been relatively slow uptake of the VLP model since it was introduced in December 2019 (the first dispatch of assets using this model was in April 2020), as many of the leading aggregators already hold an electricity supply licence.. However, Flexitricity and Habitat Energy are now using VLP model to access the Balancing Mechanism, giving them further revenue opportunities and helping the business model for flexible assets, such as energy storage.

[125] Enappsys, 2021 *March 2021* https://www.enappsys.com/gbdayahead/

Other recent improvements include the use of APIs to automate actions within the BM, reducing costs and widening access to DERs, these were first used by Tesla in September 2020[126].

There remain considerable barriers for DERs to enter the BM, including difficulty in assessing and capturing value, high risk for non-delivery, and need for round-the-clock monitoring and control resources.

Figure 19: Current balancing mechanism process based on time-boxed management (Source: adapted from Ofgem graphic)



Reforms via the EU Clean Energy Package

A number of market reforms have been required due to the recast Electricity Regulation within the EU Clean Energy Package (CEP)[127] that states that system operators need "to procure a minimum of 30% at no more than one day ahead for contracts no longer than one day." This allows for easier access to the market for new market entrants and renewable energy. A separate market at longer timescales would require derogation from this requirement.

There are also requirements on how balancing service payments are made: "availability payments can be pay as clear or pay as bid; utilisation payments must be pay as clear". This means, STOR and BM could require reform to be settled on a 'pay as clear' basis.

These reforms were required during the implementation period despite Brexit as they are already in law and the close integration of the EU and UK markets requires policy equivalence. The EU Clean Energy Package was in force in the UK up until the end of the Brexit Implementation period, December 31 2020[128]. Due to the current political uncertainty, it is unclear at this stage which rules will continue to apply on a UK level, but if the UK wants to

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[126] Energy Storage News, 2020 *Tesla become first company to go live with new API in UK Balancing Mechanism* https://www.energy-storage.news/news/tesla-become-first-company-to-go-live-with-new-api-in-uk-balancing-mechanis
[127] Specifically Article 6(9) and Article 6(4) of EU Clean Energy Package
[128] Lexis Nexis n.d., *Clean Energy Package—Snapshot* https://www.lexisnexis.co.uk/legal/guidance/clean-energy-package-snapshot

participate in European electricity markets like TERRE or MARI, then certain elements of the EU Clean Energy Package must be adopted. Additionally, certain implications for flexibility markets have been laid out in the UK and EU Trade and Cooperation Agreement[129].

The reforms include but are not limited to:

Trans European Replacement Reserves Exchange (TERRE) – There were plans for the UK to join this EU wide exchange. However, the TCA signed by the UK and EU at the end of 2020 indicates this is unlikely to happen. A Cost Benefit Analysis is planned to assess a stand-alone system for the UK.

Manually Activated Reserve Initiative (MARI) – The pan-European platform designed to deliver a platform for manually-activated Frequency Restoration Reserve (mFRR) was mandated by Article 20 of EBGL (Commission Regulation (EU) 2017/2195), of which the UK is no longer obliged to comply. The TCA does not facilitate UK participation in the mFRR process, and unless a new agreement is reached between the UK and the EU, NG ESO participation in MARI will not be possible. This does not rule out a MARI requirement in the future[130].

Capacity Market (CM) - A new emissions limit has been put in place for the CM. Changes came into force on June 30 2020 and prevent the most carbon intensive existing capacity (including coal) from competing in auctions for delivery years from October 1 2024. All new-build plants are subject to the carbon emissions limits for delivery years from October 1 2020.

Fast Reserve – Cancellation of further procurement of this service.

STOR – See section below.

In the below discussion we cover two of the key services, STOR and ODFM in more detail due their relevance to the DEMOCRASI project. STOR is being used as a service in the market simulation for the UK market by DEMOCRASI project partners. ODFM is a new negative reserve product that is focused on DERs and has shown the capabilities of this type of service.

Short-term Operating Reserve (STOR)

The Short-term Operating Reserve (STOR) product is used by National Grid ESO to balance the system and meet the short-term reserve capacity requirements. The National Grid ESO is making changes to the STOR product to keep it compliant with the EU Clean Energy Package (CEP). STOR procurement has been halted since December 2019, with some contracts continuing to be delivered in small volumes. As discussed above, the CEP from the EU obligates all Transmission System Operators to procure Balancing Capacity products at day-ahead and that the contracting period shall be no longer than one day. Therefore, the STOR tender process has now moved to day-ahead, providing other technologies, such as wind and solar PV, the ability to bid. This is part of a trend towards opening up markets to all technologies and closer to real-time tendering from the National Grid ESO and others.

[129] EU, 2020 *Trade and cooperation agreement between the European union and the European atomic energy community, of the one part, and the United Kingdom of Great Britain and Northern Ireland, of the other part* https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:22020A1231(01)&from=EN

[130] Elexon, 2021 *P407 'Project MARI'* https://www.elexon.co.uk/mod-proposal/p407/

Full implementation (100%) of the day ahead STOR market has been delivered from April 1 2021. Prior to this, a derogation was used to allow a minimum of 30% to be procured day-ahead and the rest a month ahead. National Grid ESO has made changes to make it easier to access the market by reducing the administration required upfront, bidders will not need to provide technical parameters upfront or weekly availability declarations. There is also the potential for an API to be developed to automate bids.

The existing STOR service was dominated by thermal generation (diesel and fossil gas CHP) and procured a month ahead of time or in some cases years (with 400 MW contracted up to 2025). The move to a day-ahead market is part of a general trend towards more real-time balancing markets. This action has been forced in this instance due to STOR needing reform to be compliant with the EU CEP. These changes will help to open the STOR market to other flexibility providers, including wind and solar PV, working alongside the Balancing Mechanism and other reserve markets.

Further reform of the reserve markets and products has been announced in the Reserve Products consultation[131] (See Section 6.2).

Optional Downward Flexibility Management (ODFM)

The ODFM service[132] was launched by the National Grid ESO in response to the low levels of demand in the summer of 2020 caused by COVID-19 associated lockdowns. Under ODFM small scale generation and flexible loads are asked to turn off or turn down, respectively. The service is also open to providers who can increase their demand during the periods when the service is required. Crucially this service is open to distribution connected assets that were not active on the Balancing Mechanism already. Requirements for the service include >1 MW assets (including aggregation) and 3 hours sustained service. The application of the service by National Grid ESO occurs only after all other reserve and response actions are taken (e.g. Balancing Mechanism).

In total 4.7 GW capacity across 363 sites is registered with ODFM, this is mostly wind - 2.7 GW, and solar - 1.2 GW. In 2020 it was used on five occasions, particularly on the May 2020 bank holiday weekend (23-25 May). The last time it was used was on July 5 2020, where 3.1 GW of capacity was instructed. Over 100 GWh of downward flexibility was called from assets and an average of £88/MWh. The cost of the ODFM service is one of the contributing factors to the high balancing costs in 2020.

The service was ended on October 28 2020. However, ODFM is due to be restarted for the summer of 2021 (April 30 – Oct 31 2021)[133]. National Grid ESO stated that the learning from the ODFM service will be taken forward for "negative reserve and whole system constraint management as well as ancillary services in general" and that it is not an “enduring solution”. The service was characterised by low barriers to entry and was set up in record time.

Other services from National Grid ESO that are relevant to DEMOCRASI are included in Table 11. We discuss changes in the markets and value streams in more detail in Section 6.2.

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[131] National Grid ESO, 2021 *Reserve Product reform*
https://www.nationalgrideso.com/document/187871/download
[132] National Grid ESO, 2020 Optional Downward Flexibility Management (ODFM)
https://data.nationalgrideso.com/ancillary-services/optional-downward-flexibility-management-odfm1
[133]National Grid ESO, 2020 *Operational transparency forum slides*
https://data.nationalgrideso.com/plans-reports-analysis/COVID-19-preparedness-materials/r/operational_transparency_forum_slides_28.10.20

Recent highlights in the existing markets include:

- New weekly auction trial of Firm Frequency Response (FFR) services.
- Dynamic Containment (DC) service launch with further frequency response services due in 2021.
- Ability to stack BM with new DC frequency response service, helping maximise the opportunity for DERs and other flexible assets.

Table 11: Overview of existing services from National Grid ESO that could be applicable to DEMOCRASI project (not exhaustive)

Service name	Speed of response	Duration	Minimum Scale (MW)	Other characteristics
Dynamic Containment (DC)	Within 0.5 to 1 second	15 minutes maximum at full power output	>1	• Only battery storage has been contracted to this service so far. • High technical requirements have meant that volumes have remained below the market requirements set by National Grid ESO. • First of a new suite of frequency response services. • Day ahead auctions and a paid for availability with a market price cap of £17/MW/h.
Firm Frequency response (FFR) – various versions	Between 10 and 30 seconds	20 seconds to 30 minutes	>1	• Procured monthly via static and dynamic FFR, as well as a trial weekly auction through Low Frequency Static and Dynamic Low High. • Routinely contracting over 1 GW of flexible capacity across all the services.
Capacity Market (CM)	Notification four hours ahead of delivery	De-rating factors used per technology	>1 (Updated from >2)	• De-rating factors mean that the value available for DERs is low. • Longer contract lengths of up to 15 years are now available now available for DSR through T-4 auctions. • The CM resumed in late 2019 following a state aid challenge at the EU level.

Local flexibility markets

As part of the transition to more dynamic/active Distribution System Operators (DSOs) from traditional, more passive Distribution Network Operators (DNOs), a new form of locationally driven commercial flexibility service is now in operation across the UK.

The Energy Networks Association define the role of a DSO as

"*A neutral facilitator of an open and accessible market that will enable competitive access to markets and the optimal use of Distributed Energy Resources on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation.*"

National Grid ESO services call on assets to respond to deviations in system frequency or to provide supplementary capacity or energy reserve through services such as STOR, Fast Reserve or the Capacity Market. The location of the assets that secure contracts in these markets is largely irrelevant.

For local flexibility however, the key is in the name with DNOs calling on flexible assets, (whether that be generation, demand or storage), at a local level to support the local network for locationally specific operational issues. After an initial period of DNOs developing these markets individually, some consolidation and standardisation of features such as entry requirements, service needs and commercial payment terms etc. has now started to feature across these local markets.

The UK is leading the development of local flexibility markets to provide services to DNOs who are looking to procure flexibility services at a local level, to support the local network. Tenders have been running since 2018 across the different DNOs for services in specific areas known as Constraint Management Zones (CMZs). The four flexibility services procured each cater to different network requirements. These are as follows:

- **Sustain service (scheduled constraint management)**
    - Used to manage peak demand loading on the network and pre-emptively reduce network loading at scheduled times.
- **Secure service (pre-fault constraint management)**
    - Used to manage peak demand loading on the network and pre-emptively reduce network loading a week ahead.
- **Dynamic service (post-fault constraint management)**
    - Used to support the network in the event of specific fault conditions, often during summer maintenance work.
- **Restore service (restoration support management)**
    - Intended to help with restoration following rare fault conditions. Such events are rare and offer no warning as they depend on failure of equipment.

There is a minimum portfolio size of 100 kW in most cases, making this set of services a good option for smaller DERs. Efforts have been underway to standardise the services, products, and contracts as part of the Open Networks Project (WS1A). Crucially this work has developed a

Common Evaluation Methodology that assesses the right solution for constrained areas of the network, including local flexibility tenders[134].

Flexible Power is the leading platform for local flexibility tenders and includes competitions from Western Power Distribution, Northern Powergrid, Scottish and Southern Electricity Networks and Scottish Power Energy Networks[135]. Electricity North West and UK Power Networks, and NI Electricity Networks use the Piclo flex platform[136].

In 2020 there was a significant increase in local flexibility contracts awarded, with almost five times more capacity awarded in 2020 in comparison with 2019[137]. A growing proportion of DERs are involved, including aggregated batteries and EV chargers, in comparison with previous years that have been dominated by fossil gas CHP and diesel engines. However there remains a large gap between the capacity of tendered services and contracts awarded, due to the highly locational nature of the services and lack of DER available in those areas.

The fundamental need for these services (in terms of annual capacity required) and the financial value related to these markets is very much dependent on location. The requirement and value of flexibility supplied the meet the above services can vary by:

- The DNO (e.g. UKPN and WPD will have different requirements).
- Licence area (e.g. WPD's East Midlands licence area will have different requirements to the South West licence area)
- Specific Constraint Management Zone (e.g. Reading CMZ vs Exeter CMZ will have different requirements and potentially be valued differently for the same service)

These local flexibility markets are essentially a product of a DNOs assessment of the cost of procuring flexibility in place of investing in new network infrastructure or reinforcing/upgrading/increasing the capacity of existing network infrastructure. Therefore, in terms of this as a future source of revenue for flexibility players, the potential is possibly quite time limited. With the reforms described in section 6.2, there is likely to be a point when DNOs will have to invest and reinforce their networks to adapt to the increase in electric vehicle charging deployment, heat pump uptake, and the connection of additional DER capacity.

Therefore, the value of procuring flexibility instead of investing capital in network reinforcement could decrease over time.

There is an argument that the need for local flexibility could continue to evolve, with new services dealing with different (as yet to be determined) future network needs that could mean DNOs will make use of the flexibility contracts they have in place, the marketplace structures, commercial terms and procurement platforms in order to fast-track new or adapted flexibility services. For example, in 2020 commercial reactive power services were procured via a DNO in the Power Potential project.

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[134] ENA, 2021 *Decarbonisation and decision making* https://www.energynetworks.org/newsroom/decarbonisation-and-decision-making-how-networks-can-make-the-most-of-connected-assets

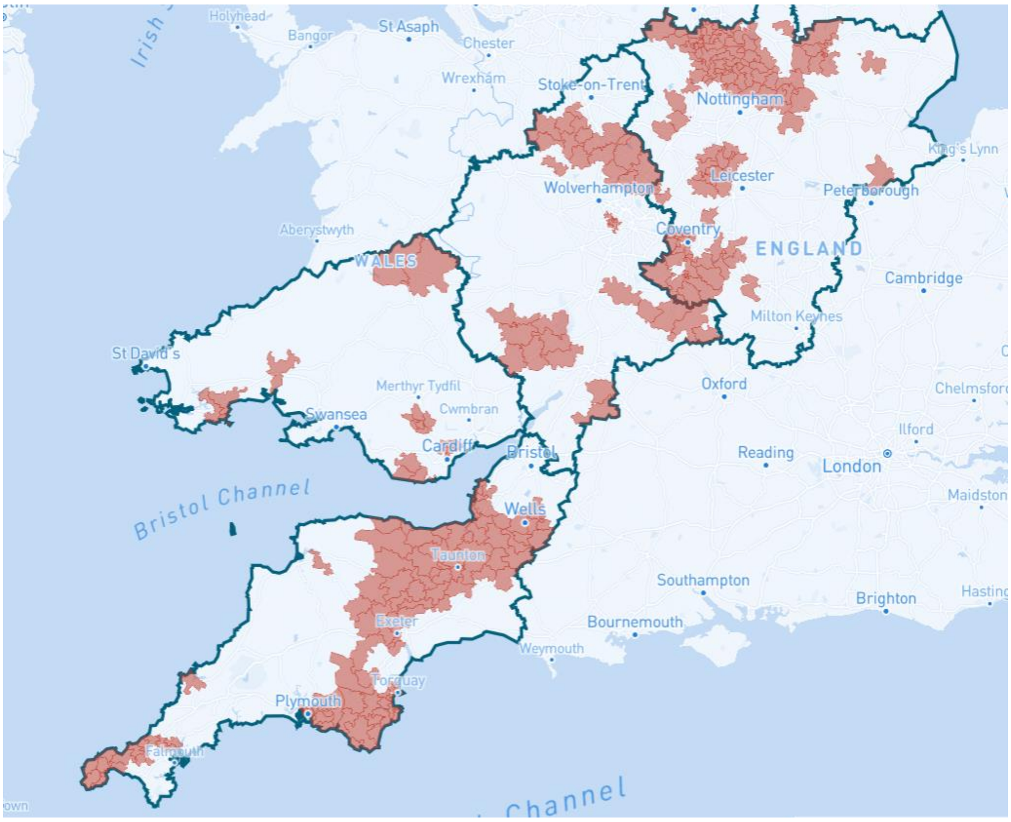
[135] Flexible Power, 2021 *About Flexibility Services* https://www.flexiblepower.co.uk/about-flexibility-services

[136] PicloFlex, 2021 *Dashboard* https://picloflex.com/dashboard

[137] ENA, 2021 *ENA flexibility figures* https://www.energynetworks.org/industry-hub/resource-library/?search=ENA+Flexibility+Figures+-+March+2021&id=267

The issue remains that these local flexibility services create a post-code lottery that requires asset operators to be "in it to win it" (Figure 20). So as a mainstay opportunity or source of revenue for generation, energy storage or demand side response proponents, it is a less lucrative and less certain opportunity than other markets.

Figure 20: Map of Western Power Distribution local flexibility market areas where services have been procured (Source: Flexible Power[138])



[138] WPD, 2021 *Flexible Power map* https://www.flexiblepower.co.uk/map-application

10.2. Overview of Canadian electricity sector (focused on Ontario)

Canada comprises 10 provinces and three territories, which are interconnected by the North American Bulk Electricity system. It covers a land area of 9.985 million km^2, more than 40 times the size of the UK. Due to its size, there is not a central Canadian electricity system and instead, decisions are made on a provincial level, with transmission and distribution responsibilities falling to provincial governments. The overarching regulation of the energy system falls to national bodies. For many years, a few integrated companies owned the entire electricity value chain from production to consumption, however in the early 2000s the provinces of Ontario and Alberta restructured and separated from the traditional system. Ontario and Alberta are still the only "restructured" provinces with competitive markets, while the other provinces and territories operate under a "vertically-integrated" system in which utilities are governed by Crown corporations but regulated by provincial utility boards[139]. National scale bodies include:

- Canadian Electricity Association (CEA)[140]: founded in 1891, CEA is the national forum and voice of evolving electricity business in Canada. CEA members generate, transmit, and distribute electrical energy to industrial, commercial, residential, and institutional customers across Canada. Members include integrated electricity utilities, independent power producers, transmission and distribution companies, and power marketers. CEA is a membership organisation and is run by an elected board of directors.
- The Canada Energy Regulator (CER)[141]: replacing the National Energy Board in 2019, the role of the CER is to oversee how energy is moved in Canada, watching over national, provincial, and territorial borders. They are a publicly owned organisation working in the public interest, providing the people of Canada with energy statistics, analysis, and information they can trust. They have jurisdiction over electricity exports, the issuance of permits and for interprovincial and international transmission lines, and environmental assessments large-scale hydroelectric projects (>200 MW).
- Natural Resources Canada (NRCan)[142]: a government-controlled body, NRCan ensures Canada's abundant natural resources are developed sustainably, competitively, and inclusively. Their work is varied and wide-reaching, including departments for energy efficiency, climate change, domestic and international markets, and science and data. They also provide funding for different projects, including the "Smart Grid Program", offering up to $100 million (CAN) for utility-led projects looking to reduce greenhouse gas emissions, better utilise existing electricity assets and foster innovation for smart grid technologies.
- North American Electric Reliability Corporation (NERC)[143]: a not-for-profit international regulatory authority whose mission is to ensure the effective and efficient reduction of risks to the reliability and security of the electricity grid. NERC develops and enforces reliability standards; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. Their area of responsibility spans the United States,

[139] MaRS Advances Energy Centre, 2018 *Market Information Report: Canada* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/761224/Canada_Report_v3.pdf
[140] Canada Electricity Association https://electricity.ca/
[141] Canada Electricity Regulator https://www.cer-rec.gc.ca/en/index.html
[142] Natural Resources Canada https://www.nrcan.gc.ca/home
[143] North American Electric Reliability Corporation https://www.nerc.com/Pages/default.aspx

Canada, and the northern portion of Baja California, Mexico. NERC is overseen by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.

For most provinces, these are the main bodies that regulate and oversee their energy system, however in restructured provinces, such as Ontario, there are additional bodies that act on a provincial scale. The Ontario Energy Board (OEB)[144] is an independent government body that regulates the energy sector in Ontario. Their role is to ensure the people of Ontario get a sustainable energy system. They actively work to:

- Set the rules for energy companies operating in Ontario.
- Establish energy rates that are reasonable.
- Licence energy companies.
- Monitor the wholesale electricity market and energy companies.
- Develop new energy policies and provide unbiased advice to government.
- Facilitate energy literacy in the people of Ontario.

The OEB has been regulating the natural gas sector since 1960 and the electricity sector since 1999. Market participants include Hydro One, Ontario Power Generation, and the Independent Energy System Operator (IESO), as well as numerous generators, transmitters, distributors, wholesalers, and retailers. An overview of the electricity system in Ontario is illustrated in Figure 21.

10.2.1. Energy policy context

In the Canadian electricity market, most decisions around energy policy fall under the jurisdiction of provincial governments. The government of Ontario, through the Ministry of Energy, Northern Development and Mines, sets the overall policy for the Ontario energy sector, mainly through laws and regulations. They support the growth of clean technology and innovation in the electricity sector, and work to support energy efficiency and conservation in Ontario[145]. The Ministry of Natural Resources and Forestry (MNRF) manages petroleum and mineral aggregate resources. The OEB assists in this by regulating the energy sector, ensuring natural gas and electricity companies follow the laws set by government. As a result of more emphasis on provincial governance, federal and provincial level strategies are often contradictory towards one another and lack inter-jurisdictional cooperation[146].

Energy is a very political topic in Canada and can be captive to election cycles. From 2003 to 2018, Ontario was led by the Liberal Party. In 2013, Kathleen Wynne, leader of the Liberal Party, was voted Premier of Ontario. In her time in office, she privatised Hydro One, organised 500 MW of peak electricity sharing between Ontario and Québec, and introduced a Cap-and-Trade scheme for carbon emissions. In 2018, she was defeated by Doug Ford of the Progressive Conservative Party who has since cancelled the provincial Cap-and-Trade system and withdrawn the province from the Western Climate Initiative, a market-based program founded

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[144] Ontario Energy Board https://www.oeb.ca/

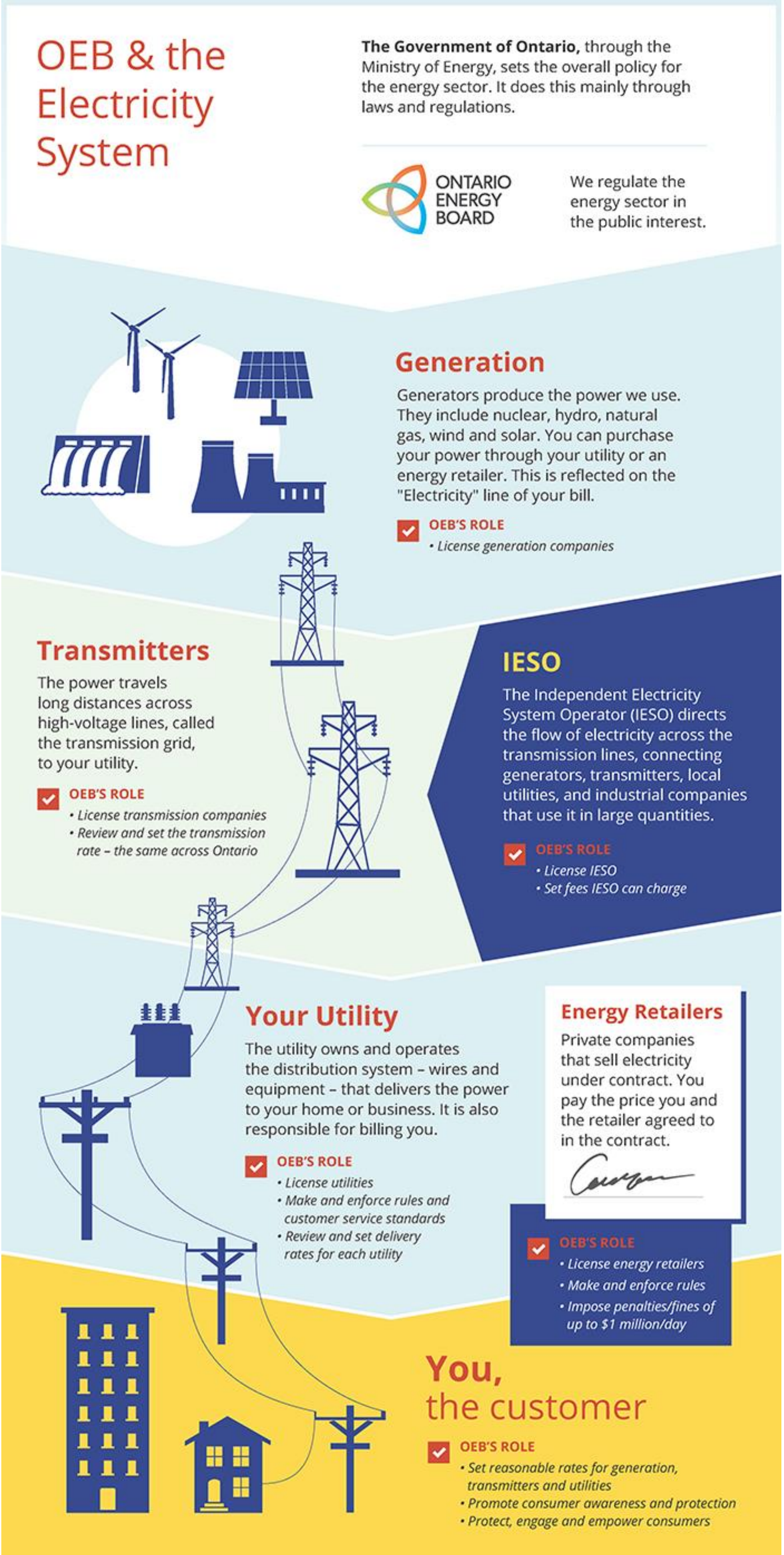
[145] Ministry of Energy, Northern Development and Mines https://www.ontario.ca/page/ministry-energy-northern-development-and-mines

[146] Fertel, C. et al., 2013 *Canadian energy and climate policies: A SWOT analysis in search of federal/provincial coherence* https://www.sciencedirect.com/science/article/abs/pii/S0301421513009816?via%3Dihub

in 2007 to reduce greenhouse gas emissions[147]. The retraction of the Cap-and-Trade emissions scheme has left businesses with millions of dollars of unusable permits[82].

[147] Financial Accountability Office of Ontario, 2018 *Cap and Trade: A Financial Review of the Decision to Cancel the Cap and Trade Program* https://www.fao-on.org/web/default/files/publications/ending%20cap%20and%20trade%20oct%202018/Cap%20and%20Trade.pdf

Figure 21: The electricity system in Ontario (Source: https://www.oeb.ca/)



Ontario used to have a dedicated Renewable Energy Facilitation Office (REFO), which facilitated the development of renewable energy projects across the province[148], including through Feed-in-Tariff schemes, until the current party in power repealed the Green Energy Act 2009. In so doing the Government introduced changes to increase the power of municipalities and provinces to reject renewable energy projects[149]. Most solar, wind or bio-energy projects in Ontario must get a Renewable Energy Approval[150] from the Ontario government, but this is not a support mechanism for these projects. Ontario is among the provinces that have opted for the federal fuel charge carbon pricing scheme under the Greenhouse Gas Pollution Pricing Act adopted on June 21 2019. Notable Provincial-level policy instruments in Ontario include:

- *The Green Energy and Green Economy Act 2009:* placing a priority on expansion of clean and renewable sources of energy, including streamlined approval process for renewable energy projects.
- *Ontario Energy Board Act 1998:* Established rules on licencing and regulating the energy market.
- *Energy Consumer Protection Act 2010:* Provides safeguards to energy consumers with respect to electricity and gas contracts and suite metering[151].
- *Renewable Energy Approval Regulation:* Outlines the common requirements of the Ministry of the Environment and Ministry of Natural Resources regarding energy projects.

In 2016, Canada introduced *The Pan-Canadian Framework on Clean Growth and Climate Change*, which aims to facilitate the national commitment in accordance with the Paris Agreement to reduce GHG emissions by 20% from 2005 levels by 2030[152]. The main goals of this framework include increased electricity generation from renewable and low-emitting sources, modernized electricity systems, and the reduction of reliance on diesel generation in northern and remote communities. As of December 2018, the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* was amended to include stricter performance standards, designed to phase out conventional coal by 2030 in Canada[153]. As a result of this regulation, of the 36 operational coal units as of 2017, 26 units with a combined capacity of almost 8,000 MW are expected to be shut down or converted to natural gas. All coal units are expected to be shut down by 2065.

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[148] International Institute for Sustainable Development, 2017 *Cities and Smart Grids in Canada* https://www.iisd.org/system/files/publications/cities-smart-grids-canada.pdf

[149] Arid & Berlis LLP | Arid & McBurney LP, 2018 *Ontario Repeals Green Energy Act, 2009* https://www.lexology.com/library/detail.aspx?g=c60114d6-e61b-4283-92cd-2757a04c8ab6

[150] https://www.ontario.ca/page/renewable-energy-approvals

[151] WeirFoulds LLP, 2010 *Legislative Update: Energy Consumer Protection Act, 2010.* https://www.weirfoulds.com/assets/uploads/6155_Litigation-Update-Legislation.pdf

[152] Government of Canada, Provincial and Territorial Governments of Canada, 2016, *Pan-Canadian Framework on Clean Growth and Climate Change: Canada's Plan to Address Climate Change and Grow the Economy* *https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework/climate-change-plan.html*

[153] Canada Gazette, 2018 *Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, SOR/2018-263* http://www.gazette.gc.ca/rp-pr/p2/2018/2018-12-12/html/sor-dors263-eng.html

Other national-level policy levers relating to the energy sector include, but are not limited to:

- *A Healthy Environment and A Healthy Economy*: A report outlining the remaining proposals for achieving the Paris Agreement commitments, targeting non-emitting sources at 90% by 2030 and 100% by 2050[154].
- *The Low Carbon Economy Fund*: A $2 billion fund that supports the Pan-Canadian framework to meet Canada's commitments to the Paris Agreement. The fund comprises of two parts – the Low Carbon Economy Leadership Fund ($1.4 billion), which helps provinces and territories to reduce emissions, and the Low Carbon Economy Challenge ($500 million), which funds projects that demonstrate ingenuity and generate green growth[155].
- *The Pan-Canadian Approach to Pricing Carbon Pollution:* a federal benchmark, giving provinces and territories the flexibility to develop their own carbon pricing system while outlining essential criteria to ensure fairness, stringency, and efficiency[156].

On a national scale, there are several tax incentives that encourage investment in clean energy projects, including the accelerated capital cost allowance (CCA) and Canadian Renewable Conservation Expense (CRCE) which enable tax deferrals. Federal budgets have also allocated funds to new programs aiming to spur cleantech development and deployment, focusing on smart grids and energy storage[139]. Smart Grid Canada and Energy Storage Canada are national organisations advancing market opportunities in these areas. Reform is more likely in provinces which do not have hydropower resources, as these provinces tend not to benefit from low electricity costs, resulting in more incentive for change.

The CER oversees the licencing process for oil and gas exploration, as well as for large hydropower projects. Most other energy licencing procedures in Ontario are set by the OEB, including the licence for the IESO to operate as the Smart Metering Entity (SME), to support its smart metering initiative. The SME is charged with overseeing the meter data management repository, as well as processing smart meter consumption data, and supporting ToU billing[157]. The historical administrative process of the OEB follows a quasi-judicial structure, where utility applications are reviewed at formal hearings and legally binding orders are issued[158]. The OEB also sets wholesale electricity market rules and carries out support program administration.

The OEB is subject to ongoing modernisation in 2020/2021 with the goal of improving transparency, accountability and sector efficiency. Some of the changes include new performance standards for applications processing, a new framework for energy innovation, and a new corporate governance structure. Many of these changes were a result of findings from

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[154] Government of Canada, 2020 *A Healthy Environment and A Health Economy: Clean Electricity.* https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/annexcleanelectricity.pdf
[155] Government of Canada, 2020 *What is the Low Carbon Economy Fund?* https://www.canada.ca/en/environment-climate-change/services/climate-change/low-carbon-economy-fund/what-is-lcef.html
[156] Government of Canada, 2019 *How we're putting a price on carbon pollution* https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/putting-price-on-carbon-pollution.html
[157] IESO, *Licensing* https://www.ieso.ca/en/Corporate-IESO/Regulatory-Accountability/Licensing
[158] Government of Ontario, 2017 *Appendix C: Discussion Notes of the Ontario Energy Board Modernisation Review Panel* https://www.ontario.ca/document/ontario-energy-board-modernization-review-panel-final-report/appendix-c-discussion-notes

the Modernisation Review Panel Final Report[159]. One important change is the resumption of the *Responding to Distributed Energy Resources Consultation* process, which will involve the review of its requirements for connection of DERs by licenced electricity distributors. The aim of this consultation is to identify barriers to connection, and standardise and improve the connection process, with a focus on generation and storage facilities[160].

Under the *Ontario Energy Board Act, 1998*, electricity retailers and gas marketers are required to obtain a licence from the OEB to operate[161]. Applicants must show compliance with the *Energy Consumer Protection Act, 2010* and certain renewable energy projects must also be approved by the MNRF. The requirements, outlined in the *Renewable Energy Approval Regulation*, include multiple reports on the topics of water, natural heritage, and consultation with local and indigenous communities, to name a few. Other responsibilities of the OEB include monitoring the wholesale electricity market for inappropriate or unusual market behaviour, reviewing and approving of energy utility rates, approving new construction, and approving changes in corporate ownership. In 2018, a regulatory sandbox was adopted for new pilot projects[162].

10.2.2. Networks

Authority over electricity generation and transmission in Canada rests primarily with provincial governments. However, for vertically integrated provinces, these companies are members of the CEA and hence are still overseen by a national body. In restructuring, Ontario and Alberta moved away from this centrally managed model through the creation of an Independent Electricity System Operator (IESO) to manage the power flows across the system and set wholesale market prices. The Ontario transmission and distribution networks are predominantly managed by Hydro One, a utility in Ontario.

Hydro One is a publicly traded company, founded in 1999, although it traces its history back to 1906 and the establishment of the Hydro-Electric Power Commission of Ontario, and is Ontario's largest electricity transmission and distribution service provider, covering approximately 75% of the geographic area of Ontario. It is part owned by the provincial government and owns over 98% of Ontario's transmission capacity[163]. In Ontario, owners of transmission facilities retain ownership of their respective components of the system. The network serves nearly 1.4 million predominantly rural customers, or approximately 26% of the total number of customers in Ontario. In 2015, Hydro One became a publicly traded company on the Toronto Stock Exchange. The Hydro One transmission network operates at 115 kV, 230 kV and 500 kV[164], while the distribution network operates at a lower voltage, covering anything under 50 kV.

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[159] Ontario Energy Board Modernization Review Panel, 2018 *Ontario Energy Board Modernization Review Panel* https://files.ontario.ca/endm-oeb-report-en-2018-10-31.pdf
[160] Ontario Energy Board, 2019 *Distributed Energy Resources (DER) Connections Review* https://www.oeb.ca/industry/policy-initiatives-and-consultations/distributed-energy-resources-der-connections-review
[161] Government of Ontario, 1998 *O. Reg. 90/99: electricity retailers - licence requirements, Ontario Energy Board Act* https://www.ontario.ca/laws/regulation/990090/v2
[162] Ontario Energy Board, 2018 *Advisory Committee on Innovation* https://www.oeb.ca/sites/default/files/Report-of-the-Advisory-Committee-on-Innovation-20181122.pdf
[163] Government of Ontario, 2019 *Electricity Transmission* https://www.ontario.ca/page/electricity-transmission
[164] Hydro One, n.d. *Introduction to Power Generation and Transmission* https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/supplytoessexcounty/Documents/SECApp_A%20Intro_Power_Gen.pdf

In total, there are currently 60 LDCs operating in Ontario, supplying the rest of the province. These can be municipally owned corporations or privately-operated entities, and include Alectra Utilities, Toronto Hydro, Hydro Ottawa, Lakeland Power, EPCOR Utilities, and Cornwall Electric. These distributors are responsible for billing customers and delivering some conservation programs (with the majority being delivered by the IESO). Distribution companies do not contract independently for their electricity supply, instead it is determined by the provincial mix of generation, which is governed by the IESO.

The interconnection between Canada and the United States is serviced by 49 transmission lines of over 60 kV, the most recent being the Manitoba-Minnesota Transmission Project of 500 kV, completed in June 2020.[165] These international transmission lines include at least one transborder interconnection in each of the seven Canadian provinces that share a frontier with the United States, crossing at 28 different locations[166].

The Canadian transmission network runs mostly north-to-south, with Ontario having interconnections with Manitoba, Quebec, Michigan, Minnesota, and New York. Recent studies have recommended the expansion of Canada's east-to-west transmission to support system decarbonisation and unlock dispatchable hydroelectric generation while moving away from coal generation.[167] One such study, *The Pan-Canadian Wind Integration Study,* provided economic modelling scenarios, showing that transmission network capacity additions could allow increased wind capacity up to as much as 65 GW by 2025, compared to 11 GW in the BAU scenario[168]. In the highest ambition scenario for Ontario, transmission capacity was added to increase the province's interface capacity with Manitoba, Minnesota, Michigan, as well as New York to increase export revenues. Currently, most imports come from Quebec, while most exports go to New York and Michigan[169]. Trade across provincial borders tends to be bidirectional and not taxed, instead there is a negotiation on the price paid for electricity between the two provinces.

Network charges

Electricity tariffs in Ontario, as set out by the IESO for market participants, include three categories of charges: Commodity charges, Wholesale Market Service Charges, and Wholesale Transmission Charges. Commodity charges relating to LDCs include the Hourly Ontario Energy Price (HOEP), which is an hourly price for non-dispatchable loads paid to LDCs, and the Actual Global Adjustment Class B Rate, which includes payments made to LDCs for conservation programs. Wholesale Market Service Charges include the Hourly Uplift, that covers energy losses and operating reserve cost. The Rural and Remote Electricity Rate Protection is an offset for the higher cost of providing service to customers in remote areas. Finally, the Wholesale Transmission Charge to LDCs and some large consumers covers costs incurred by transmission companies to construct and maintain high-voltage transmission lines from generating facilities

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[165] Manitoba Hydro, 2021 *Manitoba-Minnesota Transmission Line Project*. https://www.hydro.mb.ca/projects/mb_mn_transmission/

[166] North American Cooperation on Energy Information, 2020 *North American infrastructure map* http://nacei.org/#!/maps

[167] GE Energy Consulting, 2018 *Western Regional Electricity Cooperation and Strategic Infrastructure (RECSI) Study. Final Report.* Prepared for Natural Resources Canada https://www.aeso.ca/market/market-updates/regional-electricity-cooperation-and-strategic-infrastructure-initiative-recsi/

[168] GE Energy Consulting, 2016 *Pan-Canadian Wind Integration Study (PCWIS). Final Report.* Prepared for: Canadian Wind Energy Association (CanWEA) https://canwea.ca/wind-integration-study/

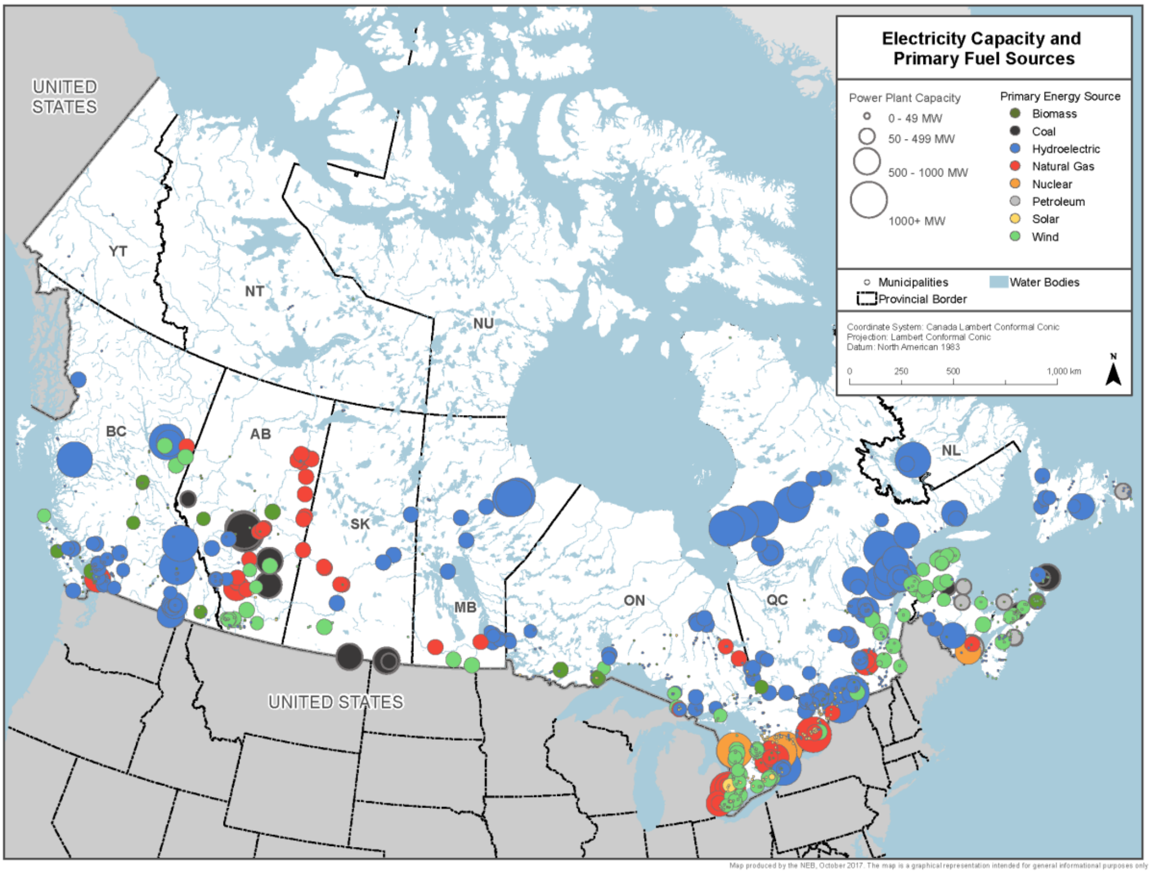
[169] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html

to LDCs or consumers[170]. It also encompasses the network charge, the connection charge and the line and transformation charge. The rate for this service is approved by the OEB. For smaller consumers, the transmission charge varies within the province and goes towards maintaining and operating the networks. The average consumer pays the vast majority of their electricity bill in the form of service charges.

10.2.3. Generation

Canada has a very large renewable sector, with hydropower making up a significant proportion of its electricity generation. There are also large amounts of nuclear and coal-fired capacity, the latter of which Canada plans to phase out by 2065 under the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations that were amended in December 2018[171]. The generation mix is dependent on the natural resources within a province or territory, as there is not a single energy network that serves the whole country. This varies significantly between provinces, as seen in Figure 22, with generation projects focused mainly in Southern Canada. Yukon, the Northwest Territories and Nunavut are notable for the absence of generation in their provinces. In five provinces, hydropower has the dominant (>85%) share of generation[139], this means that carbon emissions by province are wide ranging, stretching from

Figure 22: Electricity capacity and primary fuel sources in Canada[141]



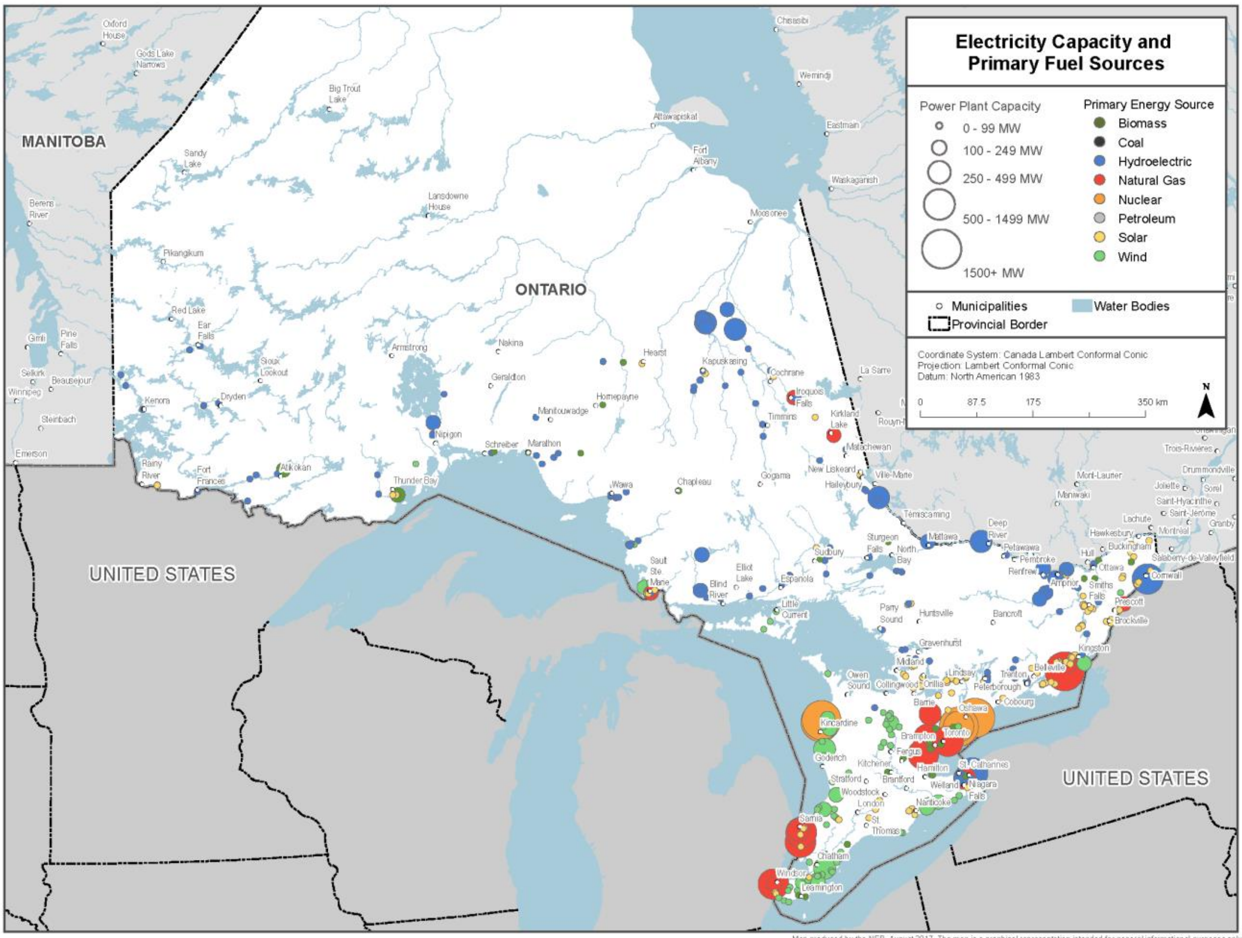
[170] IESO, n.d. *Settlements: Guide to Wholesale Electricity Charges* https://www.ieso.ca/en/Sector-Participants/Settlements/Guide-to-Wholesale-Electricity-Charges

[171] Government of Canada, 2018 *Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations: SOR/2018-263* https://gazette.gc.ca/rp-pr/p2/2018/2018-12-12/html/sor-dors263-eng.html

1 gCO_2/kWh in Quebec to 760 gCO_2/kWh in Nova Scotia, the latter of which is similar to that of India or China.

In 2018, Ontario generated c. 157 TWh of electricity, which is approximately 24% of total Canadian generation. The province has a generation capacity of 40 GW, located primarily in the South East of Ontario, as seen in Figure 23. The generation mix for Ontario in 2018 is shown in Figure 24. This has changed significantly in recent decades, in 2003 coal represented c. 25% of Ontario's supply mix whilst by 2014 coal was eliminated from Ontario's electricity supply.

Figure 23: Electricity capacity and primary fuel sources[141]

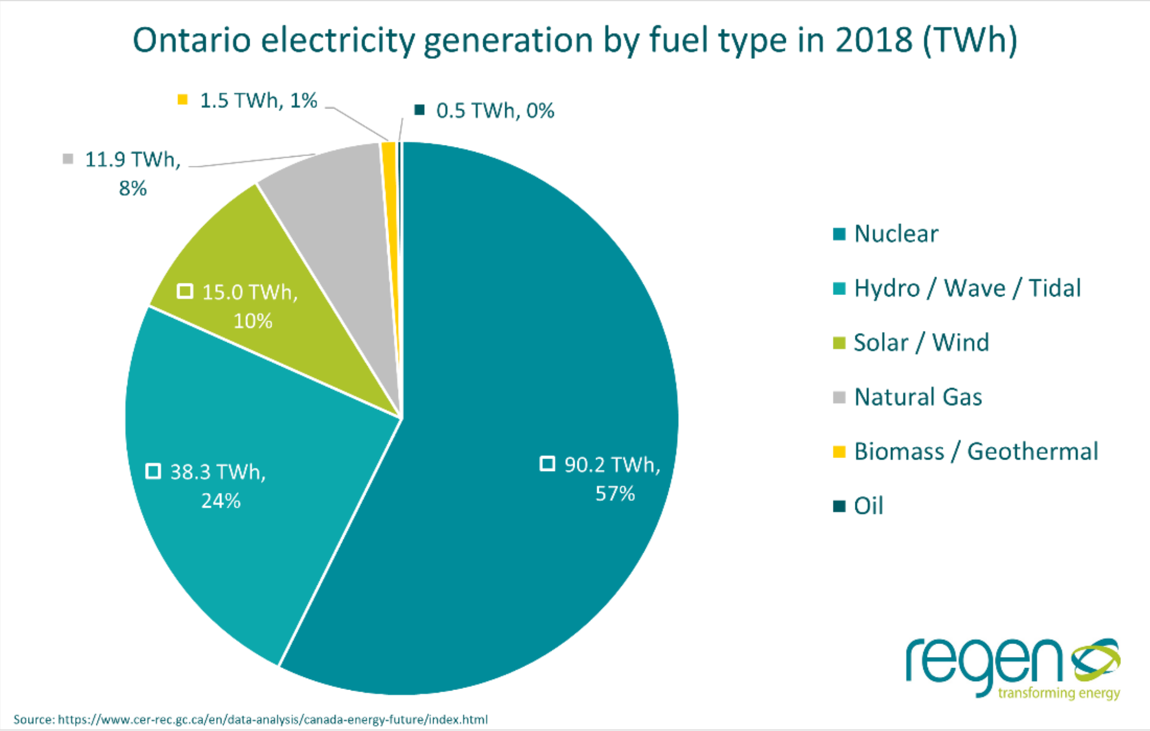


Map produced by the NEB, August 2017. The map is a graphical representation intended for general informational purposes only

There is a lower proportion of hydropower in Ontario compared to other provinces, totalling only 9 GW, which means that the province relies heavily on thermal and nuclear generation. Wind power has been the largest source of new electricity generation in the last decade, with solar and wind accounting for only 0.02% (0.026 TWh) of Ontarian electricity generation in 2005. In the second quarter of 2020, transmission grid-connected generation output totalled c. 35.9 TWh, with low-carbon sources accounting for 95.5% of generation. In terms of installed capacity, Ontario has 27.64 GW of low-carbon capacity installed in 2020, with a further 11.27 GW of natural gas capacity. Future projections of Ontario's electricity generation for 2025 are shown in Figure 25, this is based on a scenario of deep economic recession following the COVID-19 pandemic causing reduced energy demand. Ontario's baseload power is delivered by nuclear and hydroelectric sources, as these tend to produce constant amounts of energy, which does not vary significantly within the day. This is useful in securing energy supply; however, it is not flexible to changes in demand. Ontario generally relies on gas-fired power stations to provide flexibility and control as these can be switched on and off when needed.

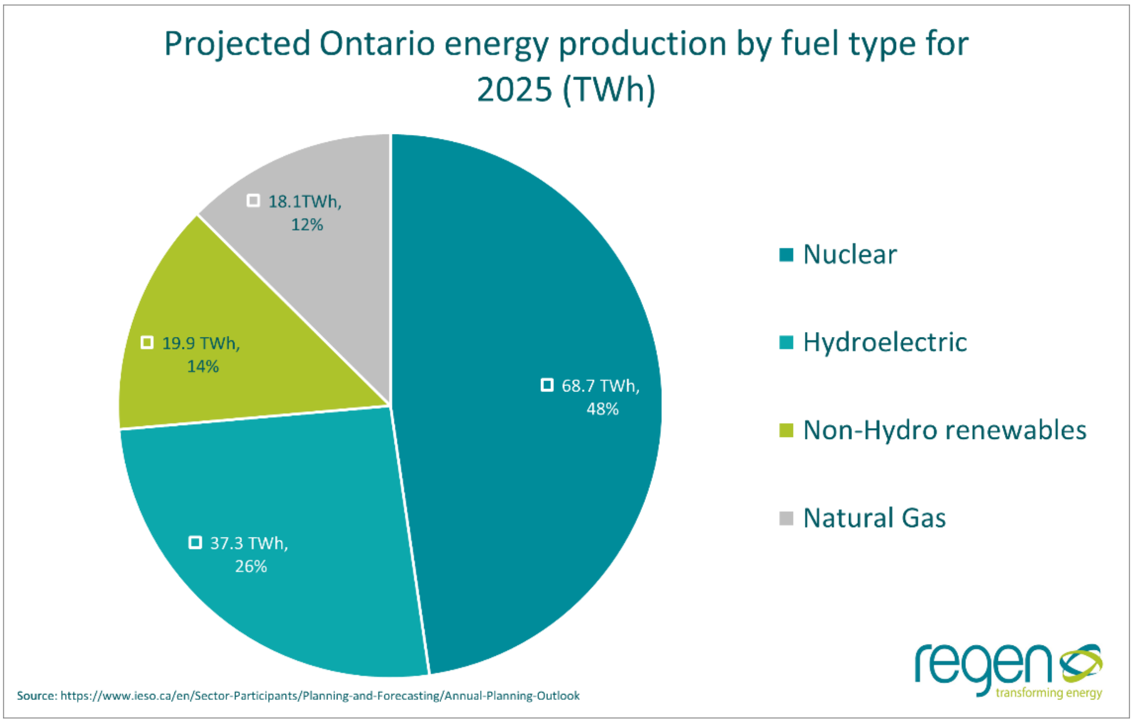
Ontario Power generation (OPG)[172] is one of the largest clean power producers in North America and has 75 generation stations in Ontario, including 66 hydroelectric stations and two nuclear stations. Its monopoly over generation in Ontario has reduced since the restructuring of the energy system, but it still accounted for 18.9 GW of Ontario's generation capacity, approximately 49%.

Figure 24: Electricity generation in Ontario in 2018, by electricity source



[172] Ontario Power Generation, n.d. *About Us* https://www.opg.com/about-us/

Figure 25: Future projection of Ontario's energy generation by fuel type in 2025, based on the assumption of a deep economic recession following the COVID-19 pandemic resulting in lower levels of economic growth, leading to reduced demand.



Gas-fired generation capacity in Ontario is set to nearly triple in the near future, to replace capacity lost through the retirement of the Pickering nuclear plant. This could reverse Ontario's downward trend in greenhouse gas emissions, resulting in c. 3-5 times the greenhouse gas emissions of today by 2030-2035[173].

10.2.4. Retail

Electricity prices in Canada vary considerably between provinces and can be over 10 times more expensive in some provinces than others. This is mainly dependent on the location of hydropower resources, which provide low-cost electricity. In high-hydro provinces, there is little want for a competitive energy market as they already benefit from low-cost electricity. In Ontario however, where significant hydropower resources are lacking, an open, competitive market was launched in 2002, 95% of Ontarians choose to buy electricity from their local utility, which is the default option. Electricity rates are then set by the OEB and customers are billed by the local distribution utilities. However, if a customer chooses to buy electricity from a private company that sells electricity under contract (an energy retailer), they will pay the price agreed in their contract. These electricity retailers include Canadian Energy Protection Corp., Planet Energy Corp, and Onit Energy Ltd.[174]

[173] National Observer, 2020 *Under Doug Ford, Ontarians can expect electricity emissions to triple by 2030* https://www.nationalobserver.com/2020/02/26/news/under-doug-ford-ontarians-can-expect-electricity-emissions-triple-2030
[174] Ontario Energy Board *Licensed Energy Retailers* https://www.oeb.ca/consumer-protection/energy-contracts/licensed-energy-retailers

By creating competition, the government of Ontario hoped to drive down electricity prices, helping to reduce fuel poverty in the province. In 2019, the government introduced the Ontario Electricity Rebate to help keep bills low and "show Ontarians the true cost of electricity"[175]. In the fiscal year 2019-20 Ontario received $291 million in dividends from Hydro One, which works out as approximately $60 per electricity customer that benefits from rebates or credits on their bill.

Overall, customers are increasingly interested in managing their own energy; choosing the type of energy from which they obtain electricity, acting as both suppliers and customers and customising how they use energy[176]. Since 2020, Ontario ToU electricity customers have had the choice how their electricity is billed. Regulated Price Plan (RPP) customers, who include households, small businesses, and farms, are able to choose between a ToU or a tiered rate billing structure, which is metered hourly. This is only for customers who get their electricity from their local distribution utility. Between January 1 2021 and February 22 2021, RPP customers paid a fixed electricity price of 8.5¢/kWh regardless of the time of day or the total volume consumed due to the COVID-19 restrictions in place[177]. Since then, RRP time of use prices have been reinstated, as illustrated in Figure 26, with off-peak charges applying all-day at weekends and holidays.

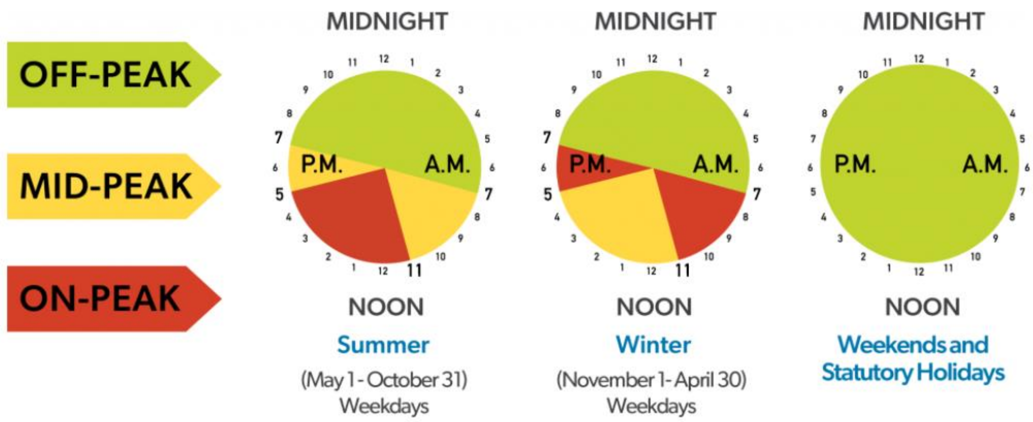


Table *12* includes RRP tiered rates, which are dependent on the customer type.

Figure 26: Current time-of-use periods for Ontario (Source: Lakeland Power[178])

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[175] Government of Ontario 2021, *Your Electricity Bill* https://www.ontario.ca/page/your-electricity-bill
[176] Canadian Electricity Association, 2014 *Vision 2050: The Future of Canada's Electricity System* https://electricity.ca/wp-content/uploads/2014/04/Vision2050.pdf
[177] Ontario Energy Board 2021, *Time use and tiered pricing resumes* https://www.oeb.ca/newsroom/2021/time-use-and-tiered-pricing-resumes
[178] Lakeland Power, 2021 *Choosing your electricity plan* https://www.lakelandpower.on.ca/choosing-your-electricity-price-plan/

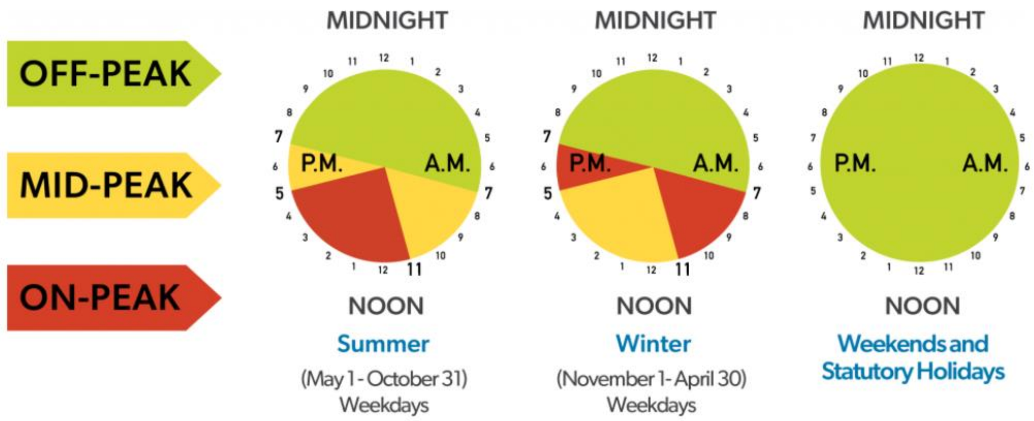

Table 12: Current tiered rate for Ontario[178]

Tier	Winter tier threshold	Prices
Tier 1	• Residential – first 1,000 kWh/month • Non-residential – first 750 kWh/month	10.1¢/kWh
Tier 2	• Residential – for electricity used above 1,000 kWh/month • Non-residential – for electricity used above 750 kWh/month	11.8¢/kWh

According to the OEB, electricity bills include the cost of electricity, local utility services, global adjustment, and regulatory charges, the Ontario electricity rebate can also be applied. The global adjustment fee is the difference between the guaranteed price of electricity that generating companies that is set and the money the generators earn in the wholesale marketplace, it also covers the costs of some conservation projects[179]. Delivery charges (or local utility services) include:

- Customer service charge: a fixed charge for costs related to meter reading, billing, customer service and account maintenance, and for general utility operations.
- Distribution charge: a variable charge for the cost of building and maintaining the distribution system.
- Transmission charge: a variable charge for the costs of transmitters to operate and maintain the high-voltage transmission system.

[179] Ontario Energy Board, *Understanding your electricity bill* https://www.oeb.ca/rates-and-your-bill/electricity-rates/understanding-your-electricity-bill

- Line loss adjustment: an adjustment for the losses incurred during the delivery of energy.

These are not fixed charges and vary depending on several different factors. Regulatory charges are made up of the wholesale market service charge, set by the OEB, and a standard supply service charge. The wholesale market service charge is made up of several different factors:

- Physical limitations and losses.
- Energy reliability.
- IESO administration fee.
- Rural and Remote Electricity Rate Protection (RRRP).
- Renewable connections.

Smart Metering Entity (SME)

In 2006, Ontario's provincial government passed a pioneering legislation that enabled the implementation of smart metering to the province's residential and small business electricity consumers. At the time, this was one of the largest smart meter deployments in North America, supporting the implementation of time-of-use rates, which enabled consumers to actively manage their electricity consumption. In a push to create a smarter and data-centric energy system, the IESO was designated the responsibility of being Ontario's Smart Metering Entity (SME), which means they are responsible for the implementation and operation of the province's Meter Data Management/Repository (MDM/R). The MDM/R is a platform that helps to manage hourly electricity consumption information and support LDCs' billing processes. As early as May 2014, 4.8 million smart meters covered almost all residential properties and small businesses, making up 45% of electricity consumed in the province[180]. Ontario's smart meters send hourly data to the MDM/R, with approximately 60 LDCs integrated into the system. However, the pricing difference between on-peak and off-peak hours has not been sufficient enough to shift consumption patterns[180]. The cost of installation is absorbed into the operational costs of suppliers.

Data in the repository can then be leveraged for energy planning, conservation, or new research for system development and energy innovation. The IESO has developed the Third Party Access Implementation Plan, with the aim to ensure third party access to de-identified meter data in the MDM/R. This access is compliant with privacy requirements and ensures ethical use of such data by parties such as government institutions, communities, municipalities, academia, and energy service providers, among others.

The Energy Transformation Network of Ontario, formerly known as the Ontario Smart Grid Forum, brings together senior leaders supported by a Corporate Partners Committee of more than 50 private sector organisations active in the smart grid sector. The network's objective is to guide the transformation by influencing policy, market and regulatory matters. There also exists the Grid-LDC Coordination Initiative which aims to understand impact of new technologies on the bulk power system and the role of DERs in addressing local energy needs.

Distributors are mandated by the OEB to install smart meters for its customers to enable time-of-use billing, however there are many different bodies involved in the initiative, as outlined in Figure 28. In the years following the legislation there were some changes, with the cost of

[180] Ontario Auditor General, 2014 *2014 Annual Report of the Office of the Auditor General of Ontario: Smart Metering Initiative* https://www.auditor.on.ca/en/content/annualreports/arreports/en14/311en14.pdf

installations exceeding projected costs by almost $1 billion[180]. The peak demand reduction targets set out in the 2006 legislation have also not been met, with peak electricity demand rising by 100 MW between 2004 and 2010. The Ministry of Energy have cited several benefits associated with the deployment of smart meters, including the ability of consumers to respond to price signals, however these have not all been realised. They believe that modernising the whole grid will help to realise more benefits for Ontario.

The Ministry of Energy, Northern Development and Mines oversees a Smart Grid Fund[181], which supports the modernisation of Ontario's electricity distribution grids. The fund is used to support innovators in developing smart technology. The Fund has supported 45 projects to date, investing $200 million. The projects can be sorted into the following categories:

- Proactive consumers – enabling customers to directly manage how they use power.
- Data analytics – enabling more powerful software to analyse electricity systems.
- Electric vehicle integration – developing smart grids that have minimal impact on electricity grids.
- Energy storage – exploring intelligent control systems coupled with energy storage.
- Grid automation – enabling automatic detection of problems on the electricity grids.
- Microgrids – enabling intelligent control of system issues, giving customers access to cleaner, more reliable power.
- Building local capacity – creating Ontario-based centres of excellence focused on the domestic and global promotion of smart grid technologies, including the local companies involved.

Settlement Process

The revenue meters in Ontario measure and record all energy injected and withdrawn from the grid for each five-minute interval, meaning that different offers come into the market every five minutes. This data then undergoes validation, editing and estimation before is ready for the settlement process, as managed by the IESO. Settlements are received daily by market participants.

A preliminary settlement statement for the physical market is available ten days after each trade day, after which a period of four days is given to submit a Notice of Disagreement. The final settlement statement is made available ten days after the preliminary statement, thus 20 days after the trade day. Invoices are made available monthly, and market participants must pay the invoice within two business days of receipt.

The settlement process for the day ahead market happens in real time, with bids and offers taking place in the morning while optimization processes run from 10:00 to 15:00 using the Day Ahead Calculation Engine.

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[181] Government of Ontario, 2019 *Projects funded by the Smart Grid Fund* https://www.ontario.ca/document/projects-funded-smart-grid-fund

Figure *27* displays the settlement process for the day-ahead market, which occurs over a 24 hour period with bids and offers opening from 6:00 to 10:00.

Figure 27: Settlement Process for Day-Ahead Market[182]

[182] IESO, 2021 *Market Manual 9: Day-Ahead Commitment Process Part 9.0: Day-Ahead Commitment Process Overview* https://www.ieso.ca/sector-participants/market-operations/market-rules-and-manuals-library

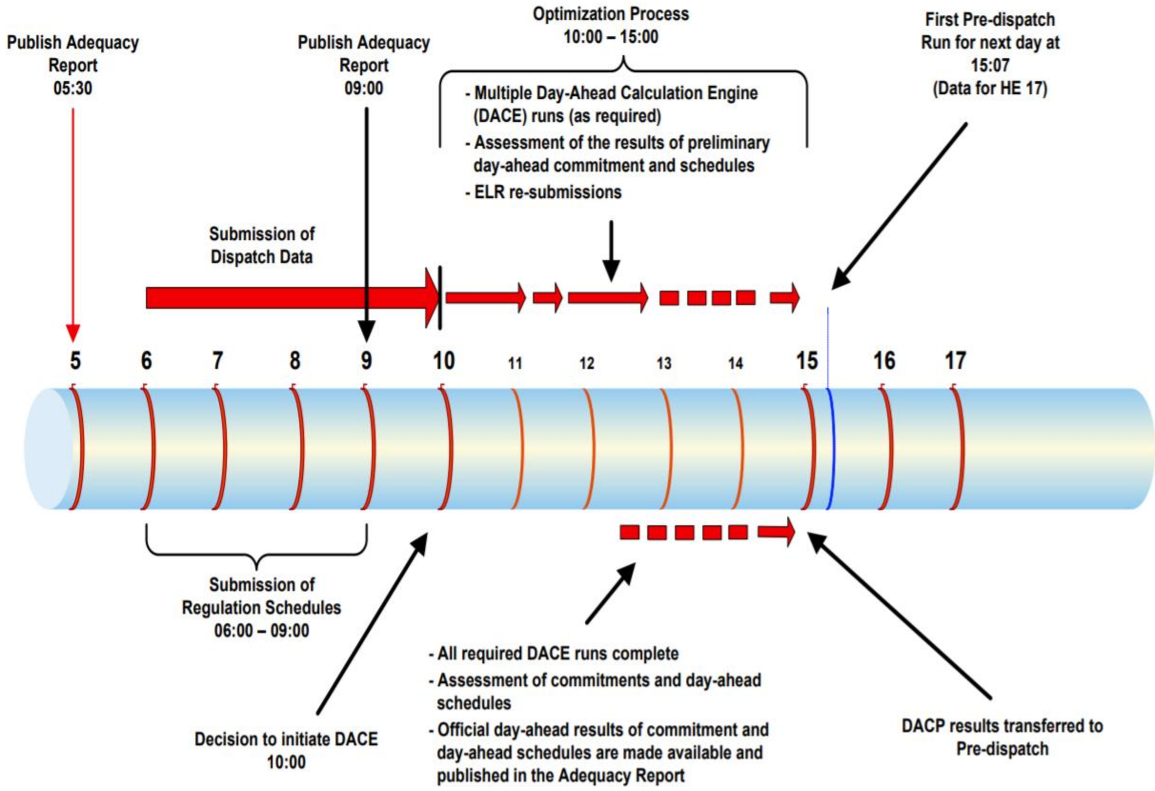
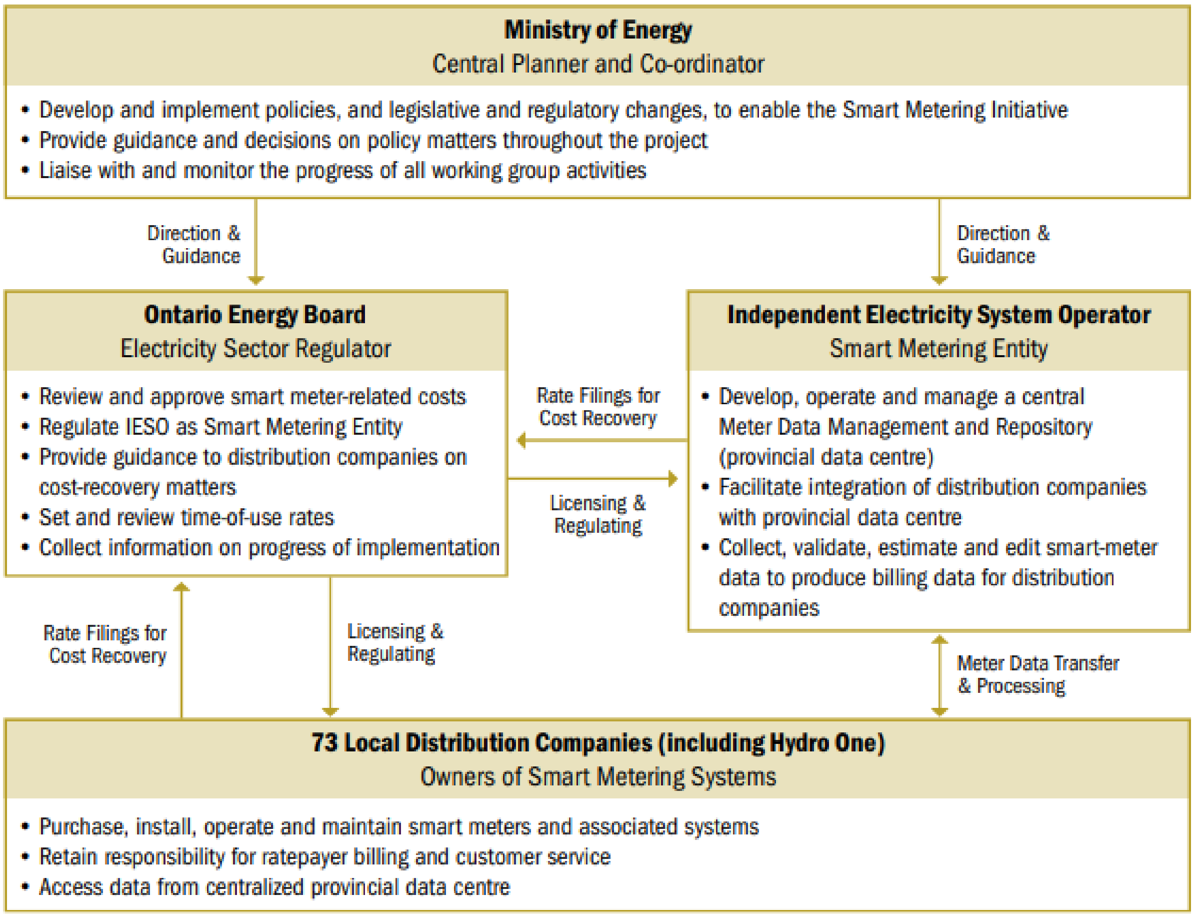

Publish Adequacy Report 05:30
Publish Adequacy Report 09:00
Optimization Process 10:00 – 15:00
- Multiple Day-Ahead Calculation Engine (DACE) runs (as required)
- Assessment of the results of preliminary day-ahead commitment and schedules
- ELR re-submissions
First Pre-dispatch Run for next day at 15:07 (Data for HE 17)
Submission of Dispatch Data
5
6
7
8
9
10
11
12
13
14
15
16
17
Submission of Regulation Schedules 06:00 – 09:00
Decision to initiate DACE 10:00
- All required DACE runs complete
- Assessment of commitments and day-ahead schedules
- Official day-ahead results of commitment and day-ahead schedules are made available and published in the Adequacy Report
DACP results transferred to Pre-dispatch

Figure 28: Key roles and responsibilities of entities involved in Ontario's smart metering initiative. (Source: Ontario Auditor General[180])



10.2.5. Electricity system operation and markets

The IESO works at the heart of Ontario's power system, delivering key services across the electricity sector including:

- Managing the power system in real-time.
- Planning for Ontario's future energy needs.
- Enabling conservation and designing a more efficient electricity marketplace to support sector evolution.

The IESO is a not-for-profit corporate entity established in 1998 by the Electricity Act of Ontario. In 2015, the IESO merged with the Ontario Power Authority (OPA) to bring together real-time operations of the electricity grid and long-term planning, competitive procurement, and energy-efficiency programs. The IESO is governed by an independent Board of Directors appointed by the government of Ontario. Pollitt (2011)[183] concluded that an independent system operator should be not-for-profit, after researching the introduction of a for-profit operator in Alberta. The attempt in Alberta was not completed, after the regulatory commission deemed that the proposed for-profit institution would be too costly and encouraged proposing members to join other membership system operators.

The IESO works with its Canadian and US neighbours to maintain continuous reliability of the interconnected North American power grid. They also ensure reliability on a provincial level by balancing the supply of and demand for electricity continuously and directing the flow of electricity across the province's transmission lines. The IESO operates and settles the wholesale electricity markets, where the market price is set based on accepted offers to supply electricity against the forecasted demand. By working closely with sector participants, the IESO aims to foster and open dynamic and sustainable marketplaces that "encourage new opportunities for innovation and increased value for the consumer". There is also a long-term market in which the IESO procures a wide range of electricity resources and services to meet the IESO's 20-year forecast of energy demand.

The IESO is also responsible for the implementation and operation of smart metering. A paper published in 2019[184], examined the potential implications for "reliability, affordability, competition, and consumer choice" of the continued shift to a distribution energy resource (DER) system. It identifies 4 GW of DERs contracted or installed in Ontario in the last 10 years, not including load control, behind-the-meter energy storage and demand response capacity. The findings of the paper concluded that the roles and responsibilities of DERs need to be determined, and that the aim should be to maximise benefits for Ontario consumers.

The IESO administers a series of markets in Ontario that together comprise the province's wholesale electricity marketplace. Ontario has an open, competitive market with multiple generators, transmitters, wholesalers, and retailers. This model for electricity markets began operating in Ontario in 2002. Moving away from a more common monopoly system was hoped to drive down electricity prices and give customers the freedom to make their own energy related decisions. This was intended to make Ontario's market more robust than those experienced in the 'vertically-integrated' provinces. The opening of the market in 2002 did not have the desired consequences straight away but has since allowed customers to be in control of their electricity. At the time, small volume customers appeared eager to participate in the new market, with more than one million customers signing contracts with various electricity retailers in preparation for the opening of the market. However, the market control of Ontario Power Generation (OPG), an electricity generation company, did not reduce as much as was intended. In 2005, OPG owned 72% of total installed electricity capacity in Ontario. Today, they still own 49%. Additionally, the competition to drive down prices proposed upon the creation of the market has not always been apparent. In December 2002, almost immediately after the market opened, the provincial government passed legislation freezing retail prices at 4.3¢/kWh for the

[183] Ofgem, *review of GB system operation* https://www.ofgem.gov.uk/system/files/docs/2021/01/ofgem_-_review_of_gb_energy_system_operation_0.pdf
[184] IESO, 2019 *Structural Options for Ontario's Electricity System in a High-DER Future.* Available from https://www.ieso.ca/en/Learn/Ontario-Power-System/etno/ETNO-Publications

next four years[185]. The freeze was retroactively applied to May 2002, undermining the decision of over one million consumers to sign fixed contracts with private retailers. The new government elected in 2003 (Liberal Party) maintained the wholesale electricity market, but also introduced legislation that reduced competition by establishing a provincial-led agency to procure new generation. The more recent shift to renewable generation and decarbonising Ontario's power have taken centre stage and the transition from a hybrid market towards a competitive market took a backseat. The IESO, along with market players, must now decide whether they will support the current detailed designs of the Market Renewal Program, a set of reforms attempting to address the problems in the current market system, or determine what the market should look like given the many unique aspects of Ontario's grid.

Real-time energy market

The electricity market in Ontario is run in real time, settling bids and offers every five minutes by means of a Market Clearing Price (MCP). Most resources participating in this market are obliged to submit bids and offers a day-ahead as part of the Day-Ahead Commitment Process (DACP). The DACP is a reliability process that allows for dispatchable resources from generators and loads to be optimised using least-cost security-constrained solution for a dispatch day based on the bids and offers submitted by all resources. The MCP represents the cost of producing electricity in real time but does not include the cost of transporting electricity or infrastructure costs, which are recovered outside of the market. One of the key improvements of the market in recent years is the integration of Demand Response (DR), which enables consumers to reduce their electricity consumption in response to prices and system needs.

The Ontario electricity market is interconnected with Manitoba, Minnesota, Michigan, New York, and Quebec. These market participants can import energy from another jurisdiction into Ontario on the DACP, as well as export energy from Ontario. They can also move energy through Ontario from one jurisdiction to another. There are no trade taxes, instead a participant will simultaneously make an offer to import and bid in another jurisdiction to export, or vice versa depending on whether they are completing an import or export transaction. These transactions are scheduled hourly. On the consumer side of the market there are wholesalers and retailers, who both re-sell electricity. Wholesalers buy energy in the wholesale market and sell to other customers, while retailers sell energy and services to consumers at the retail level.

Demand Response auction

The annual DR auction was part of the IESO's ongoing efforts to expand Ontario's DR capabilities and was launched in 2015, before being replaced with the Capacity Auction in December 2020. The DR auction allowed "large consumers, as well as aggregators of smaller institutional, commercial, industrial, and even residential customers, to compete to provide DR capacity for a summer or winter commitment period"[186]. Through a competitive procurement, the IESO secured ten pilot projects, each with unique technical characteristics, requirements and constraints and ranging from 1 MW to 35 MW in capacity, representing 70 MW of Ontario's DR. The pilot projects are being used to assess their ability to follow changes in electricity consumption and to help balance supply and demand. The two main requirements of the DR projects are 'hourly load following', where assets respond to hour-ahead market prices, and 'unit

[185] Energy Regulation Quarterly, 2020 *Ontario's Electricity Market Woes: How did we get here and where are we going?* https://www.energyregulationquarterly.ca/articles/ontarios-electricity-market-woes-how-did-we-get-here-and-where-are-we-going#sthash.fIlm8zNL.dpbs
[186] IESO, n.d. *Electricity Market Today* https://www.ieso.ca/en/learn/ontario-power-system/electricity-market-today

commitment,' where assets commit to load curtailment a day-ahead or four-hours ahead of real time. There is also a requirement to vary consumption in response to instructions for at least 100 hours per contract year.

The DR auction involved dispatchable loads that could adjust their power consumption in response to instructions arriving from the IESO to help Ontario's electricity network and to allow large energy consumers to reduce their own costs and potentially generate a new revenue stream. Non-dispatchable participants are producers and consumers who are not able to respond to five-minute signals in the real-time market. Instead, they were paid the HOEP which was calculated using the average of the 12 five-minute MCPs during the hour. They interacted with the market by submitting forecasts of energy production.

Another form of DR involves shifting demand load to times when there is excess generation. The way this works varies by the size of the consumer:

- Wholesale consumers – companies and institutions that use more than 250,000 kWh of electricity a year. These organisations pay the wholesale price of electricity, which changes hourly. They can then plan their energy use based on price trends.
- Class A consumers – companies that have an average peak demand of greater than 1 MW can control their Global Adjustment costs by reducing their energy use during the five highest demand peaks in the year.
- Residential and small business consumers – these pay time-of-use rates which encourages users to shift some of their usage from high-price peak hours to off-peak hours to reduce their impact on the system.

Capacity Auction

The IESO's Capacity Auction has replaced the former Demand Response auction to enable competition between additional resource types. The IESO held the first Capacity Auction on Wednesday December 2 2020 for the 2021 Summer obligation period. There are a few differences between the DR auction and the Capacity Auction. Firstly, there is a pre-auction period that begins two months prior to the start of the offer submission window, in which a pre-auction report is published. This includes key milestone dates for participants and auction parameters and constraints. During the auction, the IESO processes all capacity auction offers received, determines the clearing prices and quantities and then publishes the results five business days later. According to IESO stakeholder engagement documentation, the aim is to grow the capacity auction into an annual balancing mechanism while addressing short-term needs. This is dependent on attracting the desired diversity of resources, which is expected to be met by 2026 if historical growth of the capacity auction is to be maintained[187].

Operating reserve markets

These markets are used by the IESO to ensure that additional supplies of energy are available should an unanticipated event take place in the real-time energy market. The three types of operating reserve classes are:

- 10-minute synchronised (spinning) reserve.

[187] IESO, 2021 *Resource Adequacy Stakeholder Engagement 22 March 2021* Available from https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Day-Ahead-Commitment-Process#:~:text=The%20day%2Dahead%20commitment%20process,return%20for%20a%20financial%20guarantee.

- 10-minute non-synchronised (non-spinning) reserve.
- 30-minute reserve (non-synchronised).

To offer operating reserve, dispatchable generators or loads must be able to provide the energy within the time frame specified in their class and be able to sustain supplying operating reserve energy for up to one hour. They can offer into one or all three classes of operating reserve and even if their offer is not activated, they will still receive stand-by-payments for the capacity they were selected to provide. The caveat to participating in the operating reserve market is that the participant must offer equal or greater amounts of energy into the real-time market as well.

A price for the operating reserve market is determined every five minutes, as in the real-time market, based on offers in the market. Market standards have been set by the North American Electric Reliability Council (NERC) and North East Power Coordinating Council (NPCC), and the market must always be prepared for "the largest single unexpected event (contingency) plus half of the second largest contingency that could occur"[188]. This typically means the loss of Ontario's one and a half largest generators.

Transmission rights market

The transmission rights (TRs)[189] market allows market participants to reduce risks associated with transmission congestion and price volatility, helping to improve market liquidity. It does this by entitling the owner of TRs to a payment if the price of energy in Ontario is different from the price in an intertie zone. TRs are sold for specific intertie paths for either short-term (one month) or long-term (one year) ownership.

Ancillary services market

The IESO contracts for four ancillary services[190] to help ensure the reliable operation of the power system. These are:

- Certified black start facilities: these facilities can restart their generation facilities with no outside source of power, so they are helpful in re-energising the power system after a blackout.
- Regulation service: sometimes referred to as frequency regulation. This service corrects for short-term changes in electricity use that might affect the stability of the power system by varying their output in response to signals sent by the IESO. A minimum of 100 MW of regulation service is always scheduled. This may increase at points due to weather-related uncertainty, non-linear behaviour of demand patterns, and the autonomous behaviour of embedded DERs.
- Reactive support and voltage control service: this service maintains acceptable reactive power and voltage levels on the grid. Both active power and reactive power are required to serve loads, with all generating facilities that inject energy into the IESO-controlled grid are required to provide a level of reactive support and voltage control service.
- Reliability must-run: used to ensure reliability on the grid. A RMR contract allows the IESO to call on the counterparty to produce electricity if it is needed to maintain the reliability of the

[188] IESO, n.d. *Operating Reserve Markets* https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Operating-Reserve-Markets
[189] IESO, n.d. *Transmissions Rights Market* https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Transmission-Rights-Market
[190] IESO, n.d. *Ancillary Services Market* https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Ancillary-Services-Market

electricity system. Market participants are obliged to offer into the IESO-administered markets.

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