MERLIN

Modelling the Economic Reactions Linking Individual Networks

Milestone 3

Regulation and policies for local flexibility markets: Current and future developments in seven leading countries

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This report investigates stakeholder opinion on Regulation and Policies for local flexibility markets, with a specific evaluation on how this is relevant to Project MERLIN and the UK.

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Table 1: Summary of responses per country and type of party

Summary of responses	AU	FR	DE	GB	JP	NL	NO	Total
Regulators	1		1	1		1	1	5
Distribution utilities	1	1	1	3	1			7
Energy associations	1			1				2
Platforms/ marketplaces				2			1	3
Experts					1			1
Number of responses	3	1	2	7	2	1	2	18

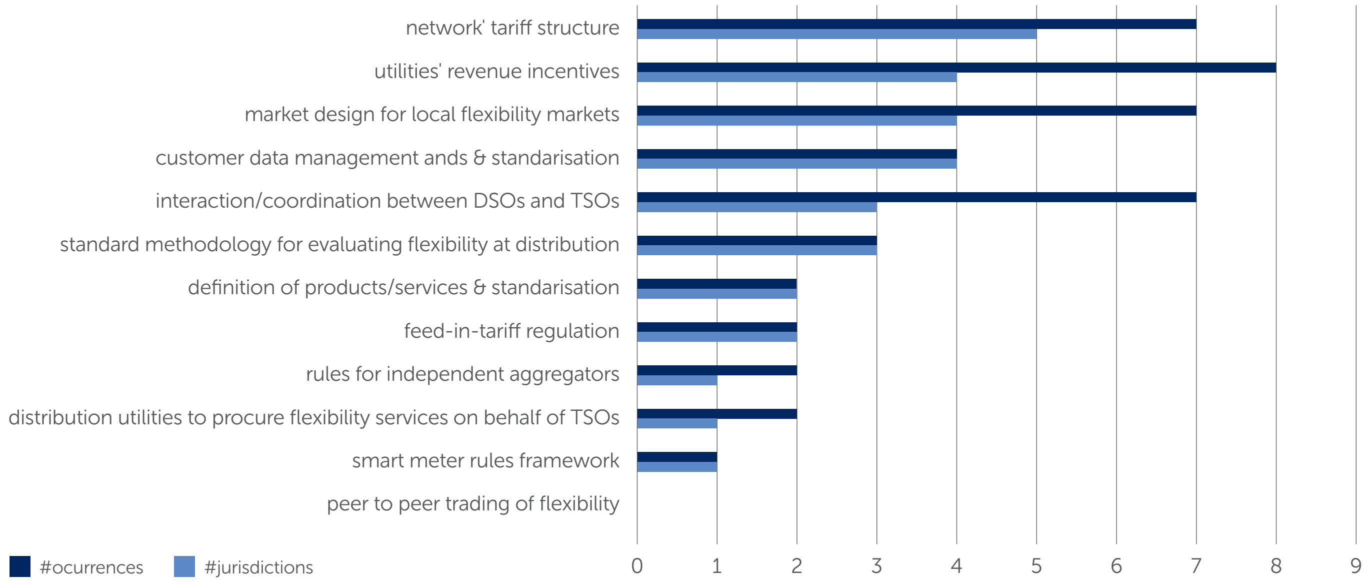
This report is the third in a series of studies on local flexibility markets written by the Cambridge Energy Policy Research Group (EPRG) as part of Project MERLIN (Modelling the Economic Reactions Linking Individual Networks).

The aim of this report is to identify and explore regulatory issues that may have an impact on the use of flexibility solutions by distribution utilities, and to identify key lessons for GB and Project MERLIN. We want to know to what extent the current regulatory frameworks from different jurisdictions support the development of the future distribution utility in its role as a neutral market facilitator, what is still missing and the status of current or future proposals to deal with this. The discussion is centered around the ways energy regulators may promote the use of non-conventional solutions such the procurement of flexibility services by distribution utilities from third parties (i.e. distributed energy resources) to solve network constraints.

A set of questionnaires have been designed to capture the insights around important aspects of the regulation of flexibility markets (e.g. utilities' network incentives, network tariff structure, market design for flexibility markets, etc.). These were sent to key parties from seven jurisdictions (Australia, France, Germany, Great Britain, Japan, the Netherlands and Norway) including distribution utilities, energy regulators, energy marketplace and experts. A total of 18 questionnaires were received (out of 23 sent), see Table 1.

Based on the analysis of the responses from the seven jurisdictions we observe a collective interest in the procurement of flexibility services by distribution utilities from distributed energy resources. New regulation or the adaptation/modification of current rules and recent consultations reflect this. However, the amount of progress with and preferences for key regulatory changes differ across jurisdictions. Among the possible areas for regulatory changes, network tariff structure ranks first and utilities' revenue incentive second, alongside market design for flexibility services, see Figure 1 overleaf.

Figure 1: Summary of responses per type of regulatory change (3 most important)



There is much that a GB stakeholder (such as SSEN) can learn from the experience and analysis arising from the six other jurisdictions, and from the diverse respondents from GB with respect to flexibility markets. Some general lessons are identified below:

1. Even where flexibility markets are highly developed (e.g. in the Netherlands) and incentives – in the form of the DSO revenue model and tariff structure – exist to undertake least cost procurement, it remains unclear as to whether such markets are cost effective at a sustainable scale.

2. More dynamic network tariffs have been or are being considered in several jurisdictions but all jurisdictions remain cautious as to the practicality of their implementation (even in France which has a single DSO capable of widely socializing the impact across all non-flexible customers).

3. While there are moves across multiple jurisdictions to specify and standardise flexibility products, it remains unclear as to whether this is the optimal way to handle customer willingness to pay which is not a function of the flexibility product but of its characteristics.

4. The market design of flexibility markets is a work in progress, and we remain in an experimentation phase. Sophisticated market designs are being considered and in some cases, do not appear to pass a cost benefit test (such as the different market scenarios proposed to integrate DER into local distribution networks in Australia).

5. There is little interest across our jurisdictions in peer-to-peer (P2P) trading as an issue in current debates about flexibility markets. The focus, outside GB, remains on procurement by the distribution utility to meet its own needs.

6. The facilitation of increased co-ordination between TSOs and DSOs is actively being pursued across most of the jurisdictions where unbundling is in place. Australia exhibits some signs of active conflict between the TSOs and DSOs in some areas, which needs to be addressed.

7. Allowing DSOs to procure flexibility on behalf of the TSO is not seen as a big issue outside of GB. However, this is somewhat surprising and reflects the fact that currently DSOs and TSOs are procuring very different types of flexibility and trying to avoid direct competition or even direct contractual relationships. It is not clear how sustainable this avoidance of conflict (and its resolution) is in the longer run.

8. Most of our jurisdictions are working on a common cost benefit methodology (of the type that already exists in New York) to evaluate flexibility solutions. There is clearly a need for this and for it to be consistent with the standard social cost benefit methodologies being used by central and local government.

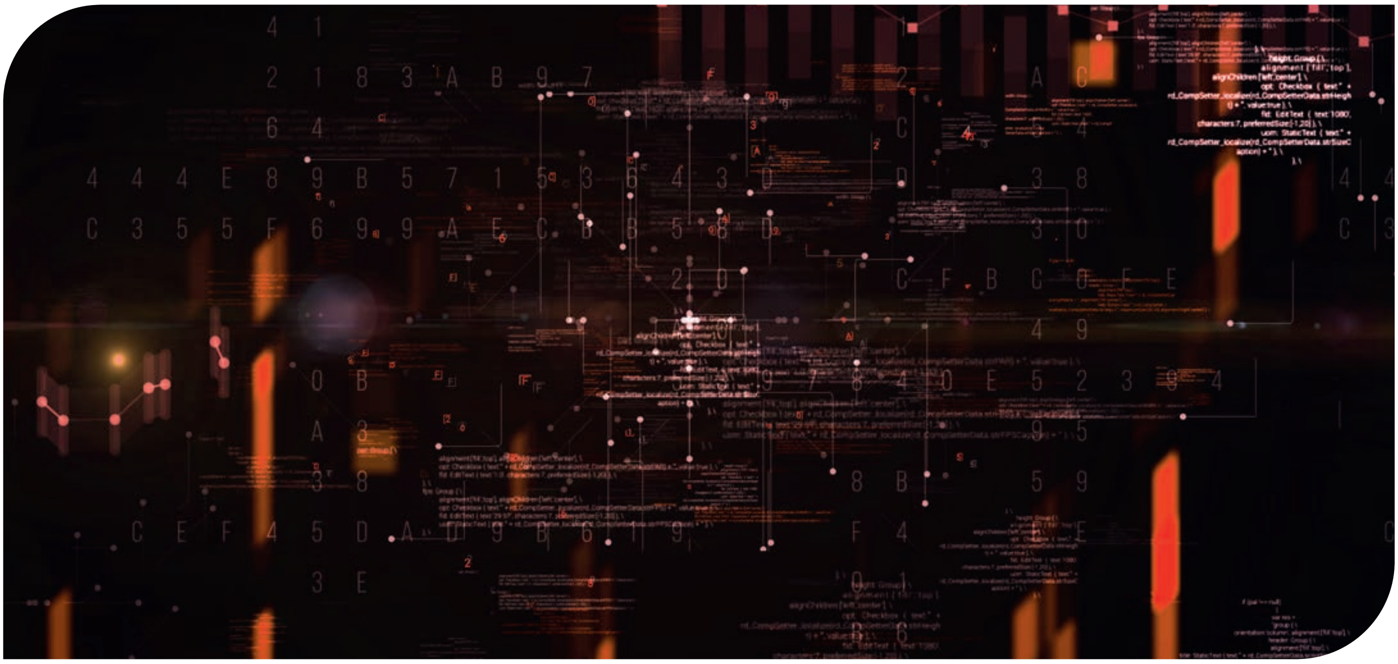
Section 1: About the Report[1]

This report is written by Cambridge Energy Policy Research Group (EPRG) as part of Project MERLIN The project aims to develop a transactive energy management system that optimises economic network investment, develops the business case for industry investors (i.e. owners of distributed energy resources – DER) and delivers efficiency benefits to ultimate electricity consumers.

This report is the third in a series of studies on local flexibility markets. The aim of this report is to identify and explore regulatory issues that may have an impact on the use of flexibility solutions (with a focus on those provided by distributed energy resources) by distribution utilities that operate in different jurisdictions.

In line with the previous reports in this series[2] the same jurisdictions have been selected (Australia, France, Germany, Great Britain, Japan, the Netherlands, Norway). A set of questionnaires have been designed to capture key insights for each of a number of key aspects from participants, including distribution utilities, energy regulators, energy marketplace and experts (18 in total). Learnings for Great Britain (GB) and Project MERLIN are identified.

The structure of the report is as follows. **Section 2** provides some background on different regulatory aspects that need to be taken into consideration in the adoption of flexibility by distribution utilities. **Section 3** explains the methodology. **Section 4** compiles and discusses the responses given by all the participants on each regulatory aspect in turn. **Section 5** analyses the responses from Great Britain and provides further insights based on the type of respondent. **Section 6** concludes.



1 The authors would like to acknowledge the generous help they have received from Ausgrid, Avacon, Centrica, ENA Australia, ENA UK, Enedis, Piclo, Nodes, SSEN, Tepco, UK Power Networks, WPD, energy experts and energy regulators from Australia (AER), Germany (BNetzA), Great Britain (Ofgem), the Netherlands (ACM) and Norway (NVE-RME). They each provided valuable inputs to the report. The authors also acknowledge the financial support of SSEN via BEIS funded Power Forward Challenge – Pilot Scale Demonstration scheme. Any errors are the responsibility of the authors.

2 See: https://project-merlin.co.uk/

Section 2: Background on local flexibility markets regulation and policies

Table 2: Distribution market in the seven jurisdictions

Country	national figures (distribution)			largest distribution utility			
	Number of DSOs	# customers (million)	network length (million km)	name (4)	# customers (million)	customers density (#cust./km)	market share (customers)
Australia (1)	15	10.45	0.75	Ausgrid	1.8	41.7	16.7%
France (2)	148	36.9	1.4	Enedis	36.0	26.5	97.6%
Germany (3)	883	51.4	1.8	Innogy (E.oN)	6.7	19.2	13.1%
Great Britain	14	29.8	0.85	UKPN	8.3	44.0	27.9%
Japan	10	70.4	0.99	Tepco	25.5	70.7	36.2%
Netherlands	7	8.3	0.26	Liander	3.2	35.2	38.6%
Norway (5)	120	3.1	0.33	Elvia	0.9		29.0%

(1) In Australia the total number of customers and network length exclude the ones from Western Australia region.

(2) In France the number of DSOs includes (1) DSO and (147) local distribution utilities - ELD); (3) In Germany, E.oN took over Innogy Group in September 2019.

(4) Ausgrid, Enedis, UKPN and Tepco are involved in this study.

(5) In Norway, Elvia was created as a result of merging Eidsiva Nett AS and Hafslund Nett AS in Jan. 2020.

Source: AER (2020), BNetzA (2019), CEER (2020), CRE (2018), EDF (2020), ENEDIS (2019), JEPIC (2019), Innogy (2020), Alliander (2019), METI (2018), NVE (2019), TEPCO (2019), UKPN (2019), utilities' websites.

There are different ways that countries promote flexible electricity resources ('flexibility') such as via markets, tariffs and connections arrangements (access rights). Indeed, energy regulatory agencies in the European single market are required to provide incentives to distribution system operators to procure flexibility services and standardised market products at the national level.

The EU Clean Energy Package (CEP) specifies directions of travel regarding the need for the use of more market-based approaches for procuring flexibility services, smart meters, data management, more active networks, etc. It also states that the distribution system operator (DSO) should be remunerated for the procurement of flexibility services to allow to recover reasonable costs IT costs and infrastructure.

In the rest of this section we identify a number of ways in which regulators could promote the procurement of flexibility and investigate the extent to which the jurisdictions that we look at have already, are in the process of or should in the future use each of these ways to promote flexibility. Many of these topics were initially identified in the evaluation of the Use Cases (A Review of international experience in the use of smart platforms for the procurement of flexibility services)[3] and complemented by an additional literature review (EC, 2019). The ways this could be done are discussed in the following paragraphs (we underline each of the key points which we ask about in our questionnaire). The characteristics of the jurisdictions we look at is noted in Table 2.

3 See: https://project-merlin.co.uk/

The way in which network operators are regulated may influence distribution utilities preferences between the use of traditional solutions (i.e. reinforcement), flexible solutions or a combination of the two. In all the jurisdictions that are part of this study, with the exception of Japan, incentive regulation is the mechanism used to regulate distribution networks (via a revenue or price cap), with different levels of sophistication across jurisdictions. The totex approach (which provides the freedom to select either opex or capex to meet network demands) looks superior to non-totex approaches which may bias network expenditure towards capex or opex based solutions. One of the things we want to know is whether the current regulatory mechanism (including ongoing or future proposals), is able to incorporate the value of flexibility in the regulatory revenue or price formula.

The use of flexibility services by distribution utilities may also be encouraged by a more cost reflective tariff structure, such as tariffs for the use of the networks and connection charges. The use of standardised definitions of flexibility products or services may also help to promote flexibility services. This facilitates the development of deeper markets with more participants.

Regulators can also play an important role in specifying the market design for flexibility markets. The role of the distribution utility as neutral market facilitator is a possibility that is envisaged in the future. In fact, jurisdictions are already experimenting with this approach to evaluate the viability and any potential regulatory intervention. Facilitating flexibility trading between third parties where the distribution utility may act as an intermediary is an example of the use of a neutral facilitator. The role of DSOs in facilitating peer-to-peer (P2P) flexibility trading is also something we explore.

Smart meters are key enablers of unlocking flexibility resources within the distribution system. Regulators may need to change the rules framework for smart meters in order to fully exploit the potential of flexibility arising from the existence and use of smart meters. Another related issue for regulators is rules on participation of aggregators in flexibility markets. This has the advantage of unlocking small DER, but the disadvantage of breaking the link between physical ownership and operation and market participation and allowing 'virtual' market participation.

Managing and procuring flexibility to solve network constraints, congestion, etc., requires more active networks and more coordination between network operators (i.e. distribution utilities and transmission system operators/system operators[4]). Better coordination is required among parties for a more cost-efficient, sustainable and reliable system operation (E.DSO, 2019), which leads to lower costs for users of the electricity grid. This coordination can be encouraged via regulation (CEER, 2018). An important part of this coordination can be allowing DSOs to procure flexibility on behalf of transmission system operators (TSOs). We want to know the way in which jurisdictions are progressing in this field and the instruments (if any) they are using to enhance coordination between DSOs and TSOs.

Feed-in Tariffs (FiTs) for smaller generators are a potential source of inflexibility within the distribution system because generators are paid a fixed price regardless of market or system conditions. Changes to FiT regulation can facilitate greater participation of DER in flexibility markets.

4 In some of the jurisdictions that are part of this study, system operation is separated from transmission operation. Another type of potential coordination is among TSOs from the same country. An example of ongoing coordination among TSOs is seen in Germany (BNetzA, 2019).

Access and management of customer data (including DER customers) is critical to capture and maximise the value of flexibility across all parties (e.g. network operators, customers, supplies/aggregators). The integration of DER creates opportunities but also challenges. Technological advances can help to have more automated systems to control and monitor data, but regulatory intervention may still be needed to standards of best practice. Data needs to be interoperable, accurate, accessible, and regulation can help with this.

Finally, the creation of a standard social cost benefit methodology for the evaluation of flexibility services can promote the appropriate procurement of flexibility. Indeed, one might expect the absence of a regulator approved methodology is likely to lead to unsustainable inconsistencies in flexibility procurement between distribution utilities in a single jurisdiction.

In addition to asking about the ways highlighted above in which regulators might promote flexibility, we let our respondents offer their own additional suggestions for ways in which their regulators might promote the procurement of flexibility.

Section 3: Methodology

In order to capture key insights about the way in which regulatory frameworks (associated with each of the topics highlighted in the previous section) can facilitate and encourage the use of flexibility by network operators, two similar questionnaires were designed. One looks at the general view (Questionnaire 1) and the other one focusses on specific projects or initiatives (Questionnaire 2), see Appendix 2. The first one was mainly sent to national energy regulators, energy associations and experts. The second one was sent to the parties involved in the Use Cases evaluated in the previous report[5] (e.g. distribution utilities, marketplace platforms).

The questionnaires aim to capture for each regulatory topic what has been already changed (past), and what is currently under consideration (present) and what should be changed (in future)[6]. In addition, considering that not all the changes have the same importance or priority, we provide the opportunity to mark the top 3[7]. We think that the diversity of parties and the mix of experiences provide a more comprehensive indication about the role of regulation associated with the deployment of flexibility markets in each jurisdiction from different business perspectives.

We have received a total of 18 questionnaires (out of 23 sent). We have at least one key organisation per each jurisdiction (i.e. the national regulatory authority or the largest distribution utility) with a maximum of 7 representatives per jurisdiction. Appendix 3 shows the list of participants per jurisdiction and type.

The questionnaire is not a representative survey given the small number of highly specialised individuals who know about these topics. What we are trying to get at with the questionnaire is a general impression of the issues in particular jurisdictions informed by participants. We summarise our overall impression, which is then reported in tables in Section 4 at the start of each subsection.

We go on to discuss specific differences between respondents in the text that follows. We use a country-level summary table per each topic to give an overview of the respective responses. If at least one of the participants confirmed any existing change, or changes being considered or changes that should be considered we mark the country response as a "Yes". Unsurprisingly, there is a lot nuance between individual participants in the survey who work for different organisations. However, there is also a lot of agreement, given that at the national level many of the individuals know each other and interact in the same industry fora[8].

5 See M1 report at https://project-merlin.co.uk/.

6 In some cases, "changes currently in consideration" or those that "should be changed" may also refer to those that have already reported as changed. This means the need to account with an improved version of the change already made.

7 The top 3 changes were marked by all the respondents except from one who indicates that at this stage it is not possible to rank any of the proposed changes.

8 We observe that in most cases there was agreement on the responses provided by the respondents from the same jurisdictions, with a few exceptions. More details about these exceptions are provided in the discussion of each topic in the next section.

Section 4: Past, current and future regulatory developments that promote local flexibility markets

This section summarises the responses provided by the 18 participants from the 7 jurisdictions involved in this study and discusses our main findings. Table 3 summarises the responses per type of participant[9].

Table 3: Summary of participants per country

Summary of responses	AU	FR	DE	GB	JP	NL	NO	Total
Regulators	1		1	1		1	1	5
Distribution utilities	1	1	1	3	1			7
Energy Associations	1			1				2
Platforms/ marketplaces				2			1	3
Experts					1			1
number of responses	3	1	2	7	2	1	2	18

4.1 Changes to utilities' revenue incentives

Respondents from three jurisdictions acknowledge changes to the utilities revenue incentives that may favor the use of flexibility. Respondents from 5 jurisdictions (a total of 10 out of 18 responses) have indicated current or future changes to the utilities 'revenue incentives that facilitate the use of flexibility. Change to utilities revenue incentives ranks first in the identification of top 3 by the respondents (8 out of 18) in four jurisdictions, Table 4 summarises the responses.

Table 4: Changes to utilities' revenue incentives – response summary

utilities' revenue incentives	AU	FR	DE	GB	JP	NL	NO
already changed?	yes			yes	yes		
change being considered or should be considered?	yes	yes	yes	yes		yes	
top 3	yes		yes	yes	yes		

Summary of responses and additional notes

In Japan, one of the respondents mentions a recent change in the price control methodology, moving from rate of return (cost-of-service regulation) to incentive regulation (revenue cap), to be implemented in 2023.

In the Netherlands, the respondent remarks that there are no specific incentives to promote the procurement of flexibility but the regulatory scheme adopted (yardstick competition based on totex) gives the opportunity to distribution utilities to select the most efficient mix of expenses: opex (i.e. procuring flexibility) and capex (i.e. reinforcement). However, the respondent also notes some concerns from distribution utilities:

9 Considering that jurisdictions that are part of this study use different names for the distribution companies (e.g. DNOs in GB, DSOs in Europe, DNSP in Australia) here we refer to most of them as "distribution utilities".

“DSOs have some concerns that an expected large increase in costs due to flexibility procurement / congestion management will be insufficiently remunerated in the current method of regulation as the current method is based on estimating future allowed revenues and tariffs based on cost and output from the past”.

The respondent suggests that the distribution utilities may get limited additional revenues[10] that are relatively small in comparison to the incurred operational costs. On top of this, it may be the case that those distribution utilities that spend more on capex (i.e. timely investment in network reinforcement) perform better in comparison to the benchmark and those that procure flexibility to manage congestion with relatively high opex performing worse. This is something that is currently under evaluation by the regulator.

In Germany, one of the respondents points out an ongoing discussion on efficiency incentives for congestion management. For instance, based on the current regulatory framework, distribution utilities are allowed to compensate controllable loads or feed-in generation in the case of network constraints (i.e. by controlling their loads or via curtailment respectively), further details are provided in section 4.2. Compensation costs (i.e. feed-in generation) are classified as permanently “non controllable cost” and therefore are not included in efficiency benchmarking. On the other hand, market-related measures are allocable as operating costs and included in the efficiency benchmarking.

Another respondent from Germany suggests that the obligation that distribution utilities have in connecting 100% of generators that produce electricity from renewable sources (Renewable Act – EEG), makes it impossible to foresee the need for connection capacity building on the use of flexibility.

In Australia, one respondent points to schemes to support distribution utilities to find non-network options with a focus on demand management, up to around $1billion (AUD) over five years: the demand management innovation scheme[11] and innovation allowance[12].

In GB, many of the respondents agree that a change has already been made with the introduction of a totex regulatory model in RIIO[13] ED1 price control in 2015. One respondent remarks:

“Changing the revenue incentive of DNOs is key to drive flexibility procurement. Moving to a totex model ensures that DNOs have the incentive to procure flexibility when it is cost efficient to do so. As a result, this aligns the incentives of DNOs to develop competitive flexibility market, which will unlock the most value within their totex regulatory regime”.

10 The size of the revenue is equal to the incremental capacity made available through congestion management times the regulated tariff.

11 https://www.aer.gov.au/system/files/AER%20-%20Demand%20management%20incentive%20scheme%20-%2014%20December%202017.pdf

12 https://www.aer.gov.au/system/files/D17-173575%20AER%20-%20Fact%20Sheet%20-%20Final%20demand%20management%20incentive%20scheme%20and%20innovation%20allowance%20mechanism%20-%2013%20December%202017.pdf

13 RIIO (Revenue = Incentives + Innovation + Outputs) framework is applied in electricity and gas networks.

They also point out that the totex regulatory model is critical and is evolving with some key changes for the next five- year regulatory period (RIIO ED2) starting in April 2023[14]. Some of the key changes are (1) the introduction of a Net Zero re-opener[15], (2) a set of obligations, incentives and deliverables, (3) strategic investment models[16], (4) innovation fund (SIF)[17] that will replace the RIIO-1 NIC, (5) enabling whole system solutions and the introduction of a CAM (Coordinated Adjustment Mechanism) re-opener, among others (Ofgem, 2020b).

Another respondent comments that procuring flexibility can save totex (i.e. reinforcement avoidance or deferral expenditure) but also means lower regulatory asset value (RAV) and that more incentives to manage uncertainty (i.e. load growth) via flexibility are needed. They suggest that these should be part of totex. Another one suggests linking flexibility with outputs and with the benefits that this can bring to the whole system. A third remarks that no-additional change is required to the current scheme for the procurement of flexibility services: there are sufficient incentives for distribution utilities. One of the marketplace respondents indicates the need to incorporate flexibility within the distribution utilities' business model and incentives to use it rather than current BAU approaches (i.e. traditional reinforcement).

Discussion

Many of the jurisdictions use revenue cap regulation based on totex, which gives more freedom to the distribution utility to select the best combination of costs (operational and capital). What we observe is that even though these models are considered superior, distribution utilities are not necessarily encouraged to use flexibility as an alternative option (even if it can be the most cost-efficient solution). The way these costs are recovered plays an important role in this. Costs can be incurred for procuring flexibility (via market based) or via regulation (this is the case of Germany with the feed-in generation scheme). If these costs are categorised as non-controllable costs, then they cannot be part of a benchmark and hence there is no incentive to reduce them via competitive procurement. An opposite case is observed in the Netherlands, where flexibility costs can be high (i.e. high congestion costs) and the distribution utility is exposed to penalties due to the benchmark. Regulation should promote the use of flexibility when it is the most cost-efficient option. The number of participants that acknowledge ongoing changes or future changes shows that some improvements to the current models are still required. Flexibility is perceived as something positive: it is currently under test via different trials many of them funded by specific innovation schemes, but for a BAU approach regulation needs to be clarified.

14 One of lessons learned from the current price control is that overall costs to consumers have been too high, among the drivers of this is underspend against allowances and rewards from quality incentives (i.e. Interruptions Incentive Scheme – IIS), Ofgem (2020b, p. 11).

15 In response of the new Net Zero GHG emissions targets set in the UK by 2050. Net Zero opener allows the price control to be adaptable (with timing funding within the price control period) in order to meet decarbonisation targets at lower costs.

16 Four models are proposed, the adoption of any of them would depend on the level of certainty (in both outputs and investment required) with consideration of centralised and decentralised schemes for forecasting outputs.

17 To fund individual innovation projects up to £5m, with a total fund of around £450m. These projects are approved to be funded via use of system charges.

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4.2 Changes to network tariff structure

Changes to network tariff structure have been reported in two jurisdictions only. Even though, in most jurisdictions (6 out of 7) changes to network tariff structure are being considered or should be considered according to the respondents (15 out of 18). Network tariff structure is among the 3 top regulatory changes according to respondents (7 out of 18), and the one with the highest level of consensus across the seven jurisdictions (5 out of 7). Table 5 summarises the responses.

Table 5: Changes to network tariff structure – response summary

network tariff structure	AU	FR	DE	GB	JP	NL	NO
already changed?	yes	yes					
change being considered or should be considered?	yes	yes	yes	yes		yes	yes
top 3	yes	yes		yes		yes	yes

Summary of responses and additional notes

In Norway, a proposal to modify the current network tariff structure to LV customers (e.g. households, vacation homes, smaller commercial business) has been made[18]. A new capacity-based tariff design[19] (currently mainly volumetric without incentives to reduce capacity) to LV customers[20] has been proposed. At present only a few distribution utilities have already implemented capacity tariffs. Three models of potential tariff design are recommended, in all of them the energy charge is equivalent to the marginal cost of network losses (only if capacity is not constrained).

Distribution utilities may adopt one of them or a combination of them. If the distribution utilities face capacity constraints, the energy charge may reflect this in the form of a price signal (e.g. via time-of-use differentiation). However, the proposal does not specify whether this price should be included, or how it can be regulated. According to the proposal, for a short-term capacity constraint flexibility can be an option (i.e. via a market-based approach), where the price is defined by the market instead. Nevertheless, it is suggested that the introduction of this price signal may add more complexity to the tariff design. Another respondent has suggested the need to have tariffs structures aligned with the development of flexibility markets. In the case of a constraint, flexibility assets that operate at a specific time of the day can be penalised, then market signals should be used instead.

18 See NVE - RME(2020a) for further details.

19 Network tariffs can be composed of energy, fixed, capacity charges and sometimes reactive charges. What is proposed is a change to the design of the charge share of the tariff. For a fuller discussion of the role of network tariffs in promoting flexibility see Pollitt (2018).

20 Large consumers or those connected to high voltage already pay network tariffs that reflect the capacity requirements (based on monthly peak demand). The new changes suggest the use of daily peak demand instead.

In the Netherlands, according to one respondent limitations of the current tariff design have been explored in terms of (1) the use of a uniform capacity-based tariff for residential consumers[21], (2) the lack of level a playing field in the flexibility market between both consumption and injection, (3) penalties applied to larger consumers when consumption is increased, (4) non-existent locational signals in distribution tariffs. Another barrier that has been acknowledged is the consideration of a maximum producer tariff set at €0.50 MWh (generators). According to the respondent, the introduction of tariffs for producers would make the current network tariff more robust.

The introduction of more flexible tariffs (i.e. dynamic pricing) in the Netherlands has been assessed in a recent study (ACM, 2019). The results suggest that the time is not yet right to implement dynamic pricing. Among the reasons are the conflict with the current tariff scheme (based on static rates for each tariff category that are the same through the year regardless of location), the higher administrative burden and the need for more complex regulation. If dynamic pricing did exist, the purchase of flexibility (services) via a competitive mechanism would be preferred instead.

In Germany, one of the respondents points out that changes regarding the connection and control of electric vehicles and heat pumps are being considered. In line with the current regulatory framework (Section 14a Energy Industry Act – EnWG), suppliers and end consumers are entitled to a discount in network tariff by distribution utilities in exchange for transferring the control of the customer's devices connected at LV to adjust their consumption (i.e. controllable loads) in case of network constraints. However, the size of the discount is not regulated and varies considerably across distribution utilities (c. 883 DSOs) with an average reduction of 55% equivalent to 3.44 ct/kWh (with the lowest and highest discount of 6% and 91% respectively) (BNetzA, 2019). Distribution utilities are required to meet this obligation, even though there may be no benefit to them. Defined network segments above a specific capacity could help (BnetzA, 2017). Then, what is still missing is the framework for the reduction of network charges and contractual arrangements (i.e. control actions reserved by distribution utilities and those by suppliers)[22].

In Australia, one of respondents notes recent network access and tariff reforms proposed/actioned by a distribution utility (South Australian Power Distribution) and already approved by the regulator. The aim of this reform is to manage minimum demand in the midday due to excess of solar generation. A new tariff scheme based on time in use will be applied from 01 July 2021. The scheme proposes a "solar sponge" structure with the lowest off-peak rates at midday (SAPN, 2020). A modification of the export limit scheme (currently static and set at 5 kW) is also acknowledged. Households with rooftop capacity will have the opportunity in 2021 (targeted) to choose between static or dynamic export limits (to be set based on real-time network conditions). The dynamic scheme offers a higher export limit to customers, but export restrictions (i.e. curtailment) will be applied by the distribution utility (occasionally rather than constant) in order to remain within network capacity limits (especially when grid voltage rises).

Other respondents in Australia agree that adequate network tariff structure contributes to a more equitable approach. This can be in the form of more locational pricing, local settlement rules and allowing pricing on exports. A recent policy consultation (AEMC, 2020b), proposes three rule change requests that aim to facilitate the efficient integration of DER for the grid of the future[23]. These changes require the provision of the right incentives to distribution utilities to provide export

21 The Netherlands introduced a capacity base tariff in 2009. Some of the reasons behind this decision were fairness (a more cost reflective approach) and lower administrative costs due to simplification in the billing process (with savings estimated at €30m a year), Van Langen (2019).

22 According to the respondent 14a EEG is currently under revision. Different options for controlling flexible loads are being evaluated including the establishment of a few hours a day for controlling the loads in case of constraints and differentiation in network access (i.e. conditional and unconditional access with thresholds).

23 The proposal changes are in response to the consultation process as part of ARENA's Distributed Energy Integration Program – DEIP, see ARENA (2020).

services[24] to DER and the establishment of the correct export charges. An amendment of the National Electricity Rules (NER) which mandates the economic regulation of distribution utilities in the National Electricity Market (NEM) may be required. Currently NEM regulation (clause 6.4) does not allow distribution utilities to charge use of system charges for export services. Considering that the service classification sets the type of economic regulation (i.e. distribution services currently linked to consumption), it is important to clarify and to re-define the definition/ scope of distribution services.

In France, it was acknowledged by the respondent that flexibility and network tariffs are two different and complementary ways to increase investment options, help grid optimisation and to prevent constraints. It is an ongoing discussion with the energy regulator to include the cost of procuring flexibility in the distribution tariff for the next regulatory period (Turpe 6). A closer look at recent regulator (CRE) consultations[25] shows the consideration of dynamic pricing in order to make recommendations related to the implementation of dynamic pricing as suggested in European Directive 2019/944[26].

In Great Britain, one of the respondents points out an ongoing reform of network access and charges (Electricity Network Access and Forward-Looking Charging Significant Code Review – SCR)[27] launched in December 2018. The evaluation covers four policy areas (access rights for transmission and distribution, distribution charges (DUoS), distribution connection charging boundary[28] and transmission charges (TNUoS)).

Shortlisted options have been recently identified (Ofgem, 2020a) in terms of:

- access rights (e.g. improved options for non-firm connections, tradable access within same local area),
- distribution connection charging boundary (e.g. move to a shallow(er)[29] approach, alternative payments),
- distribution charges (e.g. use of forecast of incremental reinforcement needed at extra HV, consideration of an ultra-long run cost model, the introduction of more granular zones for charging and time bands for time of use charges),
- transmission charges (e.g. change to reference node, consideration of time of use bands and/or agreed capacity rights).

A closer look at the relevant documentation suggests that access right reforms (definition and choices) are focused on larger users[30], dynamic charges for both transmission and distribution are not an option now, and that non- available/inaccurate network data is behind the exclusion of some initial potential reforms.

Another respondent from GB expresses concerns about whether more granularity and dynamic network tariffs will be beneficial, suggesting that the benefits are low at lower voltages. A different respondent raises some issues with the current charging boundary and the use of flexibility to solve network constraints. According to this respondent:

24 Traditionally a distribution utility's core services are to transport energy from the grid to customers (consumption services), however the opposite is also possible (export services).

25 https://consultations.cre.fr/2020-010/new

26 Suppliers with more than 200,000 final customers are required to offer consumers (with a smart meter) dynamic electricity price contracts. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019L0944&from=EN

27 See: https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

28 Depending on the regulatory framework, customers that want to connect their assets to the distribution network (i.e. generators) are subject to different categories of connection boundaries and costs. In a shallow connection boundary, the customer only pays for the connection asset, while in a deep connection boundary, the customer pays on the top of this for any reinforcement required in the distribution network to connect the respective asset. An intermediate approach is the shallow-ish connection boundary, where the customer pays for the connection asset and contributes only partially to the costs of any reinforcement up to the first transformer. In Great Britain the last approach applies. For further details see: https://www.ofgem.gov.uk/system/files/docs/2019/12/winter_2019_-_working_paper_-_connection_boundary_note_publish_0.pdf

29 A shallower approach means "a reduction of the contribution to reinforcement costs that distribution users pay for connection charges" (Ofgem 2020a, p. 3).

30 The option of defining access rights for small users is not shortlisted. Smart Users refer to "households and non-domestic users that do not have an agreement for their maximum capacity usage" Ofgem (2020a, p. 6).

"DSO flexibility services only currently used against load related reinforcement for demand due to current charging boundary. Export constraints and charges that fall to connecting users are not able to be solved via flexibility due to the complexity of recharging new users for those costs/liabilities. If connection boundary was shallower, like transmission, these costs would fall to DSO and flexibility would be used".

Discussion

Comprehensive reform of both transmission and network charges to be more dynamic in time and space is something that is on the agenda of several jurisdictions, but all the jurisdictions that we have looked at are proceeding cautiously on this. Full dynamic nodal pricing, at every conceivable node where DER flexibility might make a difference is some way off. The implementation of dynamic network tariffs at lower voltages seems very costly relative to the benefits at the moment. In addition, it adds more complexity to tariff structures. However, there have been some interesting developments to better reflect costs particularly for solar export, which is becoming significant in some jurisdictions (i.e. Australia). There seems little doubt that creative (i.e. targeted) use of price signals delivered via network charges can encourage DER flexibility.

4.3 Changes to definition of products/service and standardisation

Only in a few jurisdictions is it acknowledged that a change in the definition of products/services and standardisation facilitates the procurement of flexibility. However, respondents from four jurisdictions report current changes in consideration or agree that these changes should be considered (8 out of 18). This has been placed as one of the top 3 by two respondents only, see Table 6 for details.

Table 6: Changes to definition of products/services and standardisation – response summary

definition of products/ services & standardisation	AU	FR	DE	GB	JP	NL	NO
already changed?	yes			yes			
change being considered or should be considered?	yes		yes	yes		yes	
top 3				yes		yes	

Summary of responses and additional notes

In GB, different respondents confirm the existence of a standard set of flexibility products for distribution utilities[31]. In light of this, another respondent points out that changes to licences are being made in coordination with the system operator and other stakeholders. A third respondent notes the need for a "technology agnostic" product and for product standardisation when considering an increase in the number of interfaces and platforms. Standardised products are also recommended as part of market development function by the GB regulator (Ofgem, 2020b, p. 59).

In the Netherlands, the respondent suggests the introduction of two products as a result of the adaptation of network codes to improve rules on congestion management by distribution utilities: (1) a capacity constraint product and (2) a redispatch product[32].

31 See: https://www.energynetworks.org/assets/files/ON-WS1A-Product%20Definitions%20Updated-PUBLISHED.pdf

32 According to the respondent: "(1) capacity constraint product to be used before closing of the day-ahead market; (i.e. a grid user commits to limiting production/consumption prior to market closing, modifies its final market position accordingly, so that no counter activation is needed), (2) A redispatch product, to be used after closing of the day-ahead market (including proportional counteractivation outside of the congested area)".

In Norway, one of the respondents points to ongoing trials that aim to evaluate new products, bid size, etc. (e.g. pilot for 1MW balancing bids[33], pilot for fast frequency reserves[34]). Another respondent from Norway brings a different approach and suggests:

> "...when operating a flexibility market, parameters should be offered rather than specified products (standard products are seen at NODES as constants). This is on the basis that the DSO has a better understanding of the specific issues within their distribution network. As a result, they should be able to procure flexibility, based on the type of asset, time, location and price. The standardisation of product definition could create barriers to the type of assets offered into the market and limit the services the DSO is seeking".

Discussion

It would seem that a lot of attention has been given to product standardisation already across our jurisdictions. However there is some concern that instead of specifying the product, the underlying characteristics should be specified as it is these that consumers value and that this would allow the trading of products of different qualities provided by very different DER. This is in line with the recommendation of Greve et al. (2018) on the rationalization of frequency response markets, where the time to respond should be valued explicitly in the evaluation of bids process rather than narrowly be part of the product definition.

4.4 Specification of market design rules for local flexibility markets

Except for one jurisdiction (the Netherlands), the market design for local flexibility markets has not been settled. However, many of the respondents agree that changes are being considered or should be considered (in 5 out of 7 jurisdictions). Like the previous two changes, market design rules for local flexibility markets are among the top 3 changes selected by the respondents, see Table 7.

Table 7: Specification of market design rules for local flexibility markets – response summary

market design for local flexibility markets	AU	FR	DE	GB	JP	NL	NO
already changed?						yes	
change being considered or should be considered?	yes		yes	yes	yes	yes	
top 3	yes		yes	yes	yes		

Summary of responses and additional notes

In the Netherlands, one of the respondents mentions key developments that relate to flexibility markets such as the development of a platform for local congestion management (Grid Operators Platform for Congestion Solutions – Gopacs[35], one of the Use Cases discussed in M1 Report[36]). This makes use of ETPA (a market energy platform) for clearing the market.

33 https://www.statnett.no/en/about-statnett/news-and-press-releases/news-archive-2020/electric-vehicles-and-buildings-help-keep-the-power-grid-in-balance/

34 https://www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/kraftmarkedet/reservemarkeder/ffr/ffrdemo2020/

35 https://gopacs.eu/nl/over-gopacs/

36 https://project-merlin.co.uk/

In Japan, one respondent suggests that there is no official plan to create local flexibility markets, but a review of the international experience is being undertaken in the experts meeting on the Platform for Distributed Energy Systems[37]. They also mentioned the funding support from government (Ministry of Economy, Trade and Industry-METI) for demonstrators (e.g. VPP, P2P).[38] Another suggests that some progress is noticeable and points to the creation of the Expert Committee for flexibility markets also known as "Supply-Demand Adjustment Market", with the aim of discussing a potential market design (e.g. flexibility menus, bidding methods).

In Norway, one respondent acknowledges the establishment of a framework for pilot and demonstration projects[39], with two main purposes: "to provide better information about regulations and make the application process if necessary for dispensation later".[40] Five dispensations have been identified to date. The need for trials before implementing permanent regulatory changes has been acknowledged. A different respondent states that the development of flexibility markets is in its infancy and there is a need for additional exploration to see how flexibility markets can and should develop. According to this respondent:

> "Specification around market design at this stage will stifle innovation and limit the potential behind what is being developed. Instead there should be close dialogue between the market operators, regulators and industry as we identify lessons learned at least for the near future".

In Germany, one respondent agrees that if the distribution utility maintains strict unbundling, the creation of dedicated markets for regional flexibility at the DSO level is needed. According to CEER (2020), effective unbundling is required in order to avoid any preferential treatment towards associated business units. For instance, this is especially critical in jurisdictions with a large number of distribution utilities with less than 100,000 customers, like in Germany.

In France, the respondent suggests the need for experiments to define an appropriate market design. There is a current call for tenders (trials) to procure local flexibility resources[41].

In Australia, one of the respondents suggests that currently distribution utilities contract flexibility through other instruments rather than flexibility markets (e.g. access, tariffs, contracts, standards). At the same time they acknowledge the need for future reforms. According to another respondent, the Post-2025 Market Design for the National Electricity Market (NEM) – a long term fit for purpose market framework – will significantly change the way in which distribution and transmission networks business will operate. In fact, this may have an important effect on the way in which local flexibility markets will operate in Australia. For instance, as part of this initiative the Energy Security Board (ESB) is working on a two-sided market project (ESB, 2020). In a two-sided market all participants (sellers and buyers) respond to price based on their true cost preference (i.e. currently in the wholesale market demand is taken as "given" and based on forecasts). A two-sided market would facilitate the role of the distribution utility (DNSP) as a DSO. It does this by undertaking network optimisation considering DER operation and identifying constraints and the need for services to alleviate them.

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37 https://www.meti.go.jp/english/press/2019/1021_004.html

38 The VPP Battery project, funded by METI is one of the Use Cases evaluated in M1 report.

39 See NorFlex project: https://www.ae.no/en/aktuelt/news/successful-test-of-flexibility-trading/

40 https://www.nve.no/reguleringsmyndigheten/pilot-og-demonstrasjonsprosjekter/

41 https://www.enedis.fr/construct-jointly-local-flexibility-process

Another respondent from Australia mentions the Open Energy Networks Project (OpEN) which aims to look for market scenarios to integrate DER into local distribution networks. Four scenarios have been evaluated. Results from the cost benefit analysis suggests that large up-front costs would be required for their implementation, with net benefits to be captured shortly before 2039. The size of benefits depends strongly on a high level of DER uptake. It was recently concluded that there is no strong case to adopt any of the models in the short term (EN Australia, 2020). The establishment of a local flexibility market is envisaged in the long term (i.e. the Wholesale Demand Respond Mechanism)[42].

In Great Britain, some respondents refer to the UK ENA Open Networks project where the design of flexibility markets is being evaluated under Workstream 1A (Flexibility Services). Seven products have been identified as part of this workstream and a recent consultation has been launched: Flexibility Consultation. Another respondent indicates that today there are enough market rules (with a particular reference to the procurement of flexibility BAU via a marketplace). Still another suggests that local market designs need to be rolled out via regulation in order to guarantee fair and transparent markets and better integration with existing markets. Yet another makes remarks on the importance of establishing the roles and responsibilities of market players, but suggests that doing this too early may represent a barrier. According to this respondent:

"Specifying market design can be a barrier if done at too early a stage or in too prescriptive a manner. However, as the market matures the regulator must adapt its role to safeguard consumers, ensure that transparency and liquidity in the flexibility market continues to improve and there are safeguards against anticompetitive behaviour. Consequently, market design is important for new energy market entrants (such as independent market platforms) and existing players, such as the transition from DNO-DSO".

Discussion

The market design around flexibility markets remains a work in progress across the jurisdictions we look at. There remains a lot of experimentation and disagreement among market players. Interestingly the idea of market scenarios for the integration of DER into local distribution has been analysed in detail in the Australian context and rejected for now, this shows the dependency of sustainable flexibility markets on DER deployment. However, the non-emergence of a 'standard market design' does not preclude the role of the regulator in approving market designs.

42 Under this new scheme customers will have the opportunity to participate in the wholesale demand response market directly or via aggregators with a planned implementation date in October 2021. The mechanism proposes a new market participant category: demand response service provider (DRSP). Small customers have been excluded from the mechanisms, one of the main reasons is the cost of the extension of the mechanism to this kind of customer (i.e. imposition of higher costs to the whole system), (AEMC, 2020a).

4.5 Specification of rules for peer-to-peer trading of flexibility

Changes in rules about P2P trading to facilitate the procurement of flexibility is only supported in GB by 4 out of 7 respondents (mainly distribution utilities and energy marketplaces) and it is not placed in top 3 changes, see Table 8.

Table 8: Specification of rules for peer-to-peer trading of flexibility – response summary

Peer-to-peer trading of flexibility	AU	FR	DE	GB	JP	NL	NO
already changed?							
Change being considered or should be considered?				yes			
top 3							

Summary of responses and additional notes

Only some of the respondents from GB agree that peer-to-peer (P2P rules) may play an important role in contracting flexibility by third parties where distribution utilities act as facilitators. In GB, the offering of non-DSO services (i.e. P2P) is being evaluated via the Open Networks Project (Product 6). The assessment of different trials[43] will help to establish the best way distribution utilities can support non-DSO services.

Discussion

P2P rules that involve distribution utilities obligations that can facilitate flexibility trading to third parties, are not on the agenda in most of the jurisdictions. P2P is however already working in other sectors and its application to electricity remains of interest to many players. Distribution utilities can facilitate or act as intermediaries to secondary trading of flexibility (i.e. ancillary services) and also curtailment. Results from the different initiatives in GB that are testing non-DSO services will help to discover whether there is a relevant business model for these new services.

4.6 Changes to smart meter rules framework

Changes to smart meter regulation that may favour the use of flexibility has been reported in a few jurisdictions (3 out of 7). Respondents from four jurisdictions suggest that changes are being considered or should be considered (9 out of 18). Only one respondent from GB (distribution utility) places this change within their top 3, see Table 9 below.

Table 9: Changes to smart meter rules framework – response summary

smart meter rules framework	AU	FR	DE	GB	JP	NL	NO
already changed?	yes	yes					yes
change being considered or should be considered?	yes			yes	yes	yes	
top 3				yes			

43 Such as Transition (led by SSEN), LEO, TraDER, Piclo Exchange and ReFLEX projects, see: https://www.energynetworks.org/assets/files/ON20-WS1AP6%20Non%20DSO%20Services-PUBLISHED.pdf

Summary of responses and additional notes

In GB, a respondent states that access to smart meter data by distribution utilities is fundamental for low voltage (LV) visibility. Another draws attention to the role of smart meters in allowing automated control (e.g. for EVs) facilitating the affordability of EV flexibility. A different respondent points out the consideration of a code modification that allows distribution utilities to control smart meters to turn on/off EV charging in the case of a network emergency and also some modifications to half hourly settlement[44]. However, a different respondent suggests that smart meters are not necessarily looked at for settlement or dispatch and acknowledges other alternatives to provide asset level monitoring. Other respondents from GB and abroad (mainly distribution utilities) support the fact that a change to smart meter rules should not be considered.

In France, the respondent notes the current roll out of smart meters and remarks that their deployment will facilitate the integration of flexibility at distribution level. While in Japan the respondent expresses a view that the revision of the Measurement Law (Act) might be considered. In The Netherlands the respondent comments that an adaptation to the Meter Code is envisaged after the roll out of smart meters. This is because the allocation procedure (i.e. based on usage profiles) would need to be adapted to actual usage instead (registered by the smart meter). A respondent from Norway points out that the smart meter rules came out in 2011 and that since 2019 all end-consumers have them installed (2.9m).

Discussion

We found mixed opinions among the different parties about the need to consider changes to the smart meter framework. Some of them agree that such changes may facilitate to contract flexibility at lower voltages. There was a residual suggestion that in exceptional circumstances distribution utilities should be able to control EV charging.

4.7 Changes to rules for independent aggregators

Changes have been reported only in one jurisdiction[45], however respondents from four jurisdictions (9 out of 18) suggest that changes are currently in evaluation or should be considered. Only Japan places rules for independent aggregators as top 3. Table 10 summarises the responses.

Table 10: Changes to rules for independent aggregators

rules for independent aggregators	AU	FR	DE	GB	JP	NL	NO
already changed?			yes				
change being considered or should be considered?	yes		yes	yes	yes		
top 3					yes		

44 According to the regulator, benefits due to half hourly reform could be between £1.6bn and £4.6bn by 2045. https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-settlement-reform

45 France is the other one, however it has not been reported directly in the table.

Summary of responses and additional notes

In Australia, one respondent points out different initiatives (including consultations) that involve potential changes to the roles (or new roles) and market participation of aggregators. There are different initiatives such as the 2-sided market proposal (i.e. definition and roles of "traders", see ESB (2020)), wholesale demand response (i.e. new market participant: demand response aggregator (DRA[46])), wholesale market only (i.e. new market participant: small generation aggregator (SGA[47])).

A respondent from France, notes that in comparison with other EU member states France is already a step further in terms of independent aggregators which can freely participate in all its markets, including in demand side response with specific rules for this. It is expected that the demand side flexibility code[48] does not conflict with the existing rules.

In GB one respondent suggests that aggregators have made limited progress in flexibility markets. It is also acknowledged by a different respondent that distribution utilities should not act as commercial aggregators (mandated) and that the adaptation to industry codes to facilitate access to markets by independent aggregators is needed[49].

In Japan, one respondent states that there are no legal restrictions on aggregators, and the consideration of aggregator licences has been evaluated by the Expert Committee. Another response points out the release and recent revision of the Guidelines for Energy Resource Aggregation Business (ERAB)[50].

In the Netherlands, the respondent indicates that changes to the current framework for independent aggregators have already been evaluated and that the rules were found adequate and no changes were proposed. According to the respondent there are conflicts between aggregators and energy suppliers that aggregate individual connections across Balance Responsible Parties (BRPs):

> **"A barrier in practice is that energy suppliers perform bulk shifts of individual connections across different Balance Responsible Party (BRPs), which renders the coordination between aggregators (Curtailment Service Providers – CSPs) and BRPs more difficult."**

Discussion

Aggregators play an important role in the procurement of flexibility, especially from small-scale DER which may otherwise be prevented (depending on the size) from participating in different markets, such as wholesale, ancillary services markets, etc. Apart from France, who were the pioneers in allowing aggregators to participate in all markets, it is observed that rules about independent aggregators are evolving and some conflicts with other parties may exist. Australia and GB have introduced new market participants oriented to independent aggregators, with the aim to encourage their participation in different markets. There is some variation across jurisdictions in the extent to which changes are needed in order to facilitate the participation of independent aggregators in flexibility markets and also reduce the chance of conflicts with other players (i.e. with retailers).

46 https://www.aemc.gov.au/sites/default/files/documents/final_determination_-_for_publication.pdf

47 SGA only can aggregate small units connected to a distribution or transmission network. SGA is exempted from the requirement to register as a generator. https://www.aemo.com.au/-/media/files/electricity/nem/participant_information/registration/small-generation-aggregator/small-generator-aggregator-fact-sheet.pdf?la=en

48 The European Commission has identified demand side flexibility as one of the two key areas where new network codes could be required to achieve the European Green Deal goals. https://ec.europa.eu/info/news/public-consultation-establish-priority-list-network-codes-2020-feb-11_en

49 Wider Access changes to the Balancing and Settlement Code – BSC (Modification P344) have allowed the participation of independent aggregators in the Balancing Mechanism (BM). Independent aggregators are known as "Virtual Lead Parties" in the BSC. https://www.elexon.co.uk/documents/training-guidance/bsc-guidance-notes/virtual-lead-party-vlp-entering-the-market/

50 https://www.meti.go.jp/english/press/2020/0602_002.html

4.8 Encouragement of better interaction/ coordination between electricity distribution and transmission system operators

Respondents from three jurisdictions indicate that some changes to encourage better coordination between distribution utilities and system operators have been already made. Other respondents remark current consideration to changes or their agreement to consider them in future regulation. Respondents from Australia, Great Britain and Norway (7 out of 18) rank this change within the top 3, see Table 11.

Table 11: Encouragement of better interaction/coordination between DSOs and TSOs – response summary

interaction/ coordination between DSOs and TSOs	AU	FR	DE	GB	JP	NL	NO
already changed?	yes	yes		yes			
change being considered or should be considered?	yes			yes		yes	yes
top 3	yes			yes			yes

Summary of responses and additional notes

A respondent from Australia points out that this change was evaluated but no agreement was agreed between distribution utilities and the system operator. They pointed to **"unresolved and live tensions"** between the descentralised and centralised approaches and also the intention of the system operator to plan and operate distribution networks. A different respondent states that they are working with the transmission network business where flexibility is considered as part of their joint planning.

A different perspective is noted in the Netherlands. According to the respondent a joint proposal by all grid operators is currently under evaluation with respect to congestion management in lower voltage grids. The proposal aims to clarify products and processes for a more cost-efficient deployment of flexibility, and suggests the introduction of a new role: the **congestion service provider** (CSP), with the ability to aggregate small-scale flexibility.

In Germany, one of the respondents mentions an ongoing process for better coordination. In Japan, the need for coordination was not recognised because distribution operation and transmission operation are bundled (i.e. in the form of regional network companies). A separation of distribution and transmission is envisaged[51].

In Norway, one respondent points out an ongoing project that aims to assess the current operating practices and coordination between the transmission system operator, regional and local network operators and other key actors. An expert group has been appointed to undertake a study. Initial results for this study find that **"All network companies, must in dialogue with associated companies and customers, take responsibility for the operation of their own network"**[52]. The regulator has asked the industry for inputs to the expert group's recommendations. Another respondent suggests that due to the transition to more decentralised systems, the distribution utility is the most suitable party to address any issues (i.e. network constraint) in its network.

In France, the respondent suggests that coordination is needed because flexibility can be required at the same grid location and needs to be addressed at different voltage levels. It was also noted that better coordination optimises the participation of market players and facilitates stacking of revenue streams from both parties, improving market liquidity.

51 https://www.meti.go.jp/english/press/2020/0225_001.html

52 https://www.nve.no/reguleringsmyndigheten/nytt-fra-rme/nyheter-reguleringsmyndigheten-for-energi/driftskoordineringen-i-kraftsystemet-rapport-fra-ekspertgruppe/ . For the full report see NVE-RME (2020b).

In Great Britain, most respondents agree about the need for better coordination between distribution network operators and the system operator and the role of timely regulation in this. According to them better coordination brings benefits such as system efficiency, further market opportunities, more liquidity (i.e. revenue stacking from different markets at distribution and transmission system levels)[53], more competition, the avoidance of conflict of interest (i.e. between transmission and distribution actions), identification of key operational issues (and their origin) due to information exchange, etc. According to one of the respondents:

> "Coordination between TSO and DSO is required to avoid an overall system inefficiency. The old way of network operation (with a clear separation between distribution and transmission) is disrupted progressively by the rise of distributed local generation requiring a dynamic local control and monitoring that should not go against the overall system balancing. Clear rules and mechanisms (automated as much as possible) need to be defined to foster a better integration of the grid operation and ensure a useful and efficient flexibility market".

One of the respondents from GB also points out the introduction of coordination obligations in the forthcoming price control (RIIO-ED2). This refers to the introduction of a whole system reopener called Coordinated Adjustment Mechanism (CAM)[54], and proposed in the RIIO-2 Sector Specific Methodology[55]. The introduction of CAM is part of the whole system approach[56] and a modification of the system licence conditions for electricity distribution utilities and transmission owners is also under evaluation[57].

Discussion

Coordination between key parties such as distribution utilities and TSOs or system operators is vital. Many of the respondents have expressed different levels of and ways of promoting coordination in their respective jurisdictions, including the new approach in RIIO-ED2 in GB. With some exceptions, such as Japan and Australia, coordination rules are still a work in progress and very much supported by the electricity sector and electricity regulators. Better coordination brings many benefits (i.e. system efficiency, better visibility of DER assets, data exchange, better planning and investment, etc.). It involves the coordination of flexibility markets (coordinate flexibility markets) in order to maximise benefits (who is in charge of what, types of products to procure, etc.). This coordination should start with those able to contract for flexibility and involve integration into existing transmission level markets where appropriate.

53 For instance, there is a new product launched by National Grid ESO in GB where stacking is possible.

54 Ofgem (2020, p. 126) defines CAM as follows: "A whole system focused re-opener to protect consumer interests by supporting the reallocation of project revenues and responsibilities to the network best placed to deliver the relevant projects." There are no financial incentives for distribution utilities to use the CAM. The exploration of whole system options is expected to be business as usual.

55 https://www.ofgem.gov.uk/system/files/docs/2019/05/riio-2_sector_specific_methodology_decision_-_core_30.5.19.pdf

56 The identification of whole system outputs has been prioritised on the Ofgem-BEIS Smart Systems and Flexibility Plan, https://www.ofgem.gov.uk/publications-and-updates/upgrading-our-energy-system-smart-systems-and-flexibility-plan

57 According to the regulator the modification "will provide a structure for effective coordination of energy networks in the interest of consumers", https://www.ofgem.gov.uk/publications-and-updates/statutory-consultation-proposed-whole-electricity-system-licence-condition-d177a-electricity-distributors-and-transmission-owners

4.9 New rules that allow distribution utilities to procure flexibility on behalf of transmission level system operators

This type of change elicits less consensus across the parties with only some indication that it should be considered in two jurisdictions. As is observed in Table 12, only two respondents (out of 18) place this within their top 3.

Table 12: Rules that allow distribution utilities to procure flexibility on behalf of transmission level system operators – response summary

distribution utilities to procure flexibility services on behalf of TSOs	AU	FR	DE	GB	JP	NL	NO
already changed?							
Change being considered or should be considered?	yes			yes			
top 3				yes			

Summary of responses and additional notes

A respondent from the Netherlands points out that a collaboration between two parties is envisaged instead, according to the respondent:

> "We do not see DSOs procuring flexibility on behalf of the TSO, it rather seems that the DSOs and the TSO are increasingly going to compete with one another when procuring flexibility. The long-term objective is to allocate flexible resources to markets where they are valued most, i.e. across balancing and congestion management marketplaces".

In GB, one respondent suggests that this role has been evaluated (ENA World A) but no decision/implementation has been made. Another respondent supports this approach and suggests that distribution utilities should be able to access transmission level flexibility if is the most cost-efficient solution.

Discussion

Perhaps surprisingly, this is not seen as a big issue among our jurisdictions. This is possibly because at the moment DSOs and TSOs are currently operating in different markets for flexibility. However there is some hint that at some point they may begin to compete with one another to provide services to support the electricity grid which will raise issues to do with jurisdiction and control hierarchy, along the lines suggested by Kristov et al. (2016).

4.10 Changes to feed-in-tariff regulation

Changes to feed-in-tariff regulation is one of the changes that has already been made in five jurisdictions according to many participants. Even though participants from four jurisdictions state that a change in being considered or should be considered, the number of participants that think the opposite is higher in this case. In only two jurisdictions changes to feed-in-tariff regulation is placed in the top 3, see Table 13.

Table 13: Changes to feed-in-tariff regulation

feed-in-tariff regulation	AU	FR	DE	GB	JP	NL	NO
already changed?	yes	yes		yes	yes	yes	
change being considered or should be considered?	yes	yes		yes			yes
top 3					yes		yes

Summary of responses and additional notes

In GB one respondent reports a recent change – the introduction of the smart export guarantee (SEG) – which offers a payment to small scale low carbon generators for electricity exported to the grid[58]. Another respondent suggests that export /self-consumption should be maximised from FIT assets. A third indicates the end of the scheme in March 2019 and that no changes are being considered now.

In Japan, one respondent communicates a recent change: the adoption of Feed-in-Premium – FIP (in addition to the existing FIT). In the Netherlands, the respondent remarks the Stimulation of Sustainable Energy Transition (SDE++) scheme[59], based on a Feed-in-Premium and also a regulation applicable to residential customers with solar panels where customers are allowed to offset the amount of electricity consumed with electricity produced. It is acknowledged that due to the avoidance of different charges by these customers (i.e. energy taxes) among others, the government has announced the end of the scheme, according to the respondent:

> "This regulation was successful in stimulating renewable electricity production but is now increasing the risk of overstimulating PV-based energy with its drastically declining cost. In addition, it received criticism for not taking into account the impact on flexibility needs within the broader system. Therefore, the Ministry of Economic Affairs and Climate Policy has announced to end this particular regulation. The current plan is to end the regulation by 2023 for new users and gradually phase it out until 2031 for existing consumers".

In Norway, one of the respondents that ranks this change in the top 3, points out that: "Changes in feed-in-tariffs will be needed if there is to be a level playing field between Generation, Demand-side response and storage".

58 The scheme came into force in January 2020. https://www.ofgem.gov.uk/environmental-programmes/smart-export-guarantee-seg/about-smart-export-guarantee-seg

59 https://english.rvo.nl/subsidies-programmes/sde

Discussion

Feed-in-tariff schemes have been implemented some time ago and the mechanism has evolved too. An example of this is the Feed-in-Premium (FIP) that introduced a market-based component in the price or compensation given to the owner of renewable generation (or other type of low carbon asset), such as SEG++ from the Netherlands. Current changes or future changes to feed in tariffs that encourage the use of flexibility have been acknowledged by a few respondents. In most cases, it is not clear how to easily incentivise participation in flexibility markets by small FiT generators, considering the fixed amount that owners of DER are entitled to via their original feed in tariff scheme. Ideally the decision to opt for flexibility should be driven by the market however, this is not always the case. For instance, in Germany CHP plants receive a generous allowance in the form of direct support scheme incentives, avoided network tariffs and income from providing heating, all of which bypass the true electricity price signal (16% of electricity consumption is generated via CHP plants in Germany).

4.11 Improvements to customer data management and access

Changes to the rules regarding customer data management and access have been acknowledged in only two jurisdictions. However, respondents from most jurisdictions confirm current changes are being considered or agree that these should be considered, with a high level of consensus (15 out of 18 respondents). Respondents from four jurisdictions have placed this change within the top 3. Table 14 shows the results.

Table 14: Improvements to customers data management and access

customer data management and & standardisation	AU	FR	DE	GB	JP	NL	NO
already changed?	yes			yes			
change being considered or should be considered?	yes	yes		yes	yes	yes	yes
top 3	yes	yes			yes	yes	

Summary of responses and additional notes

In Australia, one respondent comments about a recent consultation from AEMO (2020)[60] about the minimum DER technical requirements[61], including interoperability requirements (which includes data monitoring and exchanges, communication capabilities, and controllability/coordination). Another respondent discusses the limitations that distribution utilities have on customer flexibility data, and also the limitations that customers have to capture the value of flexibility:

> "Distribution utilities have limited data on available customer flexibility. Some of this would involve better access to existing data and some of it setting up appropriate processes and incentives to capture and manage data. Similarly, whilst a customer can access their data, there are not many offerings in the mass market that take this and produce something tangible/useable that could then create the ability for customer's to see their own flexibility and respond to an offering."

60 The consultation is a response to the recent recommendation made by the Energy Security Board (ESB) in March 2020 to put in place minimum DER technical standards by October 2020.).

61 There is currently a largely unmonitored and uncoordinated nature of DER. Some uptakes of renewable energy may be more critical than others, this is the case of rooftop solar PV in Australia (AEMO, 2020).

A respondent from France notes that the implementation of flexibility at lower voltages requires the analysis of key data (i.e. load curve, geographical position, etc.), which is also useful to improve sourcing of flexible sites by generators. In Japan, one respondent points out the need for a common social platform to visualise available capacity and location of DER to make the best use of DER. While in Norway, it was suggested that centralisation and data access is essential if we are to move to a more automated and integrated energy system.

In the Netherlands there is an upcoming broad array of changes to current data management regulation to be introduced in the Energy Law 1.0 (which integrates the current Electricity Law, Gas law and Clean Energy Package legislation). The respondent advocates additional changes in data management as part of the adaption of the network code (i.e. submission of production/consumption data to grid operators for the next day), however there are some concerns regarding the predictions from grid users and difficulties in determining the baseline from which to measure flexibility. As a result, distribution utilities still rely on internal grid models (i.e. congestion forecasting).

In Great Britain, the Energy Data Taskforce report was mentioned, where a set of recommendations (currently at various stages of implementation)[62] have been provided regarding the way in which government and industry can combine efforts to unlock system benefits and to maximise customer benefits. As a result of those recommendations, the regulator requires network companies undergo effective digitalisation and discuss their digitalisation strategies in their Business Plans, with updated digitalisation strategies and action plans to be published in December 2020. Two licence obligations will be introduced for distribution utilities in RIIO-ED2[63]. Another respondent points out that as part of the distribution utilities privacy plans they are required to prepare data privacy plans which state the way in which they would anonymise the data, including the expected benefits from access to data[64]. However, access to smart meter data due to privacy issues was also noted by one respondent, suggesting that distribution utilities in GB are forbidden from accessing a single user's data and must rely on suppliers or aggregators to bring domestic participation to market.

62 A staged approach has been suggested to achieve a modern, digitalised energy system. https://es.catapult.org.uk/reports/energy-data-taskforce-report/

63 The licence obligations relate to (1) the publication of updated companies' Digitalisation Strategy & Action Plan and to (2) the use of data. Regarding the second one, the use of data should be aligned with the Data Best Practice guidance. For the latest version see https://modernisingenergydata.atlassian.net/wiki/spaces/MED/pages/319389709/Data%2BBest%2BPractice%2Bv0.21

64 https://www.ofgem.gov.uk/electricity/retail-market/metering/transition-smart-meters/smart-meters-distribution-network-operators-privacy-plans

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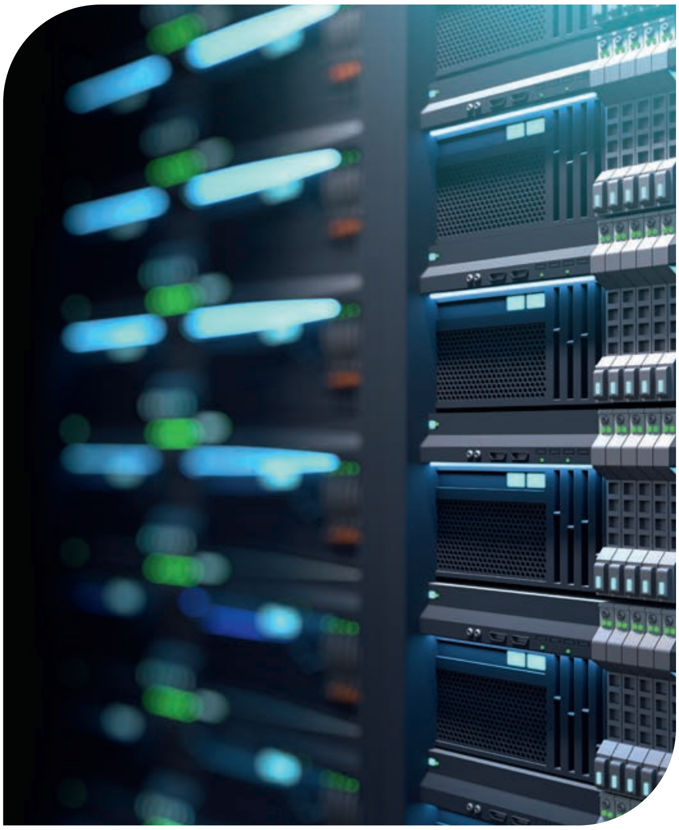
Discussion

There is consensus that data is key enabler especially at the lower voltages. The initiatives described above confirm this. Technological advances (i.e. digitalisation) can facilitate this but regulatory intervention is needed to set obligations, including technical requirements (i.e. interoperability). We observe that the rules regarding data management and access (including DER data) are being set out in different regulatory documentation/ consultations and Energy Laws. Lack of data (or access to it) may have an adverse impact in the establishment of more robust regulation that promotes the use of flexibility. For instance, regulators may prefer to exclude the implementation of new rules due to data non-availability or inaccuracy. Reciprocity is important too, so that not only distribution utilities can benefit from this (i.e. better planning, cost efficient investments, better visibility, etc) but also end customers by making more informed decisions.



4.12 Creation of standard cost benefit methodology for the evaluation of flexibility services at distribution level

No jurisdiction we looked at has reported the introduction of a common methodology to evaluate flexibility at the distribution level. However, respondents from four jurisdictions (9 out of 18) report ongoing discussions where it is being considered or agree that the introduction of the methodology should be considered, see Table 15.

Table 15: Creation of standard cost benefit methodology for the evaluation of flexibility services at distribution level – response summary

standard methodology for evaluating flexibility at distribution	AU	FR	DE	GB	JP	NL	NO
already changed?							
Change being considered or should be considered?	yes		yes	yes			yes
top 3	yes		yes	yes			

Summary of responses and additional notes

In Australia, respondents note a proposal (under review) to assess the value of DER integration (VaDER)[65], which aims to provide a common framework to evaluate the costs incurred by distribution utilities to accommodate DER on their networks. The study also considers the societal impact such as carbon reduction benefits.

A respondent from Germany points out that incentives for the use of flexibility by distribution utilities are poor or non-existent. There is a need for a clear incentive to claim costs for flex procurement (i.e. via regulated opex) and for more guidance on a CBA methodology that should be accepted by the regulator.

65 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure

Respondents from GB confirm the proposal of a new flexibility methodology developed by the Open Networks Project, currently under consultation (Product 1) along with other key products[66]. The methodology takes into account the value of reinforcement deferral, wider network and societal impacts (e.g. network losses, changes in CMLs and CI driven by the asset condition, carbon emissions etc.) as well as network costs. One respondent notes the importance of having a common methodology to reduce risks of under or over pricing that may produce an adverse impact on flexibility providers or consumers. The respondent also suggests that even though there are indicative prices for flexibility published by distribution utilities (i.e. via Piclo), there is no common methodology yet in place that can explain future price risk.

In the Netherlands, it is reported that no standard methodology has been created or is under consideration by the regulator. However, an initiative from a working group of network users and distribution utilities is noted. The working group has developed a methodology that assists distribution utilities to evaluate flexible solutions versus more traditional alternatives. The proposed method ensures that the solution is deployed with the lowest socialised costs [67]. According to the respondent:

> "As a general rule, the regulator believes remuneration for the use of flexibility must either be market-based or adhere to Article 13(7) of Regulation (EU) 2019/943 on non-market based redispatch".

In Norway, one respondent states that a methodology that considers flexibility is already in place as part of the requirements of the biannual investment planning report from the distribution utilities[68]. A different respondent remarks on the importance of having a common methodology to encourage the distribution utility to procure flexibility in local markets and to increase economic welfare. A different approach is observed in France. The respondent suggests that the CBA will depend on the grid structure or topology of the distribution utility which may be exposed to different risks and policies.

Non-monetary aspects are only considered as part of the evaluation of flexibility solutions in two jurisdictions: GB and Australia focus on carbon reductions[69]. In GB, the proposed common methodology includes carbon reduction (and the impact on network losses). In Australia, this is under review via VaDER with the consideration of carbon reductions. In the Netherlands, the respondent indicates that none of the value streams suggested are considered by distribution utilities because the valuation of flex bids/offers are basically market-based without requiring the consideration of non-monetary aspects. However, the distribution utilities are free to assess flex options against non-monetary value streams in the case of bilateral contracts.

66 https://www.energynetworks.org/electricity/futures/open-networks-project/open-networks-project-stakeholder-engagement/public-consultations.html

67 https://www.energie-nederland.nl/app/uploads/2018/06/OTE_Afwegingskader-verzwaren-tenzij.pdf

68 https://www.nve.no/energiforsyning/nett/kraftsystemutredninger/veiledningsmateriale/forbrukerfleksibilitet-og-utvikling-av-andre-energibaerere-enn-elektrisitet/

69 This refers to the answer provided as part of question 3 (Questionnaire 1).

Table 16: Other potential regulatory changes

Others	AU	FR	DE	GB	JP	NL	NO	top 3	Potential relation with
value of DER export	yes								4.11
innovation (funding, sandboxes under real conditions)				yes					4.1
climate change policies/net zero standards				yes					
DNO-DSO split				yes					
energy storage double taxation						yes			
network access reform/ more flexible or non-firm connection agreements				yes			yes	yes(*)	4.2
exclusivity of ESO contracts				yes				yes	4.8
better visibility of DER				yes					4.6, 4.11
enabling secondary market trading				yes					4.5
ring fencing	yes							yes	
maturity of flexibility market	yes								
flexibility realibility and location		yes						yes	4.11

(*) only in GB was cited by one respondent as one of the top 3

Discussion

A common cost benefit methodology for evaluating flexibility solutions versus traditional ones (i.e. network reinforcement, others) is important and should be a joint work between key energy stakeholders, including the energy regulator. We observe that most of our jurisdictions are working on or have already proposed a kind of methodology that aims to promote the use of flexibility as part of business as usual solutions. Having a common methodology that can be used by distribution utilities is crucial, adds transparency to decision making and should be aligned (if applicable) with any other methodology that the regulator or other energy authority have developed. It is also important that the methodology also considers societal benefits and is technologically agnostic.

For instance, in GB the methodology is aligned with the CBA tool for network investment decisions that the regulator requires to distribution utilities in their evaluation of business plans but it is not yet fully aligned with the central government's Green Book methodology for public policy appraisal (HMT, 2018). Apart from carbon reductions there is no agreement about the need to consider of non-monetary factors in the evaluation of flexibility bids/offers by distribution utilities.

4.13 Other suggestions for regulatory changes

Some of the parties have identified additional key regulatory changes that can promote flexibility and only a few of them have also been selected as part of the top 3. We discuss some of them in this section. Table 16 summarises them.

We observe that many of these changes proposed by the respondents can be grouped within the list of 12 changes proposed in this study. For instance, one respondent remarks on the importance of specifying the value of DER export which is related to section 4.11 (standard methodology for evaluating flexibility at distribution). Another suggests the "exclusivity of ESO contracts" in GB[70] which is linked to section 4.8 (interaction/coordination between DSOs and TSOs).

The other interesting thing is that the respondents from two jurisdictions (GB and Norway) have identified the same issue related to the offering of non-firm connections. For instance, currently in GB many distribution utilities are already offering non-firm connections (i.e. flexible connections) where the network user accepts to be curtailed (due to network constraints), for example in exchange for cheaper connection costs and a faster connection time. According to the respondent this also brings the possibility of secondary market trading. A network user with a non-firm connection may trade with another network user to avoid getting curtailed and make appropriate compensation. In Norway, the respondent suggests that the consideration of non-firm connection agreements would make it possible for both distribution and transmission system operators to buy flexibility from customers in order to reduce their costs.

The DNO-DSO split was also acknowledged by one participant. In GB this is currently under evaluation, however RIIO-ED2 has introduced a DSO incentive framework in the Business Plan Incentive[71]. The issue of double charging for storage was acknowledged in the Netherlands. According to the respondent, the removal of double charging will encourage flexibility in the market, however a short-term implementation of this change is not envisaged. This is still also an issue in GB, with a pending decision about the categorisation of energy storage by the energy regulator[72].

A participant from France states the importance of considering flexibility reliability ("key element of the service value to the grid") and location ("the lower the voltage, the stronger the impact on the grid in case of flexibility malfunctioning"). This is a very interesting point. For instance, based on the responses to the questionnaire, some jurisdictions are already setting DER technical requirements (i.e. Australia) that may help to deal with reliability.

70 According to this respondent, some flexibility services cannot participate in DSO markets as well ESO markets (e.g. Optional Downward Flexibility Management – ODFM Service). For further details see: https://data.nationalgrideso.com/backend/dataset/812f2195-4e96-4bfd-8bf0-06c3d0126c57/resource/1b2d5573-8b91-4608-8082-d93815d970bc/download/odfm-guidance-doc-v.4-06.07.20.pdf

71 The Business Plan Incentive comprises a two-stage approach: (1) quality DSO strategies and (2) Output Delivery Incentive (ODI) to evaluate the utility's performance against their strategies. Two assessments are planned, one in the middle of the price control and the other at the end. All this in addition to TIM and IIS, which encourages the use of flexibility with changes in the DNO licence (in line with DSO functions) to cover better planning, network development, network operation and market development. TIM remains the main instrument for promoting the use of competition to look for the most efficient solution (including flexibility).

72 https://www.ofgem.gov.uk/publications-and-updates/clarifying-regulatory-framework-electricity-storage-statutory-consultation-proposed-modifications-electricity-generation-licence

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Section 5: Spotlight on Great Britain

Table 17: Summary of responses (top 3 changes) per type of party in Great Britain

Top 3 regulatory change	Regulator	Energy Association	DNO 1	DNO 2	DNO 3	Marketplace 1	Marketplace 2
utilities' revenue incentives	yes	yes	yes		yes	yes	
network' tariff structure				yes			
definition of products/services & standarisation							yes
market design for local flexibility markets		yes				yes	yes
smart meter rules framework			yes				
interaction/coordination between DSOs and TSOs	yes	yes	yes		yes		yes
distribution utilities to procure flexibility services on behalf of TSOs				yes	yes		
standard methodology for evaluating flexibility at distribution						yes	
others	yes			yes			

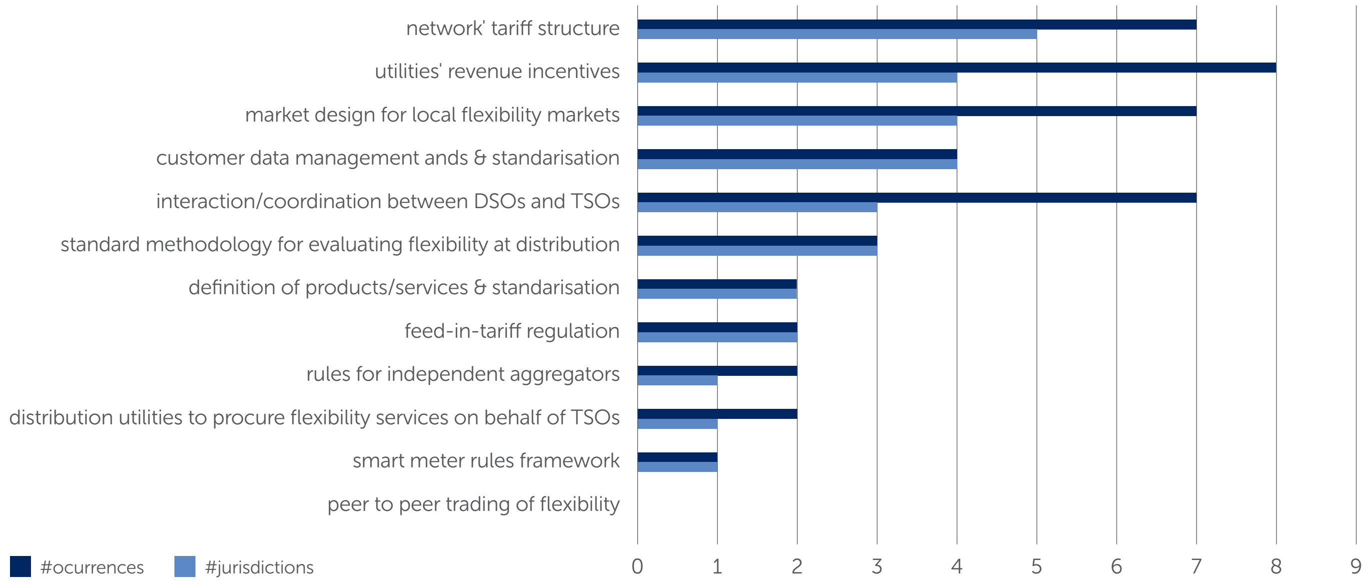
We have seven participants from GB with an interesting mix of background (energy regulator, energy association, distribution utilities and energy marketplaces). We therefore explore these respondents' preferences regarding their top 3 suggestions. Table 17 summarises these[73].

From Table 17 we see a high level of consensus for two changes: utilities' revenue incentives and interaction/coordination between DSOs and TSOs, followed by market design for local flexibility markets. Changes to network tariff structure was noted by just one participant. Unsurprisingly, distribution utilities want changes allowing them to procure flexibility services on behalf of TSOs, this was marked among the top 3 for two of them. A closer look indicates that the rationale behind this selection differs. One distribution utility states that if the flexibility option is more cost efficient (i.e. versus reinforcement for instance) distribution utilities should have access to balancing services use of system (BSUoS) funding, similar to the electricity system operator. The other distribution utility suggests that future improvements and the adoption of new systems will allow distribution utilities to manage wider system needs in the most cost-efficient way and within shorter timescales than the TSO.

Figure 2 depicts the responses provided by the 18 respondents from all the jurisdictions regarding the top 3 changes. Considering the number of jurisdictions, network tariff structure ranks first (7 out of 18) and utilities' revenue incentive second along with market design for flexibility services. Comparing Table 17 and Figure 2 at least some GB respondents agree that market design for local flexibility, interaction/coordination between DSOs and TSOs, development of a standard methodology for evaluating flexibility, definition of productions and services & standardisation are important regulatory changes that would promote flexibility.

73 Those changes that were not considered by any of respondents among the top 3 were excluded from the table (there are rules for independent aggregators, P2P trading of flexibility, feed-in-tariff regulation and customer data management and standardisation).

Figure 2: Top 3 changes – Summary



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Section 6: Summary findings and lessons for GB

This report explores different regulatory changes to incentivise the use of flexibility by distribution utilities in 7 jurisdictions. A couple of questionnaires were sent to key parties including energy regulators, distribution utilities, energy associations and energy marketplace platforms.

Looking through the main findings of section 4, there is much that a GB stakeholder (such as SSEN) can learn from the experience and analysis arising from the six other jurisdictions and from the diverse respondents from GB with respect to flexibility markets. We would highlight the following general lessons and specific ones for GB and Project MERLIN.

First, even where flexibility markets (e.g. in the Netherlands) are highly developed and incentives – in the form of the DSO revenue model and tariff structure – exist to undertake least cost procurement it remains unclear as to whether they are cost effective at a sustainable scale.

Even though RIIO is one of the most sophisticated incentive regulation mechanisms in the world, there is still some concern about the incentives that the model offers to distribution utilities to adopt a flexible solution even when it represents the most cost efficient solution. This may be more critical as the size of total flexibility procurement increases exposing the DNO to more uncertainty as to whether all of these costs may be remunerated/recovered. What is needed is a cost recovery mechanism that does not penalise the adoption of flexible solutions when it seems the most cost efficient option (which is currently an issue in the Netherlands and Germany) and also focuses on the particular incentives that distribution utilities may have to procure flexibility (i.e. regulated outputs linked to flexibility).

Trials such as Project MERLIN and its implementation at greater scale (BAU), will help to experiment and establish not only new business models for distribution utilities but also the fitness of the current regulatory incentive model to incorporate flexibility and maximise its value.

Second, more dynamic network tariffs have been or are being considered in several jurisdictions but all jurisdictions remain cautious as to the practicality of their implementation (even in France which has a single DSO capable of widely socializing the impact across all non-flexible customers).

Similar to elsewhere, GB remains cautious about the implementation of dynamic tariffs. What we would expect is that network tariff design would not deter the provision of flexibility services by those that want to offer them. The simultaneous application of both dynamic tariffs and the procurement of flexibility via markets to solve network constraints (at lower costs) should be evaluated carefully, especially at lower voltages by regulatory authorities[74]. According to CEER (2020), the combination of the two instruments makes it difficult to predict any behavior change in response to tariffs. The other issue is related to connection charges, which depending on the type of arrangements (e.g. deep, shallow)[75] may or not encourage the use of flexibility to solve specific type of constraints. We hope that the ongoing Significant Code Review addresses this issue.

On the basis of the evidence and experience so far there would seem to be little value in the use of dynamic network tariffs within Project MERLIN. However, this does not mean that outturn flexibility compensation might not vary in real time (e.g. when they are linked to wholesale energy market prices), simply that underlying network charges should not be varied in real time.

74 This would require higher penetration of smart meters.

75 See Footnote 28.

Third, while there are moves across multiple jurisdictions to specify and standardise flexibility products it remains unclear as to whether this is the optimal way to handle customer willingness to pay which is not a function of the flexibility product but of the assets' characteristics.

In GB four types of flexibility services to manage demand constraints have already been defined and standardised across the distribution utilities[76]. Flexibility markets are still at an early stage and evolving. We would expect the introduction of additional flexibility products over time that are not only linked to active power (e.g. reactive power, black start)[77], procurement closer to real time and new roles (i.e. facilitator of P2P trading). Some of them are expected to be tested in trials such as Project MERLIN. However, in mature flexibility markets there should be some consideration of output specifications (based on assets' characteristics) rather than types of product.

Fourth, the market design of flexibility markets is a work in progress, and we remain in an experimentation phase. Sophisticated market designs are being considered and in some cases, do not appear to pass a cost benefit test (such as the different market scenarios proposed to integrate DER into local distribution networks in Australia).

Market design of flexibility markets is being evaluated in GB via the ENA Open Networks project along with diverse demonstration projects. What seems to be an issue is the locational nature of some flexibility services which can deter competition and reduce market liquidity due to the lack of flexibility providers at the voltage level required (this was an issue in some of the use cases evaluated in Milestone 1 report). A larger deployment of DER and more participation from them could help with this issue. Project MERLIN is one of the pioneers in GB in testing a new approach of market design and represents an opportunity for distribution utilities to trial different aspects of this (e.g. participation rules, market liquidity, interaction with other services and potential conflicts, trading timeframes, etc.).

Apart from the ongoing trials, GB is experimenting a new model of flexibility market e.g. via the Piclo platform (as BAU)[78]. It is still at early stage, but it will help to understand and assess the viability of stand-alone local flexibility markets vs whether local markets need to be integrated into national ones (i.e. similar to Gopacs, Nodes). We have suggested elsewhere that there is a case for allowing flexibility providers at different nodes in the network to compete on price via descending clock auction with bid scoring across the different network locations to standardize the value of bids. This type of auction is one design which could solve the potential market power issues arising from allowing separate prices at different network constraint locations.

Fifth, there is little interest across our jurisdictions in P2P trading as an issue in current debates about flexibility markets. The focus, outside GB, remains on procurement by the distribution utility to meet its own needs.

The more sophisticated the market, the more need to have secondary markets. P2P trading may facilitate this. In contrast with the rest of the jurisdictions, in GB there is agreement on experimenting with P2P trading of flexibility, where the distribution utility acts as a pure facilitator. This is in line with current trials that aim to test the capability of distribution utilities to do this, Project MERLIN is among them. However, some conditions may be required by the distribution utilities if this is to move to BAU. Among them are DER registration with distribution utilities, key technical specifications (in order to avoid any adverse impact in the distribution networks), commercial obligations (service level agreements), definition of services/products to trade including timeframes, etc. P2P trading is useful for secondary trading of agreements to supply flexibility in the primary auction run by the DSO.

76 https://www.energynetworks.org/assets/files/ON-WS1A-Product%20Definitions%20Updated-PUBLISHED.pdf

77 A good example is Power Potential trial for the procurement of reactive power, for further details see Anaya and Pollitt (2020).

78 Results from the latest competition show that storage (including EVs) especially at LV are leading flexibility contracts, see: https://piclo.energy/publications/Piclo+Case+Study+-+UKPN+-+July+2020+-+Release.pdf. There is also the example of Flexible Power, which provides flexibility providers a direct path to participate in the procurement of flexibility. Four distribution utilities from GB are involved in this initiative: SSEN, SP Energy Networks, Western Power Distribution and Northern Powergrid, for further details see: https://www.flexiblepower.co.uk/

However, this is very much a second order issue for Project MERLIN at this stage. Proving that there is value in the primary auction is a necessary first step prior to facilitating P2P trading.

Sixth, the facilitation of increased co-ordination between TSOs and DSOs is actively being pursued across most of the jurisdictions where unbundling is in place. Australia exhibits some signs of active conflict between the TSOs and DSOs in some areas which needs to be addressed.

Most of respondents from GB acknowledge the benefits that enhanced coordination between key parties can provide to the electricity system. Flexibility providers aim to maximise incomes by stacking different revenue streams. However, there is still a clear need for further guidance especially related to data sharing for optimal network operation and stacking of revenues (in different or within the same timescales).[79] This would help to increase liquidity and to establish more sustainable flexibility markets.

Project MERLIN will help to identify potential conflicts between services offered to different buyers. These issues are expected to be addressed via different channels such as the Open Networks project and the introduction of new obligations in distribution and transmission licences (i.e. under a whole system approach) by the regulatory authorities. A key value of projects such as MERLIN is in suggesting what increased coordination, if any, between the TSO and DSO is beneficial to the system as a whole.

Seventh, allowing DSOs to procure flexibility on behalf of the TSO is not seen as a big issue outside of GB. However, this is somewhat surprising and reflects the fact that currently DSOs and TSOs are procuring very different types of flexibility and trying to avoid direct competition or even direct contractual relationships. It is not clear how sustainable this avoidance of conflict (and its resolution) is in the longer run.

Even though in GB the procurement of flexibility services by distribution utilities on behalf of TSOs has not been totally ruled out, especially if we refer to the procurement of services to solve locational issues. We would expect to see competition between distribution utilities and the system operator to solve identified network constraints in more established flexibility markets (i.e. like Gopacs in the Netherlands). The most cost-efficient flexible resources should be procured. Now in GB we have separated markets (i.e. new flexibility markets for distribution and balancing and ancillary services markets operated by the system operator NGESO) that potentially may be integrated at some point by independent marketplaces, increasing competition and liquidity. Project MERLIN should pay attention to who bids to provide flexibility as part of MERLIN and whether this is coming at the expense of, or in addition to existing services provided to the TSO.

A key role of DSO flexibility markets is to demonstrate additionality in bringing new flexibility resources into the market, rather than simply repurposing existing sources of flexibility which operate at the TSO level. If MERLIN succeeds in bringing forth additional flexible resources for the transmission level, this is an additional success for the project.

Finally, most of our jurisdictions are working on a common cost benefit methodology (of the type that already exists in New York) to evaluate flexibility solutions. There is clearly a need for this and for it to be consistent with standard social cost benefit methodologies being used by central and local government.

79 There are three key factors in the consideration of stack revenues from different streams: (1) baseline, (2) procurement timescales for different services and (3) penalties for non-delivery, see: https://www.energynetworks.org/assets/files/ONP-WS1A-P5%20DSO%20Revenue%20Stacking-PUBLISHED.pdf

In comparison with other jurisdictions, good progress is observed in GB with the proposal of a common cost benefit methodology to be used by distribution utilities to evaluate the use of flexibility solutions versus conventional solutions. The common cost benefit methodology provides more transparency in the evaluation of alternative solutions and is aligned with the current method suggested by the energy regulator (i.e. the CBA template) for network investment decisions. The methodology has been designed after considering the four flexibility products already procured as BAU by distribution utilities and we would expect that this should be adaptable to other types of flexibility services/products (i.e. non-active power services) of the type being procured under Project MERLIN. Project MERLIN will seek to apply this new methodology to evaluate its success and will offer feedback on how the methodology can be used and further adapted for use in practice.

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Appendix 1 – Glossary

Abbreviation	Definition
ACM	Authority for Consumers & Markets
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
CAM	Coordinated Adjustment Mechanism
DEIP	Distributed Energy Integration Program
DER	Distributed Energy Resources
DNO	Distribution Network Operator
DSO	Distribution System Operator
DNSP	Distribution Network Service Provider
ENA	Energy Networks Association
ESB	Energy Security Board
GOPACS	Grid Operators Platform for Congestion Solutions
MERLIN	Modelling the Economic Reactions Linking Individual Networks
METI	Minister for Economy, Transport and Infrastructure – Japan
NEM	National Electricity Market
NVE	Norwegian Water Resources and Energy Directorate
OFGEM	Office of Gas and Electricity Markets
SINTEG	Schaufenster intelligente Energie – Digitale Agenda für die Energiewende (Smart energy showcases – Digital agenda for the energy transition)
SSEN	Scottish and Southern Electricity Networks
TSO	Transmission System Operator
VPP	Virtual Power Plant
WEM	Wholesale Electricity Market
WPD	Western Power Distribution

Appendix 2 – Questionnaires

Questionnaire 1

Regulation and new roles of electricity distribution utilities, other parties and markets

1. How is your jurisdiction actively encouraging a move towards competitive procurement of flexibility services at the distribution level? (e.g. innovation trials, changes to regulation, changes to regulatory incentives).

2. What lessons, if any, have been learned about changes to regulatory arrangements which would encourage more competitive procurement of flexibility services at the distribution level in your jurisdiction? Please fill in the table below.

Potential regulatory change	Already changed (Yes/No)	Change being considered (Yes/No)	Top 3 in your view	Short explanation (top 3 only)
Changes to utilities' revenue incentives				
Changes to network tariff structure				
Changes to definition of products/ service standardisation				
Specification of market design for local flexibility markets				
Specification of rules for peer-to-peer trading of flexibility				
Changes to smart meter rules framework				
Changes to rules for independent aggregators				
Encouragement of better interaction/ coordination between electricity distribution and transmission system operators				
New rules that allow distribution utilities to procure flexibility on behalf of transmission level system operators				
Changes to feed-in-tariff regulation				
Improvements to customer data management and access				
Creation of standard cost benefit methodology for the evaluation of flexibility services at distribution level				
Other(s)? (Please specify):				

3. In evaluating flexibility bids/offers, which of the following non-monetary/difficult to quantify aspects may be taken into account by electricity distribution system operators?

Value stream	Already allowed (Yes/No)	Being considered (Yes/No)	Comments (if any)
Carbon reduction			
Road traffic/street level impact			
Community scheme (e.g. as per Community Credit in New York)			
Value of resilience			
Other(s)? (Please specify)			

Please do refer us to any published regulatory documents that you think would be particularly helpful for our study.

Questionnaire 2

Based on the experience of [your project/initiative], what are the most relevant changes on regulation that would be necessary to facilitate and accelerate the trading of flexibility services by electricity distribution utilities (from distributed energy resources-DER, commercial/residential customers, etc.)?

Potential regulatory change	Should be considered (Yes/No)	Top 3 in your view	Short explanation (top 3 only)
Changes to utilities' revenue incentives			
Changes to network tariff structure			
Changes to definition of products/service standardisation			
Specification of market design for local flexibility markets			
Specification of rules for peer-to-peer trading of flexibility			
Changes to the smart meter rules framework			
Changes to rules for independent aggregators			
Encouragement of better interaction/ coordination between electricity distribution and transmission system operators			
New rules that allow distribution utilities to procure flexibility on behalf of transmission level system operators			
Changes to feed-in-tariff regulation			
Improvements to customer data management and access			
Creation of standard cost benefit methodology for the evaluation of flexibility services at distribution level			
Other(s)? (Please specify):			

Please do refer us to any published regulatory documents that you think would be particularly helpful for our study.

Appendix 3 – List of Participants

Country	Organisation/party	Type of party	General view	Project/initiative specific
Australia	Ausgrid	distribution utility		yes (Ausgrid's Battery VPP)
	ENA	energy association	yes	
	Australian Energy Regulator - AER	regulator	yes	
France	Enedis	distribution utility	yes	
Germany	Avacon	distribution utility		yes (Avacon-InterFLEX project)
	Bnetza	regulator	yes	
Great Britain	SSEN	distribution utility		yes (flexibility services in Constraint Managed Zones)
	WPD	distribution utility		yes (flexibility services: Flexible Power)
	UK Power Networks	distribution utility		yes (flexibility services: Flexible Hub)
	Cornwall Local Energy Market - LEM (Centrica)	marketplace		yes (marketplace for the procurement of flexibility services)
	Piclo Flex (Piclo)	marketplace		yes (marketplace for the procurement of flexibility services)
	Ofgem	energy regulator	yes	
	ENA	energy association	yes	
Japan	Tepco	distribution utility		yes (V2G Demonstrator project using EVs and VPP resources)
	Expert	energy expert	yes	
Netherlands	Autorithy for Consumers and Markets - ACM	regulator	yes	
Norway	Norwegian Energy Regulatory Authority (NVE-RME)	regulator	yes	
	Nodes	marketplace		yes (marketplace for the procurement of flexibility services)

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MERLIN
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Scottish & Southern Electricity Networks