THE OXFORD INSTITUTE FOR ENERGY STUDIES

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OIES Electricity Day 2019

An Integrated Energy Systems Approach to Decarbonization Policy: Is it the way forward?

Summary

OIES Electricity Research Programme

The Oxford Institute for Energy Studies (OIES) held its third annual Electricity Day on 14 June 2019 at St Catherine's College, Oxford, with kind support from Energy Systems Catapult and Oxford Economics. The context for the Day was the central role of the electricity sector in the decarbonization of an economy, its links with the other elements (e.g. energy vectors, regulation, infrastructure, and institutions) within a 'whole energy system', and whether there are opportunities that the adoption of a holistic approach could bring towards efforts to decarbonize the economy through utilizing synergies and flexibilities across the entire energy system.

The Day was organized around three key questions, addressed over three sessions:

1. What benefits, if any, can 'integrated' or 'whole system' thinking bring to our approach to particular energy issues, such as the decarbonization of difficult sectors such as heat?
2. What roles do different modes of storage and different technologies play in realising an integrated, whole system approach to decarbonization?
3. What are the key policy and commercial challenges of a whole systems approach?

Short presentations to introduce the issues in each session were followed by focused discussion and debate. This document summarizes some of the main messages from the day, organized by session.[1] The content reflects the view of speakers and participants at the Day, and not necessarily those of OIES, or any of its members or sponsors.

Introduction to the Day

Over decades, energy systems have evolved, from individual energy devices with little or no dependencies, into a complex set of systems. Although the concept of a 'system' is ancient, with Aristotle's famous statement – *"the whole is more than the sum of its parts"* – often considered as the first definition of a system, the modern rediscovery of the 'systems approach' as a method of enquiry, analysis and design occurred just prior to the Second World War.

The integration of energy systems happens at least in three domains: physical (or infrastructural), institutional (markets, regulation and policy) and at scale (or geographical).

- Physical integration includes not only energy vectors (for example, combined heat and power (CHP) plants) but also across other sectors such as water, transport (for instance, the connection of EVs to electricity networks), and data and communications networks.
- An example of institutional integration is between gas and electricity markets, when agents (for example generators or suppliers) in one market utilize information in the other market in their bidding behaviour.
- And finally, an example of integration across scales is the utilization of demand response in the power grid, which increases the market footprint, with granularity all the way down to the customer level.

These interactions are driven by an objective to improve performance, increase efficiency and utilize flexibility provided by the entire energy system. They are also facilitated by the availability of cheap data and control infrastructure as well as political and economic cohesion across regions and countries (such in the European Union). Advancing energy system integration, however, requires a multidisciplinary approach ranging from science, engineering, and technology to policy, economics, regulation, and human behavior. It also requires new approaches to scalable modelling and simulation that incorporate a wide range of energy technologies and require the ability to create knowledge from large sets of energy data collected from vast numbers of controllable devices. We need energy markets and the regulations (including taxes) that are coordinated and integrated for optimal operation of the entire energy system. We also need local, dynamic prices that reflect the actual conditions and costs, and support smart and optimized operation of the entire energy system.

[1] Summary prepared by Anupama Sen and Rahmat Poudineh. A summary of the 2018 Electricity Day, which focused on *Consumer Driven Electricity Markets*, can be found here https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/10/OIES-Electricity-Day-2018-Summary.pdf?v=f5c3020d846f

1. Integrated Energy Systems Approaches – what is the rationale?

The first Session of the Day opened with some reflections on the concept of integrated energy systems. The first speaker began by proposing a definition for *Energy Systems Integration (ESI),* namely "the process of coordinating the operation and planning of energy systems across multiple pathways and/or geographical scales to deliver reliable, cost-effective energy services with minimal impact on the environment." It is important to note that *coordination of* a system is different from *optimizing* a system – the latter effectively limits the process to operating a system within certain parameters (e.g. minimizing costs) whereas *ESI* goes beyond this somewhat simplistic approach and involves bringing different disciplines together to learn about the "real world" rather than just a "model world". *ESI* approaches are however associated with a set of challenges, including:

- The lack of directly relevant data for policy planning that is in alignment with policy timescales. As a specific example, in using an ESI approach to solve the problem of wind intermittency, a key challenge is that there are few data points at high demand/low wind periods upon which to base future planning.
- The differences in features of new technologies (e.g. storage) vis-a-vis conventional technologies and the difficulties with integrating these alongside conventional technologies in the same markets.
- The multitude of uncertainties associated with large ESI models – examples include functional uncertainty (model evaluations take a long time, so the function is unknown almost everywhere), condition uncertainty (uncertainty as to the boundary conditions and initial conditions), structural uncertainty (the model only approximates the physical system), and measurement uncertainty (the model is calibrated against system data which is measured with error).
- In a future energy system – for instance the GB energy system where 20-30 million customers directly interact with the system – it will not be possible to carry out centralised control optimization. Systems approaches thus require some form of hierarchical control as an energy system has different 'layers' – including a physical layer, data link, network layer, and transport layer, among others. A key challenge is therefore to create some sort of 'system architecture' to manage this properly, before ad hoc arrangements become the norm.

A concrete example of *ESI* is the coordination of energy systems over wide areas. There is for example, a great deal of interest in interconnections between the GB energy system and the European energy system in relation to the issue of security of supply, but there still is no settled or accepted way of how this issue is treated. ENTSO-e[2] models are complex and high-dimensional – it is difficult to 'pin down' the behavior of the European system, and each of the systems are bound to have their own issues. (For instance, the uncertainty in margin in Europe is greater than link capacity).

This discussion highlighted the need to link in a wider range of disciplines to research and practice on *ESI*. The Session then moved to looking at the synergies and complementarities between electricity and the other elements (including other energy vectors, their associated infrastructure, institutions and regulatory frameworks) that might aid an 'integrated energy system' view of decarbonization policy. For instance, could a whole system approach to the decarbonization of heat lead to enhanced policies which complement the current 'default' strategy of electrification of heating?

The second speaker in the session proposed that there was "an unbreakable and intrinsic link between decarbonization and electrification." For instance, a study was presented which showed that the decarbonization of the European Union (EU) economy by 80, 90 or 95 per cent by 2050 (vis-à-vis 1990 emissions levels) would imply direct electrification rates of 38, 48 or 60 per cent.[3] The EU power sector would be carbon neutral by 2045 under all three scenarios. In keeping with an 80 per cent decarbonization scenario by 2050, the electrification of the transport, buildings and industry sectors

[2] European Network of Transmission System Operators for Electricity.
[3] *Eurelectric* scenarios. Assumes accelerated cost decline for renewables, nuclear, CCS and storage.

would imply direct electrification of these sectors of 29 per cent for transport (from 1 per cent in 2015), 45 per cent for buildings (from 34 per cent) and 38 per cent for industry (from 33 per cent). For a 90 per cent decarbonization scenario these rates would be 43, 54 and 44 per cent, for transport, buildings and industry, respectively. The main implication of these numbers is a significant future increase in the EU's electricity generation and the share of electricity in the energy mix (when one optimizes for cost) – i.e. from 3,000 Terawatt-Hours (TWh) at present, generation would increase to around 5,000 TWh under an 80 per cent economy-wide decarbonization scenario, or around 7,000 TWh under a 90 per cent scenario, by 2045.

According to this view, a carbon neutral power sector could exhibit four key characteristics:

- Renewables could represent 80 per cent or more of electricity supply driven by transmission build and rapidly declining cost.
- System reliability and flexibility needs will be provided by multiple sources in the power sector and from traditional sources (e.g. hydro, nuclear, gas) and emerging sources deployed at scale such as demand side response (DSR), battery storage, hydrogen and power-to-X.

The same view postulates that a carbon neutral power supply by 2045 can be accomplished with generation costs of €70-€75 per Megawatt-Hour (MWh). However, it should be noted that the main caveat to this outlook is that some technologies are only likely to come online subject to government policies. The transition will require a large quantity of investments to build out system flexibility. In addition, European countries have different starting points in the energy transition, based on their existing levels of resource endowment (e.g. large nuclear fleet in France, heavy dependence on coal in Poland and southeastern Europe, and on coal, nuclear phaseout and high share of intermittent renewables in Germany). A low-cost, carbon neutral power sector will need to be supported by enabling conditions, such as:

- political commitment to 'deep decarbonization' across all economic sectors;
- active engagement with and involvement of citizens (e.g. through DSR) and increased social acceptance for high renewables buildout and new transmission lines;
- efficient market-based frameworks and market design – for e.g. one that values resources based on their contribution to system reliability; and,
- a smarter, reinforced distribution grid that integrates new market participants (e.g. DSR and local flexibility sources).

The discussion then moved to looking at the decarbonization of heat in the UK in the context of a systems approach. The third speaker noted that systems thinking had not been a feature of UK energy policy in the last 40 or so years, partly as a result of the fact that the policy landscape changed fundamentally in the 1980s, with governments adopting a policy of liberalization, privatization and competition, and moving away from 'energy planning and specific quantified policy objectives'. Although the 'energy sector' tends to be discussed as a singular entity, the UK energy sector effectively comprises three end-user parts – appliances, heating and transportation, which have been treated separately with regards to policy although they are interconnected in the context of decarbonization policy targets. The energy supplied to appliances is nearly all in the form of electricity, that supplied to transport is mainly oil (over 90 per cent), and energy used in heating is mostly gas (more than 70 per cent). There is low price elasticity for demand in the appliances and transportation sectors, and there is 'little competition' *across* the sectors.

As a consequence, a high degree of 'policy lock-in' has developed across these sectors, since governments have followed three different policy paths. For instance, successive governments have not concerned themselves with relative pricing, and there has also been no real consistency on taxation. In transportation (oil-dominated) there is a form of Ramsey taxation with a high implicit carbon price (estimated at around £250/tonne of CO_2) and there is an expectation (on the part of consumers) for fuel taxes continuing at present or higher levels – e.g. the UK fuel tax has increased over 20 times since

1993. In heating (dominated by gas) in contrast, a lower rate of VAT on fuels used for heating effectively amounts to a relative subsidy, and there has been little regulation since the Clean Air Acts of the 1950s and 1960s.[4] In the power sector, which has been the main focus of decarbonization to date, the cost of decarbonization has been internalized and is borne by electricity consumers – but the sector has also achieved the highest amount of emission reductions since the 1990s.

The focus on electricity for decarbonization is leading to radical technological disruptions in the electricity sector itself, with significant implications for its future structure and operation. The industry is effectively 'turning upside-down', and moving from:

- a centralized to a decentralized generation structure;
- a mainly marginal to mainly capital cost structure;
- flexing demand to match supply vis-à-vis traditionally flexing supply to match demand;
- interactive versus passive demand; and
- 'smart' grids versus the traditional grid which provides a 'neutral conduit'.

Future policy will have a huge impact on the electricity sector, in part due to the massive disruptions brought about by increasing levels of intermittent renewable energy with near-zero marginal costs, in an energy-only liberalized electricity market in which efficient price formation requires a positive marginal cost. The sector thus faces a complex set of choices in terms of how it meets peak demand in the future – through some combination of centralized and decentralized generation, network reinforcement, international interconnections, demand response, and central and decentralized storage. All of these are regulated differently, and thus markets cannot optimize for a first-best solution – and there is no system optimizer either. There are major economic consequences as well –a report from the National Infrastructure Commission has estimated that getting the 'right mix' could save £8 billion a year. The decarbonization of electricity has therefore given new emphasis to the need for systems thinking.

Although the UK has a rigorous, legally binding, climate regime, the challenge of decarbonization is arguably getting greater, following the adoption of a zero net carbon target by 2050 prompted by the 2019 Climate Change Committee (CCC) Report – which states that a strategy for decarbonizing heat would be needed by the first half of the 2020s, with large-scale deployment of low carbon heating systems beginning before 2030. The key challenge for the decarbonization of heating is that gas demand for heating is 'peakier' than electricity demand – with peak demand in heating at least twice as high as electricity demand. There has been discussion over various possible solutions to meet this challenge – one being the use of hydrogen for heating, produced through steam reforming from methane. However, in light of the more ambitious zero net carbon target and the fact that a 'total hydrogen' solution would still produce carbon (even with CCS), and the fact that a 'heat pump' solution could impose an insuperable challenge for the electricity system (to meet demand peaks), another solution that may be emerging as a favored alternative is the use of hybrid heat pumps – i.e. heat pumps for the bulk of heat supply (around 90 per cent) and additional supply from hydrogen boilers for peak heat demand (around 10 per cent).

This solution would also fit with a systems approach, especially if it is combined with the rapid uptake of Electric Vehicles (EVs) – potentially creating 'controllable demand', and helping to reduce overall system costs. Such an approach would, however, require a great deal of coordination – across households (heat pumps and boiler conversion), gas networks (system conversion), hydrogen production, CCUS operators and the electricity system (networks and capacity). Markets could potentially coordinate in an efficient way, but this would require "*getting the prices right*" – i.e. breaking with the policy path dependence and 'silo' based approach of the past. Failing this, governments will have to manage the transition.

[4] However, a ban on fossil fuel heating systems was announced in 2019, effective from 2025 onwards.

Several other questions were explored by participants during the Session. One of these pertained to whether there is an 'optimal level' of system integration (e.g. is it realistically possible for a system operator to optimize 'every household'), and the role of economies of scale in the energy transition. Given the decarbonization target for 2050, could small-scale solutions undermine the objectives and contribution of large-scale deployment, and does the future have to be centralized or decentralized? There were mixed views. One view was that both solutions are complementary in a changing sector framework, in terms of economics. The harnessing of 'new opportunities' for demand in transport and heating could reduce system costs and potentially prevent increases in electricity prices. Another view was that the importance of economies of scale increases when governments have 'targets for decarbonization' rather than 'decarbonization targets for end-use'.

Another question arose in relation to the current debate over the incompatibility of decarbonization targets within current liberalized electricity markets: is the converse then true in developing countries – i.e. where liberalized markets do not yet exist, is it easier to get a systems approach to decarbonization? One response was that governments haven't fully developed the tools in liberalized markets that could enable decarbonization – such as a tradeable carbon target. A related view highlighted the issues of democratic consent in different countries – in terms of the politics, a strong case emerges for engaging consumers in the energy transition (including in a decentralized way), as much of it involves public acceptance of projects (for e.g. public opposition to some large-scale wind projects has been seen in some European countries). One view was that public engagement with large-scale renewable projects can be improved if the direct benefit of the project can be demonstrated more clearly (for e.g. 'if every turn of a wind turbine puts a penny into pension funds').

2. The Role of Storage in an Integrated Energy System

The second Session moved to focusing on the role of storage, exploring some of the following questions:

- How can storage facilitate a whole system approach to decarbonization? What is the role of short-term versus long-term storage? Can power-to-X facilitate the integration of parallel energy vectors to support decarbonization?
- How can electricity decarbonization benefit from an energy system that helps to integrate intermittent renewable energy by rewarding flexibility (for example, through sector coupling between the balancing electricity market and heat storage)?
- What is the role of electricity networks in facilitating these interactions? What is the role of Electric Vehicles (EVs) in linking the electricity sector and renewable integration with the transport sector? And is this role in synergy with the wider objective of decarbonization of economy?

The Session opened with a speaker who presented a range of future GB energy landscapes out to 2050 from a system operator perspective, to illustrate the roles for storage, based on levels of decentralization and speed of decarbonization.[5] In comparison with a historic peak of 64.3 Gigawatts of electricity demand, the increase in total peak electricity demand to 2050 could be as much as around 40 per cent. This is likely to be driven by EVs and heating. Two scenarios could potentially meet the UK's 2050 target:

- A *decentralized pathway* under which local energy schemes flourish, where consumers are engaged and energy efficiency is a priority – under this scenario up to 58 per cent of generation could be 'local' by 2050. Policies support onshore generation and storage technology development, as well as providing a platform for other 'green innovation'.

[5] See National Grid's *Future Energy Scenarios 2018. Note an updated version is available for 2019, which was not out at the time of the Electricity Day.*

- A *centralized pathway* characterised by large-scale centralized solutions in which consumers are supported to choose alternative heat and transport options to meet the 2050 target. Under this, UK homes and businesses transition to hydrogen and electric technologies for heating – over one third of homes could be heated by hydrogen in 2050 (e.g. through steam reforming of methane, or electrolysis). Consumers choose EVs for personal transportation and hydrogen is used in commercial transport. Policy priorities include expanding renewable capacity, improving energy efficiency and accelerating new technologies such as CCUS.

Demand will need to be met with more intermittent generation, requiring new flexible capacity, storage and interconnectors. In the decentralized pathway above, for instance, around 29 Gigawatts of storage will be required by 2050. EVs are a key part of this overall picture – smart charging vehicles could enable the storage of roughly one-fifth of GB's solar generation, and under both scenarios referred to above, over 75 per cent of EVs could be using smart charging by 2050. Storage will grow in all scenarios, driven by falling costs and its role in balancing intermittent renewable generation. Large-scale storage technologies with longer durations will be essential in meeting decarbonization as they can store much greater volumes of electricity – large scale storage includes pumped hydro, compressed air and liquid air. In the centralized pathway above, the volume of electricity that can be stored increases significantly from 2030 onwards (by around 10 Gigawatt-Hours (GWh), reaching 45 GWh).

Several questions were raised during the discussion – for instance, which of the scenarios were most likely to play out? In response, it was noted that the biggest uncertainties around the scenarios related to 'what would happen' around the decarbonization of heating – for instance, in order to meet the low carbon scenarios, a million homes a year would need to be converted in terms of heating systems. A question was also raised about electricity demand growth driven by greater digitalization and the growth of data-intensive industries, and their implications for electricity demand profiles and for storage. It was noted that while this was not a big driver in the GB energy market, there had been significant increases in electricity demand where data centers have been located (outside the UK). Another point that was argued was that demand-side management was perhaps not being sufficiently taken into account in various scenario models – and today's incentives for customers, tariffs and regulation are 'not reflecting the desirable features of economic flexibility in the system'.

The discussion then moved to looking more generally at the generic electric system, the need for flexibility, the sources of flexibility, and determining the 'adequacy of sources versus needs' (e.g. in the context of a country). The second speaker in the session characterized the need for flexibility as having three aspects:

- The first relates to *variations in demand*. This includes short-term (e.g. daily) versus medium-term (e.g. seasonal) variations; predictable versus unpredictable variations – for e.g. large-scale, short-term demand variations are predictable with very good precision, whereas small-scale, long-term demand variations are hardly predictable; and, commandable versus non-commandable variation – for e.g. some appliances can be geared to benefit the system.
- The second relates to unplanned *variations in generation*. These could be either incidental (e.g. unnotified disconnection of a generation unit) or structural (e.g. effects of passing clouds on solar PV generation, or windmill generation affected by wind variation). The disruptive effect to the system of these types of unplanned variations are a matter of scale (i.e. frequency and depth).
- The third relates to the criticality of *maintaining system stability* – i.e. the injection of power at any time must equate to the withdrawal of energy. System operators need flexibilities to manage these variations and there are different needs at different time scales.

The 'first source' of flexibility is commandable generation, the value of which is exponentiated by networks (e.g. through the mitigation of incidents, and mutualization of solutions). This includes short-term reserves (seconds and minutes), medium-term adjustments (hours) and long-term operational planning of available generation (e.g. maintenance and development). Flexible demand is the 'second source' of flexibility, and includes programmable loads through the use of tariffs, dynamic load shifting

through economic incentives, and safety load shedding through automatic devices. The 'third source' of flexibility is storage – the most familiar of which is hydro. Hydro reserve management provides flexibility from daily to seasonal timescales, and hydro pumped storage provides flexibility mainly on daily and weekly timescales. Battery storage is an emerging technology at the utility scale as well as at a decentralized level (e.g. EVs). Other forms of storage include fly wheels, power-to-gas ('P2G'), 'P2G2P' etc.

The adequacy of 'sources' vis-à-vis 'needs' effectively depends on the electric mix of a system – the obvious rationale being that the more intermittent renewable energy sources (RES) on the system, the greater the need for flexibility and flexible resources. Another related issue is asynchronous generation and inertia. Unlike conventional generators, which inherently react to frequency changes in the system due to their inertia, non-synchronous renewable energy generators, such as PV generators and many wind converters, provide no such inertia. However, there was no need to 'overdramatize' the problem, as studies show that the European electric system could cope with up to 60 per cent of RES, with 40 per cent of these being intermittent.[6] Further, the problem with inertia could be resolved with compensators, and/or synthetic inertia from asynchronous generation. The share of nuclear power in the national electricity mix of some European countries had become so important that the utilities required by design that their nuclear power plants provide maneuverability (load following) capabilities to be able to adapt the electricity supply to daily or seasonal variations of the power demand. At present, nuclear energy provides a source of both seasonal and weekly/daily flexibility (e.g. in France). Seasonal flexibility is provided through the scheduling of maintenance periods such that available capacity is maximized when demand is high (e.g. in the winter) – for instance, in France, around 20-25 GW of scheduled maintenance could be shifted over time if need be. Similarly, operational testing can be shifted from one week to another. 'Extra flexibility' is also likely to be provided through EVs and V2G technologies – while these could be used in ancillary services at present, in the future they could also contribute to peak shaving and price arbitrage. The issue is however, that we need the 'right incentives' to match 'sources' with 'needs', and to balance the system.

The discussion then moved on with a third speaker considering the case for Long Duration Energy Storage (LODES) in enabling future renewable generation. Although renewables are becoming more and more competitive with thermal energy generation, and the integration of renewables, from a sustainability standpoint, is becoming a priority for energy consumers, industry trends indicate substantial barriers to 100 per cent renewable adoption. One of the causes of these barriers is the inherent intermittency and unpredictability of the renewable resource, and the limitations of current tools – technological and financial – to mitigate this problem. The US, for instance, has seen the development of utility scale wind power generation farms matched with private-party Power Purchase Agreements (PPAs) – i.e. intermittent generation combined with fixed-volume, single price PPAs. Nevertheless, there are some risks essentially related to congestion and forecast uncertainties – this is evident in the significant number of 'negative price' hours in several US ISOs; CAISO for instance has seen an increase in wind and solar curtailments from 2015-19. A 100 per cent renewable future may thus involve dispatchable generation combined with a future PPA and energy storage.

While today's storage landscape is dominated by lithium ion batteries – this technology has a high energy unit cost and relatively short lifetime, limiting its risk management capabilities. In contrast, cost-effective LODES solutions can potentially address a large component of intermittency risks. Pumped hydro is the longest-duration/lowest-cost storage technology at present, but faces geographical barriers. Other LODES solutions would include the development of electrochemical, mechanical, thermal and chemical (e.g. hydrogen-based) approaches. A study was presented which assessed how LODES can mitigate the risks of intermittency and add value, helping to bridge the gap between renewables intermittency and predictable, dispatchable renewables. Early results of this study showed that LODES can limit the impact of increased congestion and volatility on risk and return of wind projects with long-term, hub-settled virtual PPA contracts.

[6] 'Technical and Economic Analysis of the European Electricity System with 60% RES', EDF.

Several questions were raised from participants during the Session. One view was that storage is a 'tool in a toolbox' to manage different forms of variability risk – reference was made for example to the storage business model in Australia. One issue with grid scale storage is the idea of 'value stack' in Australia, and the services relative to bulk energy. The challenges are that many of these markets are non-transparent and not contracted to the long-term. Two questions were raised in this regard. What had other experiences been (e.g. in the UK) in allowing storage to capture the value inherent to services and energy arbitrage, where the market was not very clear or not evident? And, where it has been possible to create those types of services, had there been investment? Further, one could argue that the 'true value' of storage was to provide value to network and non-network services. What were the business models which allowed values across these chains? One response was with regards to the GB energy market. Part of the success of storage in the frequency response market was to bring prices down, enabling the further market evolution of storage. There had been no examples of business models with 'value stack' in which if new storage was put into the capacity market, then it was prevented from participating in another market. Part of the challenge in bringing storage onto the system was that the system was essentially 'looking for flexibility' and storage does not necessarily have to compete with other technologies.

Another question raised was, looking at the longer-term challenges of storage (in terms of days, weeks and inter-seasonal periods), what was the optimal size of the hydrogen economy for 2050 that would provide additional value to intermittent renewables, and bring down overall system costs? Here there were mixed views. One response was that the 'centralized pathway' for GB (discussed above) included a hydrogen solution for heat, which required CCUS to bring it to scale, as well as the integration of electrolysis from offshore wind or other sources (if it was economic to do so). Another response was that there was, in general, 'no unified vision' for gas but that a carbon neutral environment (e.g. in Europe) in fact severely limited the role for gas. A certain amount of decarbonized gas would be necessary for use in high-temperature processing industries. This view also postulated that the future of decarbonized gas lay in Asian countries which are getting rid of coal. Mechanization from waste was one of the 'best ways' to produce it, but may cost 4 to 5 times the price of the molecules – the approach taken would depend on the policy favored in particular countries.

This view also noted that there was some 'confusion' around the generation of carbon-free hydrogen from renewables or decarbonized electricity. For instance, electrolytic hydrogen (power-to-gas) is an input for industrial processing, but the generation of onsite hydrogen was likely to be a more economical solution than the transportation of the gas through a network from an external location. There is also an implicit assumption that a 'huge amount' of curtailed electricity would be available to produce decarbonized gas – whereas in practice, renewable electricity is likely to be intermittently available for short durations. It was argued that what is required for electrolytic systems is in fact some sort of base load (e.g. excess from offshore wind power) – thus, electrolytic hydrogen was more likely to be viable in decentralized uses, through onsite generation and direct use in industrial applications.

A final question that was raised in the Session was with regard to the role of different storage technologies, as enablers on the path to decarbonization vis-à-vis as a part of the 'final picture' – could some storage technologies become redundant as the system evolved, and if so, what would determine this? One response was that different technologies inherently bring benefits to the operation of the system – for example seasonal demand could be managed by commandable generation, whereas shorter periods (e.g. weekly demand) could be met through hydro or EVs. But whether these benefits could be fully exploited will depend heavily on the design of incentives to evoke a response in demand (e.g. prices to incentivize smart charging of EVs, for instance).

3. Policy and Commercial Challenges of Adopting Integrated Energy Systems

The final Session of the Day moved to explore some key questions in the adoption of an integrated energy systems approach such as: what is the role of markets, regulations and policies in facilitating an integrated energy system approach to decarbonization? Can integrated energy system approaches be developed and implemented in the same way in different markets (e.g. liberalized versus non-liberalized) and policy contexts (e.g. OECD vs non-OECD countries)? And, what has been the global experience to date with whole energy system approaches?

The Session opened with the first speaker providing some reflections on the business and policy challenges to an integrated approach to energy policy. It was argued that while an 'integrated approach' tends to be interpreted by most people as a 'central planning approach' vis-a-vis one based on decentralized markets, *both* are integrated approaches, as both involve planning and coordination. Both also have problems – i.e. of government failure, or market failure. There is also an assumption that centrally planned co-ordination will be successful and not turn into a 'failed industrial policy', and that it will be delivered at 'modelled cost'. However, while some coordination is already necessary on grounds of other policy concerns (e.g. safety, use of public rights of way etc.), the literature shows that markets are generally good for renewables, emissions reduction and more sensible energy taxation.

For instance, fossil fuels with non-distortionary externality-correcting taxes can provide an integrated approach. It was argued that via fossil fuel prices, electricity, heat and transport systems *are* integrated both in policy and business terms. Key successful justified integrations in the UK, which correctly reflect underlying economic incentives, include:

- The spread of natural gas for heating in preference to electricity;
- The exit of oil from use in electricity production;
- Continued oil use in transport, but not in heating or electricity; and,
- The merging of gas and transmission networks.

Integration can, however, be improved, and many aspects of current taxation of fossil fuels can be rationalized. If current carbon taxes and carbon caps were to be raised moderately, we would decarbonize electricity but not necessarily heating or transport. New information on health impacts shows that current transport fuel taxes do not correctly tax the location of local air pollutants. We need to reflect this better (for e.g. local bans on vehicle use at peak times or during certain weather conditions, or local road use charges). 'Proper' carbon taxation/pricing would work on the supply side just as fossil fuel prices work in allocating fossil fuels between electricity, heating and transport, and encouraging business integration. 'Proper' pricing can be explicit, or implicit (via government subsidy/tax breaks) and should be extensive; it can be short-term (via spot markets) or long-term (e.g. via Contracts-for-Difference). Integrated approaches are also not just about pricing carbon, but also scarcity pricing and local congestion. In short, the pricing of externalities has to be 'right' – and this is very relevant to arbitraging technologies like storage.

Another important issue is that of *networks,* which involve fixed costs and require government support for the coordination of the planning system. This feature is not a constraint to sector coupling, which is viewed as a key component of an integrated energy systems approach – rather, sector coupling needs 'correct' prices as businesses should not just be arbitraging existing price distortions. Therefore, 'optimising prices' is an essential first step to better network coordination. One complication is the future recovery of network fixed costs. For instance, in the transport network, the move to EVs implies that the fall in fuel duty tax revenue will mean that roads are longer be self-financing, and raises the substantial issue of 'how to fairly charge for the road network'. For the gas network, there may be a 'death spiral' as demand falls – this may raise issues of how to write off the network and charge for its optionality. Finally, one of the assumptions of sector coupling is that it is possible to mix sectors and make better use of fossil fuels across networks, but it is as yet unclear whether this would be politically or environmentally sustainable. There is also likely to be pressure to 'convert networks to be zero carbon' and the extent to which this is possible in practice may also inform whether there is a substantial conversion to a mix of hydrogen or 'green gas' with conventional methane.

The discussion then moved on with a second speaker looking at the context of policy and commercial barriers related to electricity market design for a low-carbon future, focusing on the UK situation. The background to the UK Electricity Market Reform (EMR) was that it had effectively been a market intervention to get low carbon electricity into the mix by reducing the risk for low carbon investors. As a result, state-mediated contracting and centralized procurement was required to support all new capacity, and there has been less attention to price signals in 'time' and 'space' to enable better

coordination – this approach has led to a need to contract for reliability/ flexibility. While state mediated contracting has worked for renewables, it has not been effective for other low carbon sources such as nuclear or CCS. The outcome has been multiple mechanisms (and perhaps 'too many instruments') for signaling and rewarding value, with multiple interactions. These mechanisms can be broadly classified as relating to 'commodity' (e.g. markets and balancing/settlement mechanisms), 'capacity' (e.g. the capacity market), 'capability' (e.g. firm frequency response, short-term operating reserves, fast reserves), 'carbon' (e.g. the EU ETS, Carbon Price Floor, CfD) and 'congestion' (e.g. generator Transmission Network Use of System (TNUoS) charges, demand TNUoS charges etc.). This raises the question of whether this array of mechanisms can combine coherently to signal and remunerate 'system value' of generation, storage, DSR, and network capacity investments.

It was also argued that current market mechanisms fail to reflect the underlying system value (e.g. capacity markets exclude key dimensions of flexibility) of technologies - for e.g. carbon and electricity system externalities are not accurately priced. A 'whole system view' of technology costs would involve accounting for the cost or benefit of a number of aspects:

- The capital and operational costs associated with the incremental technology;
- Cost saving to the system from retiring existing capacity or foregoing new capacity;
- Impact on balancing costs in the rest of the system;
- Impact on investments to reinforce or extent the grid, and changes in power losses in transmission and distribution; and,
- Impact on costs though displacing higher marginal cost generation.

It was argued that centralized mechanisms may not adequately reward flexibility, and may reduce the space and incentive for innovative distributed solutions. Further, consumers remain mostly unengaged, with barriers to entry for more innovative and engaging propositions. It was argued that there is a case for flexible markets and contracting between buyers and sellers of system services – i.e. a more decentralized approach based on market mechanisms that more accurately and adequately reward flexibility. This raises questions about how to define 'flexibility' and incentivize it on an enduring basis.

While one approach would be to 'tweak the existing framework' by adding on local markets, Distribution Service Operators (DSOs) and network charging reform for locational price signals, another proposed approach was to rethink market design to provide more granularity of pricing electrons in time and space, with the market taking more responsibility for externalities. This view postulated a decentralized contracting 'archetype' with Energy Service Providers (ESPs) as the main interface between consumers and upstream suppliers. ESPs would contract for energy and flexibility with upstream suppliers, and provide new value-based service propositions to consumers ('warmth', 'reliability, 'greenness', 'simplicity'). Digitalization would have a key role in this model, to ensure system interoperability.

The discussion then moved to looking at the global experience with energy system approaches – this has been most strongly evidenced thus far in countries (particularly outside Europe) adopting energy systems based on specific decarbonized technologies, the most prominent of which has been hydrogen. This was explored by the third speaker in the Session. Countries/regions that are leading the push to hydrogen-based systems include:

- The EU, which published a long-term decarbonization strategy that included hydrogen pathways for achieving carbon neutrality;
- Japan, which has a Strategic Roadmap to implement its Basic Hydrogen Strategy targeting multiple sources including electricity, coal and gas, with multiple carriers and end-use applications;
- The USA – e. g. California's policy package for hydrogen transport fuels;

- China, which announced the Ten Cities programme that targets 10,000 Fuel Cell Vehicles (FCEVs) by 2020 and 1 million by 2030, plus 1,000 refueling stations; and,
- South Korea, which published a hydrogen economy roadmap with 2022 and 2040 targets for buses, FCEVs and refueling stations, and a vision to shift commercial vehicles to hydrogen by 2025.

As of 2019, eleven countries had policies in place to support hydrogen, and nine have national roadmaps for hydrogen energy. Existing policies driving this are mainly in the transport sector and include fuel economy standards, Zero Emission Vehicle (ZEV) mandates, feebates and purchase subsidies. According to the IEA, around 230 projects have been operationalized since 2000 to produce hydrogen from electrolysis. If all current dedicated hydrogen production was done through electrolysis, this would require around 3,600 TWh of electricity. With regards to costs, the declining costs of solar and wind could make them a low-cost source for hydrogen production in regions with favorable resource conditions, with costs as low as $2/kg of hydrogen in the long-term. In the near-term, hydrogen from fossil fuels will remain the most cost-competitive options in most cases – hydrogen from natural gas is around $1.5-$3/kg compared to $2.5-6/kg using electricity from solar PV or offshore wind.[7]

One of the main commercial barriers to a 'hydrogen system' includes value chain complexity and infrastructure needs. According to the IEA Hydrogen Report (2019), there are four different potential value chains which could be developed to bring a hydrogen pathway to scale and reduce costs in the process:

- Creating coastal industrial clusters that are co-located near ports, existing fossil fuel production facilities and CO_2 storage sites;
- Utilizing existing gas infrastructure networks to tap into 'dependable demand' – for e.g. the IEA estimates a 5 per cent blend of low carbon hydrogen into existing gas grids could reduce CO_2 emissions by 2 per cent (but at a higher delivered cost of gas).
- Focusing on 'fleets, freight and corridors' to make FCEVs more competitive, through policy synergies with the global drive towards cleaner transport and urban air pollution.
- Establishing shipping routes to 'kickstart' international hydrogen trade.

The main policy and technology barriers relate to a lack of globally binding commitments to sustainable energy systems, and the development of standards and regulations. The resolution of many of these barriers involves establishing credible long-term signals for investment, such as 'demand-pull policies' (e.g. obligations on fuel supplies to reduce carbon intensity), and guarantees of origin to certify CO_2 intensity and provenance of hydrogen supplies (e.g. accounting systems that enable trading of CO_2, such as CertifHy in Europe).

Several questions raised by participants at the end of the Session and the Day. For instance, the 'decarbonization problem' has a global dimension – what is the likely dynamic to achieve it when global integration is 'far away'? And, is it possible to improve systems integration within a tight decarbonization schedule? If done through pricing and fiscal adjustments, how can governments do so in a way that avoids 'yellow jacket' type protests? What is the Willingness-to-Pay in different societies for faster decarbonization? And finally, in all scenarios, it appear that the solutions could involve a mix of central planning and markets – how could this work in practice? One view was that the continuation of progress towards achieving decarbonization targets will depend upon the continuation of democratic support. In one sense, although this is a global problem, the solutions may involve local community approaches. The capacity for decarbonization to be delayed by the democratic process is equally high. Another view was that as interconnections become a part of the solution, this could mean countries with stringent climate targets could be linking to those less with ambitious ones – this may prompt future border tax adjustments for energy-intensive regions.

[7] The numbers given are based on assumptions made in the IEA Future of Hydrogen Report – which can be found at https://www.iea.org/hydrogen2019/ - and for the year 2030.