Energy system crossroads - time for decisions

UK 2030 low carbon scenarios and pathways - key decision points for a decarbonised energy system

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Executive Summary

Successful reduction of greenhouse gases will depend upon the decarbonisation of the energy system. A large number of UK energy system scenarios envisage substantial progress with decarbonisation in the period to 2030.

To assist the new Government in thinking through key decision points, this paper reviews a broad spectrum of recent UK energy system scenarios and seeks to provide an explicit linkage between the outcomes that the scenarios envisage (for 2030 and beyond) and the policy choices and investor actions that will be needed in the coming years.

Linking scenarios to policy is not uncomplicated. One reason is that many scenarios use optimisation models that behave a bit like a central planner. In the real world there is no perfect foresight, and decisions are made by multiple agents. The paper does not seek to 'centrally plan' a route to decarbonisation, rather it derives the key decisions and actions – some to be taken directly by government bodies, others to be encouraged indirectly through market instruments and regulation – necessary for delivery. This is not a prescription of what must happen, rather a consideration of the policy implications of achieving the decarbonisation envisaged in scenarios. Simply put, the paper assesses what action is likely to be needed ***if*** the decarbonisation outcomes are to be achieved.

Many of the decisions derived from the scenarios may be needed rather earlier than is commonly recognised due to the long lead time associated with network infrastructure and large capital projects, such as nuclear power stations, or the time taken to roll out very large numbers of new consumer products. This is especially the case if they are dependent on new or extended infrastructure, where there can be substantial costs and impacts associated with the transition that may not be well represented in existing models and which need further analysis and consideration.

The paper looks at the challenges from a whole-system perspective and recognises that an overall framework of decisions will be needed. It also analyses the sequencing of these decisions with a practical reflection on physical delivery and recognition of the interactions and interdependencies across sectors.

It deliberately starts from the demand side because this helps to ensure that the implications for supply and distribution can be properly assessed. Since most scenarios foresee significant electrification of heat and transport at some point, any approach to power sector development and decarbonisation must take these other sectors into consideration and recognise not only the overall demand to be satisfied, but also the distribution of this in time - across the day and across the seasons - and geographical location.

By making simple, but realistic assumptions about real life delivery challenges the paper lays out the key junctures at which various types of decision and action are needed. It makes clear that all those involved will be able to make better informed choices if there is clarity about the overall destination, which also makes it easier to decide what to do as new crossroads are encountered and to determine what corrective action should then be taken when hurdles are encountered, even if there is remaining uncertainty about exactly which pathway is correct, how some participants might behave, or whether each and every policy will be a success.

The paper links scenario outcomes to decisions across heat and personal transport, and for power generation. Scenario outcomes which point in similar directions are highlighted – especially where this reveals actions of low or no regrets. Where they contain mutually exclusive elements, or diverge significantly, the paper outlines the informed choices that must be made to narrow down the range of options and focus limited resources, especially when enabling network infrastructure is required.

Other decisions are recommended which put in place backstop regulation to ensure that desired outcomes are not only incentivised, but also underpinned. It will be important to achieve the right combination of approaches, appropriate for each situation – regulation, on its own, may be more effective and cost less than financial incentives, but might be seen as too draconian and lead to poor acceptance and political risk.

The paper starts by looking at heat (because of its large energy use and its extreme daily and seasonal demand fluctuations) and then transport before considering the power sector. Some of the key recommendations for each sector are summarised below:

Heat

- Long term, effectively targeted investment programme in residential and commercial buildings to reduce energy demand for space heating and hot water
- Analysis of the potential role for 'decarbonised' gas to allow continued use of valuable gas network infrastructure and storage
- Clear plans at a local level for the potential use of heat pumps and district heating
- Regulation of any move away from natural gas boilers and to adapt appliances for alternative fuels
- Regulatory backstops to ensure the necessary measures are deployed to reduce and manage heat consumption.

Transport

- Stronger regulatory measures to underpin the move away from fossil fuel powered vehicles
- Clear local plans for the stepwise roll out of electric vehicle charging points and/or hydrogen refuelling points, building on local public sector and business requirements.

Electricity

- Carbon intensity target for electricity production and/or phase out plans for coal and oil
- Market and regulatory reform to support necessary system services - security, flexibility and balancing
- Plans for the next stages of CCS deployment and infrastructure delivery
- Enhanced competition for nuclear contracts through expedited design approval of multiple technologies
- Guidance on locational and volume aspirations for renewables

The paper concludes that, unless key decisions about deployment and the supporting network infrastructure are made, the necessary investment in innovation, production and standardisation needed for cost savings is unlikely to be forthcoming. Therefore, delaying or making no decision, even if this is pending better information about costs, could actually be the most expensive option.

1 Introduction

Successful reduction of greenhouse gases will depend upon the decarbonisation of the energy system. A large number of UK energy system scenarios envisage substantial progress with decarbonisation in the period to 2030. Policy decisions made at an EU and Member State level will play a central role in determining whether this happens (European Commission 2014). With a new UK government in place, the Fifth Carbon Budget due in December 2015 (Committee on Climate Change 2014) and the Government's response to this to be published in 2016, there is an ideal opportunity to inform the decision making process about the transition to a low carbon energy system.

Building on the accompanying analytical annex where leading energy system scenarios are summarised, this discussion paper seeks to stimulate debate about important and urgent choices that will affect progress with decarbonisation. It seeks to link energy system scenarios to energy policy and delivery actions, particularly those actions that may need to be initiated in the immediate future and during the current parliamentary term.

The paper reveals that the significance, speed and scale of changes envisaged in scenarios for 2030 is not yet matched by an urgency and clarity of purpose in policy, let alone action. The paper therefore considers in particular these key ***decisions*** that will need to be made by policymakers to stimulate the ***actions*** that will need to be undertaken by industry, consumers, operators and other participants in the energy system if satisfactory levels of decarbonisation are to be achieved.

The paper does not seek to 'centrally plan' a route to decarbonisation, as if all possible actions were in the hands of central government. As we discuss in Section 2, although many scenario-modelling exercises do use optimisation models that plan an idealised future energy system, the real world is much more complex and uncertain.

The paper seeks to create an understanding about what decisions and actions are needed ***if*** the changes that the scenarios envisage to meet Government's targets and legal obligations are to stand any chance at all of coming to pass. It also differentiates between the key decisions and actions, acknowledging that some will be taken directly by Government bodies, both central and local, whilst others can only be encouraged indirectly through suitable incentives and regulation.

One reason decisions are urgent is the long lead time associated with network infrastructure and large capital projects, such as nuclear power stations. There is a further challenge – the time taken to roll out very large numbers of new consumer products, something that may also be dependent on new infrastructure (examples include electric cars and charging stations or domestic heat pumps and power network upgrades). This can create problems where 'chicken and egg' decisions prevent progress – e.g. without a charging infrastructure electric vehicles are less viable yet until electric vehicles appear in large numbers the case for creating a charging infrastructure is limited.

In some cases the paper also argues that there are potentially substantial costs and impacts associated with transition and new infrastructures that may not be well represented in existing models and need urgent further analysis and consideration.

The paper concentrates on the UK and builds on previous UKERC research, including a working paper which reflects on historical energy system scenarios (McDowall et al 2014) as well as an in-depth review of more recent energy system scenarios undertaken by Imperial College, which was discussed at an expert workshop hosted by UKERC in June 2014. The paper has also been informed by the wider programme of research being undertaken by UKERC, including work on energy system uncertainties (UK Energy Research Centre 2014) and estimating future costs (UK Energy Research

Centre 2013b) as well as work by Imperial College on the decarbonisation of heat, (Sansom & Strbac 2012) and the long-term role of coal (Gross & Speirs 2014).

Section 3 discusses the general context in terms of decarbonisation scenarios. Section 4 discusses the heat sector, electrification of heat, the potential for re-purposing of the gas networks and the role of distributed heat. Section 5 discusses the transportation sector, including future demand levels, fuel prices and the electrification of transport. Section 6 discusses the electricity sector, decarbonisation pathways, investment levels and technology assessments. Section 7 provides a summary of the recommended decision points.

The chosen sequence is a practical reflection of the need to ensure that changes to the supply of energy and associated networks properly reflect changing patterns of energy use. In other words, it deliberately starts from the demand side because this helps to ensure that the implications for supply can be properly assessed. For example, partly driven by a wide consensus that in all scenarios the electricity sector must be decarbonised extensively and quickly, many detailed discussions begin (and often end) with ideas for electricity supply and networks. However, since most scenarios also foresee significant electrification of heat and transport at some point, any approach to power sector development and decarbonisation must take other sectors into consideration and recognise not only the overall demand to be satisfied, but also the distribution of this in time - across the day and across the seasons - and geographical location.

2 Background - A plethora of scenarios and an appetite for indecision?

2.1 Introduction

There are a large number of models and scenarios for the future energy system (Analytical Annex 2015). Many recent UK scenarios have important commonalities, for example scenarios from the Committee on Climate Change, Department of Energy and Climate Change, National Grid, UKERC and others all point to the need to substantially decarbonise electricity generation in the period to 2030. These scenarios are listed below and are further described in the Annex (Analytical Annex 2015).

Scenario Sets	**Selected Scenarios**
CCC 4th Carbon Budget Scenario	
National Grid Future Energy Scenarios 2014	Gone Green
	Low Carbon Life
UKERC Scenarios Update 2011	Low Carbon
DECC-AEA Carbon Plan 2011	DECC-1A-IAB-2A

Table 1: List of Selected Energy Scenarios

Yet this 'consensus' can disguise a raft of differences, for instance the mix of renewables, nuclear and carbon capture and storage varies markedly across scenarios (Gross & Blyth 2014). Models will produce different outcomes given different judgements about future technology costs, build rates for new technologies and various policy decisions. Unsurprisingly, scenarios that seek to meet a particular objective (for example a target level of CO_2 g/kWh) describe a different mix of generation options from those that seek to explore market drivers without a carbon constraint. Those that model a high carbon price come to different conclusions from those that concentrate on feed-in tariffs or other measures.

Substantial differences also arise with regard to the scenarios which have been developed to represent how future demand for decarbonised domestic heat will be met (routes being varied in terms of the role of energy efficiency, gas, heat pumps, district heating, renewable heat and others). In the transport sector scenarios again vary in terms of the rate of roll-out of electric vehicles, penetration of advanced hybrid vehicles or how important a role biofuels and other vectors like hydrogen can play.

A recent UKERC working paper (McDowall & Keppo 2014) evaluated historic energy system scenarios dating back to 1978. It produced a number of findings, a selection is summarised below:

- Scenarios in the past were not just wrong, but real outcomes lay outside modelled boundaries, and developments considered too unlikely did materialise
- Scenarios mirrored the biggest concerns of the time, but what turned out to be the most important were not always captured – this was especially true of institutional, political and governance elements
- Actual pathways were more challenging than 'least-cost' models suggested
- Communication of results is important and should recognise that, on the one hand, ambiguity was often ignored or used as a reason to discredit and reject findings as unreliable, while on the other, quantification was often too precise and created a false impression of accuracy and certainty.

This led to a number of conclusions which are useful in setting the context of this paper:

- Diversity is important – thinking must be opened up to a wide range of possibilities, perspectives and framings, and be supported by a range of tools and techniques – the richest and broadest picture of uncertainty emerges when insights from multiple scenario studies by different organisations are combined.
- Too great an emphasis on consistency across methods and approaches to thinking about the future generates a mistaken focus on a narrow range of uncertainties and possible futures.
- Future work should include examination of scenarios in which goals (e.g. security of supply, climate change mitigation, cost reduction) are not met or only partly met, and should include greater attention to social, political and institutional uncertainties alongside policy and technology.

With this in mind it is perhaps unsurprising that scenario exercises can differ significantly from each other and from reality. Many scenarios make use of an idealised modelling framework in which costs are minimised and the system optimised as if it were centrally planned. However, in the real world there is no central planner with perfect foresight, and decisions are made by multiple agents as well as government – from a single regulator, through a few monopoly network operators to millions of households.

What also becomes very clear is that the scenario outcomes are determined to a great extent by decisions about the key inputs and parameters applied. This is a direct parallel to the real world where outcomes will also strongly depend on the decisions that are made, or indeed, not made.

Therefore, if the UK is to get even close to the scenario outcomes, important choices have to be made. Once there is clarity about the destination, it is easier to decide what to do as crossroads are encountered - corrective action can then also be taken, even if there is uncertainty about exactly which pathway is correct, how some participants might behave, or whether each and every policy will be a success.

The key purpose of this paper is to show how insights from the scenarios can be used to guide and inform which up-front decisions and subsequent actions are needed to determine the path towards, and the ultimate shape of the future energy system.

2.2 Policymaker indecision?

For a variety of reasons UK policymakers have tended to stress the need to keep options open, support a broad variety of approaches and technologies and avoid 'picking winners' (Gross et al. 2012). This concept was right at the heart of the Government's Carbon Plan in 2011 where it announced it would be running a "low carbon technology race". Option creation is indeed an important component of policy and it is essential that policy continues to promote and reflect innovation. However, in an increasing number of areas, if the 2030 goals for decarbonisation are to be met, then strategic decisions are needed, so that technologies and systems can be implemented efficiently at scale – particularly where new or modified supporting network infrastructures are needed, where large scale investments are required and where large volumes must be rolled out in in order to have a material impact on emissions.

There is no shortage of policy tools – what is missing are the decisions about what these tools are meant to deliver and a consistent, long term approach to their application.

For instance, on the supply side of the electricity sector, Electricity Market Reform (EMR) has created a framework where tenders and auctions run by or on behalf of government will largely determine how much of what is built, and when. One of the EMR mechanisms is designed to stimulate investment in low carbon power generation, the Contract for Difference (CfD) (DECC 2014a). By 2030 scenarios suggest that between 320 and 420 TWh of low carbon electricity will need to be produced annually (DECC 2014a). However at the time of writing there is very little clarity about how the government proposes to use the CfDs once the current pipeline of projects is built. There is uncertainty about when/whether the next CfD auction will take place. Beyond 2021 there are no signals at all to investors – the size of the levy control framework has not yet been decided and the government is yet to specify whether CfDs will continue to be auctioned in 'pots' based upon technology maturity and which technologies will be eligible.

On the demand side things are also in a state of uncertainty – despite most models suggesting that energy efficiency and demand management investment will be required to drive 20-30% reductions in heat consumption by 2030, there is no clear plan or enduring policy framework to show how this will be delivered – the Green Deal has been removed, perhaps for understandable reasons, but it is important for government to move quickly to determine how it will be replaced. Previous schemes which have mainly been obligations were determined by Government and changed regularly (e.g. ESOP, EEC, CERT, CESP, ECO, Warm Zones, Warm Homes) (Rosenow & Eyre 2014). ECO is again due to be overhauled in 2017, yet the aspirations for delivery levels remain unknown.

Even where the market could be left to decide, without clear guidance of the desired outcome it will be impossible to plan and deliver the differing network infrastructure requirements associated with each option – as we discuss in the sections that follow. It may also undermine confidence and investment in the supply chain, a point also returned to later.

2.3 The importance of network infrastructure

In many cases the ultimate determinant of a successful outcome (such as roll-out of CCS in power generation and industry; domestic heat production and decarbonisation; or development of offshore renewables) may be the availability of supporting network infrastructures. The desire by policymakers to maintain optionality could lead to the development of multiple, mutually exclusive infrastructures with the attendant risk of stranded assets and unnecessary costs to the consumer, or to nothing at all being developed.

Infrastructure, such as power grids, district heating or the built environment, is long lived, has extended lead times, and often requires strategic decisions to be made decades before infrastructure development can be completed (House of Lords Science and Technology Committee 2014). Some of this, particularly in the electricity sector, can also interact with near European neighbours and appropriate governance and decision making processes are essential to optimise the overall costs – an opportunity for this might be the production of National Energy Plans as part of the EU 2030 package. Quantitative analysis of this has been carried out at Imperial College (Strbac et al. 2014).

The relevant decision making processes for infrastructure must be recognised. In most cases it is delivered by regulated monopolies, therefore, even if it were possible or desirable to "let the market decide" on end use or energy generation/production and consumption issues, this simply will not work for networks and so informed choices may be needed at an early stage to enable the regulated organisations and their regulators to deliver in time.

It is also important to consider that many of the changes needed to decarbonise the energy system are of such a scale that their costs and impacts could be much more significant than those of simple incremental developments. There are also likely to be greater interdependencies that must be considered and managed.

Many of the main changes, e.g. in the heat and transport sectors, are not seen until after 2030, so there is a risk that decisions are assumed not to be needed imminently. As this paper will demonstrate, this is not correct since many of the key infrastructure choices would have to be made early in this Parliament if network developers are to be provided with the necessary signals to build and to pave the way for appropriate demand and supply measures to follow. A good precedent for this approach has been demonstrated in the past by the work of the Electricity Networks Steering Group (ENSG) on long term transmission investment needs. (ENSG 2012)

2.4 Linking scenarios to decisions

The previous section reinforces the importance of producing a clear outline of what needs to be created, and a narrative which guides how it will be achieved so that those involved in delivery can understand who has to do what, and when. In short, if objectives are to be met, then there is an overarching need for the opportunities and options identified in the scenarios literature to be narrowed down and translated more clearly and directly into delivery.

By making simple, but realistic assumptions about delivery pathways the remainder of this paper lays out the key junctures at which various types of decision and action are needed if scenario outcomes are to be achieved and Government objectives and legally binding targets are to be met.

Scenario outcomes which point in similar directions are highlighted – especially where this reveals actions of low or no regrets. Where they contain mutually exclusive elements, or diverge significantly the paper outlines the informed choices that must be made, especially when enabling network infrastructure is required.

Other decisions are recommended which put in place backstop regulation to ensure that desired outcomes are not only incentivised, but also underpinned. It will be important to achieve the right balance - high levels of financial incentive may be considerably more costly than regulation, but too draconian an approach may lead to poor acceptance and political risk.

Some further areas are highlighted (***bolded and italicised text in the document***) where further work is required. This is particularly the case where it may not have been possible for the full impacts and costs of transitions and networks to be incorporated into previous studies, and where further analysis is therefore needed as a priority before any decisions can be recommended.

3 Heat Sector Issues

3.1 Introduction

Significantly more energy is needed to provide space heating and hot water to residential and commercial buildings than to provide power and other stationary energy services. In residential buildings 83% of energy is used for this and in commercial buildings it is 64% (including ventilation and cooling) (DECC 2014b). Approximately 25% of total heat is attributable to the industrial sector, and the rest – over 500TWh – is needed for space heating, hot water and cooling in the residential and commercial sectors (DECC 2012b). Given this predominance, this paper focusses on the residential and commercial sectors.

Heat is often the largest proportion of household and many business energy costs. Energy efficiency investment in buildings and other related measures can have a very significant impact and lower energy bills by an estimated £400 - £500 per household (Cambridge Econometrics 2012), at the same time making homes more comfortable and healthy, while also reducing carbon emissions in line with targets and legal requirements (DECC 2012a). Nevertheless, it has proved difficult to incentivise the necessary levels of investment needed.

Added to the high overall level of heat use, the distribution of peak heat demand on a half-hourly basis varies tremendously throughout the year between a summer trough of 25GW and a winter peak of roughly 300GW. As can be seen from Figure 1, the overall and peak consumption levels as well as the scale of daily and seasonal fluctuations in heat are far greater than those for electricity.

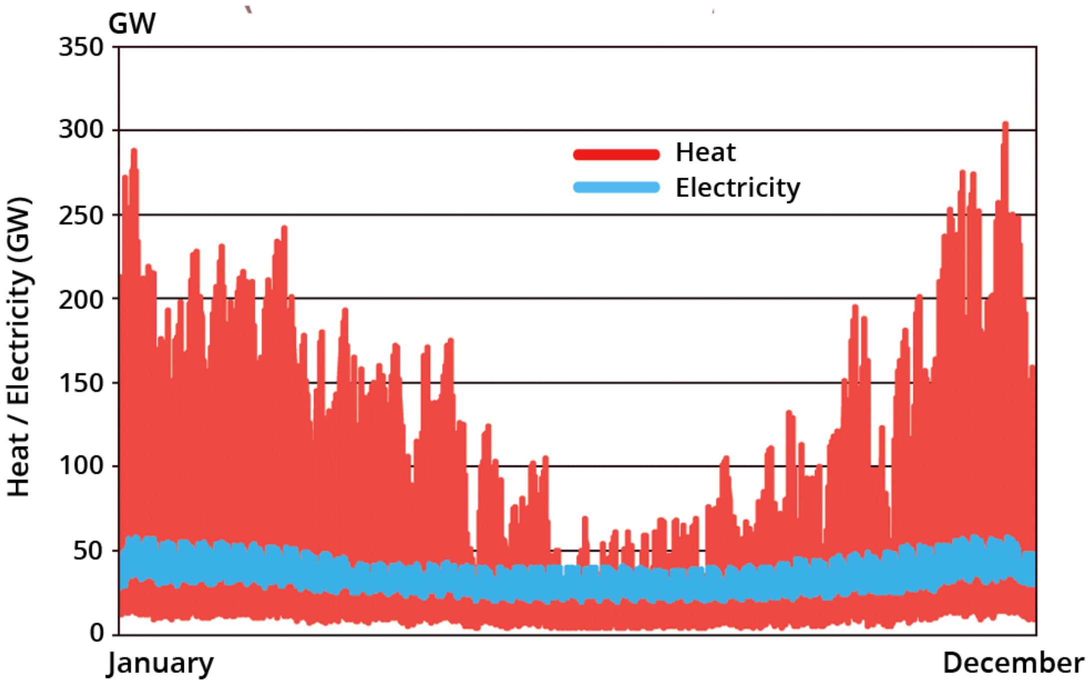
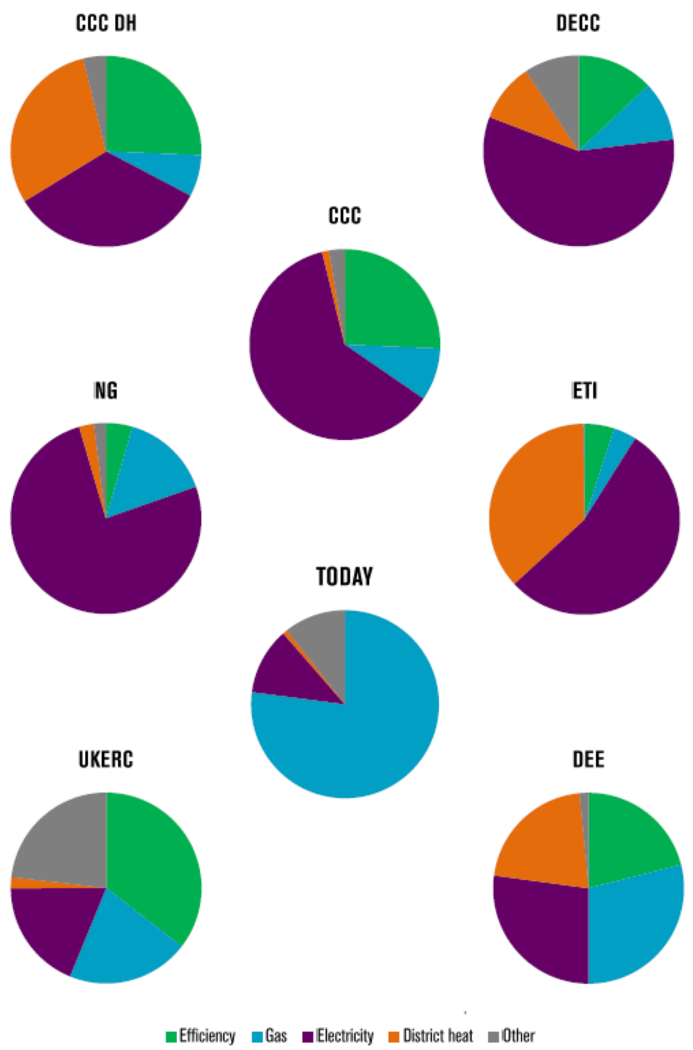


Figure 1: Half-hourly heat and electricity demand in 2010 (Sansom & Strbac 2012)

There are significant interdependencies and trade-offs between the demand and supply side measures which can be considered as options to decarbonise the heat sector. Each potential alternative has its own different costs, non-financial impacts and timescales for implementation. More importantly, differing infrastructures and supply chains will be required.



Perhaps as a consequence and as illustrated in a recent report (Carbon Connect 2014) (figure 2), significant differences arise with regard to the scenarios which have been developed to represent how future demand for decarbonised domestic heat will be met (routes being varied in terms of the role of energy efficiency, gas, heat pumps, district heating, renewable heat and others).

Figure 2: Summary of heat scenarios

Heat, by its nature, is produced and consumed locally. It is therefore likely that many building and heat initiatives will vary from region to region and between property types. Choices are likely to be made in a devolved manner and have significant involvement of Local Authorities, although this is still likely to be within a broad framework and according to standards set nationally.

Overall, the UK faces a difficult task with regard to reducing carbon emissions from heat – it has the lowest deployment of renewable heat in the EU (Eurostat 2013), some of the worst housing with regard to insulation and its consumers are currently happy with the gas boiler solution that three quarters of households have adopted (UKACE 2013).

The following sections describe the infrastructure needs of demand side measures and the main potential solutions for heat provision – gas networks, heat pumps and heat networks.

3.2 Reducing demand

By 2030, all scenarios indicate a gross reduction in heat consumption from buildings of 20-30% (Analytical Annex 2015). This could lower consumption in buildings to about 450TWh pa (Analytical Annex 2015). This level of demand reduction depends on a significant programme of investment in residential and commercial buildings (Analytical Annex 2015). To achieve this, approximately 1 million properties per annum will need to be treated through to 2030 (and beyond), roughly equivalent to the peak deployment levels of loft insulation under CERT (Rosenow & Eyre 2014) albeit with a much wider and deeper range of measures for each property.

To achieve such deployment levels, an investment programme must start between now and the end of ECO in 2017 and continue on through into the 2030s. Since contracting for measures by energy suppliers under ECO is likely to be complete well before the end of the scheme, decisions on its successor must be made as a matter of priority, if the supply chain is to be maintained or indeed developed further to deal with increased volumes. It is worth noting that the Scottish Government announced in June 2015 that it was making investment in buildings a National Infrastructure Priority, although exact details have yet to be finalised (Scottish Government 2015).

There is generally a strong economic case for energy efficiency investment in buildings – nearly all of the investments pay for themselves through energy savings in a relatively short period of time. Although there is a debate surrounding the current economic effectiveness of solid-wall insulation, almost all other domestic efficiency improvements are unambiguously cost effective (Cambridge Econometrics 2012).

Cambridge Econometrics also highlight the trade-offs between demand and supply side measures that should be considered and, in particular, that in line with the law of diminishing returns, solid wall insulation may be a more expensive solution than some supply side measures which reduce consumption and or carbon more effectively.

Despite the overall positive economics, paying for measures up front is impossible for low income households or tenants living in rented accommodation, and is often a significant, real or perceived hurdle for others. In the case of rented properties, the benefits of lower bills accrue to the tenants, but the costs of investment would normally lie with the landlord.

Reducing heat demand will continue to involve substantial investment to support low income households (Hills 2012). However, to reach decarbonisation goals it will be necessary to ensure measures are also adopted by properties which belong to more affluent households and businesses, where heat use is greatest and often most profligate . Efficiency and carbon savings in these areas are likely to be more significant, being less susceptible to a rebound effect, since ‘comfortable’ levels are probably already being enjoyed, despite the cost.

Progress to date has predominantly been made through use of regulations and supplier obligations, rather than by a market approach, so it will be essential for the even larger task ahead that appropriate interventions are launched that also cover the afford to pay sector. Analysis of the most recent initiatives, ECO and the Green Deal, in comparison to their predecessor schemes has been produced by Eyre and Rosenow, (Rosenow & Eyre 2014) who also propose measures which could be taken to improve the impacts of such schemes.

Decision 1. If energy demand reduction of at least 25 – 30% is to be achieved by 2030, then a long term, substantial and effectively targeted investment programme in residential and commercial buildings has to take place. Delivering this will require concerted policy efforts across building codes/regulation, market transformation, incentives, labelling and billing. Policy needs to target both low-income households and the ‘afford to pay’ sector.

3.3 Managing peak requirements

Peak heat demand considerations do not feature strongly in the scenarios. Nevertheless, meeting peak demand will be a fundamental challenge for any replacement for gas. As Figure 1, above, shows, the current daily and seasonal variation in heat demand is extreme, with a factor of 12 difference between the summer trough and winter peak.

One way of illustrating the scale of the peak and the potential to reduce it is to compare the actual peak to the idealised level that would arise if annual consumption could be averaged evenly across the day and the year. For annual levels of heat consumption from residential and commercial buildings of up to 600TWh, this theoretical, idealised level would be 68GW. This compares with the actual maximum of over 300GW – between 4 and 5 times higher, and the level of use in the summer months which drops to about half of this.

For comparison, in the electricity sector, there is an annual consumption of about 350TWh which equates to an idealised average of 40GW against the actual peak of 60GW, only about half as much again. The drop in summer use is also much less marked.

Without a change to peak requirements, any replacement system for gas heating would have to deal with this seasonal fluctuation, an extremely ambitious task. It is therefore essential that there is a better understanding of if and how peak heat demand may develop under reduced energy consumption and with the different technology options in any future scenarios.

The peak is a combination of the seasonal and daily variations. The difference between summer and winter needs will remain and it is unlikely that demand side solutions will offer the opportunity to impact on this. There is nonetheless significant potential to impact on the in-day variations - options include:

- Reduce peak capacity of heat generation (possible with more efficient buildings and generators, especially heat pumps)
- Use heaters for less time during peak periods
- Use heaters in a different mode (e.g. constant temperature, no cooling down overnight)
- Use heat storage to smooth or time shift (little attention is paid to heat storage in the scenarios despite the potentially significant role it can play in daily peak load shifting. ***Storing heat is an area which would benefit from further research and analysis***).

Some of these impacts can be achieved indirectly through other recommended policy decisions, especially investment in the energy efficiency of buildings (Decision 1), or directly through regulatory decisions about generation type. However, anything requiring a change to usage patterns is unlikely to be achieved through voluntary actions alone, and might need a more significant intervention into end use patterns although this could face potentially strong resistance from consumers (Palmer 2012) if the balance between demand side management and interference is pushed too far.

Decision 2. If peak demand patterns are to be modified in order to optimise system capacity and costs, then interventions should be considered by DECC and Ofgem which complement and underpin voluntary consumer actions to shift heat load.

3.4 Decarbonisation - the future of gas networks?

As discussed in the annex and shown in Figure 2 above, despite the key role that it currently plays, there is no clear consensus amongst scenarios on gas and gas network use for heating in the 2020s nor what will happen beyond 2030.

It is also important to properly consider the inherent value of the gas networks that today provide an almost uniquely flexible part of the energy system – not only delivering the energy needed, but also the ability to transport and store the fuel to meet the un-paralleled extremes of daily and seasonal heat consumption patterns, at the same time capable of bridging use across the three main sectors of heat, transport and electricity. If there is a more limited future for the gas networks, then serious consideration must be given to the costs and implications of replacing these intrinsic properties in some other way.

Replacing this existing asset with alternatives, e.g. heat networks or upgraded electricity cabling could be expensive and cause significant disruption over an extended period of time. Therefore the full replacement costs, including storage, flexibility and means of meeting peak demand, should be considered before the implementation of measures that would lead to the decommissioning of gas networks.

Some research has started under Ofgem's Low Carbon Network Fund (LCNF) and Network Innovation Competition (NIC) to examine the potential to re-purpose the gas networks for gasses other than natural gas, e.g. biomethane from anaerobic digestion, hydrogen and synthetic natural gas (SNG), as well as on 'power to gas' where excess electricity from renewable sources could be used to produce hydrogen at low cost rather than being constrained off the system at times of high output and low demand.

Decision 3. Further research should be supported by DECC and Ofgem to understand that if gas networks are to be maintained, then what alternative forms of gas (biomethane, synthetic methane, hydrogen) could be used instead of/as well as natural gas or, if they are to be replaced what costs and impacts would be involved in replacing their functionality.

3.5 Electrification - Heat Pumps

Without the use of heat pumps to reduce the input energy for a given heat output, like-for-like replacement of a kWh output from gas heating by electricity could triple the fuel cost based on the current differential between the cost of gas and electricity. Moreover, it could double the carbon emissions while gas continues to provide marginal electricity production, even more if it is coal, since the efficiency of using gas locally to produce heat is about twice as high as using it first to produce electricity, and then to generate heat.

For this reason, in electrification scenarios, heat pumps which more efficiently convert electricity to heat are shown to be the main replacement for gas, certainly by 2050, with up to 400TWh pa heat output being provided by them and up to 200 TWh pa by 2030 (Analytical Annex 2015). Nevertheless, significant penetration of heat pumps could double or treble the peak electricity demand and the size of the electricity system (Sansom & Strbac 2012).

However, standard heat pump units are currently more expensive than equivalent gas boilers and, despite their efficiency, heat pumps will only perform effectively and economically in well insulated buildings and may require a change to the internal radiator system, the costs of which must also be considered.

The performance of air-source heat pumps is particularly dependent on the ambient temperature and falls off rapidly at lower temperatures (Sansom & Strbac 2012) and the associated real life impacts on the peak requirements of the electricity system could be very significant. This impacts not only on electricity generation but also on power networks, distribution in particular. Since the lifetime expectancy for the power networks is decades, knowing the trajectory for 2050 should mean that any works carried out before 2030 will already anticipate 2050 demand to avoid the further cost and disruption in the future of repeated incremental upgrades.

Major upgrades to transmission networks are known to take up to 15 years to deliver (e.g. Beauly – Denny, where scoping work began in 2001 and completion is not expected till 2016). Distribution projects can also be delayed significantly by the consenting process. Moreover, major works, like those required to upgrade urban networks, could be very disruptive to local access and transport so are likely to face strong opposition.

It is therefore essential to understand future needs and how these are dependent on decisions and actions by the network operators and the regulator so that they can be agreed and delivery progressed in a timely manner. It goes without saying that anything required before 2030 with a potential delivery timescale of 15 years can obviously no longer be guaranteed.

As discussed previously, any substantial uptake of heat pumps in residential buildings could require more than a doubling of the capacity of the electricity system to meet peak demand. This is an example of how transitions of this scale can lead to a non-incremental system change and could have a more significant impact on disruption and cost than the business as usual modelling that would normally be used to assess an individual system upgrade would indicate.

Some scenarios suggest the use of hybrid electric heat pumps and gas boilers, at least in the interim, in order to mitigate the effects of the high winter peak loads and performance/acceptance issues. ***The costs and benefits of hybrid heat pumps, particularly with regard to managing the transition and reducing peak demand should be further researched and analysed.***

It is also not clear which, if any of the costs and impacts of transition and infrastructure have been incorporated into models and ***it is essential that the full costs are adequately and expeditiously researched to enable appropriate, informed decisions to be taken***.

Furthermore, the carbon abatement potential of electrically driven heat pumps is highly dependent on the carbon intensity of the grid (Carbon Connect 2014). Should the UK fail to decarbonise its power sector by 2030, abatement from heat pumps could be reduced as the electricity used to run them would carry a high carbon-intensity. Any decision about heat pumps is contingent upon ongoing support for power sector decarbonisation, which is discussed later.

This all reinforces the importance of a structured local approach to heat strategy - first determine the appropriate energy efficiency investment programme before making an informed decision about if, and where heat pumps can be rolled out and then evaluate and plan what impacts this will have on local infrastructure.

Decision 4. If a significant move towards heat pumps is to be made in any locality, then in line with energy efficiency investment and reductions in the overall carbon intensity of the grid, plans for the roll out of heat pumps should be coordinated across the relevant organisations, taking into account the local and national transition and infrastructure implications, costs and timescales.

3.6 The role of Distributed Heat

Although there is no consensus on the exact proportions of the differing heat supply solutions, all referenced scenarios conclude that alongside heat pumps, a key alternative to individual gas boiler systems on a larger scale is district heating - some form of shared heat generation combined with a heat network to distribute this to nearby buildings (DECC 2013b) (Analytical Annex 2015)).

Shared heat systems, due to economies of scale, can be much more efficient in the production of heat, can significantly lower electricity system peak loading (as long as the heat isn't produced with electricity), and may also more readily incorporate options for storage which can reduce peak demands, help to provide constant levels of heating and higher comfort in buildings (DECC 2013b). The amalgamation of district heating with Combined Heat and Power (CHP) and renewable electricity generation can prove a valuable means of balancing supply and demand across the heat and power sectors (Andersen 2007)

One key advantage of shared heat production is the variety of heating sources which can be used and the ability to change this with no disruption to individual users fed by the heat networks. Alongside heat pumps, different fuels with varying carbon intensity can be used to centrally generate heat. These include natural or synthetic gas, biomass and hydrogen, although it was not always clear from the scenarios, which of these was being considered.

The key decisions that need to be considered with regard to such solutions relate not only directly to the economics and practicability of the specific scheme, including its infrastructure requirements, but also to the general regulatory requirements of shared schemes in a liberalised market and how these may be influenced by other developments in central policy.

The cost and impacts of installing any heat network must be considered on a scheme by scheme basis, however most decisions relating to this are likely to be quite local in their nature. This makes them more suitable for devolved planning and decision-making at a Local Authority level. However central decisions may still be required about how to regulate such schemes (e.g. use of waste heat, third party access, right to switch) as well as in regard to funding or financing requirements that cannot be met locally.

For any shared development there will be a minimum level of uptake required to justify the investment. If potential consumers have recently invested in an alternative solution, for instance a heat pump, they will not wish to 'strand their asset' and write off that investment by joining the scheme. Reducing the number of customers would adversely impact on the business case, therefore it needs to be clear where there is a likelihood of such a development to ensure that the potential customer base is maximised. This may not be problematic in all cases since there are some types of buildings and areas that readily lend themselves to a shared solution (e.g. tower blocks) and others that clearly do not (e.g. sparsely populated rural areas) and a system of heat zoning could be used and publicised, perhaps as part of Local Plans.

The cost of finance of district heating will be a key factor in determining the overall cost and, since it is likely that Local Authorities will play a central role in the development of any heat networks, achieving lower cost of finance through their participation, directly or in Special Purpose Vehicles, might make financial sense.

Decision 5. If distributed heat solutions are to be developed, then Government, both central and local, must make appropriate plans and inform potential consumers about which building types and zones will be considered, and on what timescales roll out will happen.

3.7 Replacing gas boilers

As a consequence of a shift to heat pumps and networks, all scenarios illustrate that natural gas use for heat provision in buildings should start falling significantly after 2030, either through complete replacement or through partial displacement with hybrid heat pumps or alternative fuels (Analytical Annex 2015).

It has been previously noted that decarbonisation of the gas grid should be adequately analysed and considered. Although none of the previous scenarios show significant use of hydrogen or other gases by 2030, a number do suggest increasing and significant use of gaseous fuels other than natural gas towards 2050. It is not always clear from the scenarios which incorporate heat networks as an option, how the heat is being generated, but gaseous fuels could certainly play their part.

If the gas grid is decarbonised, for instance by a move to hydrogen or synthetic/bio- methane with a different specification to natural gas, then measures will be required to prepare the system and appliances for such changes, potentially similar to those that were undertaken in the switch over from town gas to natural gas (Analytical Annex 2015). Suitable guidance and regulation will be needed both for the regulated monopolies which now own and operate the gas networks and the commercial supply chain for the provision and installation of end-user equipment.

For natural gas usage to fall if there is no decarbonisation of the gas grid, then, depending on the expected lifespan of new boilers, regulation would be required to avoid perpetuating gas usage and to protect consumers from investing in assets with a life span limited by regulation. This could mean preventing further standard gas boilers being installed beyond the early 2020s.

If alternative technologies are to be installed then similar preparations would be required. For example with heat pumps, there would be a need to provide improved siting and installation practices to ensure consumers are supported. Hybrid heat pumps/gas boilers are also a possible solution proposed in scenarios, but are comparatively new on the UK market and would require significant advice and support for consumers.

Decision 6. If it proves to be more cost effective to move to heat pumps/hybrids/district heat than to decarbonise gas then it will be necessary to regulate to phase out of the installation of non-hybrid gas boilers. If decarbonising gas appears feasible then this too may require mandatory changes to appliances, as with the switch from town gas to natural gas. Either approach is likely to require phase out regulation as soon as the early 2020s if substantive heat decarbonisation during the 2030s is to take place and stranded assets are to be avoided.

3.8 Backstop measures

Unlike the power sector, decarbonisation of the heat sector will be driven primarily by end-use energy consumers such as homeowners and commercial landlords, rather than large power companies.

Even with the use of constraints or other significant modifications, it is difficult for any cost optimisation model to predict the outcome of decisions made in the real world, where a wide range of financial constraints, behavioural considerations, non-price market failures and other factors often lead consumers to make choices that diverge from the 'optimal' outcome that the model delivers. Regulation may be a useful tool to reinforce, although not replace, incentives and ensure modelled outcomes are actually achieved.

In the heat sector, in particular, many of the measures, both for efficiency and heat production, will go right to the heart of peoples' homes and could have a significant, if transitional impact. In the absence of regulation, there is evidence to suggest that energy efficiency becomes underinvested, with positive incentives and discounts not enough to convince significant numbers of customers to invest (Carbon Connect 2014).

There are good precedents that reinforce the importance of regulation – from April 2005 it was made compulsory for all new boilers to be efficient condensing ones. National Grid estimate that the time to reach 90% penetration was reduced by this regulation from 200 years prior to introduction to 20 years after. Corroborating this, Dr Cliff Elwell at UCL has calculated that the relatively simple and low cost regulation quadrupled installation rates and has led to gas consumption savings which reached more than 60TWh per annum (ca. 15%) by 2013 (Elwell & Biddulph 2014).

It is therefore appropriate to look at how to complement drivers for acceptance and adoption with backstop measures to ensure that those not participating in any voluntary process are also brought into compliance at a combination of appropriately set trigger points, like selling, renting or developing a property. This could be further underlined through a pre-announced and well publicised backstop year by which a particular measure, irrespective of trigger point, would need to be in place in order to comply. This is not unreasonable, if proposed measures will provide a pay-back and/or suitable help with finance and financing is being provided.

Decision 7. If consumers are to make the necessary changes to heat conservation and consumption practices, then appropriate regulatory backstops for heat policy must be set, for instance regulations on achieving a minimum EPC rating before the sale, rental or extension of a property after a specified date; or minimum performance or emissions criteria for equipment installed after a particular date.

3.9 Further considerations

Both of the two main alternatives to gas boilers outlined in the scenarios, heat pumps and district heating, not only pose challenging consumer acceptance issues (Energy Saving Trust 2010) but will also require significantly upgraded or entirely new infrastructure to support them. For either or both to be successful it will be necessary to understand the cost and physical impacts, both transitional and permanent, and to ensure adequate thought is given and resources put in place to overcome any resulting barriers. Coordination will be needed to avoid replication of effort and stranded assets.

It is essential that the social and political implications of these different approaches are considered – as has been seen with onshore wind and insulation measures, despite these being good technical and economic low-carbon options, there are social and/or political barriers that, if not dealt with appropriately, can prevent their full economic potential being realised.

4 Transport Sector

4.1 Introduction

As in the heat sector, planning the decarbonisation of transport is essential both because of the level of energy use and emissions involved, and the impact that decarbonisation of transport will have on electricity generation and supporting infrastructures. While progress has been made on combustion engine efficiency, there has been no clear fall in the demand for transport services, nor a clear view that this will decrease in future. Supporting a transition towards battery, hybrid and fuel cell vehicles will be essential to achieve transport decarbonisation, and requires appropriate supporting infrastructure to be developed and barriers to adoption by consumers to be overcome.

After heat, the transport sector is the second largest in terms of energy consumption at 621TWh representing 36% of total energy in 2013. Unlike the heat and electricity sectors which consist of mainly static installations, by definition, the main requirement in the transport sector is for energy sources which are capable of reliably providing power on the move. This imposes additional size and weight limitations on the potential sources which can be considered for decarbonisation.

The sector is significant with regard to carbon emissions and was responsible for 117MtCO_2 in 2013, accounting for approximately 25% of UK emissions covered by carbon budgets (DECC 2014a). Nearly three quarters of these emissions were associated with road transportation (Analytical Annex 2015) and this paper focusses on this dominant sub-sector.

4.2 Demand

The UK has seen some progress in reducing transport energy demand over recent years. Between 2000 and 2012 energy consumption in the road transport sector decreased by approximately 28TWh. Importantly however this was driven by improvements in efficiency rather than by reduced demand for transport services (DECC 2014c). If there had been no vehicle efficiency savings between 2000 and 2012, energy consumption in 2012 would have been approximately 28TWh higher than the actual level (DECC 2014c).

Many of the efficiency gains have been driven by the EU regulations stipulating a steadily decreasing carbon intensity for all vehicle manufacturers which determines the carbon emissions per kilometre for their light vehicle fleet averages. (Wadud 2014)

A reduction in demand and the greenhouse gas emissions of transport can be achieved in a number of key ways:

- encouraging consumers to buy smaller, lighter vehicles,
- improving the operational efficiency of vehicles,
- altering user practices to reduce transport demand and
- decarbonising transport fuels.

Despite many of the decisions relating to the vehicles themselves being taken at an international level, the scope for influencing the outcome at a national (and local) level is still significant. Impact can be achieved through the use of the tax system and financial incentives, as well as through the investment in supporting infrastructure like charging stations or refuelling points.

This is an example in common with many where the infrastructure issues must be considered in relation to interactions with other sectors – charging stations with the power sector, and the use of hydrogen with both power and heat.

4.3 Fuel prices and other costs

The pace and type of transport decarbonisation seen in the scenarios is influenced by fossil fuel prices. Perhaps reflecting volatility in the past, there is uncertainty and divergence in the scenarios about the direction and scale of future price movements. This impacts on the business case for adopting new technologies including electric vehicles, and also for further internal combustion engine efficiency improvements. Low fuel prices could mean that electric vehicles, which are relatively expensive, do not become cost competitive in the 2020s, reducing consumer uptake in the absence of policy to counteract this. Conversely, higher fuel prices could increase consumer uptake of new technologies (Analytical Annex 2015).

The CCC scenario is based on cost-optimisation modelling which considers the relative whole-lifetime costs of different technologies even though consumers may not consider costs over the full vehicle lifetime when making a purchase decision. Although some consumers say they would be more likely to choose an electric vehicle if fuel prices were higher (Egbue & Long 2012), there is evidence that many consumers give greater weight to upfront cost than the fuel and maintenance cost savings over the lifetime of an electric vehicle (Wu et al. 2015), (Egbue & Long 2012). Consumers may be unwilling to pay a premium for electric vehicles even in situations where the relative price of fuel and electricity make today's electric vehicles cheaper overall.

There is some evidence that consumers with greater experience of electric vehicles are more willing to pay a premium for them (Larson et al. 2014), although the direction of causality between such relationships is not clear (Krause et al. 2013). Presenting consumers with information about the total cost of ownership or five year fuel savings of electric vehicles compared to conventional materials, or some combination of these, could increase the uptake of electric vehicles by potential buyers who may be put off by the high up-front cost (Dumortier et al. 2015). ***The most effective way to present such information could benefit from further research***.

Approaches that focus on providing information to the consumer assume that consumers find it difficult to compare costs over vehicle lifetimes, but an alternative explanation is that high upfront costs are simply undesirable to consumers, which would make price support a more effective policy than improved information (Larson et al. 2014). In an analysis of 30 countries, financial support was found to be significant in rates of electric vehicle adoption, but the availability of such incentives did not ensure higher adoption rates (Sierzchula et al. 2014). In a survey of the US, state financial incentives were not significant in levels of interest in electric vehicles, probably because consumers had very low awareness of them. Any price support that is implemented should be appropriately publicised, and regularly reviewed to account for price changes as a result of learning effects. It is likely to be politically unfeasible to increase fuel or CO_2 tax to levels required to provide an alternative to price support. (Gass et al. 2014)

In the longer term, a key policy goal is to reduce the capital cost of electric vehicles– this could be achieved through funding for further R&D, for example into battery technologies, as well as subsidies to stimulate demand, which can be expected to decrease costs through economies of scale and learning effects (Thiel et al. 2010).

It is also important to note that whilst high fossil fuel prices might be considered a driver for investment in electric vehicles, studies show that this is seldom a replacement for direct support for electric vehicle deployment and technology development; particularly in the early stages of deployment (UKERC 2009). Indeed, whilst taxation accounts for some 80% of consumer petrol/diesel prices, current prices lie below the ranges modelled in the scenarios reviewed for this paper. This reflects the relatively recent and dramatic decline in world oil prices since late 2014 and underlines the high uncertainty associated with fossil fuel price.

It is impossible to predict or decide what future prices of fuel will be, however it is essential nonetheless to establish measures that will underpin the change away from conventional fossil fuelled vehicles if the fuel price remains below that needed to drive market choices, in which case government intervention may be needed to either provide funding and/or to regulate for the desired measures to be adopted anyway.

Decision 8. If a move away from fossil fuel powered vehicles is to be underpinned, then regardless of the alternative chosen, a series of back-stop measures, to regulate the phase out should be agreed and implemented.

4.4 Types of vehicle

There is general consensus across the scenarios that the share of non-hybrid internal combustion engine vehicles falls dramatically - to zero in some cases - for new sales by 2030 (Analytical Annex 2015).

There is similar consensus that electric vehicles, both battery and hybrid, are the dominant alternative for cars, although hydrogen, after first gaining traction in bus and HGV sectors transport, later makes an impact in all road transport.

The scenarios only see a limited role for biofuels (4-8% of total fuel demand).

Aside from fuel and other costs, a range of barriers specific to different alternative vehicle types exist, and the success of any economic interventions may be conditional on these being overcome (Egbue & Long 2012).

4.4.1 Battery electric vehicles

An important area of divergence between the scenarios is the relative roles for pure battery electric vehicles versus hybrid electric vehicles. Whilst there seems to be a general consensus that hybrid electric vehicles will be cost-competitive in the lead up to 2030, there are many barriers in addition to high upfront costs that threaten the wide-scale deployment of pure battery electric vehicles.

Firstly, many consumers generally prefer to use traditional, familiar technologies and may have low tolerance for the perceived risk of new technologies. Consumers may have low awareness or misconceptions about aspects of the technology, including performance and safety as well as purchase price, fuel and maintenance savings and available incentives (Krause et al. 2013). Consumers who have had experience of electric vehicles may have higher opinions of EVs than those with less exposure to them, and this can include a change in attitudes from before and after using electric vehicles (Bühler et al. 2014).

Consumers may also have specific concerns about range and reliability, the availability of charging infrastructure and speed of charging. Some consumers may feel concerned by the potential failure of the battery (Egbue & Long 2012). Consumers may prefer to have access to a much greater driving range (for occasional use, for example for a family holiday) than they undertake on a day to day basis (Bunce et al. 2014).

The availability of charging infrastructure was found to be significant in adoption rates of electric vehicles across 30 countries (Sierzchula et al. 2014), although awareness of public charging stations had only a weak relationship to interest in electric vehicles in one Canadian survey (Bailey et al. 2015). Generally, charging infrastructure is accepted as necessary for the roll out of electric vehicles, but local decision makers may be uncertain about the best strategic locations and types of charging points (Bakker & Jacob Trip 2013). There are also commercial and regulatory barriers to developing charging infrastructure: while charging infrastructure is necessary for the roll out of electric vehicles, service providers will not have a large market until the number of vehicles increases, meaning it may not be cost effective to bill for use of public chargers; developing public charging may involve new, untested collaborative business models, which some businesses are hesitant to adopt, and for which a legal framework may not currently exist; and there are variations in billing and charging technology around the UK and Europe (McKinsey & Amsterdam Roundtables Foundation 2014).

Local authorities can work alongside commercial vehicle users in their area to contribute towards a critical mass of charging points for their own use.

Support and regulation for infrastructure development could include developing building regulations that require a percentage of new homes to have chargers or be ‘charger ready’, particularly where this may be difficult to achieve without intervention (such as apartment blocks or terraced houses), and explore processes for retrofitting charge points to such locations.

A planning framework for public charging could support local authorities in creating strategic plans and overcoming practical difficulties, and government could accept some of the risk faced by service providers developing infrastructure before a large market exists. As a minimum, government should provide information on charging and parking locations nationwide, work to unify regulations and payment methodology for parking and charging, and facilitate nationwide billing; and lobby for the development of European standards for charging technologies to avoid the need to carry multiple plugs and cables.

Depending on the combination of scenarios for demand and vehicle type, as much as 60TWh would need to be met by electrification by 2030. Based on National Grid’s current experience which shows that actual peak is about 1.25 times the theoretical minimum (if demand was spread evenly across the day and year), this consumption level would translate into an increase in the de-rated peak requirement for the power system of 11GW by 2030. The impact on peak could be higher if charging patterns were allowed to emerge which saw greater use at peak times (Cambridge Econometrics 2013).

Decision 9. If electric vehicles are to be encouraged and their use facilitated, then a clear plan for the design and stepwise establishment of charging stations and their impact on the electricity networks and generation adequacy should be established, initially at a local level, building on local authority and local business users’ needs.

4.4.2 Hydrogen vehicles

Modern hydrogen vehicles no longer use internal combustion engines, but instead have an electric drive train where the electricity used is generated by hydrogen fuel cells, and thus hydrogen refuelling infrastructure rather than electric charging is required.

The scenarios are consistent in suggesting that it is likely to be larger vehicles such as buses, HGVs and LGVs that will be the first vehicles to adopt hydrogen technology on the basis that battery electric vehicles may be unsuitable due to size, weight and cost of the battery required (Analytical Annex 2015).

The different scenarios see varying roles for hydrogen by 2030 (3 – 10% of new sales by 2030). Findings from the preliminary phase of the UK H2Mobility project indicate that through early adopters among car and van drivers, it is feasible for the uptake of hydrogen vehicles to reach 10% of new sales by 2030 (Analytical Annex 2015).

In order to have any degree of penetration it will be essential to establish the minimum requirements for a refuelling network. UK H2Mobility estimate that to support a roll out of 10% of new sales would require a refuelling network comprising 65 stations in 2015, growing to 1,150 by 2030 with at least one per local authority district (Analytical Annex 2015). Again, local authorities alongside local business users can help build the foundations of a refuelling infrastructure.

There are significant potential synergies and interactions between the heat, power and transport sectors with regard to hydrogen, its production, storage, transportation and usage which must be contemplated. Consideration should also be given to the use of hydrogen fuel cells as part of hybrid electric vehicles, and the benefits this could offer for reducing battery size and cost to correspond to daily driving distances, while maintaining the flexibility of longer ranges overall (Offer et al. 2011). An alternative approach could be the adoption of battery electric vehicles where these will be used for shorter journeys, and fuel cell vehicles for longer journeys (Dijk et al. 2013).

Decision 10. If hydrogen vehicles are to be encouraged and their use facilitated, then a clear plan for the stepwise establishment of a critical mass of hydrogen refuelling points should be coordinated by Local Authorities, building on their own and local business users' needs.

5 Electricity Sector

5.1 Introduction

There is generally much more detailed analysis in the scenarios of the power sector than found for the heat and transport sectors. Most of the scenarios concentrate on supply side measures to reduce carbon emissions through an increase in low-carbon electricity generation. Demand side measures, however, clearly should not be ignored.

Through changes introduced by EMR, the electricity sector more than any other is dependent on Government decisions to issue contracts which will determine to a great extent on the supply side how much of what will be built and when. For this reason, it is particularly important that the necessary decisions are made.

All of the scenarios and the analysis in this paper confirm the fundamental role that a decarbonised electricity system can play in directly reducing carbon emissions and creating options for reducing emissions in the heat and transport sectors. This further underlines the need to make any decisions and informed choices as expeditiously as possible.

Scenarios show that underlying demand for electricity, not taking into account electrification of heat and transport, is likely to remain at similar levels to today, with efficiency savings, predominantly driven by product standards, being balanced by increased demand for appliances powered by electricity, especially electronic ones. However, they also suggest that once electrification is taken into account, electricity supply will increase by approximately 12 - 24% by 2030, which could mean between 450TWh- 600TWh of total supply (Analytical Annex 2015).

Despite divergence in specific modelling outputs, there is more a difference in ***when*** higher levels will be reached, not ***if*** this will happen. It is therefore important with regard to planning the development of the electricity system to look beyond 2030, since this will give a better indication of the opportunities and risks associated with investment in supporting infrastructure, potentially ahead of need, and to ensure it is appropriately dimensioned and will not require repeated upgrades in the short to medium term.

The main areas of convergence and divergence in the scenarios are discussed below.

5.2 Pace and timing of decarbonisation

There is a broad conclusion across the scenarios that by 2030 the UK's power sector carbon intensity will have to fall by at least 80% on 2012 levels to about 100g CO_2/kWh. There is still no consensus about whether it will fall significantly further, although the UKERC Low Carbon scenario suggests that it might even drop so far that the power sector achieves negative emissions (Analytical Annex 2015). This therefore raises serious questions about the likely pace of the UK's decarbonisation efforts leading up to 2030 and beyond, making it risky and expensive for investors to take forward any plans regardless of whether they are for high or low carbon plant. This highlights the importance of having a clear trajectory, analogous to the one set for carbon intensity of vehicles in the transport sector.

Decision 11. If targets are to be met, especially when electrification is the basis for the decarbonisation of other sectors, then the corresponding long term trajectory for carbon intensity of power generation portfolios should be agreed, ideally in line with CCC trajectories.

5.3 Levelised costs of low-carbon technologies by 2030

In the scenarios there is little clarity about the future (or even current) cost of many low-carbon technologies (UK Energy Research Centre 2013b). Different technologies also have very different network requirements. Therefore, whilst government might want to use auctions to reveal which technologies are cheaper it also needs to do this in conjunction with the necessary strategic decisions, factoring in network infrastructure costs and impacts.

There is strong evidence that costs do fall as deployment rises (for example through learning effects, ongoing innovation, scale effects, and standardisation), although, this may not always be the case if other factors have a major impact, most notably fuel and commodity prices - costs can even rise before they fall due to learning effects and supply chain development (UK Energy Research Centre 2013b).

However, as a general point, technologies are more likely to reduce in cost if constructively supported to allow a critical mass of deployment to develop – this has been documented with regard to offshore wind recently in research carried out for the CCC (BVG Associates 2015)

It is also important to question whether on its own, the levelised cost of energy (LCoE) for the different technologies will be a useful indicator of system costs in the future. With increasing intermittent and inflexible generation, the additional costs to balance, provide system services and ensure system adequacy start to play a very significant role in overall costs, which are not captured in the LCoE.

A significant recent change in costs has been seen for solar PV, which has surprised many with the pace and scale of the reduction that has been achieved– both for the equipment itself and also for installation. The most recent auctions for CfDs saw some solar projects clearing at below £80/MWh (for 15 year contracts) – this compares with rates of up to £433/MWh for Solar PV under the original Small Scale Feed-in Tariff introduced in the Energy Act (2008).

In contrast, despite the maturity of nuclear generation and the hopes that many have placed in the role it can play in decarbonising the electricity system, many were surprised by the very high CfD price that the Government negotiated for the latest nuclear plant at Hinkley Point C, at over £100/MWh in 2015 money (for a 35 year contract).

A number of the scenarios analysed in this report will not have caught up with this more recent cost information. Solar PV has been an example where actual results have lain outside the boundaries of the scenarios and 'the unthinkable' has happened, albeit in a positive way, driven by other countries' decisions and determination to achieve the critical volumes needed for this to happen.

5.4 Fossil fuel technology assessment

5.4.1 Oil and coal

There is general agreement across the scenarios that unabated coal and oil generation should fall dramatically, reaching almost zero by 2030. Oil has already all but disappeared from the UK system.

Nonetheless, a significant proportion of existing coal capacity could still theoretically be operational in 2030 – how much is likely to be primarily a function of the carbon price in the absence of other policies to constrain the use of existing coal fired power stations (Gross & Speirs 2014). In some scenarios the carbon intensity of the power sector would remain so high that the UK would run a serious risk of failing to meet its Fourth Carbon Budget (Gross & Speirs 2014). This suggests that in the absence of other policies to constrain the role of coal generation, the view of plant operators on the future level of the carbon price will be a key driver of investment and operating decisions relating to coal out to 2030.

It is desirable to avoid this uncertainty by providing a more bankable trajectory for the UK Carbon Price Support in the 2020s. Since this is a tax which easily can be (and already has been) changed, this could mean finding an alternative means, such as primary legislation or contracts for difference, to more convincingly underwrite the level. This could be further reinforced by continuing to support a strong fundamental carbon price through the EU Emissions Trading Scheme and with additional clarity for investors being provided by an Emissions Performance Standard (EPS) applied to existing IED compliant coal plant as well as prospective new build coal.

Decision 12. In the absence of other measures, if achievement of decarbonisation targets is not possible with coal still on the system, then a clear regulatory phase out plan should be introduced to act as a back-stop and provide the necessary clarity for investment in alternatives.

5.4.2 Gas

All scenarios model a continuing significant role for (unabated) gas plant in 2030 with most suggesting around 35GW of capacity needed (Analytical Annex 2015). However, reflecting uncertainty about other elements of the system, the energy production and attendant load factor for this gas plant does vary significantly from an average of approximately 20% where good progress is made with low carbon technologies to approximately 50% if deployment is slow. This is then reflected in varying and potentially adverse carbon intensity and overall emissions levels.

There should therefore be little risk to investors in ensuring that this level of gas capacity is deployed, even though the running regime remains unclear. However the combination of capacity and energy payments necessary to amortise the investment will vary considerably and investors would need confidence that, whatever the outcome, an appropriate balance between the two would materialise.

The availability of gas as a fuel will also be critical to the future operation of plant. The UK has built up a resilient combination of sources of gas to achieve this. Looking at future gas supplies, a comparison of the scenarios raises some questions about the role of shale gas, which is often wrongly positioned as a technology choice, rather than a source of fuel. Scenarios acknowledge that despite the uncertainties surrounding the extent of the UK's shale gas reserves and what proportion of this might be cost-effectively recovered, shale gas could make a contribution to the UK's gas supply but that it would be highly unlikely to satisfy the UK's full gas demand and its contribution is unlikely to have a significant impact on gas prices because these are dictated by international markets (in a way that they were not for the US) (UKERC 2013). It will make little or no difference to carbon abatement when compared to conventional gas (MacKay & Stone 2013).

The future role of gas plant will also be influenced by developments in CCS technology and could be interlinked with potential future availability of alternative forms of gas: bio-methane, synthetic methane and hydrogen. This must be factored into decisions discussed earlier about their use in the heat and transport sectors.

Decision 13. If gas generation is to play the range of roles outlined in the scenarios, then the market and regulatory framework must incentivise the necessary level of investment to maintain existing and to build new plant as well as to secure fuel supplies.

5.5 Low carbon technology assessment

5.5.1 CCS

CCS has made only slow progress to date with any first large scale demonstration projects in the UK not due before the end of the decade. Perhaps not surprisingly, the models agree that CCS is not expected to be commercially viable until the late 2020s at the earliest and could, at best, account for a modest proportion of capacity by 2030.

There is still much work needed before even a low contribution from CCS can be relied upon and therefore essential that rapid progress is made with the UK demonstrator programme and a close watch kept on other international projects. To maintain even this limited momentum, plans should be advanced for the next stages of demonstration and deployment beyond the first pilots, including plans for the necessary supporting infrastructure. This is important not only for the power sector, but also for heavy industry and potentially the decarbonisation of synthetic methane and production of hydrogen.

The oil and gas industry, with an eye on keeping open a route to market for key products, have a greater incentive to make CCS work than the power industry, who generally see it as a source of extra cost and lower plant efficiency and flexibility. It will be essential for all industries to work together and be given clarity on a funding path to support moving from demonstration towards technical and commercial maturity as well as an economically sustainable model for future operation. There is a strategic need to decide locations of plant, pipelines and storage sites, preferably in areas where clusters of generating plant and heavy industry or synthetic gas production could utilise the same infrastructure, especially since these are likely to operate at much higher efficiency.

Decision 14. If CCS is to be capable of development towards any significant future role, then plans for the next phases of CCS demonstration and deployment as well as for the funding and commercial models needed to take CCS into normal operation must be implemented.

5.5.2 Nuclear

The scenarios show nuclear providing low-carbon baseline electricity supply with up to 18GW of new capacity modelled to come online during the 2020s (Analytical Annex 2015). However most, if not all, scenarios came to this conclusion using nuclear costs that were much lower than have now been established by the Government negotiations on Hinkley Point C (HPC).

Despite the high strike price, a final investment decision on HPC has again been postponed due to a combination of new technical concerns about the quality of steel used in the pressure vessels, legal challenges to the state aid ruling and difficulties with finding partners to co-finance the investment following the withdrawal of Centrica and the near bankruptcy of the equipment supplier, Areva. This, combined with the continuing cost overruns and delays being seen in the limited roll out of nuclear generation across Europe, has raised serious questions about the deliverability of new nuclear in the UK, both with regard to cost and to timescales.

However, there are other potential suppliers of nuclear technology to the UK (Hitachi/Horizon and Toshiba/NuGen) who, despite starting later in the process, may be able to deliver more quickly and cost effectively. In the absence of this, it is difficult to see how nuclear can make a significant contribution to the UK electricity supply in the 2020s and early 2030s, beyond what is possible by building on the good track record of efficiency improvements and life extensions of existing stations.

The Government has already made clearer, and more specific decisions on the need and support for nuclear than for other technologies and therefore, other than to consider applications for Generic Design Approval (GDA) for new technologies expeditiously, can now do little more to influence if, when, and at what cost, new nuclear plant is constructed and commissioned.

Decision 15. If progress on nuclear generation is to be accelerated and downward pressure brought to costs, then consideration of GDA for new nuclear designs must be carried out as expeditiously as possible to allow allocation of contracts to be subject to competition.

5.6 Renewables technology assessment

5.6.1 Wind

Scenarios all show new offshore and onshore wind capacity being rolled out extensively in both the late 2010s and early 2020s with the potential to provide significant capacity by 2030 (approx. 30-50GW). This is a reflection of the momentum that already exists and the current pipeline of projects, mostly developed under the Renewables Obligation. However, there is much less clarity going forward.

Offshore wind is not yet mature – although falling, its costs are still high and despite costs being estimated in the scenarios in a narrower range than CCS, there is still significant debate on long-term levels (Analytical Annex 2015). There is a trade-off between continuing technology developments which are tending to push the costs down (Offshore Wind Task Force 2012), and an increasing drive, often for consenting reasons, for deployment in deeper waters, further from the shore which push costs in the opposite direction.

Offshore wind projects are much bigger than onshore wind or solar PV, so it is likely to take longer for volume effects to drive costs down and this is compounded at an international level (in comparison to onshore wind and PV) by the limited number of countries where it is possible to use the technology. The UK has been the largest developer to date and should therefore maintain this position to be confident of further deployment, cost reductions and inward investment. However, uncertainties about EMR and associated changes in policy for supporting offshore wind have been credited with increasing risks and costs for developers, and leading to a very significant abandonment of projects and the writing-off of hundreds of millions of pounds, as can be seen in the 2014 SSE annual report, for example (SSE 2014). This has made investors nervous and any reduced ambition for future volume could seriously threaten further cost reduction as well as supply chain investment in the UK (IEA 2012).

Government's aspirations for offshore wind (DECC 2014a) shows a wide range of new build requirements of 0 – 33GW between 2020 and 2030, but there is no indication of what, if any, LCF allocations may be forthcoming – this is not helpful to investors raising the finance for investment in projects, technologies, innovation or production facilities

This has been reinforced by a recent study carried out for the Committee on Climate Change (CCC) by BVG Associates (BVG Associates 2015) which concluded that to unlock these opportunities, confidence in a future market is the most important driver.

The CCC conclude that the Government must take measures to ensure the power sector can invest with a 10-year lead time and extend funding under the Levy Control Framework to match project timelines (e.g. to 2025 with rolling annual updates).

Significant investment is also required in off- and on-shore transmission infrastructure to support the deployment of offshore wind. The timescales for delivering controversial onshore developments can be many years, for instance the Beauly to Denny upgrade will have taken at least 15 years between initial scoping work in 2001 and final commissioning in 2016. Transmission owners and the regulator must be given sufficient advance warning of the need to develop, finance and construct the necessary supporting infrastructure.

Onshore wind has consistently shown cost reductions as deployment volume has increased. Some projects cleared at under £80/MWh in the recent CfD auctions. As with solar PV, there is sufficient volume and standardisation internationally to keep equipment costs down however, non-technology costs such as consenting, land acquisition and network charges are specific to different countries. In the UK, transmission connection charges account for a relatively small portion of costs but the use of system charges can be a considerable burden, especially in remote areas, like Scotland, where the wind resource is often best. The costs of planning requirements are increasing due to growing public sensitivity, complying with environmental requirements and the decreasing availability of good sites (DECC 2013a). In comparison, projects in the US are being built at a median LCoE of $60/MWh, about half of the UK level (US National Renewable Energy Laboratory 2014).

Assuming appropriate supporting policies (Lund 2011), there is an expectation that efficiently sited projects could reach 'grid parity' and be realised without subsidy during the 2020s. However, the main barriers for onshore wind in the UK are increasingly from the planning system and political opposition. Although good progress has been made in Scotland, the position in England has made it very difficult to deploy onshore wind projects.

Therefore future deployment rates could be much more dependent on regulatory/consenting decisions and costs than technology economics. If there are to be limitations, then to avoid the unnecessary expense of developing and trying to consent projects, these must be made explicit.

Aside from important public acceptance issues, onshore wind would appear the natural, rational choice of a low carbon electricity generation technology - well suited to the UK weather, deployable at scale, with costs capable of reducing towards grid parity and free of the uncertainties surrounding CCS, nuclear and offshore wind.

5.6.2 Solar PV

Solar PV prices have decreased dramatically in recent years, and the speed of this decrease is not reflected in some earlier scenarios (Analytical Annex 2015). There is little consistency across the scenarios about the future role for solar PV, probably related to whether modelling was performed before or after this fall in PV costs. This is an interesting specific example of the potential impact of the uncertainty about future costs, as well as of the age of the scenarios, on the accuracy of predicted outcomes.

A range of factors, including the dramatic reduction in crystalline silicon modules (45% from mid-2010 to March 2012), driven by improved manufacturing at scale and cheaper feedstock, as well as reduced costs in system integration, transportation and installation (UK Energy Research Centre 2013a), have been among the factors which have helped solar PV to reduce costs much more and faster than expected. It is likely that future scenarios will present a more positive outlook for PV deployment on the basis that costs have fallen dramatically, although none of the modelling will have yet caught up with levelised costs below £80/MWh, which was the clearing price for some solar PV projects in the most recent CfD auctions.

With such low costs, solar PV could be deployed in significant amounts, even in countries like the UK where solar radiation levels are not optimal. However, as with onshore wind, some of the greater threats to future solar PV deployment in the UK relate to the planning system and non-technology costs. The recommended decisions are therefore the same.

5.6.3 Biomass

Despite all the scenarios expecting an increasing role for biomass, perhaps reflecting differing views about cost, fuel availability and sustainability, there is no clear consensus about the levels of biomass generation reached by 2030, with a range of capacities from 9 – 26GW producing between 36 and 61 TWh (9-15% of electricity compared with 7% in 2013).

More recently there has been an increased international focus on Bio-Energy with Carbon Capture and Storage (BECCS) to create 'negative emissions' in an attempt to compensate for lack of progress on more direct decarbonisation measures. Careful research is needed to clarify the uncertainties regarding biomass, especially if it is to provide the remedy for shortfalls elsewhere. For instance, the International Council on Clean Transportation has raised a number of serious concerns about the amounts of truly sustainable biomass available for use in the energy sector (Searle & Malins 2015).

5.6.4 Hydro and Marine

Most of the scenarios project relatively modest deployments of hydro and marine electricity generation by 2030.

5.6.5 Overall objectives for renewables

Despite the good progress made with renewables deployment, recent Government announcements about withdrawal of financial support as well as on planning restrictions have created a high degree of uncertainty for all investors and seen the UK lose the top ten position it has always previously held in the EY Renewable Country Attractiveness Index, published in September 2015.

Under current conditions, it will be difficult for any further investment developments, beyond those already in the pipeline, to attract the necessary finance to be realised. Because of the planning and consenting uncertainties, this is even true of those technologies like onshore wind and larger scale solar PV which are nearly deployable without subsidy.

Decision 16. If further investment in renewables is to take place and for costs to continue to fall, then clarity must be given about future aspirations and limitations with regard to volume, location and, where still relevant, the Levy Control Framework.

5.7 Market issues

As more optimistic scenarios for solar PV and wind deployment by 2030 are now becoming realistic, and if nuclear and CCS are to play an enhanced role, the government will have to give serious consideration to the implications that such a large intermittent and/or inflexible capacity will have on the wider system, identifying a strategy to better integrate this capacity and complement it with other more flexible low-carbon energy technologies and/or demand side and storage options. Interconnection options with other European nations may also play a significant role in balancing the system by 2030 as long as appropriate and coordinated action is agreed for demand and supply side measures across all of the interconnected areas.

Similarly thought must be given to the impacts this will have on the wholesale market which was designed for the historic system, dominated by high short run marginal cost plant and driven by energy-only price signals. In contrast, solar PV and wind as well as nuclear and, to some extent CCS, have high up-front capital costs and low(er) marginal costs, and supporting policies must focus on securing the capital investment required. The lack of impact of wholesale price signals on the operation of such generators in energy markets can lead to inefficiencies such as negative prices and large peaks and troughs in generation independent of demand.

The residual market might also benefit from reform in order to be able to better provide the necessary price signals and drivers to value and reward the diverse performance characteristics of the evolving low carbon energy system. This is likely to be necessary to maintain system stability as deployment of low carbon technologies increases (IEA 2013).

As a result of uncertainties in relation to the overall electricity demand, the level of decarbonisation, the costs of different technologies and the volumes of each to be delivered, it is unsurprising that there is also uncertainty in the scenarios around the overall cost and the level of investment required to deliver a 'low-carbon UK power sector' by 2030 - estimates vary significantly between £88bn and £300bn, although most agree that is likely to be at least £200bn (Analytical Annex 2015).

One thing is clear – unless key decisions about technology deployment and the supporting network infrastructure are made, the necessary investment in innovation, production and standardisation needed for cost savings is unlikely to be forthcoming. Therefore, delaying or making no decision, even if this is pending better information about costs, could actually be the most expensive option.

Decision 17. If market signals are to drive appropriate responses from all generators for energy, capacity and system services, then a market design appropriate for the future electricity system and capable of differentially rewarding and influencing the characteristics of energy production, capacity/ adequacy and system services, must be developed.

6 Summary of Recommendations

Heat Sector

Decision 1. If energy demand reduction of at least 25 – 30% is to be achieved by 2030, then a long term, substantial and effectively targeted investment programme in residential and commercial buildings has to take place. Delivering this will require concerted policy efforts across building codes/regulation, market transformation, incentives, labelling and billing. Policy needs to target both low-income households and the 'afford to pay' sector.

Decision 2. If peak demand patterns are to be modified in order to optimise system capacity and costs, then interventions should be considered by DECC and Ofgem which complement and underpin voluntary consumer actions to shift heat load.

Decision 3. Further research should be supported by DECC and Ofgem to understand that if gas networks are to be maintained, then what alternative forms of gas (biomethane, synthetic methane, hydrogen) could be used instead of/as well as natural gas or, if they are to be replaced what costs and impacts would be involved in replacing their functionality.

Decision 4. If a significant move towards heat pumps is to be made in any locality, then in line with energy efficiency investment and reductions in the overall carbon intensity of the grid, plans for the roll out of heat pumps should be coordinated across the relevant organisations, taking into account the local and national transition and infrastructure implications, costs and timescales.

Decision 5. If distributed heat solutions are to be developed, then Government, both central and local, must make appropriate plans and inform potential consumers about which building types and zones will be considered, and on what timescales roll out will happen.

Decision 6. If it proves to be more cost effective to move to heat pumps/hybrids/district heat than to decarbonise gas then it will be necessary to regulate to phase out of the installation of non-hybrid gas boilers. If decarbonising gas appears feasible then this too may require mandatory changes to appliances, as with the switch from town gas to natural gas. Either approach is likely to require phase out regulation as soon as the early 2020s if substantive heat decarbonisation during the 2030s is to take place and stranded assets are to be avoided.

Decision 7. If consumers are to make the necessary changes to heat conservation and consumption practices, then appropriate regulatory backstops for heat policy must be set, for instance regulations on achieving a minimum EPC rating before the sale, rental or extension of a property after a specified date; or minimum performance or emissions criteria for equipment installed after a particular date.

Transport sector

Decision 8. If a move away from fossil fuel powered vehicles is to be underpinned, then regardless of the alternative chosen, a series of back-stop measures, to regulate the phase out should be agreed and implemented.

Decision 9. If electric vehicles are to be encouraged and their use facilitated, then a clear plan for the design and stepwise establishment of charging stations and their impact on the electricity

networks and generation adequacy should be established, initially at a local level, building on local authority and local business users' needs.

Decision 10. If hydrogen vehicles are to be encouraged and their use facilitated, then a clear plan for the stepwise establishment of a critical mass of hydrogen refuelling points should be coordinated by Local Authorities, building on their own and local business users' needs.

Electricity sector

Decision 11. If targets are to be met, especially when electrification is the basis for the decarbonisation of other sectors, then the corresponding long term trajectory for carbon intensity of power generation portfolios should be agreed, ideally in line with CCC trajectories.

Decision 12. In the absence of other measures, if achievement of decarbonisation targets is not possible with coal still on the system, then a clear regulatory phase out plan should be introduced to act as a back-stop and provide the necessary clarity for investment in alternatives.

Decision 13. If gas generation is to play the range of roles outlined in the scenarios, then the market and regulatory framework must incentivise the necessary level of investment to maintain existing and to build new plant as well as to secure fuel supplies.

Decision 14. If CCS is to be capable of development towards any significant future role, then plans for the next phases of CCS demonstration and deployment as well as for the funding and commercial models needed to take CCS into normal operation must be implemented.

Decision 15. If progress on nuclear generation is to be accelerated and downward pressure brought to costs, then consideration of GDA for new nuclear designs must be carried out as expeditiously as possible to allow allocation of contracts to be subject to competition.

Decision 16. If further investment in renewables is to take place and for costs to continue to fall, then clarity must be given about future aspirations and limitations with regard to volume, location and, where still relevant, the Levy Control Framework.

Decision 17. If market signals are to drive appropriate responses from all generators for energy, capacity and system services, then a market design appropriate for the future electricity system and capable of differentially rewarding and influencing the characteristics of energy production, capacity/ adequacy and system services, must be developed.

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