Programme Area: Energy Storage and Distribution

Project: Multi Vector Integration

Title: Barriers to Multi Vector Energy Supply

Abstract:

This Deliverable is the report summarising the work completed in Work Package 5 and provides the following:

1. A summary of economic modelling findings
2. Identification of key technical, commercial and regulatory barriers across Case Studies.
3. Classification of the barriers identified, based on:
   - Impact – the scale of potential system benefit of multi vector operation
   - Risk – the extent to which these barriers are surmountable
4. Discusses the innovations that might mitigate these barriers, comprising the necessary technical capabilities, and the required regulatory and commercial frameworks.
5. Assesses the additional work for multi vector operation to achieve commercialisation at scale, comprising:
   - Investment
   - Timescales and necessary uptake rates
   - Skills gaps, required operational transformation and strategic considerations

Context:

The project aims to improve the understanding of the opportunity for and implications of moving to more integrated multi vector energy networks in the future. Future energy systems could use infrastructure very differently to how they are employed today. Several individual energy vectors - electricity, gas and hydrogen - are capable of delivering multiple services and there are other services that can be met or delivered by more than one vector or network.

Multi Vector Integration Study

D5.1 – Barriers to Multi Vector Energy Supply

for

The Energy Technologies Institute

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1 Introduction

The ETI Multi Vector Project aims to develop understanding of the opportunity for, and implications of, energy that is generated, supplied, distributed or stored using a range of vectors, rather than the current approach in which the operation and planning of each vector is considered in isolation.

1.1 Previous Project Work

We have adopted a Case Study structure for this analysis, determining the potential scale and value of a set of multi vector energy supply solutions and the barriers to moving to multi vector operation:

Initially, we identified and filtered long and short lists of Case Studies in partnership with the project steering committee. We then represented each short listed case in a bespoke techno-economic model, and compared a range of single and multi vector scenarios.

The benefits of multi vector energy supply across a range of future energy system pathways is quantified and discussed in detail in the WP3 report *Assessment of Local Cases*, which accompanies this analysis.

1.2 Report Structure

This document:

1. Summarises the findings of the economic modelling.
2. Identifies key technical, commercial and regulatory barriers across Case Studies.
3. Classifies these barriers, based on:
    - **Impact** – the scale of potential system benefit of multi vector operation
    - **Risk** – the extent to which these barriers are surmountable
4. Discusses the innovations that might mitigate these barriers, comprising the necessary technical capabilities, and the required regulatory and commercial frameworks.
5. Assesses the additional work for multi vector operation to achieve commercialisation at scale, comprising:
    - Investment
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1.3 Summary of Techno-Economic Findings

The analysis detailed in the WP3 report *Assessment of Local Cases* is summarised below; the value of the multi vector configurations assessed is summarised in the System Value column; this is used to rate the barrier's impact and significance of possible solutions, which are explored in Section 2.

Table 1 - Summary of Techno-Economic Analysis

Case Study	Description	Key Findings	Value
Hybrid heat pumps	We determine, for the City of Newcastle: • Network upgrade costs for a range of heat pump uptake scenarios. • The share of these costs avoided through multi vector heating– using heat pumps to supply base and gas boilers to supply peak, demand. • Fuel cost and emissions for each heat supply option.	1. Substantial electrification of heat (transition of domestic heating from gas to air-to-water heat pumps at a third of homes) requires significant grid reinforcement (especially the LV feeder cables), the undiscounted total of which is between £2,000 and £5,000 per household by 2050; between 50% and 100% of the installed cost of the hybrid unit. 2. Multi vector supply avoids between 75% and 100% of these upgrade costs, depending on the specific implementation and grid headroom. Over 90% of heat demand is met electrically. 3. Heat can then be securely supplied within the existing network infrastructure through multi vector operation. Given the small total usage, and the low heat pump CoP during times of peak demand, the fuel cost and environmental impacts of multi vector gas use are moderate. 4. Savings accrue to DNOs, while gas network operators must provide a largely unchanged service to multi vector homes, who consume only 10% of their counterfactual gas demand. Depending on implementation, multi vector heat supply costs might include: • Upgrade to LV network telemetry • Building the aggregation and control platform • Potential value sharing with GDNs and consumers, to maintain an operational gas network and boilers. 5. This is a true multi vector benefit; the single vector alternative - intelligent use of domestic thermal storage - cannot in general obviate the need for a peak supply vector. 6. Hybrid heating does not require a smart control system – undersized heat pumps can deliver baseload with gas boilers providing peak demand. We find a 50% sized heat pump provides 92% of thermal demand, and avoids around two thirds of network upgrade costs.	High
CHP and HP in heat networks	We determine under which future energy system scenarios multi vector heat networks, in which a gas CHP provides heat to the network and power to a heat pump, lower the cost of heat. We investigate the benefit to the scheme operator, the system, and to the local grid.	1. Marginal reductions in heat network lifetime cost are achieved through use of multi vector DH under a range of central and high carbon prices. 2. Multi vector plant capital costs are lower than those of a similarly sized ground or water source heat pump. However, under high carbon prices and decarbonised power generation multi vector heat supply costs are higher than for heat pumps. Multi vector supply may therefore be a lower risk stepping stone to decarbonised heat supply for networks or large facilities. 3. Analogously to a gas-engine heat pump, and at a similar CoP, multi vector heat supply allows heat networks to be constructed without connection to the power grid. Gas-only operation is unlikely to be a cost effective long term option, but may be viable in the medium term. 4. Proximate CHP/DH schemes and heat pumps can also reduce their supply cost of heat through electrical supply by private (or virtual private) wire.	Moderate

PiV fuel switching	We determine the option value in supplying hybrid plug-in vehicle (PiV) demand using petrol/diesel rather than electricity in response to times of reduced power generating capacity, or price spikes.	Given the extent to which the electric demand of hybrid vehicles can be flexibly managed, and the higher efficiencies of electric, rather than petrol or diesel, engines, we find no benefit to the system or to users, in matching demand through the liquid fuel, rather than the electric, vector.	Low
Power to Gas – Transmission Level RES to H_2 and RES to CH_4	We investigate: • The system value in electrolysers absorbing surplus renewable generation and injecting hydrogen (or methane) into the gas grid. • The renewable generation capacity, and degree of oversupply required to make electrolysis for grid injection viable.	1. Power to Gas as a system reservoir for renewable oversupply is better than "doing nothing", but worse than intelligent grid reinforcement. Due to the shape of its duration curve, economically optimally sized electrolysers only capture a small portion of oversupply. 2. There is system benefit where methanation is used to capture carbon that would otherwise be released into the atmosphere (in this case, the environmental revenue is many times higher than the fuel cost – the plant is essentially a carbon capture facility). Given the carbon price required to build renewable capacity sufficient to generate significant oversupply, large unmitigated carbon sources are likely to be uneconomically costly, and therefore scarce. 3. Current Demand Turn Up availability payments do not make electrolysis profitable, but novel ancillary service provision represents a potential future revenue stream.	Moderate
Power to Gas – Electrolysis for Hydrogen Networks	We investigate the potential for electrolysers to augment the hydrogen supply of a converted gas network; given the relative costs and flexibility of electrolysis and steam methane reforming (SMR) – creating hydrogen from natural gas.	1. Electrolysers compete at meaningful scale with SMR only at average power prices of around £25/MWh, around 55% of the ESME scenario average 2050 levels. 2. Where SMR and storage ramp rates are highly constrained, electrolysers may play a larger role in network supply. 3. This analysis assumes a CCS cost of around £42/tonne CO_2, which is significantly below the ESME 2050 carbon price.	Low
Power to Heat – RES to DH	We investigate the potential for district heating to mitigate constrained renewable generation on weak grids by connecting two independent systems: 1. A heat network supplied by a large heat pump (with thermal storage used to avoid peak price power). 2. A wind farm connected to a constrained export circuit.	1. The benefit to the system is sufficient to pay for less than 1km of private wire connection between the wind farm and district heating system; there are unlikely to be many suitable locations in the UK. 2. Given avoided use-of-system charges, operator value may be as much as ten times this; hence there may be circumstances where there is a viable business case. 3. An alternative to true private write is to pool the wind farm and heat pump in some local supply arrangement, using the public distribution network but at reduced pass-through costs, with local demand-matching reducing balancing costs and losses. Opportunities for such "virtual private wire" arrangements will depend on the network connection points of the wind farm and heat pump, and are currently rare in the UK.	Low

Domestic turn up and thermal store (SETS)	We investigate the potential for the smart management of domestic electric heating to mitigate the curtailment of renewable generation on weak or isolated DN circuits.	1. The ability to absorb renewable oversupply through the real time control of electric heaters is worth between £20 and £100 per household per year – between one and five times the control platform costs. This is likely to be a lower bound, as we do not value ancillary services, or consider the role of weather and demand forecasting in optimising the system. 2. By 2030, there are likely to be more than 15GWe of controllable electrical domestic heaters, which could combine cost effectively to match local generation and provide ancillary services. Conversations with suppliers, network operators, and aggregators suggest that demand management of commercial-scale energy demand will outcompete its domestic counterpart in the medium term. The geographic distribution of electric heating and small –to-medium scale renewables will therefore determine the potential scale for this solution. 3. SETS is an operational technology, though value sharing between suppliers, DNOs, generators and consumers remains a stumbling block to operation at scale. In particular, SETS is not viable at the customer participation fees in current trials (around £10/month).	Moderate to Significant
Energy from Waste (EfW) Anaerobic Digestion/Gasification to CHP or Gas Grid Injection	We investigate the revenues and capital costs of upgrading EfW plants to provide multiple output vectors, i.e. adding gas clean-up and injection facilities to existing plants with biogas/bioSNG CHP or adding CHP to plants already configured for injection into the gas grid.	1. Multi vector operation is the lowest cost configuration for AD plant; gas injection is preferred at gasification plants. 2. Multi vector EfW plant operation may be difficult to realise given: • the efficiency losses associated with ramping thermochemical processes • Fuel costs of propanation, where the CV or Wobbe Number must be increased • power price competition from operational gas turbines 3. CHP heat sale increases scheme returns; a heat price below 25% of the gas price makes CHP upgrade to allow multi vector operation at gasification facilities viable. EfW plants are often situated away from populated areas; I&C thermal demands might be more frequently found in proximity to EfW plants, and therefore be better candidates for heat sale.	Low to Moderate

2 Barriers to Multi Vector Energy Supply

We have identified a range of technical, commercial and regulatory barriers to transition to the multi vector energy supply configurations above, following extensive consultation with energy system stakeholders, including technology companies, network operators, suppliers and policy makers (these are explored in detail in the following section). Across these, we have identified the following key barriers, based on the multi vector value determined in the case studies, and the extent to which the barrier impedes multi vector operation.

Table 2 – Summary of Key Barriers

Barrier	Multi Vector Case Studies Affected
Distribution Network Telemetry	1. Hybrid heat pumps[1] 6b. Domestic turn up and thermal store (SETS)
Domestic Demand Response Platform	1. Hybrid heat pumps[1] 2. CHP and HP in heat networks 6b. Domestic turn up and thermal store (SETS)
Need for Clarity in Low Carbon Heat Policy	1. Hybrid heat pumps[1] 2. CHP and HP in heat networks 7. Flexible CHP/Grid injecting EfW plants
Gas Network Charging	1. Hybrid heat pumps
Future of Hydrogen	4. P2G- injection into NTS 5. P2G into dedicated hydrogen network
Increased Coordination	All Cases Studies

[1] Multi vector heat supply might also mitigate network loads by under sizing heat pumps and supplying peak demand using gas; this would not require sophisticated network telemetry or a DR platform, but does depend on policy to maintain gas connections and boilers at heat pump equipped homes.

2.1 Barriers

1. Distribution Network Telemetry

Where multi vector operation involves active management of existing power grids to accommodate growing peak demand or renewable generation, implementation requires an accurate picture of the grid loads at each component. This however requires highly granular, real time data on network loads; while the HV network is monitored, most of the LV network is unmonitored and has historically been designed on a "fit and forget" basis. Also, LV network upgrade costs are significantly more expensive per kW than their HV counterparts. Realising the full value of single and multi vector supply configurations through demand response will therefore require significantly increased network telemetry (we have considered multi vector heating in detail in this study, however the telemetry and network management systems required for multi vector heating may enable further grid services, such as mitigating the risk of high summer reverse power flows as more PV is installed, and enabling vehicle to grid services).

Load monitoring and active network management are the focus of several recently concluded and ongoing innovation projects, which explore means to increase DNO capacity for embedded generation and low carbon technologies (LCTs) – these trials are discussed in Section 0.

2. Gas Network Telemetry

Increased telemetry on the gas distribution network may also be required under multi vector operating modes, e.g. involving injection of distributed gas sources. As biogas and hydrogen are blended into gas distribution networks, distributed network telemetry is one means by which the Wobbe Number and/or calorific value (CV) might be recorded, for safety and local energy billing reasons respectively. These readings inform maximum injection levels for hydrogen and biomethane or bioSNG suppliers, in order to ensure the gas quality and CV remains within acceptable limits.

The tools to determine hydrogen content of gas and to measure CV are currently expensive. Trials are ongoing to develop prototype chromatographs, and commercialise these to allow their deployment across the network.

3. Domestic Demand Response Platform

The impacts and management of the electrification of heat, and potentially transport, represent a key innovation area for network operators and suppliers. The potential role and implementation of active network management in electrification are the subject of several ongoing NIA and NIC trials, many of which explore how domestic demand is best managed to:

- minimise grid upgrade requirement
- ensure security of supply
- maximise use of renewable generation

Potential candidate mechanisms include:

- direct load control
- time-of-use tariffs
- limiting appliance or household demand

There are a variety of concerns around automated control of consumer loads, particularly where domestic consumers are involved, which include consumer participation and acceptance, data privacy, cyber-security, reliability, and unintended consequences, e.g. disadvantaging certain socio-economic groups. The optimal solution may incorporate elements of each of these mechanisms; the analysis in the WP3 report *Assessment of Local Cases* suggests that hybrid heat pumps sized to 50% of peak demand supply over 92% of total heat. A smaller heat pump and a gas boiler might therefore be a lower total cost means of decarbonising domestic heat, even at high carbon prices; there may still be value in actively managing smaller heat pump demand to reduce further the required grid upgrade.

There are also barriers to the operation of large scale heat pumps and CHP in response to real time power prices around information exchange between power markets and heat network operators. However, even where real time power price data is not available to multi vector heat network operators, weather and demand forecasts can give a good estimate of day-ahead power price, and grid use charges (which can total as much as the generation costs) are prescribed in DNO DUoS charge schedules, so that plant operation can be planned accordingly.

4. Synthetic Diversity for Active Network Management

Active power network management though direct load control or half hourly power pricing may result in large instantaneous drops or spikes in demand, with loads connected to or taken off the network as a price is updated – for example, if all EVs connected to the network cease charging as power prices rise above some threshold, the precipitous fall in demand may adversely impact the grid, potentially forcing grid frequency above the mandated limits.

5. Effect of Multi Vector Supply on the Gas Network

Multi vector heat supply leads to greater interdependence of gas and electricity demands; the switch-over from electric to gas heating (and vice versa) could lead to sharp increases or decreases in power and gas network loads.

Gas distribution networks are designed to their 6-minute peak flow. While the hourly gas demand associated with multi vector heat supply will not exceed current levels, a demand management platform which links power prices and gas throughput could lead to surges in gas demand on the timescale of seconds, rather than minutes, as thermal demand is rapidly moved off the power grid.

Consultation with gas distribution network operators has not identified any concerns regarding demand spikes and rapid pressure drops as a result of multi vector heating on (particular areas of) the low pressure networks. This is supported by modelling carried out by Element Energy and the Sustainable Gas Institute into the impact of highly coordinated dispatch of domestic micro-CHP systems on the low pressure gas network, which found:

- few issues with pressure drops across various types of low pressure network, and
- none that could not be solved by a minor adjustment to network operating pressure.

Further, given the relatively long timescale over which heat can be delivered, demand diversity might be reintroduced to multi vector fuel switching (and DSM more generally) through a random delay of several seconds between the signal to change operating mode (e.g. a change in electricity price) and the actuation of the switch-over of the device; thereby synthesizing some of the diversity which currently arises naturally.

As our analysis is conducted on an hourly resolution, economic findings are unaffected by this issue.

6. Need for Clarity in Low Carbon Heat Policy

Our analysis considers the following heat supply technologies:

1. Supply as power to (possibly hybrid) heat pumps and smart storage heaters.
2. Hybrid heat networks (CHP powered heat pumps and multi vector EfW).
3. Hydrogen injection into the gas network.
4. Hydrogen networks as a heat supply vector.

None of these technologies currently operate at scale in the UK, and their future role in the decarbonisation of heat will be driven in part by technological progress, but substantially by policy. Policy uncertainty and lack of support may lock out some of these potential multi vector configurations, in particular:

1. Future domestic multi vector heat supply depends on today's infrastructure decisions; customers and housing developers are not currently incentivised to install or maintain flexible heat supply plant and infrastructure – e.g. gas network connected hybrid heat pumps rather than pure electric units, or smart, aggregator-ready storage heaters. Where up-front capital costs are higher for multi vector infrastructure than for single vector alternatives, policy could leverage future benefit to support uptake of multi vector ready solutions.
2. Heat networks de-risk the decarbonisation of heat, particularly for new build and large facilities, as supply plant can be chosen and replaced based on carbon prices and environmental policy. However, only around 2% of UK demand for space heating and hot water is supplied through heat networks[2]. The development of heat networks, and the use of energy from waste, waste heat and other secondary heat sources, should be the subject of a more comprehensive, long term policy, which might include:
    - Increasing revenues of CHP; around 6GWe of CHP are installed in the UK, almost all in large buildings or facilities where they offset local power demand. Simplifying local electricity supply arrangements, for example under licence exemptions or arrangements such as Licence Lite, would improve CHP viability (although gas CHP is likely to reduce carbon emissions only in the medium term as the grid decarbonises, heat networks can upgrade their thermal plant as new environmental policy is developed).
    - More efficient, low temperature heat networks are difficult to develop due to the generally poor levels of home insulation; increasing thermal efficiency of UK build stock would make development of low temperature heat networks more viable (as well as paying for itself in lower fuel costs and decreased carbon emissions).
    - Policy to disincentivize heat dumping has encouraged the development of heat networks in northern Europe around fossil fuel and EfW plants. Similar policy in the UK would encourage the utilisation of heat which is currently vented. As gas (which supplies around 85% of UK heat) prices are low and capital infrastructure costs of heat networks are high, such models are difficult to develop commercially, and government support may be required. We find in Case Study 7 that CHP may be the most viable use of EfW at low (but non-zero) heat prices; despite this, most of the 4TWh/year of AD CHP heat is vented; process or network use of this heat may be difficult however, as many such plants are in remote rural locations.
3. Significant R&D is required before hydrogen can be blended into the gas network at scale. While blends of up to 10% hydrogen are seen in distribution networks in Germany, the GS(M)R in the UK stipulates a maximum hydrogen content of 0.1% (molar). The HyDeploy project which recently commenced with funding from Ofgem's National Innovation Competition (NIC)

[2] The Future of Heating §2.6

will explore the feasibility of blends of up to 20% hydrogen for UK gas grids, based on trials using Keele University's onsite gas network.

On the National Transmission System (NTS), any change to permissible hydrogen content of the gas blend must be agreed by all connected users, including gas turbine power plants, whose typical warrantied maximum hydrogen content levels are around 2%. These turbines are expected to remain in use for several decades, which may limit the potential for significant hydrogen blending on the NTS.

4. The feasibility and cost of hydrogen network conversion must be established; the Leeds City Gate H21 project has begun to investigate these issues, and identifies many of the hurdles to switchover. Further theoretical studies are required however, as well as field trials on real networks (initially, these are likely to be limited in size, but demonstration at increasing scale will be required), before conversion of networks to hydrogen can be deployed at scale. This work will require significant levels of innovation funding. Any decision to transition to hydrogen networks is likely to be driven by government policy, i.e. mandated as a strategic infrastructure decision (consumers in an area of network conversion will no longer have the option of remaining on natural gas), rather than market forces.

   In addition to investigating the feasibility and cost of re-purposing gas networks for hydrogen, several other policy decisions will be relevant to a widespread switch to hydrogen for heating, including:

   - Development of UK carbon capture and storage infrastructure.
   - Development of UK offshore and onshore gas resources.
   - Engaging and educating the public to achieve acceptance of hydrogen supply.

Significant work is needed to provide the evidence base needed to inform strategic decisions regarding the decarbonisation pathway for the heat sector. It may be that several solutions will co-exist, as different parts of the country are better suited to different solutions.

Further, heat sector policy will have inter-dependencies with strategy in other areas; the decision to progress with widespread conversion to hydrogen, in particular, is likely to have strong inter-dependencies with policy around deployment of CCS and decarbonisation of transport.

The challenges associated with defining a UK heat strategy are significant, and government wishes to pursue policies that keep options open for as long as possible. However due to the significant differences between the various options in:

- infrastructure requirements
- energy market design
- regulatory framework

and other areas, there is a risk of wasted effort, innovation spending, and stranded assets if government does not provide a strategic lead.

7. Gas Network Charging

Uncertainty surrounds the future of the gas network; depending on the future of heat, it may be:

- Incrementally decarbonised, using low carbon gases such as biomethane and green hydrogen.
- Re-purposed to carry pure hydrogen.
- Decommissioned due to falling utilisation, at least at lower pressure tiers, e.g. under large-scale switchover to electric heating.
- A mixture of these outcomes.

Under the RIIO model, network investment – currently dominated by the Iron Mains Replacement Programme – is paid off over 45 years; this depreciation period makes it difficult to incentivise GDNs to invest in infrastructure if there is a perceived risk that the assets could become redundant.

At present, GDNOs charge shippers to use their networks; these charges are passed on to suppliers, who recover them from consumers. The charges levied on shippers are dominated by capacity (maximum flow) charges (which typically make up 97% of GDN use costs). Shippers charge suppliers both for their total gas use and their share of the gas transportation charges, while suppliers charge consumers on a largely per kWh basis, with standing charges comprising around 10-20% of a typical gas bill.

If domestic heat is substantially, but not entirely, electrified and some homes use gas as a peak supply vector, a new model to pay for the gas distribution networks will be required, particularly where total gas demand falls precipitously – perhaps to less than 25% of current levels – leading network charges to represent an increasing fraction of gas bills[3].

This might involve greater weighting of capacity – rather than commodity – charges, to achieve an equitable distribution of network use charges across persistence gas and multi vector consumers. More sophisticated tariffs represent another solution, though as part of the Ofgem drive to simplification, currently tariffs must comprise a standing charge and a unit price only[4]. Other potential charging models are discussed in the

Multi vector coordination can be categorised into central and distributed tasks, respectively:

- Analysis carried out by multi vector operators, such as optimising CHP and heat pump operation to relative power and gas prices, which are possible currently or without structural reform of the energy system. These tasks involve weighting data from across supply vectors; such as:
    - The per kilometre cost of HV grid reinforcement
    - The price of hydrogen
    - The calorific value of biomethane

  Coordination in these cases may require technical progress, but no significant changes to regulation or commercial codes.

- Tasks where total energy system costs can be reduced through concerted action of disparate agents, or where parties who realise value through multi vector supply do not control all levers necessary to implement it. In such cases, coordination of these actors, weighing the costs and benefits to the various parties, and sharing of relevant

[3] Under the amortisation rates stipulated in the current RIIO model, using the gas network as a peak-only supply vector leads to a threefold increase in system use charges.

[4] Ofgem - Simpler choices

data will not be achieved by the market, and some central governing authority will need to be empowered or created. For example, to enable grid management through hybrid heat pump supply:

- Multi vector heating will need to be trialled and demonstrated as a secure ANM tool.
- Uptake of hybrid, rather than pure electric, heat pumps will have to be incentivised.
- The gas network must remain operational, and gas network charges must not undermine the consumer case for multi vector heating – a very high standing charge might for example lead consumers to switch to total electrification.

Only the first of these is within the purview of the network operators – and several innovation projects are ongoing (e.g. the NIC funded FREEDOM project).

One solution may be for the energy system regulator to demand consideration of multi vector supply – perhaps requiring all permitted investment requests are compared to a multi vector solution – and then coordinate the necessary parties, e.g. agreeing revenue sharing models where multi vector supply is found to be optimal. However, this would require increased regulatory coordination – OFGEM's current practice reflects the parallel operation of the power and gas networks.

Alternatively, energy distribution might be coordinated on a local, cross-vector basis. While transmission and large scale generation would remain centrally administered, planning and regulation of distribution networks and small scale generation could devolve (in part) to local government. Local authorities are beginning to consider energy supply, for example, in 2016 the GLA published the London Energy Plan, comprising a set of energy demand scenarios to 2050, and low carbon energy resource mapping. Other localisation of energy includes local supply companies e.g. the Bristol Energy Company, and the GLA application for Licence Lite supply. Further development in this vein could lead to dedicated local energy policy units that consider supply opportunities across vectors.

Innovation section.

8. Future of Hydrogen

The role hydrogen will play in the future UK energy system is unclear, but there is growing interest in distributing hydrogen through the gas grid as a heating fuel, either blended with natural gas at up to 20% by volume (9% by enthalpy), or supplied through a converted gas network carrying 100% hydrogen.

Hydrogen use as a transport fuel is in the early stages of deployment, in both light and heavy-duty vehicles – cars and vans, and trucks and buses respectively. In light duty vehicles, fuel cell passengers are available in the UK from Hyundai, Toyota and Honda, with sales currently focused in fleets and private hire applications in Greater London. A network of around 20 hydrogen refuelling stations is being deployed under several EU-funded projects such as HyFIVE and H2ME, with the UK H2Mobility coalition acting as a discussion forum between vehicle suppliers, station operators and government departments. Deployment volumes are expected in the low hundreds of vehicles before 2020, with significant increases after that date following the introduction of lower cost, second generation vehicles. In heavy vehicles, several UK cities (London, Birmingham, Aberdeen and Dundee) are participating in the EU-funded JIVE fuel cell bus project, and are in the process of jointly procuring tens of fuel cell buses for introduction in the next 2 years.

Work at the Keele HyDeploy project, and subsequent trials on a live network, will establish a hydrogen blending limit which is "no less safe" than current levels (0.1% by volume). Once this is agreed, and gas CV and Wobbe Number monitoring requirements are determined, policy decisions and subsidy design will determine the role of hydrogen blending; it may be that:

- Maximum blend limits are targeted; across all GDNs this would require national hydrogen production of 25TWh[5] (630,000 tonnes) annually.
- Power to gas is used as a reservoir for renewable oversupply (our modelling suggests hydrogen prices of at least £50/MWh are required for this to create value).
- No hydrogen blending occurs, e.g. because biogas is a lower cost means of decarbonisation, or because networks are converted to pure hydrogen supply.

The pathway to NTS hydrogen content limits of more than 2-3% by volume is less clear, and may require international coordination.

The development of national hydrogen infrastructure, especially the conversion of gas networks to hydrogen supply, will not be possible without government playing a substantial coordinating role, encompassing:

- Supporting R&D and the necessary field trials.
- Creation of legislation relating to commercial, regulatory and safety aspects of hydrogen supply, and of the various parties the operate the generation, supply and distribution of hydrogen.
- Consumer engagement; gas appliances will have to be replaced with hydrogen units, and switch-over may need to be mandated (customers may be able to opt not to connect to the hydrogen network, but not remain on gas).

[5] Based on a 20% by volume (9% by energy) blend limit and total 2015 domestic gas demand of 292TWh

- Coordination of switchover; gas appliances will have to be replaced on a street by street basis, with small parts of the networks isolated, and all attached homes converted [6].
- Financing of conversion and cost recovery – the total installed cost of hydrogen appliances alone across a single Local Distribution Zone (LDZ) will be in the hundreds of millions; given the size of the outlay associated with conversion, the H21 report expects these costs will be paid by government and recovered through a levy on energy bills or taxation.
- Consideration of vulnerable populations e.g. for consumers in fuel poverty.

Significant use as a heat supply vector will require a substantial increase in production capacity; hydrogen can be produced at scale in several ways, including:

- Steam methane reformation (SMR) of natural gas
- Upgrade of syngas from waste gasification using the water-gas shift reaction
- Bio hydrogen, using anaerobic digestion[7]
- Water electrolysis

The first three depend on the viability of CCS; which is undemonstrated at scale and which will require significant support to make operational. Our modelling suggests that electrolysis cannot compete with SMR (we assume power prices of £47/MWh and CCS costs around £42/tonne CO_2). At lower power prices (around £25/MWh), electrolysers may provide significant hydrogen to dedicated networks, though a very large renewable generation fleet will be needed to significantly decarbonise heat through electrolysis.

There is currently no specific financial support for hydrogen on a per kilogram basis; support to date has been provided in the form of EU or the UK government grants to fund part of the capex and opex of refuelling stations and vehicles; as a transport fuel, hydrogen competes with petrol or diesel taxed at around 60p/litre. The UK government is consulting on a proposal to include renewably-sourced hydrogen in the Renewable Transport Fuels Obligation, which would make hydrogen supply eligible for certificates in the same way that biofuels are currently supported. From a vehicle user point of view, equivalence with diesel on a per kilometre varies by vehicle type – approximately £7/kg (£175/MWh) for passenger cars and £5-6/kg for buses. Electrolyser costs below current levels and high levels of utilisation of both the electrolysers and the refuelling stations are needed to achieve this price without public support. Analysis conducted by UK H2Mobility, as well as the Fuel Cells and Hydrogen Joint Undertaking, suggests that these prices can be achieved from the early 2020s if vehicle demand is sufficiently high and if electrolysers can make use of low cost renewable energy and supply grid services - varying their output in response to network conditions. Environmental support will also encourage use of hydrogen as an energy vector; zero-carbon hydrogen competes with gas as a heating fuel at carbon prices of around £100/tonne[8].

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[6] Some manufacturers believe that hydrogen boilers can be developed which can run (possibly at reduced efficiency) on natural gas; these may simplify the process of replacing existing plant, allowing it to be carried out over a longer timeframe.

[7] Progressive Energy predict bio-H_2 will be produced at the same cost as biomethane – between £20/kWh and £25/kWh– within the next 5 years.

[8] Given the carbon intensity of gas – 0.185 tonnes/MWh – its environmental cost is around 20% of the carbon price per MWh heat supplied. At a gas price of £30/MWh, a £100/tonne carbon price gives an equivalent hydrogen-for-heat price of £50/MWh – the level at which our modelling finds power to gas may be viable, and the price used in the H21 Study.

If hydrogen is to supply key energy demands, market design will need careful consideration if it is to foster competition between the various supply means and guarantee security of supply; the degree of market liberalisation, and separation between distribution and supply as the market grows will be key factors.

9. Increased Coordination

Coordination required across vectors in our Case Studies is summarised below:

Table 3 – Coordination Requirements Across Case Studies

Case Study	Vectors Involved	Coordination	
		Planning and Development	Operation
Hybrid heat pumps	Electricity, gas	Connection to, and O&M of, gas networks will need to be maintained to allow multi vector supply; this may need to be incentivised by DNOs, whose upgrade costs are then reduced.	If implemented through DLC or power prices, grid management platform may need to communicate with GDN, or smooth signal transmission.
CHP and HP in heat networks	Electricity, gas, heat networks	CHP links gas, heat and power networks. Multi vector energy centres which initially connect only to the gas network, (connecting to power grid only as carbon prices rise) and linking CHP and HP across existing or bespoke network, may allow development of heat networks, where e.g. grid is constrained.	Operators will optimise to heat demand and power prices, especially if CHP power supplies local demand, creating a gas-powered heat and power micro-grid.
PiV fuel switching	Electricity, liquid fuel	Real time power pricing could signal PiV drivers to fill up at a fuel station rather than charging, and to offer them the value of the fuel.	A PiV energy supply control system would need to monitor half hourly power prices and the capacity of liquid fuel distributors (across a largely unstructured market) to increase the supply of liquid fuels. As times of undersupply are of interest, grid constraints should not bear on this analysis.
Power to Gas – Transmission Level RES to H_2 and RES to CH_4	Electricity, gas	Geographical analysis of grid capacity and blending limits will be needed, alongside the relative costs of building gas and power transmission infrastructure if electrolysers are to be located centrally.	Oversupply will vary with renewable generation and demand; H_2 blending limits are determined by gas flow at the injection point. Real time power and gas network data (locally or nationally) will therefore be required for P2G.
Power to Gas – Electrolysis for Hydrogen Networks	Electricity, hydrogen	The scale of future hydrogen demand, and the role of electrolysers in meeting this demand, will depend on both technical development, and policy and support for hydrogen. The timescales over which supply contracts are settled, and the priority given to zero-marginal cost supply will need to be carefully designed.	Where electrolysers (perhaps using low cost power, e.g. from renewable oversupply) and SMRs (which are ideally operated at constant output) both contribute to network supply, diurnal demand forecasting and control of output on operational timescales will be required.
Power to Heat – RES to DH	Electricity, district heat	Proximity between RES generation and district heating systems will determine the viability of power-to-heat. Areas of existing or potential RES locations could be considered in prioritising DH development. Where costs of laying private wire infrastructure are prohibitive, local supply arrangements using public distribution lines may provide a viable business case and create system-level benefit.	Operators will need to balance heat supply and renewable oversupply; requiring forecasts of local heat, renewable generation and system and local level power demand.
Domestic turn up and thermal store (SETS)	Electricity	Smart thermal heaters with appropriate storage capacities must be incentivised for upgrade, and potentially new build.	An aggregator will need to generate turn-up signals based on forecasts of generation and electrical and thermal demand.
Energy from Waste Anaerobic Digestion/Gasification	Electricity, gas, heat networks	Multi vector EfW plants would ideally be located near heat networks, where gas throughput is high, and where power prices	Real time power prices and LDZ biogas capacity (determined by Wobbe Number and possibly FWACV) will need to be monitored.

to CHP or Gas Grid Injection		vary diurnally, e.g. due to high red band DUoS charges.	

Multi vector coordination can be categorised into central and distributed tasks, respectively:

- Analysis carried out by multi vector operators, such as optimising CHP and heat pump operation to relative power and gas prices, which are possible currently or without structural reform of the energy system. These tasks involve weighting data from across supply vectors; such as:
    - The per kilometre cost of HV grid reinforcement
    - The price of hydrogen
    - The calorific value of biomethane

  Coordination in these cases may require technical progress, but no significant changes to regulation or commercial codes.

- Tasks where total energy system costs can be reduced through concerted action of disparate agents, or where parties who realise value through multi vector supply do not control all levers necessary to implement it. In such cases, coordination of these actors, weighing the costs and benefits to the various parties, and sharing of relevant data will not be achieved by the market, and some central governing authority will need to be empowered or created. For example, to enable grid management through hybrid heat pump supply:
    - Multi vector heating will need to be trialled and demonstrated as a secure ANM tool.
    - Uptake of hybrid, rather than pure electric, heat pumps will have to be incentivised[9].
    - The gas network must remain operational, and gas network charges must not undermine the consumer case for multi vector heating – a very high standing charge might for example lead consumers to switch to total electrification.

  Only the first of these is within the purview of the network operators – and several innovation projects are ongoing (e.g. the NIC funded FREEDOM project).

One solution may be for the energy system regulator to demand consideration of multi vector supply – perhaps requiring all permitted investment requests are compared to a multi vector solution – and then coordinate the necessary parties, e.g. agreeing revenue sharing models where multi vector supply is found to be optimal. However, this would require increased regulatory coordination – OFGEM's current practice reflects the parallel operation of the power and gas networks.

Alternatively, energy distribution might be coordinated on a local, cross-vector basis. While transmission and large scale generation would remain centrally administered, planning and regulation of distribution networks and small scale generation could devolve (in part) to local government. Local authorities are beginning to consider energy supply, for example, in 2016 the GLA published the London Energy Plan[10], comprising a set of energy demand scenarios to 2050, and low carbon energy resource mapping. Other localisation of energy includes local supply companies e.g. the Bristol Energy

[9] This support would need to reflect uptake levels; below 20% uptake heat pumps lead to minimal reinforcement requirements, so multi vector operation provides little grid benefit. Further, grid reinforcement mitigation through multi vector heating is yet to be demonstrated in operational hybrid heat pump trials.

[10] GLA London Energy Plan

Company, and the GLA application for Licence Lite[11] supply. Further development in this vein could lead to dedicated local energy policy units that consider supply opportunities across vectors.

2.2 Innovation Needs

In this section, we discuss current work toward mitigating these barriers. A summary of relevant recently concluded and ongoing work is included in the section on

Current Projects.

[11] DD1416 Licence Lite –GLA application to Ofgem

2.3 Barriers

1. Distribution Network Telemetry

The spatial and temporal telemetry resolution required to safely maximise utilisation of existing LV network assets is the subject of several innovation projects, such as WPD's Open LV project, which aims to make detailed real time data from 80 substations available, allowing third party software developers to create applications that provide demand management services to customers and/or DNOs. The project funding requirements suggest an upgrade cost of not more than £50k per LV substation, including the outgoing feeders. On this basis, the costs of LV network telemetry for Newcastle (on which the Case Study 1 analysis is based) would be £375m – around 10% of the costs of network upgrade necessitated by substantial electrification of heat (based on 65% heat pump uptake by 2050).

Smart meter roll-out might provide an alternative means of improving DNO LV monitoring:

- Real time smart meter data may provide sufficient information to determine the instantaneous load at network components; in this solution, DNOs will need to create a coherent network flow model which takes real time or half hourly MPAN readings as inputs; there may be data quality, resolution and data protection concerns around this.
- Even without a deterministic load model, smart meter consumption data may allow a stochastic model, calibrated against historical usage patterns, to predict network loads based on time, date, weather forecasts, occupancy patterns and other data. This model could then adjust power prices to avoid breaching network capacity constraints (perhaps on geographically randomised or time delayed basis, in order to avoid surges in power or gas demand). Use of a ANM models which infer, rather than measuring or calculating, component loads will need to carefully consider the risk of prediction failure, though current comparatively simple models can predict network demand relatively accurately, based on time of day, day of the week and weather forecast. Smart meter data may allow extensive fine tuning, development and testing of these predictions.

Smart meters can also report gas demand on a half hourly basis, but while the value smart meters can unlock for electricity utilities has been the subject of significant attention, there has been less focus to-date on the opportunities for the gas networks. Smart meters are expected to bring cost savings through more efficient meter reading (and potentially easier identification of leaks), but could also enable smarter management of gas distribution networks. This could include, for example, use of demand-side response techniques (e.g. variable tariffs) to influence gas consumption patterns, potentially balancing injection profiles of distributed gas sources (the opportunities associated with better data on the gas distribution networks are being explored through SGN's Real-Time Networks project[12]. Increased gas network telemetry may be required under some multi vector supply configurations, such as those involving injection of distributed gas sources or hydrogen blending. As biogas and hydrogen are injected into gas networks, distributed monitoring is one means by which the Wobbe Number and/or CV might be monitored for safety and local billing reasons. These data could also determine maximum injection levels for hydrogen and biomethane or bioSNG, ensuring gas characteristics remain within acceptable limits. The tools to determine the hydrogen content of natural gas, and to measure gas CV are currently expensive; trials are ongoing to develop prototype chromatographs, and commercialise these to allow their deployment across the network.

Gas Network Telemetry

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[12] https://www.sgn.co.uk/real-time-networks/our-trial

2. Increased telemetry on the gas distribution network may also be required under multi vector operating modes, e.g. involving injection of distributed gas sources. As biogas and hydrogen are blended into gas distribution networks, distributed network telemetry is one means by which the Wobbe Number and/or calorific value (CV) might be recorded, for safety and local energy billing reasons respectively. These readings inform maximum injection levels for hydrogen and biomethane or bioSNG suppliers, in order to ensure the gas quality and CV remains within acceptable limits.

2.3.1.1 The tools to determine hydrogen content of gas and to measure CV are currently expensive. Trials are ongoing to develop prototype chromatographs, and commercialise these to allow their deployment across the network.

2.3.1.2

3. Domestic Demand Response Platform

Several related issues around domestic demand response remain poorly understood, including:

- The relative merits of the various load control strategies (e.g. DLC, ToU Pricing)
- The relationship between size of price signals and to demand moved (elasticity)
- Consumer attitudes to load control
- Fixed, running, and (especially) user participation costs

Time of Use electrical pricing has been trialled at many innovation projects, including:

- Several Tier 2 Low Carbon Network Fund projects, (such as Customer-led Network Revolution and Low Carbon London).
- Various smart-meter trials (e.g. the Irish Smart Metering Trials).
- As business-as-usual further afield, e.g. California.

UK trials have demonstrated some success in shifting load from peak times; the Low Carbon London dynamic pricing trials achieved responses of up to 150 W/household, with an average response of around 50 W/household to a constraint management pricing event.

Limited trials of direct load control have been undertaken in the UK to-date, including the CLNR project, which trialled the direct load control of wet appliances with some encouraging results, and the WPD ECHO project, which found:

- limited evidence that direct load control is superior to a tariff
- that the costs of domestic DR (without smart meters) for network management are prohibitively high (see the ECHO project results in section 4).

For reasons of customer simplicity, domestic scale demand management trials to-date have tended to pay participants a fixed fee (€10/month at the SSE Real Value scheme, or up to £190[13] for participation in the LCL ToU pricing trial), typically greater than the value created by the management of their demand. Smart meters may:

- reduce control costs for domestic demand response
- make real time energy use transparent
- normalise consumer demand response.

The ECHO report concludes:

[13] LCL Learning Lab - Residential Consumer Responsiveness to Time-Varying Pricing

> Future integration between Time of Use Tariffs, Smart Meters and home appliances should create the opportunity to develop [a domestic DSM] system.

The roll out of smart meters is then likely both a prerequisite, and a large part of the solution, for customer demand management[14]. Substantial work will be required in the creation and demonstration of a DSM platform through which DNOs can ensure sufficiently firm load control to obviate grid upgrade without compromising network operation; some candidate mechanisms are discussed below.

Table 4 – Domestic Multi Vector Heat DSM Mechanisms for LV Network Management

Mechanism	Implementation and Coordination	Required Grid Reinforcement	Consumer Attitudes	Platform Cost
Direct Load Control (DLC)	DNO would need control over heat pump interface or connected circuit. Smart meter auxiliary load control switch (ALCS) is one option, control of gas boilers may also be necessary.	Our modelling suggests DSM might obviate all grid upgrade, provided feeder loads are monitored, and there is at least 25% network headroom.	Potentially the most contentious solution; but would require minimal user involvement once operational. The WPD Smart Plug ECHO trial found an appliance control cost of £6.6/kWh, prohibitive for ANM, though these findings may not apply to multi vector heating, where gas substitution should allow uninterrupted heating.	These solutions are likely to have similar platform costs, (the firm control costs per kW may be lower for DLC).
Time of Use Pricing (ToU)	Customer ToU pricing is controlled by suppliers; DNOs would have to set price signals for all suppliers across their network which were then efficiently communicated to users. Consumers must “opt-in” to smart meter half hourly settlement, which may represent a barrier to ToU pricing ANM.		Consumer price elasticity is not well understood; the Low Carbon London trials found average reductions of 0.05kW/household (up to 0.15kW/household) during peak price periods. As above, it is not clear that these findings are directly applicable to multi vector heating.	
Appliance Sizing	Limiting system hybrid heat pump load by under-sizing the electrical unit - device electrical power might be limited through regulation e.g. installers might provide HHPs or support structure, with low carbon subsidy qualification made subject to selection of a heat pump of prescribed size (and perhaps minimum building fabric standards).	We find load limiting avoids substantial upgrade without need for a DSM system; it may therefore be a preferred solution where HHP uptake is modest and LV grid headroom is significant.	Lower up-front costs may incentivise consumer take up of smaller HPs, though mandation of undersized units may be unpopular.	None, though there may be some administration costs

[14] Second generation SMETS 2 smart meters will include a control switch for auxiliary loads (ALCS); designed for EVs, it may also be possible to control heat pump demand through this system.

4. Need for Clarity in Low Carbon Heat Policy

Government policy has in recent years has been largely technology agnostic - designed to enable the market to decide the direction of energy strategy to a certain extent, while operating in a regulatory framework that has driven decarbonisation and security of supply objectives. In developing policy on low carbon heat, government remains keen to keep options open, rather than pick winners, but recognises that the potential scale of transition that certain low carbon heat pathways involve may at some point require more active intervention. As an early task, government should identify a range of low regrets actions that can be pursued in the near-term to move heat decarbonisation forward.

Of the 2050 stock, new build (post 2004) will comprise only 30% of extant buildings, and around 15% of thermal demand. Policy to ensure future heat supply flexibility must therefore focus on current buildings, which are expected to undertake overhaul or replacement of their heating systems at least once in the next 35 years. Phase 3 (Required Policy Changes) of the Bridgend Future Modelling[15] project considers consumer incentivization required to drive uptake of low-carbon heating under a range of up-front contribution and carbon tax levels, using real world data from 12,000 households. It concludes that current support mechanisms are too subtle and offer too little value to drive switchover at scale, and that the RHI funding mechanism is “self-limiting”, as it is paid for by levies on customer bills (heat pumps are not included in the Bridgend analysis, though the household capital costs of hybrid heat pump installation are similar to those of the options assessed – gas micro CHP and heat networks, see Section 1).

Operating and maintaining both a heat pump and gas boiler – either as a hybrid system or separate units – may be more expensive (due to gas network connection) and complex than using an electric heat pump only. Therefore, hybrid heat pumps reduce consumer and social costs – producing long term value that can be leveraged to incentivise flexible heat supply – only where heat pump uptake is significant (installed in 20% of homes or more). Hybrid heat pump uptake at scale is unlikely under current policies; they are too costly compared to their fuel savings, and logistically less appealing that pure electric units. If hybrid heat pumps are to provide significant future low carbon heat, it will require a bespoke policy instrument; any such policy will need to consider the risk of underused, or stranded, boilers infrastructure if heat pump uptake remains marginal.

Analysis described in the WP3 report *D3.1 Assessment of Local Cases* suggests heat network supply through gas CHP is viable where cogeneration can be reliably used to offset local demand, avoiding pass-through charges on power that would otherwise be imported. Further, CHP operators may see higher returns from purchasing a heat pump to absorb CHP power and serve an expanded heat network than from selling cogeneration to the grid. Expansion of existing CHP heat networks, and policy to encourage local supply of CHP power (perhaps preferentially for heat pumps), may therefore be a means to encourage the decarbonisation of heat.

[15] Understanding the Home Energy Policy Needed to Satisfy Consumer Willingness to Pay to Change

5. Gas Network Charging

Decarbonisation – Hydrogen Blending

Hydrogen blending might displace up to 9% of the carbon emissions of gas (at a 20% blend by volume), blending is discussed in the following section.

Decarbonisation – Biogas

Production of biomethane at scale could substantially decarbonise gas; based on 2011 CCC figures, gasification and AD might reach "gas parity" – equal production cost to natural gas - by 2025, and provide up to 100TWh (a third of current domestic gas demand) by 2050. Connection of gasification facilities, and the technical requirements required to amend the current commercial regime (FWACV), are the subject of the ongoing studies in the CLoCC and Future Billing Methodology projects, (see Section 4).

Gas as a Peak Supply Vector for Hybrid Heat Pumps

Gas network costs are largely recouped from users on a commoditised basis. As consumption falls the network component of gas will rise; at demand around 10% of current levels the network component of gas costs would increase four-fold. In order that network costs are distributed equitably, distinct single and multi vector gas tariffs might be created, with the latter dominated by a standing charge. As multi vector heating requires gas supply only during winter periods of peak demand, some provision would be required to discourage seasonal switching between single and multi vector tariffs; notifying GDNOs of hybrid heat pump installation might be required, (as DNOs must be informed of heat pump installation as part of RHI qualification). Alternatively, given the system level benefit in avoided grid upgrade costs and the environmental benefits of (largely) electrified heat, the costs of continued operation of the gas network under much reduced throughput could be socialised.

Table 5 – Potential Means of Charging Gas Network Connection

Basis of Charging	Description	Impact
Current System	Suppliers are charged by GDNs; >95% of this charge comprises a capacity charge. Suppliers recoup these charges from domestic customers through tariffs comprising a standing charge and a (flat) unit price.	Domestic gas network use is charged on a commoditised basis. As total gas use falls, recovering largely fixed GDN costs from single and multi vector users on a marginal use basis may lead to higher fuel costs; significant gas users (e.g. homes on persistence gas heating) will therefore subsidise the use of system costs of peak-only users.
Local Connection Zones	Increased granularity of gas network connection charges could reflect the extent to which users drive usage or investment costs, particularly where individuals can choose the relative size of their HP and gas boiler, and have significantly different heat demands (e.g. due to property size). For hybrid heat pump users, this tariff could reflect some combination of level and frequency of gas use.	Local connection charging might discourage e.g. new build connections to congested gas networks and encourage biomethane plants to connect to them.
Multi Vector Tariff	Hybrid heat pump users could pay a gas connection cost that reflects their pass-through charges more efficiently e.g. through a capacity charge based on their maximum use.	As an increased component on multi vector bills, this may disincentivize hybrid heat pump uptake.
Paid with avoided DNO investment	Some fraction of gas system cost recovery could be subsidised by avoided electricity system investment. For example, part of the gas network regulated asset base (RAB) could be transferred to the electricity DNO, to be recovered from electricity customers.	A form of socialisation of gas grid cost. It may prove unpopular with electricity consumers, particularly those without a gas connection.
Socialisation	As gas throughput falls, increases in standing charges could be capped, with any shortfall in GDN cost recovery socialised across all energy consumers (this cost could be controlled via the Levy Control Framework budget), or through general taxation.	Effectively subsidising the energy supply of multi vector homes may be inequitable and/or unpopular.

Other gas price components could also incentivise lower total gas use and the electrification of heat:

- Environmental and social levies on gas and power currently comprise 2% and 12% of average consumer prices respectively[16]. These could be reversed, particularly as the carbon intensity of power decreases, favouring electric (heat pump) over gas heating.
- Gas prices could rise as a function of total use (this is not currently permitted).

[16] Ofgem - Energy Bill Breakdown

6. Future of Hydrogen

There are challenges to both blending hydrogen with natural gas in the existing gas grid, and re-purposing gas networks to carry 100% hydrogen.

- In the former case, GSMR regulations currently limit the permissible concentration of hydrogen in natural gas to 0.1%, although there is evidence that much higher concentrations could be tolerated without issues (National Grid's HyDeploy NIC project will explore this issue).
- The latter case constitutes a huge challenge; concerted policy action is needed (as discussed above) and switching in the most efficient manner is a complex coordination task. Several key technical questions regarding the optimum system design and the role of supply technologies are unresolved.

Our analysis suggests that:

- Power to hydrogen for injection into the gas grid does not represent a cost-effective means of absorbing renewable oversupply at a per kWh hydrogen price equivalent to that of natural gas. A carbon price, or hydrogen specific support instrument, could improve the viability of electrolysis from low cost electricity.
- Electrolysis may play a role in hydrogen for heat supply where power prices are substantially (around 45%) lower than average, perhaps due to substantial renewable curtailment or very low use of system charges. Further work (studies and trials) to explore the business case for electrolysis in areas of high renewables potential but weak grid infrastructure is required.

7. Increased Coordination

The assessed multi vector cases require increasing cross vector coordination, particularly between power and gas networks, for both operation and development. There is currently little of either, so significant additions to the organization of the energy system will be needed.

Operational coordination will focus largely on data sharing; in many cases it will be in all parties' interests to coordinate in this way, regulation may be needed where e.g. priority to supply a particular demand must be decided. Coordination of the development of future energy networks will require more substantial modifications to the architecture of the energy system.

At the regional level, local authorities (or Local Enterprise Partnerships) might play a role in fostering this coordination by developing local energy plans. A local authority could use their convening powers to bring the relevant network operators together, including gas and electricity network companies, but potentially also heat network operators and generators. The local energy plans could include a holistic understanding of demands and resources in the region, and how these are expected to evolve, including:

- Spatial mapping of heat and power demands and supply opportunities, drawing on DNO data, central government resources (e.g. heat mapping, wind speed maps)
- Demographic data, such as homes in fuel poverty
- Opportunities for novel energy supply, e.g. hydrogen for public transport
- Council owned or controlled energy demands, for e.g. private wire supply

This could inform a set of local energy planning priorities which future network upgrades and generation projects would have to consider. Local government provision of energy planning functions might require a central funding pot, administered in partnership with BEIS to procure relevant expertise, or fund field trials. Local energy plans would become increasingly valuable to DNOs as they transition to a DSO role, with a greater remit to consider localised balancing of supply and demand.

Need for increased trials of cross vector coordination

While there is currently a large amount of R&D funded across gas and electricity networks through the Network Innovation Stimulus (and its predecessor the Low Carbon Network Fund) projects, the number of projects that involve trials of multi vector solutions and the cooperation of network companies across vectors is relatively limited.

One such project, which investigates a potential high value multi vector opportunity, is WWU and WPD's cooperation in the FREEDOM project. Within this project, WPD and WWU are investigating the DN coordination tasks involved in the intelligent control of hybrid heat pumps to:

- Enable operator investment deferral and constraint mitigation on their networks
- Lower consumer heating bills
- Explore consumer attitudes to load control and hybrid heating technologies
- Develop the processes needed for flexible heating roll out and control

In addition to the technical and operational findings, trials such as these may provide insight into how the network coordination processes are delivered and overseen. Further funding of research into multi vector projects will be required, potentially through Innovation Stimulus.

2.4 Summary of Innovation Opportunities

Some priority areas for innovation are highlighted in the table below, we discuss the timescales over which they might be required, and high-level estimates of the scale of investment needed. While some are specific to multi vector energy supply, many of them form part of wider work on future energy system pathways, but are nonetheless important if multi vector operation is to be realised. The innovation opportunities are rated on a three point scale (Red/Amber/Green), reflecting how difficult and how critical, their solution might be to multi vector supply.

Table 6 – Innovation Opportunity Rating

RAG rating	Impact	Risk
Minor	Not a key requirement to multi vector operation, or alternative solutions are available.	Innovation requirements appear straightforward, given current capabilities and operation.
Moderate	Multi vector operation may be difficult without this innovation	Some risk that innovation will be difficult, or require substantial change to current operation.
Major	Multi vector operation will be difficult without this innovation	Significant risk that innovation will be difficult, or require substantial change to current operation.

Table 7 – Summary of Innovation Opportunities

Innovation Area	Innovation / Action	Rating		Potential Solution / Outcome	Timescale	Investment
		Impact	Risk			
Barriers **Distribution Network Telemetry**	**Installation of bespoke LV telemetry to provide more granular data on LV voltages and load flows**			Availability of LV network data in real time enables dynamic solutions such as ANM and balancing.	This solution is unlikely to be pursued unless a smart meter based approach (and perhaps other ANM solutions) proves unsatisfactory; no sooner than the mid 2020's.	LV substation and associated feeder telemetry costs no more than £50k - around £375 per household, or 10% of multi vector benefit.
	Use of Smart Meter Data			An alternative to increased LV network monitoring, DNOs may be able to infer information on network state from smart meter data, potentially in real time. If real time data is not available, historic profile data may be sufficient to identify which feeders / transformers are becoming overloaded (real time data likely to be necessary for balancing).	Smart meter roll out finishes in 2021, though LV network demand spikes due to electrified heat are not expected until heat pump uptake reaches 20-25%, which is likely to be later.	Although infrastructure costs are effectively zero, though creating a network load model from instantaneous MPAN readings that can control a DSM platform
Need for Clarity in Low Carbon Heat Policy	**Development of new market mechanisms that support multi vector interactions**			There are significant questions regarding the operation of the gas market under different multi vector configurations, e.g. different market arrangements may be required if gas is utilised as a peak supply vector compared to the case of hydrogen supply. The electricity market may also need to adapt to reflect multi vector integration, for example to account for more complex demand forecasting, availability of gas as balancing plant, new ancillary service providers.	Initial work to assess potential market models under different energy system scenarios can proceed without delay. Over time, as the technical system architecture emerges more clearly, market models will need to be revised. New market models may be trialled at a localised level as part of innovation programmes.	Early analytic work at cost of £millions in total. Trials are likely to be part of wider demonstration projects, at cost of £10s millions (see below). Consultation and eventual overhaul of market design and other relevant codes will be a significant programme of work - £millions.

Innovation Area	Innovation / Action	Rating: Impact	Rating: Risk	Potential Solution / Outcome	Timescale	Investment
					Today to 2020 to develop options. 2020 to 2025 to consult and begin revising market arrangements.	
	Develop and fund research into multi vector energy systems			Technical work and trials will be required to explore multi vector system options in detail. This work has already started through the current innovation funding programme, e.g. projects are underway to trial hybrid heating systems (WWU's Freedom) and several projects are considering various aspects of hydrogen in the gas network (Leeds H21, NG's HyDeploy, SGN's 100% hydrogen). Significantly expanded scale trials will be required. Micro grid, CHP networks, local energy supply companies might allow energy supply across power, gas and heat vectors can be explored.	Several pieces of work are underway under existing innovation programmes. Continued technical work and field trials expected to 2020 – 2025, depending on the complexity.	In-depth innovation projects and field trials at increasing scale - £10s – 100s millions.
	Encouraging hybrid heat pump uptake, or maintenance of legacy boilers.			The case study analysis has shown that substantial savings on distribution network upgrades can be delivered by multi vector hybrid heating systems rather than pure electrification of heat. However, hybrid heat pumps do not currently benefit from any additional incentives, compared to pure electric heat pumps. Due to the greater overall system benefit delivered by hybrid systems it could be argued that there is a case for increased incentivization.	The role of heat pumps in the decarbonisation of heat is not clear, and historical projections of uptake now appear optimistic. Winter network capacity begins to strain at around 20% uptake of unmanaged heat pumps, by which time any policy to drive	Installation of heat pumps in gas heated homes does not typically require removal of the boiler[17], though space requirements and consumer preference may complicate this assessment. The costs of multi vector capability comprise those of boiler

[17] Given their lower operating temperature range, switchover to heat pumps is not possible in some legacy building stock, though transcritical CO_2 heat pumps can supply heat at the same flow and return temperatures as gas boilers, so that no modifications to pipes and radiators are required. Such units are currently very expensive, and only available for new build, but are expected to come down in price as the technology matures.

Innovation Area	Innovation / Action	Rating Impact	Rating Risk	Potential Solution / Outcome	Timescale	Investment
					flexible supply configurations would have to be established – though when this corresponds to is unclear.	maintenance and/or replacement (remembering that the boiler will operate at a much lower load factor) and continued connection to the gas grid, on the order of £100 annually.
	Encouraging smart electric heating and storage.			Around 12-15GW of electric heaters are connected to the UK grid, and this number is expected to rise. By 2030, all this demand could be flexibly controlled, assuming a unit lifetime of around 15 years, provided the DR costs do not disincentivize consumers from choosing aggregator-ready units.	Deployment dictated by the rate of heating system turnover in the stock – increasing presence of smart electric heating and storage over the period to the early 2030s.	Annualised control system costs are estimated at around £20 per household at scale; less than the value of avoided curtailment. Although a template commercial framework to share value between suppliers, generators, aggregators and scheme participants has not been found, SETS can be implemented at almost any scale – private and community developers are therefore likely to invest in this platform[18].
Demand response	**Further trials of intelligent and automated demand management**			A number of multi vector systems rely on firm demand response of 'behind the meter' loads	Some trials of automated DSR have been	Additional trials of automation technologies,

[18] We note that SSE and WPD do not expect domestic DSM or ancillary service provision to compete in general with I&C load; this is therefore likely to remain a marginal service in the medium term.

Innovation Area	Innovation / Action	Rating: Impact	Rating: Risk	Potential Solution / Outcome	Timescale	Investment
				(the case studies have tended to focus on domestic loads, but I&C loads are also of interest). Automated demand response that can deliver the response without active participation of the occupant is likely to give a higher response rate. Intelligent systems are required to respond to control signals (pricing, network peak load, CO_2 emissions etc.) while ensuring occupant comfort / utility is not undermined. Awareness raising and education will be required.	conducted in innovation projects, together with trials of time of use pricing (combined with varying degrees of automation). Further trials are expected over the period to 2020. Following completion of the smart meter roll-out (2021) and anticipated introduction of half-hourly settlement for all, barriers to commercial automated DSR will be reduced, although it is expected to become established first in the I&C sector, with domestic uptake mid to late 2020s.	communications, aggregation platforms if required - £10s millions. Smart meter roll-out costs are not assumed to be additional.
Gas network charging	**Novel network connection and use of system charging.**			Depending on the future role of the gas network, new models for network companies to recover their investment in the networks may be required. For example in the case that the gas network becomes largely a peak load supply vector, the charging model is likely to transition to a capacity dominated charge, rather than use of systems. Analysis of potential models for GDNO cost recovery under a range of scenarios for the future role of the gas network is a low regrets action and something that BEIS is already beginning to explore (also recent work	Analytical work on this issue is already underway and is likely to be revisited as future options for heat decarbonisation and the role of gas within the system becomes refined. This work should proceed in tandem with work on the market structure (up to 2020)	Requirement for additional studies on regulatory design (likely to be several iterations) and consultation on proposed changes to the charging model - £millions.

Innovation Area	Innovation / Action	Rating: Impact	Rating: Risk	Potential Solution / Outcome	Timescale	Investment
				by the Committee on Climate Change has considered this issue).		
	Establish upper bound limits on hydrogen concentration in the gas network			Current GSMR limits on hydrogen concentration in the gas grid preclude hydrogen blending. However, significantly higher concentrations have been carried by the gas network in the past (town gas) and are permitted in some European countries. The National Grid HyDeploy project will explore the impact of H_2 blends of up to 20%. Work is required on the impact of higher concentration blends on the network (leakage, embrittlement) and on hydrogen using appliances and plant, including power generation technologies. The FCHJU and H2020 programmes also make funding for H_2 projects available; though have so far not looked at gas blending.[19]	This work is starting today with the HyDeploy project, but further trials are likely to be required, considering increased scale deployment and to comprehensively assess the impact on all gas users.	The likely requirement for additional trials will need further innovation funding - £10s millions
	Develop alternatives to propanation as the solution to injection of low CV gas			Alternative gases such as hydrogen, bio-methane and bio-SNG have lower CV than the typical average CV of natural gas. The current FWACV regime stipulates that the energy content of charged gas must be within 1 MJ/m^3 of the flow weighted average CV within the zone, resulting in a large amount of unbilled energy (shrinkage) when low CV gases are injected. Raising the CV by addition of propane is costly and can undermine the business case for alternative gases. National Grid's Future Billing Methodology project is considering	The results of the Future Billing Methodology project will inform this debate over the next few years. Any proposed changes will require submission of change proposals to Ofgem and will likely require consultation. Potential for changes to the charging regime over the period to 2022.	Total investment requirement (including Future Billing Methodology) of £5 – 10 million.

[19] FCH JU Projects

Innovation Area	Innovation / Action	Rating Impact	Rating Risk	Potential Solution / Outcome	Timescale	Investment
				alternative local charging regimes to limit shrinkage.		
	Trial ways to address network capacity issues for injection of distributed gases into the gas distribution network			For smaller scale producers of alternative gases, which tends to include biomethane and might also include hydrogen production via electrolysis, a lack of capacity in the lower pressure tiers of the network (limited to the minimum demand downstream of the injection point) can be a barrier to connection. Within grid compression can provide a solution to this issue, which involves gas being pumped up to higher pressure tiers when there are capacity constraints. A limited trial of in-grid compression has been undertaken in National Grid's network to-date, but no full-scale demonstration under a variety of network loading conditions. Parallel work on the commercial implications will be required. Provision of within-grid compression will require capital investment, triggered by the request by a distributed facility operator to inject gas. The investment in the compressor might undermine the business case for a single producer and the investment will potentially benefit subsequent producers connecting to the same network. There may therefore be a case for including the investment in the GDNO RAB and socialising through network charges.	Opportunity for a near-term demonstration to prove the technical feasibility of within grid compression. Work on the commercial & regulatory issues will require consultation. However, commercial implementation of within grid compression in the period to 2022 is realistic.	Requirement for demonstration projects and work on commercial / regulatory framework - £10s millions
	Modelling gas and other networks under various multi vector operating profiles. Possible role for trials.			Improved modelling tools that capture the inter-dependencies between vectors and have sufficient spatial resolution to inform scenario planning and investment forecasting at	Development of improved modelling tools could be developed as a low regrets action, potentially with NIA	Development of a sophisticated modelling platform – low £millions.

Innovation Area	Innovation / Action	Rating Impact	Rating Risk	Potential Solution / Outcome	Timescale	Investment
				distribution network level would be useful for both electricity and gas network operators. Dedicated gas network modelling could be developed to explore issues under specific multi vector configurations, e.g. ramp-rates on gas networks in hybrid heat systems, availability of injection points for H_2 blending etc.	funding. This could be developed as a cross-industry led project, involving gas and electricity DNOs. As above, governance, likely as cross vector regulation, will be key.	
Future of hydrogen	**Substantial programme of research and field testing**			The conversion of the gas grid to supply pure hydrogen opens up a number of multi vector opportunities. However, the challenge of converting the grid to H2 is immense. The Leeds H21 study has provided initial evidence that these challenges are not insurmountable, but this will need to be proven with detailed engineering studies and trials of major components of the system, from production to end-use appliances. Such trials may investigate some multi vector opportunities directly, e.g. power to gas and waste routes to H_2, but the establishment of a H_2 gas grid can be seen more widely as an enabler to multi vector systems.	Gathering the technical evidence base will be a long-term programme of work, likely to extend to the mid-2020s. In parallel, work on the market design and necessary overhaul of technical and commercial codes, as well as the regulatory model will be a long-term project and may not start in earnest until significantly greater certainty on the technical implications has been gained. Overall, this programme is likely to extend throughout the 2020s (note the iron mains replacement programme is due to complete in 2032).	Outside of the large investment required in the IMRP, this will require significant innovation funding and may require different instruments to the NIA / NIC - £100 million.

Innovation Area	Innovation / Action	Rating		Potential Solution / Outcome	Timescale	Investment
		Impact	Risk			
	Public Engagement			Hydrogen is expected to be no less safe than natural gas as a heating fuel, and will eliminate the risk of in-home carbon monoxide poisoning. Nevertheless, public perception has been highlighted as a risk to gas-to-hydrogen conversion, although public acceptance of hydrogen as a transport fuel has not been problematic[20]. The H21 report, identifies the following areas as important in any public engagement plan: • How to manage information regarding physical trials • How to engage the media • How to engage the public in key areas • How to educate the public on hydrogen • How to give confidence in the strategy	Initial schemes, currently targeting 2031 for deployment, will require most engagement, after this it will be possible to refer to the experiences of operational schemes.	Likely to be marginal in cost terms compared to the infrastructure costs of network conversion.
Increased Coordination	**Closer alignment of electricity and gas distribution network operators in forward planning**			With the increasing electrification of heat, seasonal electric demand profiles will increasingly reflect those of gas demand and implementation of multi vector approaches will increase the inter-dependencies between the networks. Local network capacities will therefore need increasingly to be considered together for planning and operational requirements.	Improved coordination between network operators, principally electricity and gas, could be implemented without delay. Ofgem leadership is likely to be required (e.g. evidence of a coordinated approach in strategic / investment planning could be required as part of the	Development of modelling tools and scenarios to inform planning could be done under NIA projects (captured above). Other additional costs to coordination in strategic planning seem to be low.

[20] Conversion of the UK gas system to transport hydrogen, Paul E. Dodds, Stéphanie Demoullin, 2013

Innovation Area	Innovation / Action	Rating		Potential Solution / Outcome	Timescale	Investment
		Impact	Risk			
					next round of RIIO submissions).	
	Develop processes and technical systems architecture to ensure sharing of information between relevant parties across vectors (operationally and real time)			As demand for gas, district heat and hydrogen interact increasingly with the power grid, their integration and flexible operation will require a coordinated strategic planning framework and data sharing ideally in real time around demand, capacity constraints, emissions factors and so on.	Coordination in real and operational timeframes to develop line with the electrification of heat, roll out of heat networks and uptake of hydrogen as an energy supply vector respectively.	Increased telemetry to ensure data is available to optimise multi vector systems in real time are captured above. Additional communications and IT systems may be required for sharing data between network operators - £millions.

2.5 Specific Multi Vector Energy Trials

Above, we identified broad innovation areas and barriers that will need to be addressed to create the conditions for greater deployment of multi vector energy systems. In the table below, a number of more specific trials that have been devised to address key issues are described in greater detail. These trials and modelling projects could be undertaken in the near term.

Table 8 – Potential Innovation Projects to Facilitate Multi Vector Energy Supply

Trial	Description	Outcomes
LV network visibility using smart meter data	The Case Study 1 analysis has shown the potential value of monitoring the LV network at the substation and potentially feeder level, to optimise control of a multi vector heating strategy and avoid network reinforcements. However, LV network monitoring is currently rare outside innovation projects, and the business case for investment in monitoring devices and associated telecommunications to gain good coverage of the large number of LV network assets is uncertain. This project would seek to understand the extent to which smart meter data can obviate the need for LV monitoring by enabling development of real time predictive models of network loads. It would assess the accuracy of predictive models which apply big-data techniques (e.g. machine learning) to large sets of smart meter data, together with weather data, demographics, etc. LV network monitoring would be required in a trial area (potentially a number of areas of differing characteristics) to provide the target values for learning algorithms.	Increased understanding of the potential of smart meter, together with other, data to inform real time predictive models of load on network components. Development of a prototype model platform to demonstrate promising techniques. Tests of model accuracy in a number of areas of the network against monitored network data.
Flexible low carbon heating – comparative analysis	Trials of hybrid heat pumps and micro-CHP alongside alternative single vector low carbon heating technologies, such as pure electric heat pumps and smart thermal storage technologies, to understand impacts on the networks, demand flexibility and the services that can be provided to DNOs and other stakeholders. The trials could assess a number of aspects of demand management of flexible heating technologies, such as: i. *Role of thermal storage* – Efficacy of thermal storage options (potentially including high density storage technologies) in providing demand flexibility when combined with different heating technologies. ii. *Gas network impacts* – assess impact of multi vector technologies such as hybrid heat pumps and micro-CHP on the gas network when operated under demand management to support the electricity network	Understanding of the impact on the network and extent of demand response flexibility offered by a range of heating appliances, including hybrid heat pumps, gas micro-CHP, pure electric heat pumps and thermal storage, storage heaters. In each case, understand the potential to manage peak loads on the electricity network, the additional services that each system can supply and the implications in terms of the size of appliance, load factor and size of thermal storage required. Empirical validation of theoretical models' predictions that pressure drops associated with aggregated operation of gas heating

	iii. *Control technologies and strategies* – potential to involve a range of HEMS technology providers to assess different methods for control of heating appliances (including direct load control and pricing based techniques). iv. *Technology performance* – gain insights into the performance of different technologies in a range of house types with differing thermal performance. This is a significant scope of work and may be split into a number of separate innovation projects, focussing on specific aspects of these tasks.	technologies, such as HHP and micro-CHP, on low pressure networks can be managed through appropriate control strategies and do not necessitate network reinforcement, for example network storage. Improved evidence on the effectiveness of control technologies and strategies (load control & pricing) for delivering firm demand response.
Transcritical CO_2 heat pumps for legacy build stock	A further trial particularly concerned with the applicability of heat pumps, including hybrids, would be to assess the applicability and performance of heat pumps operating with higher temperature refrigerants, such as CO_2. CO_2 heat pumps can supply heat at temperatures high enough for central heating systems with small radiators and pipe diameters, allowing them to be used at the same time, and flow temperatures, as gas boilers.	Determine whether CO_2 heat pumps and gas boilers can operate in tandem in existing central heating systems. Determine whether heat pumps can incentivise uptake, through more "boiler like" operation.
Electrolyser ancillary service provision	A number of the case studies have considered the role that electrolysis might play in power-to-gas systems, either blending hydrogen into gas networks, providing hydrogen for methanation before subsequent grid injection and as a producer for dedicated hydrogen networks. The business case for electrolysis has been shown to require future electrolyser cost reduction and low-cost electricity supply (although the opportunity related solely to surplus electricity has been shown to be limited). We have noted that the business case could be improved by electrolysers providing ancillary services. Building on the Scottish & Southern Energy Networks (SSEN) Impact of Electrolysers on the Network project, further trials are required to understand the potential for network, supplier and ancillary service provision from electrolysers when operating in different applications. For example, the SSEN project focussed solely on an electrolyser-based hydrogen refuelling station and was most concerned with operation of the refuelling station and technical impacts on the network. Further work is required to assess the potential impact on the business case of providing these various additional services and whether offering these services has implications for the optimum technical design of systems in, e.g., power-to- gas installations. A pre-requisite for commercial deployment of power-to-gas is an increase in blending limits of hydrogen in the gas network. A comprehensive programme of work in this area is underway, through projects such as HyDeploy, Future Billing Methodology and Opening Up the Gas Market (which looks at the use of higher Wobbe Number gases). These projects are expected to identify areas of further work needed to achieve a change to the hydrogen content limits in GSMR (or a type exemption of the kind granted to biomethane plants regarding oxygen content).	Trial data on the ability of electrolysers to provide network, supplier or ancillary services when operating in different applications (including power-to-gas, e.g. as part of ongoing trials on the impact of increased hydrogen blending limits in gas networks). Improved understanding of the revenues available and the impact of providing these services on the electrolyser business case.

Future Market for Ancillary Services	Related to the above expanded electrolyser trials, it would be useful to determine demand for future grid balancing services under a range of grid decarbonisation and Low Carbon Technology (LCT, e.g. heat pumps, PV, EV) uptake scenarios.	Likely future market size and value across ancillary service.
Joint network planning	One of the key requirements for closer integration of energy vectors, in a variety of multi vector configurations, is closer coordination between the network operators. Currently electricity and gas DNOs plan their network investments in isolation (although they will consult on the proposals with key stakeholders before finalising their business plans), based on their own projections for expected demand. Better outcomes might be achieved if the electricity and gas DNOs were to develop a joint plan, identifying opportunities for cost-effective multi vector energy systems. For example, in a scenario of general widespread deployment of heat pumps, the joint plan might identify the optimum level of retained gas heating to avoid major power network reinforcements. Such joint planning between gas and electricity network operators represents a shift from the current business planning process of the network operators. An initial trial might involve a theoretical exercise, where the network operators assess a particular area and test the process of creating a joint plan. This would help to identify the data that would need to be shared between the network companies and the areas of commercial tension in creating such a joint plan that would need to be resolved (for example the joint plan might increase overall cost-effectiveness of network investment, but as a result lead to a reduction in regulated revenues of one or other partner compared to their individual plans – Ofgem would have a role in considering how such tensions could be resolved). This study could also involve the local planning authority, which would bring information on planned development in the area and, if they had been active in energy planning, further spatial data, such as heat mapping and opportunities identified for heat networks. The use of ETI's EnergyPath Networks tool could, for example, inform the joint network planning exercise.	Development of a procedure for electricity and gas utilities to collaborate on joint infrastructure planning. Identification of commercial and regulatory barriers to joint planning which will need consideration of Ofgem. Trial of closer cooperation between utility network operators and local planning authorities in developing cross-vector infrastructure plans for local areas.

3 Case by Case Barriers

Barriers to operating the energy system in the multi vector configurations modelled and analysed in the WP3 report *Assessment of Local Cases*, have been identified and collated following consultation with stakeholders; these are classified per the schema below:

Table 9 – Categorisation of Barriers to Multi Vector Operation

Category	Barrier Types
Commercial	Barriers to multi vector operation around the system value of a service or product not being reflected in its market value, diffuse benefit, or a lack of market place.
Regulatory	New or modified policy or regulation required to allow or incentivise the multi vector solution.
Technical	Multi vector implementation requires the collection or dissemination of operating data, or for current control and operating practices to be upgraded, developed or expanded.

The extent to which barriers identified might impede a move to multi vector operation is categorised on a four-point scale, which captures:

- **Impact** –the scale of potential multi vector benefit the barrier impedes, or solution cost
- **Risk** – the extent to which these barriers are surmountable, or might impede multi vector operation.

Table 10 – Barrier Risk Rating System

Risk	Impact		
	Minor	Moderate	Major
Major	Moderate	Significant	Major
Moderate	Minor	Moderate	Significant
Minor	Minor	Minor	Moderate

3.1 Case Study 1 – Domestic heat pumps and peak gas boilers

In this study, we investigate a high heat pump uptake future, and determine the grid reinforcement costs avoided through moving peak thermal demand onto the gas network; we consider multi vector heat supply implemented both through DSM, and by limiting the maximum electrical demand of heat pumps, and finds that multi vector heat supply can save between £2,000 and £4,000 per user, over an unmanaged single vector counterfactual.

Commercial

1. Substantial Decrease in Utilisation of Gas Networks

Risk	Moderate	
Impact	Moderate	

As gas use shifts to peak-load-only use in buildings with electric heat pumps, the utilisation of the gas network will fall - particularly on the low-pressure network to which most homes and small non-domestic buildings are connected – but fixed network costs will not decrease to the same extent. Gas transportation charging will therefore come to be dominated by the capacity, rather than use of system, charges.

Despite the significant drop in utilisation, it will be difficult to decommission any of the gas network, so that network depreciation, return and O&M levels will need to be maintained near current levels. Low utilisation therefore presents economic issues in terms of cost recovery for the network operators, who must recoup their largely fixed network costs over a much-reduced volume of gas transported, resulting in a significantly increased network cost component (standing charge) of the overall gas supply cost.

Assuming the iron mains replacement programme (IMRP) is completed as planned (currently due to be complete by around 2030), the leakage in the low-pressure network should be significantly reduced. Together with the reduced overall demand, and more seasonal nature of gas demand, this may allow network operators to reduce their headcount and therefore operating costs to some extent. However, the presence of significant fixed operating costs associated with meeting service level obligations means that opex will not fall as much as throughput; decreases in gas distribution network operator (GDNO) revenue requirements will not reflect the reduced utilisation of the networks.

The economics of operating the gas networks depend on overall gas consumption, comprising:

- *consumption for power generation,*
- *demand at larger industrial and commercial sites,*
- *potential use in LPG and CPG vehicles, and*
- *potential use in CHP*

Consumption in these sectors (which is not considered in detail here) may mitigate the economic impact of the fall in consumption across the domestic sector due to uptake of heat pumps. However, an equitable pricing structure which shares investment and O&M costs of the low-pressure network across persistence gas boiler and multi vector (peak only gas) users will need to be determined and agreed by the regulator (see section 2.1.4 *and* 2.2.4*).*

Regulatory

2. Incentivization of Multi Vector Operation

Risk	Major	
Impact	Major	

While DNOs own the liability for the grid upgrade required as heat is electrified, avoiding these costs through multi vector heat supply requires the cooperation of many agents, some outside the electricity generation and supply industries. In particular, gas network connections to existing buildings, and their boilers, must be maintained.

Despite the social cost saving, no mechanism exists to encourage consumers or housing developers to choose flexible thermal supply options; under high, unmanaged heat pump uptake, peak winter electric heat load will outstrip network capacity (timescales are explored in the report section on Component Load Growth). Home energy controllers are increasing in popularity, and their potential to allow control of consumer energy demand for network management is an area of considerable interest, though the required commercial and regulatory frameworks are not yet in place.

As a regulated monopoly, DNOs are not fully exposed to market forces, and can amortise Ofgem permitted investment in upgrading their networks over many years. Regulatory coordination is required to realise investment avoided through multi vector supply, to procure the services needed, and to ensure continued, affordable operation of the gas network.

Creating policy to encourage multi vector heat supply will require:

- *An assessment of the role of heat pumps as part of a roadmap to low carbon heat, and identification of locations where multi vector heat supply is cheaper than the single vector alternative.*
- *Policy to reflect the system value of supply flexibility in support mechanisms for low carbon heat plant.*
- *Design of an equitable levy to fund the development of a multi vector heat supply platform, (rather than the higher social costs of large scale grid reinforcement)*

Technical

3. Gas Demand Becomes Peaky on Seasonal and Diurnal Timescales

Risk	Moderate	
Impact	Moderate	

In this solution, multi vector gas boilers are used in a highly-coordinated manner, especially during winter peak morning and evening heating times - potentially resulting in high gas demand ramp rates and potential issues with pressure drops along the network.

Given that the network has capacity to meet current, relatively un-diversified peak heating demand, it is expected that the current network would be able to cope with the changed pattern in gas use without significant issues, particularly given the underlying trend of falling gas demand due to energy efficiency improvements.

- Element Energy and the Sustainable Gas Institute have recently modelled the impact of highly coordinated dispatch of domestic micro-CHP systems on the low-pressure gas network (NIA project on the impact of gas CHP on gas networks, to be published) and found few issues with pressure drops on different types of low pressure network. Of the issues that did arise, none could not be solved by a minor adjustment in operating pressure of the network.
- The likelihood that the dispatch of gas heating technology will be highly coordinated depends on the method used to control it. For example, gas heating plant dispatched by direct load control, e.g. by a network operator, could be phased to ensure network pressures remain within an acceptable operating band. This would require monitoring of the gas network low pressure point, and coordination of the management of the gas and electricity networks.

Were appropriate control systems to manage fuel switch-over not in place, and ramp rates on low pressure networks were found to cause network problems, gas storage capacity might be required at the MP level; this might be provided in the form of pipe arrays. A potential lower cost alternative would involve oversizing the HDPE pipes laid as part of the IMRP, at a cost margin of around 10%.

4. DNOs Lack Visibility of Heat Pump Installation

Risk	Minor	
Impact	Moderate	

Currently, network operators have little data on which customers install heat pumps in their homes, making it difficult to plan network reinforcement or to target demand response strategies to proactively address operational issues.

Where they are limited to acting in a responsive manner, DNOs cannot plan load growth mitigation strategies or more cost-effective reinforcement investments.

DNO visibility of heat pump installations will be significantly improved by the roll-out of smart meters, enabling characteristic heat pump load profiles to be identified. While homeowners installing heat pumps are required notify the local DNO, operator data on installed locations is patchy, and subsidy and DNO data agree only partially. A regulatory solution might require installation firms, rather than private users, to notify the DNO.

5. Ensuring Gas is Used only at Appropriate Times

Risk	Major	
Impact	Moderate	

It is necessary to ensure that multi vector households use gas at system appropriate times (i.e. times of peak electrical demand). Conversely, over-use of the gas heating capability will result in lower than expected environmental benefits from the deployment of electric heat pumps.

Failure of householders to reliably switch to gas heating during electricity network peaks or generating capacity shortfalls could negate the benefits of the multi vector system and require investment in the electricity system to meet the worst-case scenario for electric heating load. Overloading of circuits could result in faults and customers losing supply, with significant cost implications.

Management of consumer heat supply is key to this solution - without it users may for example operate their heating systems to minimise bills, irrespective of grid loads. In addition to the technical implementation questions, direct control of home heating technologies raises significant consumer acceptance as well as potential data privacy and cybersecurity issues.

The required patterns of use of electric and gas heating could be controlled by price signals, direct load control by a network operator or third-party, or by features built-into the end-use appliance:

1. *Widespread roll-out of time-of-use pricing will require smart meter roll-out, and the introduction of half-hourly settlement for domestic and small commercial customers; it will also require that suppliers pass network charges through to customers. Some studies on ToU tariffs are references below, but further work is required, encompassing:*
    - *Efficacy - the relationship between price increase and demand moved*
    - *their effect on demographic groups and customers who are not individually metered, such as prepayment scheme or housing association members*
    - *concerns around consumer engagement, particularly given the BEIS push for simpler retail tariffs.*

2. *Direct load control of heating systems by network operators or third-parties could deliver a more reliable switch from electric to gas heating at the appropriate times. This relies on roll-out of smart meters or alternative gateway devices within homes to establish a home area network (HAN), broad coverage of a wider area communication network (WAN) to enable communication with individual homes and for the electric and gas heating devices (which may be separate or hybrid) to be able to communicate over the HAN. One simple solution is the Climote system, in which the DNO reports load on the final transformer to all connected customers, who are not permitted to connect additional demand when the transformer is operating at capacity (the more stringent the direct control over domestic heating, the more a regulatory requirement for a backup vector may be required).*
3. *Constraining electrical load that heat pumps impose on the electricity network by limiting heat pump capacity. Product regulations could be used to ensure that heat pumps are only sold for use within a bivalent heating system (either as a hybrid system or alongside an existing gas heating technology). The limit on heat pump capacity constrains the impact on the electricity system while ensuring that consumers use alternative heating technology to achieve comfort during peak heating time. This solution may need to be combined with another mechanism, such as time of use pricing, to ensure additional electric heating (e.g. electric convection heaters) is not used to meet peak demands, and to ensure that gas use is limited to the peak periods.*

Whichever implementation is selected, some requirement or mechanism that ensures users do not override the control of their heating system may be required. Getting users agree to control of their energy demand may require a guarantee that their bills will be "lowest possible"; this may involve a rebate being paid to customers where their metered bill is greater than a bill optimised on price alone. As thermal supply is switched from the electric to the gas vector largely at times of low CoP, the difference, and therefore total rebate costs will not be large (these are discussed in the Fuel Bills section in the report).

6. Interoperability of HEMS Controllers and Aggregation Platforms

Risk	Minor	
Impact	Major	

For direct load control, the aggregation platform should be able to interface with the most manufactures' heat pumps and space heaters.

HEMS manufacturers, particularly large, multi-disciplinary firms, have an incentive to make their smart devices interface only (or most cheaply) with their own devices and aggregation platforms (where they offer these). Although aggregators can typically bolt control units onto most home energy controllers, allowing them to interface with proprietary systems, this can increase the solution cost by up to £250.

Device protocols should be agreed and standardised – examples include the OpenADR and Zigbee Alliances (both are free to users, but require developers to pay an annual license fee), and the Open LV platform currently being trialled by WPD using broadband-over-powerlines.

As well as telemetry, smart meters may reduce control costs; DNOs can issue control instructions to auxiliary loads through smart meter ALCS functionality; provided gas supply can be automatically substituted this should not affect consumer comfort, though it would likely be an "opt-in" service.

7. Network Component Monitoring

Risk	Moderate	
Impact	Major	

Load management solution requires the ability to react to real time, detailed understanding of grid load at individual components.

Where implemented through responsive means, such as direct load control or variable tariff, the platform will need real time load data from substations and, to maximise multi vector value, transformers and feeder cables. Current DNO monitoring capabilities are largely confined to the HV system; all primary substations, and some HV feeders, are monitored on a half hourly (in some cases 10 minute) average resolution. Some operators are increasing their LV component monitoring capabilities, but generally secondary substations and downstream feeders have no telemetry.

In addition to the requirement to fund gas infrastructure maintenance and engage with heat pump manufacturers, multi vector heat supply may require DNOs to upgrade their infrastructure monitoring capabilities. Some current domestic DR for grid management projects monitor loads only at consumer connected transformers, which allow the upstream network state to be calculated.

Smart meter rollout may also represent at least a partial solution to this problem –demand data may allow upstream the substation and feeder loads to be inferred. As a designated Service User[21], DNOs may take instantaneous readings from smart meters. While this approach is expected to suffice for long term capacity planning, there are concerns with using aggregated smart meter readings to run a responsive DR platform around:

- *the quality of the data connecting MPANs and circuits*
- *data resolution and reporting protocols.*
- *data availability due to user concerns around privacy*

Under current guidelines, customers must opt-in to sharing their half hourly consumption data with their suppliers, and permit further sharing with network operators. HHM data coverage may therefore be an issue if opt-in rates are low; it remains to be seen whether the value of domestic half hourly metering can be leveraged to increase participation.

Smart meter data may also play a role in fine-tuning highly granular demand prediction models. Similar small-scale trial and larger operational models based on weather, time of day etc. currently used to forecast demand show good agreement with data; whether they suffice for ANM is an open question.

8. Domestic HP and Gas Boiler bivalent operation

Risk	Moderate	
Impact	Minor	

Most available hybridised systems switch between pure heat pump and pure gas boiler operating mode (usually triggered by an external temperature set-point), rather than running in concert. This is due to the fixed pump speeds and the difference in boiler and heat pump flow and return temperatures.

UK domestic central heating systems are typically designed to run at 81°C/72°C, or 75°C/60°C, flow and return temperatures. Subject to some improvement in building fabric, the same systems can maintain comfortable conditions in homes at a lower, heat pump optimised temperature range (perhaps 55°C/30°C if in conjunction with underfloor heating systems). Heating systems which include both gas boilers and heat pumps are usually configured to operate either technology, but not both, at

[21] Smart Metering Implementation Programme End to End Technical Architecture

a given time. At warmer external temperatures, the heat pump will operate to provide warmth to the home, but when the outside temperature drops to a certain level (the 'bivalent point') the systems switch from heat pump to gas boiler operation, which can provide the higher flow temperatures needed to adequately heat the home. This is not a barrier to achieving the main multi vector benefit of hybrid heat pumps, i.e. shifting peak heating loads off the electricity network to avoid network reinforcements, but increases the environmental cost of hybrids (compared to pure electric heat pumps) as the boiler will provide a greater amount of the total heat demand than if the boiler only provided 'top-up' heat across the whole temperature range. Note that arrangements where the boilers operate in top-up only mode are possible, but this is currently more common in commercial installations where the heat distribution circuit operates with a variable flow rate.

CO_2 heat pumps, described in report appendix 5.2, will operate at higher flow temperatures and resolve this problem. This issue does not limit the potential of multi vector heat supply as a grid management tool, but may result in minor model underestimates of the environmental impact of switching to gas.

Multi vector heating represents an opportunity for significant cost savings to DNOs. Implementation will require the cooperation of suppliers, GDNOs, aggregators and consumers, and will require central coordination.

How customers are incentivised to choose flexible thermal supply and join the demand management scheme, and how their loads are controlled are open questions, though they are the subject of several ongoing trials, including CLNR, Low Carbon London, and individual DNO projects.

Multi vector heating at scale will require a commercial model to pay the network costs of the backup vector; in the modelled case, as throughput on the gas network (particularly the LP sections) falls, the current pricing model will become increasingly inefficient, and a model in which standing charges reflect network O&M costs will need to be introduced.

3.2 Case Study 2 – Gas CHP and heat pumps supplying heat networks

Case Study 2 considers the potential for multi vector operation to lower heat network supply costs, and the potential balancing services such projects might offer though import of low cost, and export of high value electricity.

Commercial

1. Real Time Energy Centre Price Optimisation

Risk	Moderate	
Impact	Moderate	

Optimising multi vector heat supply mode to half hourly electricity prices requires that the system operator has access to these prices, and that the plant can be ramped up and down sufficiently rapidly.

Electricity suppliers are required to settle their positions in the market on a half hourly basis, and will contract with users and generators for amounts of energy up to gate closure (one hour before the start of the corresponding settlement period)[22]. This notice period will determine the plant ramp time requirements for heat schemes that import and/or export electricity to and from the grid.

[22] BSC P305: Electricity Balancing Significant Code Review Developments

Gas turbines are currently the main source of short and medium timescale turn-up services to the National Grid, and are awarded Frequency Response (FR) and Short Term Operating Reserve (STOR); availability payments for increasing their generation on timescales of a few minutes or two hours respectively. To enable ramp up on an FR timescale, turbines typically operate at 90% output, while to provide STOR they typically run at "hot standby", kept warm but producing negligible output. To allow the scheme to ramp up and down in response to movement in the electrical price, CHP engines and boilers must run in an intermediate low-throughput mode; it may be possible to use some of the heat and power produced in idling mode. As with all thermochemical plant, ramping up and down may lead to increased wear and lower efficiencies.

More fundamentally, CHP operators need access to wholesale electricity market prices, to which plant operation can be adjusted - depending on the requirements and logistical costs of access to the wholesale market, it may be lower cost to secure a long term PPA with an electrical supplier. CHP plants on the 10MWe scale typically make such arrangements.

We note however, that hybrid operation – in which a CHP powers on on-site heat pump, and both supply heat to the network - constitutes the optimum heat supply configuration for over 90% of run hours at carbon prices below £90/tonne[23], in this configuration power import and export prices are immaterial to scheme returns.

To incentivise flexible operation of the CHP and heat pump, any PPA might be structured to comprise a large fraction (>90%) of the wholesale cost, rather than a flat fee.

Electricity wholesale prices are set at the national level; several multi vector heating schemes could form a commercial unit, and offer their combined output to the market collectively.

DUoS variation in is entirely - and wholesale price variations are somewhat – predictable; multi vector operation can take advantage of the resulting imperfect price predictions; indeed many facilities use on-site diesel generators to avoid network use at red band DUoS times.

2. Novel Multi Vector Configurations

Risk	Moderate	
Impact	Moderate	

This analysis assesses the coordinated operation of CHP engines and heat pumps in a heat network energy centre; the findings however apply equally to heat pumps and CHP not co-located - connected through electrical networks. Such arrangements will require the construction and operation of private wire networks, or the use of sections of the existing network; both are associated with costs and logistical demands.

The construction of a private wire network requires planning permission, other HSE and environmental permitting and the CHP operator may have to qualify as a license exempt supplier; this may not present a significant barrier to new heat networks, but connecting existing plant may be prohibitively complex. Cable dig and installation costs will vary by area, but are likely to be high in urban areas where heat networks are most viable; again, if these are installed at scheme construction, the marginal costs are likely to be much lower than if bolted on to existing schemes.

Virtual private wire arrangements - connection of CHP and heat pump over existing DNO infrastructure – are also a potential means of cost reduction; in these the CHP and heat pump would be metered together, behind a virtual MPAN or Balancing Mechanism Unit (BMU). Operator use of system charges, will depend on the network topology and capacity; to maximise operator value, a suitable DUoS schedule would need to be agreed with the DNO; if charged on a net volume, time of use basis, such

[23] In our techno economic modelling, we took the CCC carbon prices as the Base Case; these and the DECC Central projections hit £90/tonne around 2032.

a tariff would be high at times of average electrical prices but encourage export (through high GDUoS[24]) at times of high - and import (through low DUoS) at times of low - demand.

Technical

3. Management of CHP and Heat Pump Thermal Output

Risk	Moderate	
Impact	Moderate	

High temperature heat from the CHP may need to be utilised on the same network as lower temperature heat pump heat to achieve the carbon and economic benefits of the hybrid system.

On a high temperature network, provided a low enough return temperature can be maintained, the heat pump can be used to provide the initial heating of the return flow before the output of the gas CHP boosts the temperature to the level required for flow.

There may however be difficulties in efficiently using the higher temperature CHP heat on a medium or low temperature network (which provides overall efficiency gains if supplying suitable buildings). During times of low thermal demand, modern heat pumps can reduce their output to 15-20% of their rated capacity (due to variable speed compressors); gas CHP may not be able to modulate its output in the same way however (reciprocating engine based CHP for example typically has poor part-load performance). There may be issues in matching the CHP output in hybrid mode during times of relatively low heat demand.

The CHP could operate with partial grid export, i.e. to supply the heat pump and export the remainder to the grid, however this is likely to result in heat rejection. Thermal storage could potentially help to manage this, however over summer periods of prolonged low heat demand this is likely to necessitate very large thermal stores.

Rather than operating at partial load, it may be possible to use e.g. two CHPs sized to one third and two thirds total demand, allowing at least one of them to run flat out most of the year.

There are few barriers to hybrid multi vector heat supply – using a CHP to power a heat pump – and the hybrid configuration – equivalent to a gas engine heat pump – constitutes the lowest heat supply option at carbon prices below £90/tonne. The system value of heat supply flexibility - the potential to absorb surplus, and mitigate scarcity, of electricity - is however dependent on heat network operators access to the wholesale electrical price. Currently, schemes of this scale do not typically trade their electrical demand and generation on the open market, but commercial arrangements such as PPA design and pooled generation, might allow future DH operators to realise much of this value.

3.3 Case Study 3 – PiV fuel switching

Case Study 3 considers the possibility of switching hybrid cars and vans to liquid fuel supply at times of electrical price spike. As the modelling shows application of this multi vector interaction to be of very limited interest, the barriers to implementation are not considered further.

[24] Generator Distribution Use of System charges; time dependent margin paid by the DNO to generators for exporting to the network by time.

3.4 Case Study 4 – Power to gas – transmission level RES to H_2 and RES to CH_4

Case Study 4 considers the potential for dedicated electrolysers to absorb renewable oversupply at no cost, and use it to generate hydrogen (which is potentially then upgraded to methane) and injected into the gas transmission system up to some blending concentration limit.

Commercial

1. Availability of and Competition for Cheap Electricity

Risk	Moderate	
Impact	Major	

Electrolysis is modelled as a reservoir for renewable oversupply at zero supply cost. However, other technologies that can store low cost electricity in some form (e.g. pumped hydro) may compete for this energy, and exert upward pressure on the price.

Half hourly wholesale electricity prices will fall to near zero when instantaneous total renewable generation exceeds system level demand (though network capacities and usage costs will complicate this assessment). The extent to which supply outstrips demand –renewable generation less off-peak demand levels - will determine the amount of available free electricity. Mechanisms such as demand side management will act to reduce the frequency and severity of these events as more renewables are brought online, and few economically-plausible future hydrogen electrolysis (or other low-cost electricity) business models consider operation at zero electricity price only.

The upward pressure on low electricity prices from competing single and multi vector services is beyond the scope of this study, though we note that given the Case Study 80% efficiency and a £28/MWh hydrogen price (£1.1/kg), electrolysers run profitably only at electricity prices below £22.4/MWh – around 50% of the annual average; the ESME2PLEXOS price series is below this value 5% of the year (these do not include network use and balancing costs). We note that the EMSE price - £1.1/kg is below current merchant hydrogen price.

2. Provision of Ancillary Services by Electrolysers

Risk	Moderate	
Impact	Moderate	

Positive multi vector benefit may be achieved through the provision of ancillary services; moving demand onto or off the grid within mandated response times. Some electrolysis technologies may offer only a subset of these services, and uncertainty surrounds future requirement for grid regulation, and the price at which competing technologies, most obviously battery storage, will provide these services.

Although the future market is unclear it is likely that as in today's market, a suite of grid regulation services will be tendered for; with different response and duration time requirements and at different availability and utilisation payment rates. Electrolyser technologies will have different response times to movement in set-point, current order of magnitude response times and a summary of grid regulation service requirements are shown in the report section on Additional Revenue Streams for Electrolysers.

While the total market size for regulation services is necessarily uncertain; National Grid estimate in their 2015 System Operator Framework[25] that between 2015 and 2020, frequency response requirement will increase by 30-40%, and this increase is expected to continue as the grid

[25] National Grid, System Operability Framework 2015

decarbonises. Electrolysers are a natural fit for the provision of future grid regulation; an NREL report[26] of September 2014 recommended:

> that electrolysis devices be considered in the planning and selection process for supporting end-user energy management, transmission and distribution system support, and wholesale electricity markets.

For non-turn up services, electrolyser facilities may have to operate at high power prices, or re-electrify hydrogen; due to round trip efficiencies of below 50%, provision of these services may be better suited to batteries. Power to gas for supply to other sectors, especially transport, may be more commercially viable, see section 0.

Technical

3. H_2 Concentration Limits for Gas Networks

Risk	Moderate	
Impact	Major	

Hydrogen blending - the injection of hydrogen into the gas grid - is constrained by the H_2 concentration limit, which exists to guarantee the integrity of the gas network (particularly iron mains) and appliances.

For large-scale electrolysis using surplus energy from renewables such as wind farms, diurnal gas throughput at hydrogen injection points will define the maximum allowed volume of injected H_2:

Hydrogen concentration limits are informed by:

- Risks associated with bacterial growth in underground gas storage facilities leading to the formation of H_2S; an associated limit on the maximum acceptable hydrogen concentration in natural gas has not yet been determined.
- Specification UN ECE R 110 stipulates a limit value for hydrogen of 2% by volume for steel tanks in natural gas vehicles; the industry is however moving to Type 4 carbon fibre tanks which can accommodate hydrogen at any concentration.
- Gas turbines - most currently installed gas turbines were designed for a natural gas hydrogen fraction of 1% by volume or lower; 5% may be attainable with minor modification or tuning measures, some new or upgraded turbines will be able to cope with concentrations of up to 15% by volume.
- Gas engines - hydrogen concentration levels of no more than 2% by volume are recommended; Clarke Energy quote a hydrogen current limit of 4% by volume. Further R&D may increase this limit; concentrations up to 10% by volume may be possible for dedicated gas/hydrogen engines with sophisticated control systems, provided the methane number[27] of the natural gas/hydrogen mixture remains above the engine minimum value.
- Analysis - many process gas chromatographs are not capable of analysing hydrogen content; Emerson have recently obtained Ofgem approval for a new gas chromatograph that can meet Ofgem accuracy requirements including hydrogen.

[26] NREL, Novel Electrolyzer Applications: Providing More Than Just Hydrogen
[27] The Methane Number of a natural gas blend gives a measure of knock tendency; pure methane has a methane number of 100, hydrogen gas has a methane number of 0, biogas will often have a methane number over 100.

Most hydrogen tolerances could likely be increased with the appropriate R&D and infrastructure upgrade; 10% seems a reasonable long-term limit assumption, see project see report Appendix 5.1 for further analysis.

Acceptable hydrogen levels on GDNs will be agreed by the HSE in an amendment to the 1996 Gas Safety Management Regulations, which will be investigated in the HyDeploy project and later, once a safe level has been empirically demonstrated, in a trial on an open gas distribution network. Along with the Future Billing Methodology project, which aims to create a mechanism for local billing of gas use in line with variations in CV, this will allow distribution level hydrogen blending without the requirement for changes to legislation.

Transmission level blending however will require the sign-off of all connected users, and in particular, turbine and gas engine OEMs. This is expected to be a more complicated process; no European countries operate transmission level hydrogen blending, even where distribution level schemes have been commercialised.

We note that as unit volume hydrogen carries only one third of the energy of methane, blending needs to be at high levels to have a meaningful impact on emissions.

Distributed hydrogen storage might alleviate short term blending limit constraints by enabling hydrogen to be stored at plant and injected into the gas grid when throughput at the injection points rises to appropriate levels. Alternatively, hydrogen might be supplied to other markets, such as the refining and steel industries, or as fuel for FCEVs.

Mixing problems are encountered at the Haven Energy Bridge electrolyser; and resolved through the purchase of gas, which is blended with hydrogen, and sold back to into the NTS.

4. Supply Chain and Transportation

Risk	Moderate	
Impact	Moderate	

How power is delivered to electrolysers/methanators, and the points at which the H_2 / CH_4 produced is injected into the gas grid, will be determined by the capacity and demand on the gas and electric grids.

P2G solutions might be integrated into the energy system in the following ways:

1. producing H_2/ or CH_4 at large-scale electrolysers or methanators, located close to large-scale renewables (such as large wind farms) and then injected into the gas grid via dedicated pipelines.
2. using smaller-scale electrolysers or methanators, close to smaller renewables sites, and delivered to the point(s) of injection into the gas grid using a network of pipelines for the transportation of H_2 or CH_4 to the NTS.
3. using electrical cables to bring surplus electricity from decentralised renewables to a central electrolyser or methanator close to a gas pipeline for direct injection.

A cost-benefit analysis to decide this would need to consider:

- the location of renewables sites, their expected levels of curtailment and their proximity to gas pipelines
- the economies of scale of electrolysers and methanators,
- cost of building new H_2/gas pipelines and
- cost of new or reinforced electrical cables.

Per the base case (ESME scenario 3), up to 5.3 mcm of hydrogen could be produced via electrolysis daily; to accommodate this amount of hydrogen on the gas transmission system, throughput of nearly 50 mcm/day of natural gas would be needed (at a 10% limit on hydrogen concentration). With national summer demand levels falling to around 100 mcm/day, this could not be achieved at a single location, but might be accommodated if produced across 3 or 4 electrolyser plants at strategic locations on the NTS (this clearly become more challenging at the hydrogen blending limit lower than the 10% assumed above).

Under the High Value Case - in which the Leeds H21 project H_2 sales price is assumed - the quantity of hydrogen viably produced could reach 15 mcm/day. At summer demand levels of around100 mcm/day, and a 10% hydrogen blending limit, this level of electrolysis could not be accommodated on the NTS throughout the year, regardless of the number and location of electrolysers. In such a case, alternatives such as hydrogen storage, methanation, or supply of hydrogen to other markets would be required. Clearly, a 20% concentration level would mitigate this constraint, although uncertainties around future gas supply profiles mean that even at this blending limit, some electrolysed hydrogen may not be injectable into the NTS.

Where secondary H_2 and synthetic gas markets are considered, products can be delivered by other means, such as road transport of liquid or gaseous H_2/CH_4.

5. Ramping and Injection/Storage Switching - Monitoring and Control Requirements

Risk	Moderate	
Impact	Moderate	

Electrical networks, electrolysers and gas networks would need to share capacity data in real time - failure to switch to electrolysis of generation at the time when the electricity network is constrained pose a risk to electrical assets. Similarly, when hydrogen is injected at the blending limit and gas throughput at the injection point falls, failure to switch to H_2 storage could put the gas grid at risk.

Specialised monitoring and control equipment is needed for measurement of H_2 content downstream of the injection point, with the provision for automatic reduction in electrolysis output (or switch to hydrogen storage) if blending limits are exceeded. Any GTSO impose limitations on variation in electrolyser output (e.g. ramp rates) would be subject to an agreement between the operator of the electrolyser and the transmission system operator, and set out in the Network Entry Agreement or Local Operating Procedures.

The gas transmission system operator should be notified about injection of hydrogen into the gas network, in accordance with the requirements of the Uniform Network Code. At present, this involves the shipper "nominating" the quantity of gas they plan to bring onto the system on a day-ahead basis, with periodic opportunities to modify the nomination during the gas day. The operator of the delivery facility also notifies the system operator of its intended gas flow via "delivery flow notifications"; differences between nominated and actual gas flows may attract scheduling charges. As electrolyser output is unpredictable on diurnal timescales, hydrogen shippers may need other gas sources that can be flexible deployed for balancing purposes.

ANM systems might appraise the operator on real time grid load, allowing appropriate turn up of the electrolyser. Switching to storage near grid blend limits would likely be part of an agreement with the GTSO; it is not possible to determine the costs of such a control system, and appropriate storage volumes, from current data.

6. Network Injection Capacity

Risk	Minor	
Impact	Moderate	

For electrolysis to act as a reliable reservoir for renewable oversupply, injected H_2 or CH_4 must be given priority over the network intake of further natural gas, where both would result in excessive operating pressures or other operational concerns.

Significant, short notice electrolyser injection into the NTS may require upstream input to be deferred, or gas on the NTS to be put into store; this might be achieved either through the actions of the H_2 or CH_4 shipper seeking to stay in balance, or through the actions of the system operator via the balancing mechanism. These are expected to be relatively minor concerns though, since:

- On the timescales under consideration here, gas throughput will be significantly reduced, leading to large NTS capacity
- Where there is insufficient capacity for injection, the system operator can rebalance the network; for example, it could accept a bid for the system to sell gas at some entry point, leading to a reduction in network input (this is subject to the blend limits above, which are resolved more – rather than less – throughput of gas).
- While electrolyser operating stipulations - such as the notice period required and the ramp rate - will be subject to an agreement with the GTSO, breaches of such regulations are currently enforced only where they cause an operational issue to the system.

Given this, and as renewable oversupply is predictable on a timescale of several hours, network capacity constraint is likely to impose minimal constraint on grid injection.

The business case for grid injecting electrolysers as a reservoir of renewable oversupply is not compelling, and barriers remain to hydrogen blending, with R&D ongoing to determine:

- the upper limit on safe concentration levels.
- the potential for electrolysers to offer grid regulation services.

Alternative future trajectories of the generation mix, and especially the emergence of other markets for hydrogen, may offer greater opportunities to electrolysers.

3.5 Case Study 5 – Grid power to hydrogen for dedicated hydrogen networks

Case Study 5 considers the potential for electrolysers to supply a dedicated hydrogen network, working in concert with, and reducing the capacity requirements, and therefore the capital cost, of SMRs and storage.

Commercial

1. Availability of Low Cost Electricity

Risk	Moderate	
Impact	Major	

Electrolysis is potentially viable as a H_2 network supply option only in areas where low price electricity is available.

A potential power source for electrolysis is renewable generation that would otherwise be curtailed, though as shown in Case Study 4 the duration curve of renewable oversupply means an electrolyser sized to achieve an economic load factor produces little hydrogen annually. Electrolyser economics might be improved through the provision of grid services; both alkaline and (particularly) PEM electrolysers can change their output rapidly in response to control signals and can therefore provide both reserve and response services, though the potential size of the market for grid services on timeframes consistent with conversion of the gas grid to hydrogen (or the large-scale adoption of hydrogen fuelled vehicles) is necessarily uncertain.

As above, electrolysers may therefore be of greater system value near renewable generators on weak or constrained grids, but raising the cost of heating fuel is likely to be politically unpopular. A study on the size of the future balancing services market, allowing for the significant evolution expected in the power sector, would inform assessments of the likely role for electrolysers in the energy system.

2. Framework for Co-Existence of SMR and Electrolysis

Risk	Moderate	
Impact	Moderate	

A commercial framework will be required for the parallel supply of hydrogen through SMR and electrolysers, covering production and transportation of hydrogen from multiple sources.

Several different models are possible, for example:

- An integrated, highly regulated approach, whereby the network operator seeks to optimise the system through its operation of the transportation infrastructure and purchases of the commodity and of storage services.
- A liberalised approach, more akin to that in place for natural gas, with full separation between transportation and supply, and retail competition.
- A middle-ground of some sort, e.g. with separation of transportation and supply and a monopoly supply franchise.

While any of these approaches could be made to work, greater levels of liberalisation give rise to the more complex frameworks (note that in the Leeds H21 model, the supply of hydrogen to the distribution network is profiled across the day to match demand).

This suggests that the commercial framework would have to operate on an hourly basis, rather than the daily basis used in the liberalised gas market[28].

Alternatively, the hydrogen distribution network operator might take responsibility for intra-day storage, with hydrogen suppliers required to deliver their production uniformly over the day. However, since electrolysis could play a role both as a hydrogen supply source and a substitute for transportation capacity and/or diurnal storage, a further level of framework complexity would be required to accommodate electrolysis.

For this analysis, in which we determine the 'size of the prize', we assume that a highly integrated, command-and-control style framework is in place, under which the network operator can optimise resource use (albeit without perfect foresight of gas and electricity prices) by calling on production from SMRs and/or electrolysers and controlling inputs and outputs from the storage facilities.

Priority order would have to be given to electrolysers for them to recoup their capital costs at times of low electricity prices.

[28] In the gas market, the distribution network operator must provide diurnal storage, with gas provided (commercially) by shippers on a flat basis.

The injection of hydrogen produced by electrolysis into the MP system would necessitate the offset of an equivalent amount of production from the upstream system (assuming no linepack or network storage at the lower pressure tiers of the network, as is the case on the gas grid today). This is straightforward in a command-and-control solution run by a single operator, but more of an issue in a liberalised hydrogen supply market; requiring prioritisation of producers (some linepack is likely to available in the higher pressure transmission pipelines which could help to manage variation in hydrogen supply).

There are also likely to be operational constraints within which the network operator has to manage, such as the rate at which SMRs can increase and decrease levels of production (+/- 5% of design capacity per hour); the availability of storage and (potentially) HTS linepack would help with this.

Technical

3. Use of Electrolysers on Weak Grids

Risk	Minor	
Impact	Moderate	

Electrolysers are potentially significant loads, which could face expensive network connection charges in demand constrained areas. On actively managed networks, ANM might reduce the load factor of electrolysers, particularly if they were connected on a LIFO basis.

As well as potentially mitigating export constraints on renewable generation, electrolysers may themselves overload parts of the grid, depending on output levels, electrolyser ramp rates and grid topology. As electrolysers operate only below some threshold electricity price, these times of their use are unlikely to overlap with high levels of grid demand. Electrolysers are likely to operate preferentially at times of oversupply (low power prices), and are therefore unlikely to be constrained by network management.

As shown in the SSEN Aberdeen electrolyser trials[29], electrolysers can modulate output to stay within demand limit; in this trial it was demonstrated that electrolysers can respond rapidly to set-points and so avoid breaching a demand constraint. The report notes that a charging mechanism will be needed to incentivise this behaviour, such as time of use, real time pricing or payments for participating in a demand side response or active network management scheme, and that:

> For electrolyser developers seeking connection to the distribution network in future, the outcomes of this project strongly support their capability to operate under a demand or generation constraint to avoid triggering reinforcement on the network

4. Impact on Power Factor

Risk	Minor	
Impact	Moderate	

Electrolysers increase the capacitance of the circuit to which they are connected

The Aberdeen electrolyser study demonstrated that electrolysers can have a significant impact on power factor on the network – with increasing electrolyser loads resulting in a reduction of the power factor. This could require significant power factor correction to be applied. The Aberdeen report makes the point that reactive power is not necessarily a problem and indeed could be used to manage voltage issues, for example those caused by wind generators.

[29] Impact of Electrolysers on Distribution Networks, part of the Aberdeen Hydrogen Project, SSEN, November 2016

5. Integration of Multiple Hydrogen Sources

Risk	Moderate	
Impact	Moderate	

A clear control process will be required to integrate electrolysers, SMRs and storage within a medium pressure hydrogen network

Assuming no line pack or network storage, (as is the case today at lower pressure network tiers) the injection of hydrogen produced by electrolysis into a medium pressure system would necessitate the reduction of production from the upstream system by an equivalent amount; SMRs (especially larger plants) are typically very tightly energy integrated and are optimally run at, or close to, steady-state.

The control process would require real time monitoring of input flows and a platform allowing the system operator to adjust flows from upstream sources (this problem is avoided in the H21 Study, where a new transmission system is proposed with a single point of supply).

Fluctuations in flow resulting from diurnal demand variation on the GDNO can be solved using a combination of dedicated and embedded network storage, and electrolyser ramping. Embedded storage can be increased by oversizing the network; capacity can be doubled at an increase in installed cost of around 10%. The cost drivers that determine the role of electrolysis in supply matching are discussed in Case Study sensitivity analysis.

Regulatory

6. Policy Uncertainty

Risk	Moderate	
Impact	Major	

There is no concerted policy driving a transition to hydrogen for heat, and no low-carbon heat incentive for electrolysers.

Significant unresolved policy and regulatory questions around the conversion of gas networks to supply hydrogen include:

- uncertainty around heat policy, and the lack of a roadmap to the decarbonisation of the heat
- unclear future of the gas network, and whether customer led switchover is feasible

These make it very difficult for network companies to plan investment, and represent a barrier to the substantial work required to develop appropriate industry codes (many of these issues are covered in detail elsewhere, for example the Leeds H21 report and CCC report on Future Regulation of the UK Gas Grid[30]).

A co-ordinated planning process is required to integrate the use of electrolysers and SMRs within a hydrogen network.

Broadly speaking, the presence of an electrolyser supplying a hydrogen distribution network is analogous to a biomethane plant injecting into the current gas grid; the potential for an electrolyser to supply, acting as substitute for transportation capacity and diurnal storage, adds a potential level of complexity, which lends itself to a more integrated regulatory approach.

[30] Future regulation of the UK gas grid, Frontier Economics and Aqua Consultants, CCC, June 2016, www.theccc.org.uk/wp-content/uploads/2016/10/Future-Regulationof-the-Gas-Grid.pdf

The role of electrolysers in supplying heat networks appears marginal, as per the H21 report, and commercial framework arrangements to accommodate both SMR and electrolysers appear complex. Without a dedicated hydrogen transmission system however, there may be value to gas network operation, in the potential for local generation.

3.6 Case Study 6a – Power to heat – district heating

Case study 6a considers the system benefit in using an electrically powered heat network to absorb the oversupply of a nearby wind farm, rather than upgrading the local grid.

System Benefit

The benefit in using a nearby heat pump to absorb electricity that would otherwise be curtailed justifies investment in less than 1km of distribution network. In determining the system benefit, we assume no difference in the cost of power (and in particular, pass through charges) by source; value derives from the reduction in losses associated with transmission of power around the grid (also, we include no environmental benefit for using renewable, rather than grid power at non-zero carbon intensity; this estimate is therefore may slightly underestimate the true value).

Operator Benefit

While the system benefit is limited, if we consider the reduction in grid use charges associated with a private network use, the potential heat network operator value could be over ten times this figure; depending on contribution of the components of the power price above generation cost (indeed, the price the local wind farm operator receives for electricity that would otherwise be curtailed may be lower than the market price). While still moderate, there may then be sufficient benefit to justify private investment in a bespoke network connecting renewables on constrained networks to district heating systems at distances of up to 10km.

The technical and operational issues associated with this configuration appear limited; the wind farm operator would agree to a non-firm connection to the local DNO, allowing the network to curtail the wind farm at times of constraint, e.g. by sending a signal through an active network management system. At this point the wind farm would disconnect from the local distribution network, and the private electrical circuit feeding the district heating system be energised. Under private wire supply, electricity would be delivered to the heat pump at a point located 'behind-the-meter', i.e. on the heat pump side of the electricity supplier MPAN, thereby reducing total imported electricity.

The issues around connection of renewable generators and heat networks (using either boilers or heat pumps) are largely understood, and the potential for renewable curtailment to be absorbed by electric heating schemes has been explored in Germany and Denmark, where it has so far been found economically viable only for frequency regulation.

While technically straightforward, the commercial potential for this multi vector interaction appears limited; aside from the relatively small number of potential locations around the UK, the multi vector benefit only pays for a few kilometres of private network.

3.7 Case Study 6b – Power to heat – smart electric thermal storage (SETS)

Case study 6b considers the potential for distributed domestic smart electric thermal storage (SETS) to offset renewable curtailment on weak or isolated grids.

Commercial

1. Sharing Value with Scheme Participants

Risk	Moderate	
Impact	Moderate	

Management of domestic thermal demand to balance renewable energy supply may lead to heaters being run at peak, rather than off-peak, times – increasing consumer energy bills.

A mechanism is required to ensure participation is attractive to scheme participants, considering that demand management is likely to be implemented as direct control by an aggregator, rather than purely based on price signals, to ensure the required 'firm' DSM response from a potentially limited number of customers. In particular, commercial arrangements must ensure that consumers benefit (or at the very least, see no total cost increases) as a result of SETS participation.

Aggregators and home energy control firms are beginning to offer innovative heating solutions to DNOs (or DNOs and suppliers jointly), mainly involving the use of immersion elements for hot water supply -of the current trials looking at aggregation of smart demand, most have used a flat fee to encourage participation, with SSE paying participants in the Real Value scheme around € 10 each month.

Potential solutions include:

- ***A customer rebate*** *– customers could be provided a rebate for participation in the scheme. This would be relatively simple to implement, and not necessarily require a change in their tariff.*
- ***Local time of use tariff*** *– Suppliers could offer a time-varying tariff, with lower electrical prices at times of high renewable generation. This tariff would ensure that consumers benefit from the management of their demand (Domestic half hourly metering and settlement would be required for a time-varying tariff.*
- ***Pooled demand and generation*** *– Generation and demand could be pooled within a 'virtual MPAN'. In this case, a local supply company, acting as a licence exempt supplier, would bill the consumers based on half-hourly consumption data and a time varying tariff, ensuring the consumers benefit from demand management. The renewable generation and aggregated demand are pooled behind the virtual MPAN and the energy company then settles their net position with a licenced electricity supplier.*
- ***DNO management with a local tariff*** *– An aggregator manages the demand as a service to the DNO (potentially as part of an ANM scheme), and the DNO recoups cost through an increased GDUoS charge on the generator for generation that would have otherwise been curtailed. In this case, consumers could still be billed by the electricity supplier, with a lower tariff offered to scheme participants (funded by a share of the increased generator GDUoS).*

2. Use of Existing Networks to Match Generation to Local Demand

Risk	Moderate	
Impact	Moderate	

Systems that match local supply and demand currently realise very little of the system level benefit they create.

Grid balancing is managed at the national level; there is no general mechanism to encourage the supply of a customer on the same network circuit rather than one on the other side of the country. SETS and other demand matching schemes may comprise Local Balancing Zones, and many projects are looking at retaining generation value locally of this, such as Energy Local. There are currently no structural incentives to match local generation and demand, though local matching can assist supplier balancing and reduce line losses; these benefits can then be passed on by the supplier.

Networks Preference cannot be given to Local Supply

In general, there is no means by which renewable generators can guarantee that their generation will be used preferentially by local demand, despite the savings above. As such, parallel private networks are being constructed in some areas, though planning permission for these can be difficult to obtain. Energy Local and SSE's Virtual Private Wire are examples of schemes under which small portions of existing grids can be used to match local demand and generation.

Technical

3. DNO Monitoring Infrastructure

Risk	Moderate	
Impact	Moderate	

Real time distribution network telemetry is required to:

- **Determine where turn up is required to reducing net flow on constrained circuits.**
- **Confirm that a turn up signal results in sufficient increase in demand.**
- **Share value with the appropriate customers, (depending on the incentive structure).**

As in Case Study 1, grid telemetry is key to unlocking this multi vector value. All HV substations and some HV feeders are monitored; wind farm and hydro facility generators are likely to connect here, so that their output can be monitored, at least on a 10minute average basis. Rooftop solar PV may connect to the LV network, so some model of real time network load may be required to avoid reverse power flow to thermal rating exceedance.

The introduction of smart meters may go some way to resolving this problem, a DNO platform to convert this to a real-time network model would be required however.

4. Control System Platform and Requirements

Risk	Moderate	
Impact	Moderate	

In-home systems and communications infrastructure are required to enable consumer demand response.

SETS depends on the reliable control of domestic electric heaters. Smart thermostats that manage in-home control enable demand flexibility to be offered to suppliers and DNOs (managed by a third-party aggregator) while ensuring consumer comfort is maintained.

Enabling heating appliances to provide additional ancillary services, such as rapid frequency response, is likely to require further bespoke hardware and software (current commercial smart thermostats do not offer this service, devices to provide this response are being commercialised, such as the units offered by V-Charge).

These systems must also be compatible with aggregation platform.

The supplier of smart thermostats that manage the in-home comfort and provide longer-term demand shifting is not necessarily the same organisation that provides the demand management platform (e.g. the aggregator). This demand management platform must collect data from the installed smart thermostats on the availability of flexible demand and to be able to send control signals to these thermostats. The aggregation platform may analyse past consumption data and weather data to predict future availability of flexible demand (alternatively this could be done at the local device level). Where different organisations are involved, open communication protocols are used to enable two-way communication between local devices and aggregation platforms.

Note that the management of domestic heating appliances does not rely on smart meter roll-out, although clearly a means of communicating with appliances is required. In the ACCESS project, for example, this is achieved via home broadband connection and Wi-Fi connectivity of smart appliances and thermostats. For certain of the commercial models that can be envisaged to share revenues between generators and demand managed customers, half-hourly metering could be required to enable time-varying tariffs.

In addition to the communications with the homes, an inter-tripping arrangement is required between a monitoring point on the transmission system, i.e. at the constrained point, and a breaker that can trip out the generator should the constraint be breached.

Communication protocols and wireless range

Any control platform is likely to communicate over the internet, most likely with a unit that interfaces with a user's wireless router. This may represent a problem with e.g. immersion tanks in the garage, or hot water tanks in the roof.

A signal booster can resolve this problem at a one-off-cost of around £30. Alternatively, broadband over powerline protocols can be used where internet connectivity is poor, though these require a control unit to interface between the grid and controlled devices.

Regulatory

5. Parallel use of Aggregation Platform to Provide Ancillary Services

Risk	Minor	
Impact	Moderate	

Managed demand might provide ancillary services or mitigate imbalance risk, creating further value; such services would need to be compatible with management of the transmission constraint which would need first refusal on available demand.

Electric heaters are well suited to the supply of ancillary services, as they can turn on and off without affecting customer experience, and often have access to storage. SETS aggregators therefore have an incentive to offer these services to the grid operator, even where their provision conflicts with a requirement for increased demand.

To maintain the integrity of the SETS solution, priority would have to be given to the turn up signal over any grid regulation service request, even where the value of the latter exceeds that of SETS provision. SETS participation would need to include a guarantee of availability to ensure firm amounts of Turn Up; likely comprising a contractual and a control component.

Barriers to SETS are relatively minor, with current projects in operation, though many commercial questions remain to be answered before scaling up of this solution can be seriously considered.

3.8 Case Study 7 – Energy from waste – electricity generation and grid injection flexibility

Case Study 7 considers an energy from waste (EfW) plant[31], and determines the 2050 option value of the ability to switch between generation of:

- power for sale at the hourly exchange price, or
- biomethane for injection to the gas network

in response to variation in the power price; a range of heat prices are also considered. We find that:

- where gas and power prices are substantially decoupled, there may be some value in the installation of a CHP for power-only export (all heat generated is vented) at AD, though not gasification plant.
- Upgrade to allow gas injection at CHP power only export plant creates substantial value to both AD and gasification facilities, and most of their output is then put into the gas grid.
- A relatively modest heat price – less than 1p/kWh – is needed to make CHP upgrade viable at gasification facilities.

Currently, CHP EfW plants tend to sell their power through a long term PPA, which may include some component that reflects hourly price variation, but are not exposed to the full variation in prices.

Commercial

1. Competition to Supply High Price Electricity

Risk	Moderate	
Impact	Major	

The benefit of adding a CHP engine to an AD or gasification plant comprises electricity sales at times of high electricity prices[32]. Gas turbines connected to the network (which are also likely to be more electrically efficient) are to compete with CHP generation for power sales as prices rise; exerting downward pressure on the power price (and potentially upward pressure on the gas price, depending on the timescale on which gas is priced).

Unless the effective price of heat is high, or there is some local premium for electricity price, the LCOE of a new biogas turbine will be undercut by existing gas generators. Whereas in Case Study 2 the per unit grid use costs for electricity represent an appreciable fraction of the generation cost, the levy on moving unit gas across the NTS, in this case to the nearest CCGT, is a small fraction of the price of gas[33].The degree of competition will be informed by use of system charges, e.g. under high GDUoS, the premium for local embedded generation may encourage EfW power export.

Subsidy design will affect this calculation; for example EfW subsidies are currently paid for CHP and not power only; therefore gas injection may be supported by environmental support for which power export does not qualify

[31] Both anaerobic digestion and gasification (ACT/ATT) plants are considered.

[32] And potentially heat sales, though the price of heat will be lower, and vary significantly less

[33] Conversations with CNG.

2. Gas Clean-up Requirements

Risk	Moderate	
Impact	Moderate	

Conversion from CHP operation to grid injection may require further gas clean-up – depending on the chemical composition of the gas.

Around 7.4TWh of biogas were produced through AD in the UK in 2014; of which 1.5TWh was injected into the grid, and 5.9TWh was burned in CHP engines (of this, most of the 3.7TWh of heat generated was vented[34]).

The requirements around injection of biogas into the grid are relatively well understood; the ADBA state[34] that in 2014:

> Some of [the >5MW] plants are now being incentivised to add gas grid connections to claim the RHI: one [of 3] outside the water sector, and three [of 8] in the water sector to date [with 4 more plants, with total output of 2750m^3/hour, in planning]. They may keep the existing electricity generating equipment until the end of their lifetime to provide different options to operators, with the choice of using electricity for on-site demand or exporting gas or electricity depending on market conditions.

The 2017 RHI documentation for AD producers however notes:

> As few biomethane facilities currently operate within the UK, the technology and regulatory framework around biomethane production is still developing. We will therefore seek to introduce more detailed guidance in this area as the sector develops.

It notes also that compliance with the gas Uniform Network Code (UNC) is the standard against which biogas for injection is assessed, as more biomethane producers come online, a bespoke set of AD gas regulations may be created allowing further energy to be put into the grid.

CHP equipped gas injection schemes may be able to burn fractions of the biogas that are not suitable for grid injection, though total energy produced is unlikely to do much more than offset plant energy demand.

Gasification, through ACT and ATT, is a less mature technology (the National Grid BioSNG Project is ongoing), and it is not clear how straightforward the clean-up of bioSNG will be, or what the associated costs are.

Regulatory

3. Propanation

Risk	Moderate	
Impact	Major	

Grid injection of any gas requires its Wobbe Number (WN) and calorific value (CV) to be in the range stipulated but the GSMR and FWACV regulations respectively. As the WN and CV of pure biomethane are below the required levels, it must be blended with some higher CV gas, such as propane, before it can be introduced to the gas distribution networks, at significant cost.

[34] Anaerobic Digestion Market Report

The Gas Safety Management Regulations[35] (GSMR) specify the operational Wobbe Number[36] range for grid gas. Biomethane from AD and bioSNG from gasification have lower Wobbe Numbers than most UK natural gas, though typically there are no operational barriers to grid injection.

However, the Flow Weighted Average Calorific Value (FWACV) regime which governs gas billing stipulates that the CV of billed gas cannot be more than 1MJ/m^3 above the minimum CV of gas injected into the Local Distribution Zone (LDZ). As the calorific value of biomethane/bioSNG are lower – at 36MJ/m^3 - than typical UK grid gas mixes– at around 39.5MJ/m^3 – grid injection of biomethane and bioSNG requires blending with a gas of higher volumetric enthalpy; this process is called propanation, as propane is typically is used. Propanation represents an additional cost to the operator; which depends on the molecular composition of the biogas and the FWACV of the LDZ; an Element Energy study on distributed gas sources[37] found that propanation costs might represent up to 10% of revenues, at 0.3p/kWh injected.

We note that this is a function of regulatory design, rather than a safety concern.

Technical

4. Geographic Constraints

Risk	Moderate	
Impact	Moderate	

Build locations for EfW plants are often constrained by local opposition; they are typically built outside population centres, making the heat generated though CHP difficult to put into heat networks. Network connections for electricity and gas export may also be made marginally more expensive.

UK planning law relating to the provision and construction of EfW facilities is decided at the Local Authority level; planners are typically reluctant to site EfW plants near enough population centres that their heat output can be cheaply exported to heat networks, thereby increasing the return on investment of a CHP engine. Access to gas network or grid capacity will be key factors in siting AD/gasification plant for gas injection, CHP or both, and as the only other location requirement is that waste can be delivered to the site in bulk, this is unlikely to represent a barrier to new plant. Upgrade of biomethane plants on constrained grid, or CHP plants far from the MP or HP gas grid may however prove expensive.

Domestic heat networks are not however the only potential heat customer; high temperature CHP heat may also be suitable for local industrial (or on-farm, for rural AD) heat requirements, which may vary less seasonally (for this reason process, rather than space heating, demand may be preferred as anchor loads in the development of heat networks). Where no heat demand is available, an EfW operator may consider installation of electricity-only plant at a lower capital cost (at £490/kWe used in the model, significant cost reductions would be needed to pay for power export only multi vector upgrade at grid injecting gasification facilities).

[35] A Guide to the Gas Safety (Management) Regulations 1996

[36] The Wobbe Number indexes the interchangeability of fuel gases.

[37] To be published shortly.

Multi vector benefit is marginal at EfW plant, especially for gasification rather than AD facilities. A positive, but modest, heat sale price significantly improves the case for CHP installation at gasification facilities, though it may make optimisation for power prices more difficult. Planning policy, as currently constituted, is also a hurdle to heat supply, especially for domestic demand.

A viable case for installing power only plant at gasification facilities requires a 25% increase in average power prices. This case may be undermined by other gas turbines; which may drive the price of gas up, and the price of power down, at times of high electric demand.

4 Current Projects

Current and recently concluded innovation projects relevant to multi vector energy supply are summarised below.

Innovation Area	Trial	Description	Aims / Focus or Key Findings / Outcomes
Domestic Demand Response Platform	Open LV	Open LV looks at making grid state data available for software developers to create DR control algorithms for grid regulation and/or consumer savings.	WPD are trialling several approaches to managing power flows as solar PV, EVs and heat pumps are connected to the LV network.
	ECHO	Completed trial looking at smart plugs – devices which communicate with a central platform over Wi-Fi and prevent devices from operating – at 200 statistically representative households. It found that the costs were too high, and the demands on participants too great, on this basis, it was concluded that direct load control is no better than a variable tariff.	"…customer utilisation payments required when instigating a DDSR event equates to approximately £6660/MWh. The initial capital outlay, including equipment, software and control centre, for the purposes of this trial was £325 per connected appliance, which equates to approximately £6 million per MW of available domestic load. … full scale roll-out would reduce costs greatly but it is not envisaged that the reduction would make this method competitive with other approaches." "…average STOR utilisation price, as of January 2015, was £131.94/MWh, fifty times less than the figure presented above. Current high-end lithium battery estimates put the cost of MW installed at £1.4 million, a quarter of the cost shown above." "… participants were receptive of the idea of DDSR events being run on their large domestic appliances. However … the effort required to setup the system and iron out any issues quickly demotivated participants. Having to spend time maintaining a system was seen as the biggest obstacle to the long-term application of this method of peak-load management."

	LV Connect and Manage	LV Connect and Manage assesses ANM as a short and long-term alternative to grid reinforcement as low carbon technologies are added to the grid. Specific focuses are broadband over powerline as a means of controlling bi-directional flows, and business processes that can managed demand using current technologies.	Project Success Criteria are: 1. Demonstration of the active management of [LCTs to control] load profiles and [alleviate] electricity network constraints. 2. Development of a replicable architecture for the LV ANM solution, which can be utilised by WPD in their other License Areas and by other DNOs. 3. Development of novel business processes for deploying ANM technologies into LV networks.
	Low Carbon London	Low carbon London comprises a series of UKPN trials to investigate future network operation questions, across several areas of interest to multi vector energy. • Demand Side Response and Distributed Generation • Electrification of Heat and Transport • Network Planning • Future Distribution System Operator	Dynamic pricing trials achieved responses of up to 150 W/household, with an average response of around 50W/household to a constraint management pricing event. It finds also that demand response is time dependent, with "reduction potential during peak demand periods will be higher than suggested by average response numbers"[38] It also found that local and system pricing drivers may conflict, and that "socio-economic factors hardly affect response magnitude."
	Access	Access is funded by Community Energy Scotland	These projects focus on using demand side management enabling community owned generators to connect on isolated grids with limited interconnection.
	Shetland Nines	An SSE project, a 4MW electric boiler has been added to the island DH scheme, allowing absorption of renewable oversupply from a 6MW wind farm; other technologies are also used as part of a smart heat and power network.[39]	ANM through heat network operation and use of smart storage heaters to absorb load and provide grid balancing services are investigated, especially their ability to allow greater connection of distributed generation.

[38] LCL Residential consumer responsiveness to time-varying pricing

[39] Due to their high capital costs, and the requirement to supply heat at temperatures suitable for an existing heat network, heat pumps are not used.

	SSE Real Value	This project looks at the network management value of domestic scale thermal storage, across the energy system, including the system operator and DNO. It is based in Ireland (Eire Grid and ESB are project partners) where wind power comprises around 20% of generation. Parallel projects are also running in Germany and Latvia.	The project investigates the value of flexible demand management across the energy system, including renewable integration, power price arbitrage, and reduced emissions. Of specific interest to our analyses are real world data on how much controlled demand is needed to mitigate a generation constraint
	Heat Smart Orkney	Heat Smart Orkney aims to use DSM to create a local energy economy which will: 1. Use existing local grid monitoring to establish when wind energy is being curtailed due to lack of grid. 2. Identify the 'marginal generators' in grid zones which are being restricted at any given moment 3. Identify local thermal loads that can provide demand in the zone and remotely energise them, and 4. Allow for the local Smart grid to lift the restriction of marginal generators and allow increased generation by those turbines.	This project aims to • reduce carbon emissions, • ease the pressure on the local grid, • achieve higher turbine revenue and give communities better and more affordable heating Again, data from this trial is likely to be relevant to demand matching schemes more generally, though we note load forecast models are not explicitly included in the project scope.
	FREEDOM	The Flexible Residential Energy Efficiency Demand Optimisation and Management (FREEDOM) Project, investigates the effect of hybrid heat pumps on the LV grid; at between 50 and 75 homes in west Wales which have been supplied with the plant and control boxes.	"The project aims to 1. Demonstrate the ability of the hybrid heating system to switch between gas and electric load to provide fuel arbitrage and highly flexible demand response services 2. Demonstrate the consumer, network, carbon and energy system benefits of deployment of hybrid heating systems with an aggregated demand response control system; and 3. Gain insights into the means of balancing the interests of the consumer, supplier, distribution and transmission network while seeking to derive value from the demand flexibility. Of specific interest to multi vector operation, the project objectives include developing "business process (polices, standard techniques etc.) for the use of hybrid heating system"

Future of **Hydrogen** and Need for Clarity in **Low Carbon Heat Policy**	HyDeploy	The NIC funded HyDeploy project investigates upper technical and engineering limits on hydrogen content for distribution gas networks at the isolated University of Keele network. Once this level is agreed with the HSE and Ofgem, a similar trial on a public network will be needed before limits can be increased on national infrastructure.	The project goals are 1. Determine maximum safe blend limit for hydrogen on GDNs. 2. Examine the requirements for H_2 injection to follow gas demand, and maintain a reliable level of hydrogen supply. The safety case involves examining the effect of blend level on constituent parts: 1. Supply side of the meter network 2. Customer side of the meter network (pipes) 3. Boilers, burners and other connected devices.
	Haven Energy Bridge	This NIA funded trial considers early issues around blending hydrogen generated using power from a 5MW solar plant into the NTS.	Once the electrolyser and injection facilities are constructed, this project will serve as a lab for investigation of hydrogen blend levels on NTS connected components.
	Aberdeen Hydrogen Refuelling Facility	A £20m project looking at the potential for electrolysed hydrogen as a transport fuel for fuel cell buses operates a 1MW PEM electrolyser. Several aspects of electrolyser use are to be investigated.	To date, an analysis on the effect of electrolysis on the grid, and the ability to react to grid set-points has been published[40]; further research is ongoing.
	Surf'n'Turf Orkney	As part of a suite of renewable demand matching solutions, a 500kW EMEC PEM electrolyser generates hydrogen from renewable oversupply.	The electrolyser is operated to absorb generation from a wind farm and tidal array, it is then transported by road and ferry to Kirkwall harbour, where it is used in a CHP fuel cell. There are also plans for hydrogen fuel cells to replace the diesel engines used by island ferries. Findings of these projects will be relevant to small scale electrolyser and fuel cell deployment nationally.
	Leeds H21	This massive project investigates conversion of the gas distribution network of Greater Leeds area, part of the North East LDZ, and all connected appliances, to hydrogen operation by 2031[41].	This study investigates many aspects of gas-to-hydrogen network conversion, including particularly the costs of generating hydrogen from methane and the associated carbon capture costs.

[40] Impact of Electrolysers on the Distribution Network

[41] Our electrolyser efficiency values (80%) are taken from this study. We note the hydrogen price (£50/MWh) used here is higher than that estimated in ESME.

	WindGas and the Thüga P2G demonstration plant	In parts of Germany, hydrogen can be injected into the grid at concentrations up to 10% by volume, and the 2 and 1MW PEM electrolysers at Falkenhagen and Hamburg respectively inject up to 625m^3 into the gas network hour. The Thüga group run a similar 300kW, 60m^3/hour ITM system in Frankfurt.	As well as hydrogen blending, these projects allow investigation into matching electrolyser operation to renewable generation.
Need for Clarity in **Low Carbon Heat Policy**	Bridgend Future Modelling	The project investigates pathways to low carbon heat, based on consultation and data from 12,000 households. Phase 3, currently ongoing, focusses on consumer incentivization and subsidy design.	Previous project stages found that: "current UK Energy Policy would have minimal effect on changing consumer behaviour and hence little effect on changing the current levels of UK gas usage". "that over 80% of consumers would not, or could not afford to, change to lower carbon heat provision."
	National Grid BioSNG	A £5m facility producing bioSNG from waste making 20GWh/year of biogas (equivalent to the demand of 1,500 homes) has recently completed its 3-year operation. A commercial scale facility – making around 300GWh/year from 120,000 tonnes RDF - is in its second year of delivery, and scheduled for commissioning in 2018.	These trials focus on the oxy-steam fluidised bed gasification technology. Technical and operational data e.g. of costs of bioSNG clean-up, will be key in determining the role and scale of bioSNG from waste in future UK energy policy.
	CLoCC and Future Billing Methodology	The CLoCC (Customer Low Cost Connections) Project aims to reduce the cost of connection to the NTS from around £2m to below £1m, and to deliver connection within 12, rather than 36, months - aiding in the development of unconventional gas sources. The future billing methodology aims to develop tools and techniques to allow gas enthalpy to be determined, and then billed for, on a local (sub LDZ) basis.	These two projects are key to develop significant injection of bioSNG into the gas grid at commercially viable rates, innovation delivered through these projects is a prerequisite to distributed gas generation and supply at scale.

5 Glossary

Term	Definition
ACT	Advanced Conversion Technologies
ALCS	Auxiliary Control Load Switch
AD	Anaerobic digestion
ATT	Advanced Thermal Treatment
BAU	Business as Usual
BEV	Battery electric vehicle
CBA	Cost benefit analysis
CCC	Committee on Climate Change
CCGT	Closed Cycle Gas Turbine
CCS	Carbon capture and storage
CHP	Combined Heat and Power
CIBSE	Chartered Institution of Building Services Engineers
CO_2e	Greenhouse gas CO_2 equivalent
COP	Coefficient of Performance
DH	District heat
DHW	Domestic hot-water
DLC	Direct Load Control
DN	Distribution network
DNO	Distribution network operator
DSR/DSM	Demand side response / Demand side management
DUoS	Distribution Use of System
EHP	Electric heat pump
ETI	Energy Technologies Institute
EFR	Enhanced Frequency Response
EfW	Energy from Waste
ESME	Energy System Modelling Environment
EV	Electric vehicle
FCEV	Fuel Cell Electric Vehicle
FOM	Fixed O&M

FR	Frequency Regulation
GDUoS	Generator Distribution Use of System
GSMR	Gas Safety Management Regulations
GSP	Grid Supply Point
GWP	Global Warming Potential
HHM	Half-hourly metered/ Half-hourly metering
HP	Heat Pump
HV	High Voltage
I&C	Industrial and Commercial
ICE	Internal Combustion Engine
IMRP	Iron Mains Replacement Programme
LCOE	Levelised cost of energy
LCT	Low Carbon Technology
LP	Low pressure
LRMC	Long run marginal cost
LTS	Local Transmission System
LV	Low Voltage
MP	Medium Pressure
MPAN	Meter point administration number
MV	Multi vector
NG	National Grid
NPG	Northern Power Grid
NPV	Net Present Value
NTS	National Transmission System
O&M	Operation and maintenance
OCGT	Open Cycle Gas Turbine
PEM	Polymer electrolyte membrane
PHEV	Plug-in hybrid electric vehicle
PiV	Plug-in vehicle
PLC	Programmable Logic Controller
PPA	Power Purchase Agreement

RIIO	Revenue = Incentives + Innovation + Outputs, *(the Ofgem gas network cost model)*
SAP	Standard Assessment Procedure
SMETS2	Smart Metering Equipment Technical Specifications 2
SMR	Steam methane reformer
SNG	Synthetic natural gas
SO	System Operator
SRMC	Short run marginal cost
SV	Single vector
ToU	Time of Use
TUoS	Transmission Use of System
VDH	Virtual district heating
VOA	Valuation Office Agency
VOM	Variable O&M
VPW	Virtual Private Wire