MARKETS, POLICY AND REGULATION IN A LOW CARBON FUTURE

Policy and Regulatory Frameworks to Enable Network Infrastructure Investment for a Low Carbon Future.

John Rhys. March 2016

This paper has been prepared in response to the request of the Energy Technologies Institute (ETI) for a high level perspective on conceptual approaches to a reformed framework for the governance and regulation of network infrastructure investment appropriate to a low carbon energy sector.

It aims to take a wide ranging look at a number of issues associated with investment in energy networks, and various aspects of markets, regulation and policy as they impact on particular sub-sectors, including those identified as of particular significance in the ETI scenarios. These include the power sector, carbon capture and storage (CCS), heat, gas and other networks. Inevitably this leads into some questions not just for investment and networks per se, but for future operations and for consumer participation in these markets, and also for other elements of technology choice and competition, eg between hydrogen and battery powered vehicles. With such a wide ranging overview of a large number of potentially transforming changes, this inevitably includes a number of assumptions and speculations, some of which may clearly deserve further detailed attention and verification. However the paper aims to set down some quite robust ideas for an approach to the future of a low carbon energy sector.

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CONCEPT SUMMARY

Policy and regulatory frameworks to enable network infrastructure investment for a low carbon future

a perspective by John Rhys

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Strategic concept for reform

A number of market failures and co-ordination challenges influence investment in network infrastructure and security of supply, and are accentuated in any transition to a low carbon energy economy. They apply to the energy sector and energy use in general, but the central position of electricity in all decarbonisation options results in their particular relevance to the power sector. Changes are needed to balance the roles of policy interventions, regulation and markets in achieving low carbon objectives. This implies serious attention to creation of appropriate institutional and regulatory architecture to facilitate the low carbon transition.

Policy, market and regulatory frameworks for network infrastructures need to bring forward the right investment at a reasonable cost of capital (the 'investment phase'), enable efficient operation of networks (the 'operational phase'), and support retail markets that empower consumer choice and involvement.

The reforms proposed in this perspective seek to provide both greater long term certainty for investors and more co-ordination in the 'investment phase'. They aim to retain competitive disciplines, including competition between generators and technologies for new investment, and contract incentives for efficient operation. In retail electricity markets they aim to promote forms of competition, not currently present, that encourage innovative approaches to managing consumer demand. For the heat sector, this perspective recognises questions for strategies based on both individual and collective (district heating) choices, proposing initiatives to help promote and enable heat network infrastructure.

Key priority measures

- Formalise the recent trend towards central strategic direction of decisions for the UK energy mix, by creating a technically competent central procurement agency (CPA) for electricity capacity. The CPA's duties would be to procure a sufficient, balanced portfolio of generating capacity, while ensuring that low carbon objectives for the sector are met.
- The CPA would enter into long term power purchase agreements (thereby securing a lower cost of capital) and would resolve investment co-ordination between capacity and power procurement, system operation and transmission functions. Contracting through a CPA would obviate the need for a separate capacity market instrument, since long term contracts could be structured to reward capacity and availability.
- Enable more effective competition in the supply market, allowing electricity suppliers to act more innovatively as demand-side aggregators, with radically different service offerings for customers that will also help shape consumer loads.

- Create a new Heat Networks Authority to facilitate early roll out of heat networks, identify the most promising candidate locations for early adoption of district heating, and promote best practice. It might also anticipate and resolve coordination and other issues with the power and other sectors in areas (possibly a majority) not covered by heat networks.
- Encourage heat network deployment by government support for and underwriting of early "model" projects, while reviewing means to regulate the decentralised heat monopolies.

Supporting analysis: Key challenges and issues

1. Markets cannot be relied on to deliver low carbon policy objectives, because the price of CO_2 emissions does not adequately reflect the carbon externality, and may not do so in future. This affects investment, the operation of assets, and consumer choices.
2. Investors in infrastructure, or immobile, use-specific assets, face 'time inconsistency' risks inherent in recovering an adequate return on investment once costs have been sunk. Particularly important threats to future revenue are policy and regulatory risk, since the asset will typically not enjoy alternative sources of revenue or market outlets.
3. Relying on wholesale markets to deliver security of supply in electricity poses problems intrinsic to the market structure, since SRMC-based price signals are and will be insufficient to reward investment in new capacity, even for conventional thermal plant. (Reliance on scarcity and periodic price spikes attracts regulatory and political risk.)
4. New low carbon generation technologies create additional complexities for system operation, and the conventional equation of merit order operation with wholesale markets is unlikely to continue as an adequate basis for efficient operations and decision making.
5. The low carbon transition raises a range of broader co-ordination issues, within and across network infrastructures, which may not be capable of resolution through familiar market mechanisms. This includes handling integration and interactions with CCS, a hydrogen sector, and vehicle charging demands and infrastructure.
6. Demand side management must play a major role in low carbon systems but this requires a mix of cost reflective price signals, control technology and new models for the service provided to consumers – the "consumer offering".
7. Low carbon heat solutions face multiple challenges. These include: managing the diversity of alternatives, questions around compulsion and choice, and the best models for enabling collective, co-ordinated solutions where appropriate.
8. Other regulatory assumptions and policy norms will need to change. Transition to a low carbon economy may end any residual "predict and provide" approaches to energy policy, and lead to adoption of different reliability standards for different energy uses, possibly more geographical discrimination in service and pricing, and approaches to network "use of system" pricing that fully reflect system conditions rather than cost averaging.

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1. INTRODUCTION

The work of the ETI shows that, at least in purely technical and resource terms, meeting UK 2050 targets for CO_2 emissions is demonstrably feasible. Their analysis has however also identified a significant number of coordination and investment questions that relate both to low carbon energy futures in general, and to elements in their scenarios. The scenarios illustrate and exemplify a number of questions and issues common to many alternative paths to achieving low carbon objectives.

The exercise raises questions for markets, governance and regulation whose resolution is required to deliver outcomes such as those suggested in the scenarios. These reflect practical commercial, market and organisational questions on how to implement technology-focused solutions, and corresponding structural, institutional and regulatory changes. This means identifying barriers and problems, including those that stem directly from the technical and logistical features of the various scenarios, and making proposals for their resolution.

The structure of this paper is as follows. After setting down some general themes in this introduction, Chapter 2 considers several major challenges relevant to the energy sector as a whole, and presents some general principles and ideas for their resolution. Chapter 3 offers an approach to the power sector that can help meet these challenges both for power and the sector generally. How such a model might operate commercially is elaborated in an Annex, which also discusses the roles of markets, government and sector regulation. Chapter 4 looks at the heat sector and similar challenges for heat networks. Chapter 5 discusses a range of issues for particular technologies, including interactions within the energy sector. Finally Chapter 6 provides a summary and conclusions.

<u>Setting out main objectives</u>

Michael Grubb's analysis[1] of climate issues categorises climate mitigation and energy policy options within three domains, loosely summarised as:

- **transformative**, strongly linked to all the major issues of technology policy and strategic investment, and generally linked to timescales measured in decades. This domain is fundamentally strategic and policy driven.
- **optimising**, strongly associated with the operation of the major energy industries, with markets and prices, and the assumptions and methods of neoclassical economics as a major pillar of policy; and both short and medium term timescales.

[1] *Planetary Economics*, Michael Grubb, 2014

- **consuming*,*** or part of the "satisficing" domain within the Grubb paradigm, with a focus on day to day consumer behaviour and choices rather than energy industry operations. Relevant policy in this domain has often focused much more on regulatory solutions, through building standards and appliance labelling for example. The targeted time dimension is the more immediate, including behaviours relating to the ways consumers buy and use energy.

The ETI contribution, with a strong technology focus, belongs mainly to the first, transformative, domain. Its scenarios are indicative of the kinds of transformation required to meet longer term policy targets. The aim of this paper is to set out how their ideas, if adopted, might move forward to practical application within all three domains, where the realities of finance, actual markets, actual utilities and actual consumer behaviour start to define some critical issues and obstacles.

Our analysis corresponds to the Grubb paradigm, at least superficially, but will be described more simply as the **investment domain** governing the way investments are chosen and made, the **operations domain** covering how the energy industry capital stock is utilised, and the **consumption domain** dealing with consumers and their choices. In each domain there is likely to be some combination of market driven choices and decisions, policy intervention or formal coordination, and regulation. Investment is the prime ETI concern, but this cannot be isolated from the matter of confidence in the future arrangements governing both operation and consumption.

The basic economic and practical objective is therefore to define the conditions required for efficiency and effectiveness, in investment, operation and consumption. This means considering how to:

- finance and deliver an efficient mix of investment, in the quantity needed, and without incurring excessive capital costs.
- incentivise and deliver efficient and secure operation of those investments once made, together with operation of the existing capital stock.
- achieve allocative efficiency by ensuring consumers can respond to cost reflective pricing, with appropriate technical and commercial options, to allow a potentially large contribution to getting an efficient low carbon economy.

<u>The Role of Markets and Mandatory Interventions</u>

A recurring theme is choice between reliance primarily on market based solutions, on the one hand, and reliance on mandated outcomes, dominated by regulation and planning, on the other. This is sometimes misrepresented as a dichotomy between centrally planned energy supply, with minimal competition and consumer choice, or a world of largely unregulated atomistic competition in decentralised markets.

We contend that this is a caricature of the real choices and that such a dichotomy is neither necessary nor useful. There were and are already "hidden" interventions (eg as market rules) and "command and control" features (eg in system operations) even within the paradigm of "fully liberalised" UK markets, as well as current support for renewables or nuclear. The perspective this paper aims to offer is to recognise the places where policy and practicality require interventions to deal with market failures or more formal coordination of network investments, and distinguish from those where coordination can be more easily provided by price signals and market forces.

In some cases this will imply a redefinition of the roles of markets and regulatory or other measures. Interventions should in most cases be consistent with retention of most of the benefits of competitive markets, and still place a heavy emphasis on "allocative efficiency" and on prices and tariffs as market signals. Some interventions can aim to increase innovation and competition, compared to the status quo.

The key, in essence, is "horses for courses", finding the right mix of necessary interventions and regulations within complex inter-related and multi-sector frameworks, while aiming to retain as much as possible of the benefits of market incentives and disciplines.

Electricity sector as a key vector in a low-carbon economy

Another feature of this paper is the particular attention paid to the power sector. Electricity assumes crucial significance, now widely recognised, as the key vector in a low-carbon economy, for a number of reasons. First, in mainly fossil systems, it accounts for a high percentage of total CO_2 emissions. Second, it is the primary choice of vector for most if not all of the available low carbon technologies, including nuclear and renewables. Third, it is widely assumed to underpin substitution for fossil fuels in the other major sectors with high emissions. Low carbon transport depends on either electric batteries or hydrogen (which can be produced from surplus electricity), and low carbon heating on heat pumps, resistance heating or heat produced in combination with electricity (CHP). Decarbonising the power sector is therefore a necessary if not a sufficient condition for substantial reduction in CO_2 emissions. In the long run, global targets may well imply this decarbonisation has to be almost complete, ie 80% or 90% plus.

One core theme of the paper is to explore the case for more central or strategic direction to develop power sector infrastructure. In part this reflects issues already evident or unresolved in conventional fossil-based systems and liberalised electricity markets, intensified by operational or economic features of low carbon technology. But a well organised power sector should also enable better coordination with other key parts of the energy sector. Potentially key interactions are in carbon capture and storage (CCS), combined heat power, biomass, hydrogen and transport.

Maintaining Strategic Options

Some of the issues are common to both ETI "clockwork" and "patchwork" scenarios, and indeed to most combinations of centralised and decentralised developments. The actual course of development is hard to predict and will depend inter alia on market driven developments and consumer responses. Any approach to structure, competition and regulation needs to be capable of flexible reaction, eg in promoting technical choices which widen rather than narrow options; technical examples include choice between CCS technologies, and seasonal storage.

2. MARKET FAILURES/ MARKET CHALLENGES.

This chapter covers five directly relevant challenges, linking them back to the domains of investment, operations or allocative efficiency.

2.1 Failure to internalise the CO_2 externality.

An annoying and inconvenient truth: ***"If damaging externalities are not internalised in prices, there is no basis to assume that free markets and free trade will improve human welfare".***[2] In the absence of adequate carbon pricing a purely market-based approach is unable to deliver low carbon investment or even to ensure the most carbon-efficient operation of an existing stock of plant. In other words additional policy instruments become a necessity. This impacts on all three domains - investment, operations and allocative efficiency.

For a variety of reasons, the prospect of a generally agreed measure of these externalities, and its application to the pricing of carbon, may be illusory. Policy makers are increasingly influenced by an appreciation of the potentially catastrophic scale of failure to address climate issues, and it is global risk management concerns, rather than the arguably inadequate and incomplete tools of cost benefit analysis, that drive policy. Nevertheless measures do exist, have been embodied in Treasury guidelines and do serve a useful purpose as a very loose benchmark against which to evaluate, at least superficially, costs of failure to deal with the externalities.

The largest adverse consequence of failure to internalise costs may be the effect on low carbon investment incentives, such as the failures to incentivise the carbon capture investments widely recognised (not least by ETI) as key to a least cost decarbonisation of the power sector. But it can also lead to perverse operational choices, an obvious recent anomaly (in Northern Europe) being the closure of highly efficient gas power stations, while coal stations continue to operate baseload due to cheap coal. In climate terms this is an expensive anomaly, even though the immediate financial implications for the utilities were relatively trivial.[3]

It is easier to attach a value to current operational anomalies than to investments foregone. Recent UK experience is an illustration of the scale of the issue at the operational level. Between 2009 and 2012 the substitution of coal for gas, induced by changes in gas/coal price relativities, increased UK coal consumption by about 15 million tonnes. This increased CO2 emissions by around 20 million tonnes, to which past Treasury guidelines[4] might have attached a notional "social cost of carbon" value of around £ 1.2 billion. Actual fuel savings to generators are likely to have been at most 10% of this amount. In other words this single failure to price carbon will have generated a hypothetical long term net "social cost" of around £ 1 billion.

If investment choices were also to be based on a projection of very low carbon costs, corresponding measures of welfare loss would be of a much larger magnitude, even

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[2] Attributed to Michael Grubb. BIEE Climate Policy Seminar.

[3] Deficiencies in the EU ETS giving rise to very low carbon prices are well documented elsewhere and are not discussed in any detail here.

[4] *Valuation of energy use and greenhouse gas emissions for appraisal and evaluation.* October 2011. DECC and HM Treasury.

with these very conservative measures of social cost. The real cost however would be comprehensive failure to meet emissions targets, and consequences of that. The inability of existing market structures to incentivise and bring forward low carbon investment provides a primary justification for intervention.

Several points can be made about carbon pricing.

- In some senses this is a transitional issue. Since the direction of travel is to a near zero carbon economy, the regulation and organisation of the sector in the longer term will not depend on carbon markets or taxes. Energy prices may in principle reflect only the cost of supply from low carbon sources.

- Nevertheless significantly higher carbon prices are likely to assist attainment of cumulative emission objectives in the timescales with which we are concerned, even if they remain insufficient to incentivise investment.[5]

- An important role for carbon prices in this transitional context is to counteract the "rebound effect", when higher energy efficiency induces (through lower costs to the consumer) additional use. This is important for the heat sector, where energy efficiency programmes are a major policy instrument.

- Carbon prices can also be seen as implicit targets. Given the increasing marginal costs of abatement, and the particular problems in finding low cost, low carbon alternatives to reliably meet peak loads, there may be significant structural differences between strategies for prima facie "good" results, eg 80% reductions, and for necessary final outcomes, eg 100% reduction.

- If the cost of CO_2 emissions is at least partly internalised, explicitly through a tax or cap and trade regime, or implicitly in policy, then consistency matters. Inconsistent or incomplete coverage will lead to "leakage" between sectors or geographies[6], with perverse effects that can drive up total emissions.

- Consistency between vectors is particularly important in contexts of consumer choice. Inconsistency is implicit in UK Treasury guidance[7], notably between "market" and "non-market" sectors. Inclusion of aviation in the carbon traded sector attaches a lower value to CO_2 in aviation than in road transport. So hypothetical schemes to promote biofuels would show a higher return if they displaced diesel as a road fuel (excluded) rather than aviation fuel (included), even though, ceteris paribus, the opposite might prima facie be better policy[8].

[5] €15/ tonne may be sufficient to induce early gas for coal substitution in existing plant, for example. One claim made for the EU ETS is that companies are now basing their planning on an expectation of much higher carbon prices, eg. €40/ tonne, even if these are not sufficient to induce the major generation investments. Both these numbers were quoted in a recent address by the Director of the Commission's Directorate for Climate Change Action

[6] In relation to industrial energy prices, this is often expressed as concern over international competitiveness

[7] "Comments On October 2011 Guidance Issued By Treasury On Valuation Of Greenhouse Gas Emissions", *Oxford Energy Comment*, March 2012. http://www.oxfordenergy.org/2012/03/comments-on-october-2011-

[8] There are currently fewer low carbon options in aviation. A similar anomaly arises in the treatment of gas and electricity.

2.2 The investment problem for infrastructure assets.

This relates primarily to the investment domain, as a problem of **infrastructure, policy, regulation and risk.** Its general relevance has been recognised explicitly by the ETI. Economists describe it as a "time inconsistency" problem. Ex ante, policy makers want to make sure an investment is made. Ex post, with investments made and costs sunk, political and regulatory priorities can turn rapidly towards consumer interest in low prices. This applies to energy and other infrastructure investments where costs of fixed assets are recovered directly through charges to consumers.

Conceptually at least, low carbon technologies do not alter the problem. However the possible scale and extent of policy interventions, observed policy changes or reversals[9], higher costs of low carbon alternatives, and controversy over climate change or energy policy generally, all tend to increase policy, regulatory and market uncertainty. This is one of the most critical questions for the organisation and proper regulation of the energy sector as a whole.

A particular market manifestation of the problem is relevant when the future cash flow to reward the investment depends on one or more prices set in a market, particularly in imperfect markets or those dominated by a small number of buyers. It is most easily defined and evident in the electricity sector, but may affect other vectors, if for no other reason than their intimate connections[10] with the power sector.

The risks to the investor include those associated with the organisation and behaviour of markets, both in the rules for the conduct of wholesale markets and capacity markets, and also the potential exposure to decisions of regulators and downstream purchasers who may encourage the creation of surplus capacity, not always on a level playing field, in order to drive down prices. An interesting example is an investment in an interconnector to exploit an arbitrage between different power systems. The operation of the first interconnector may be highly profitable, but there will be diminishing returns to any further interconnection, possibly at the instigation of buyers or regulators, which eliminate the profits of the first.

A more familiar question is that of who pays the capital cost of the fossil peaking plant needed only for a few hours a year, during which it earns an SRMC based wholesale price that is set by its own fuel cost. There is clearly no profit even in the few hours for which it operates. Not covering capital costs is an intrinsic and largely unresolved problem for SRMC-based wholesale markets in general. It is a serious and well recognised challenge, at least within liberalised power markets. It is a major issue even in fossil-based systems, but it will be accentuated dramatically within low carbon systems where many renewables have zero marginal cost and are frequently "at the margin", setting SRMC and hence the wholesale price at zero.[11]

Its resolution requires either the confidence that reliance on "scarcity pricing", as another component of a market solution, will ultimately bring forward adequate

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[9] A recent (November 2015) example has been withdrawal of CCS funding in the UK..

[10] eg via hydrogen

[11] For various reasons, such as perverse incentives for renewables or actual costs of reducing output for nuclear, prices in these markets can even be negative.

capacity, or on some form of direct administrative intervention, such as the creation of capacity markets that will complement “energy only” markets.

Reliance on a market solution, in which prices rise with the effect of both reducing demand and bringing forward supply, poses a number of questions. The first is simply the time lags, of several years, before new investments can come on stream. Given the general investment issue, this would imply strong futures markets stretching many years ahead, or very stable prices, together with the confidence of investors in such markets to underpin their investments. Neither of these is in evidence.

Scarcities also tend to produce more immediate “price spikes” which attract instant political and regulatory attention. This reinforces the “time inconsistency” problem described above, and undermines confidence that investors might otherwise place in a “market price”. Finally any external intervention in the market, for example by subsidising additional capacity, will distort existing market trends, possibly in unpredictable ways, and further undermine the confidence of investors in market based price signals.

One pragmatic approach to ensuring adequate revenues for generators, in some jurisdictions, has been toleration of a degree of market fixing in which large generators can use their market power to set a higher price , for example by “withholding” capacity at particular times.[12] However this also removes the theoretical underpinning for the assumption that a market results in optimal allocation of resources in system operations. Even in a purely fossil system, this means there will likely be occasions when it leads to sub-optimal dispatch of plant. There will also be a constant risk that this behaviour will be seen as unacceptable by the regulatory/ competition authorities, and lead directly or indirectly to forced divestment and/or major changes in market rules. Use of market power to set a higher price is not the same as scarcity pricing, which is the natural response of a market to inadequate supply. It may therefore also send the wrong signals on not just how much but what kind of capacity is required. Again none of these considerations are likely to inspire confidence among infrastructure investors.

If we turn to direct or indirect policy interventions to ensure adequate capacity, these most commonly involve the introduction of some form of capacity payment. However it must be emphasised that capacity payments and capacity auctions are not a pure “market” solution. They are themselves the product of a central intervention, and pose many questions: who is to be the party responsible for making the capacity payments, how much capacity is required, who is to conduct the auction, how is it to be conducted, what should be the contract length, how to define and monitor what is being supplied, and a host of questions on how to measure and compare capacity from very different sources (eg wind, nuclear or fossil). In other words this implies the existence of an agency that can make a large number of important decisions on generation investment, inter alia on technology choice, with an ability to make substantial financial commitments.

[12] Exemplified by recent experience in Alberta, Canada. http://calgaryherald.com/news/politics/economic-withholding-goes-under-the-microscope-after-spring-power-price-spike

Introduction of capacity markets can therefore be seen, correctly, as a substantial first step towards central direction of investment in generation[13], and towards the installation of a "single buyer".

Link to choices on level of security of supply

The issue of how much capacity is also closely tied in with that of setting standards for generation security (capacity adequacy), with which governments and/or regulators are always closely concerned.

An alternative form of intervention, adopted in the UK in 1990, was to set a penalty charge for failure to supply, constructed around a value of lost load (VOLL). This was intended as a minimal intervention, and to mimic how a market might operate under conditions of capacity shortage, with the level of VOLL as the critical parameter in setting the security standard expected by consumers. It was a clever administrative device. However it too implied and depended on the incidence of substantial price spikes, which provoked regulatory and political concerns, as well as accusations of market manipulation. It is less clear that it would work effectively within a low carbon power sector where demand management is an important factor, and where consumers may choose very different security standards for different components of their consumption, so that attempts to value security through VOLL mean very little.

Relating capacity to a VOLL makes it explicit that decisions on capacity represent a balance between cost and capacity adequacy, with a higher VOLL leading to a higher standard and conversely. In other words the whole issue can also be described in terms of setting standards for generation security.

The overall problem of "missing money" is most obvious in electricity wholesale markets. The complications inevitably migrate to new situations and vectors where electricity is involved as back-up or as a competitor. One plausible example in the context of ETI scenarios is the economic valuation of facilities for the storage of hydrogen and its subsequent use for flexible generation. In the absence of vertical integration, "missing money" or "paying for capacity" has always been a well-recognised challenge for the power sector. It is a real and largely unresolved issue even in fossil-based systems, but is accentuated greatly by zero marginal costs.

Implications for progression to a low carbon energy sector

Revenues based solely on a wholesale price equal to short run marginal cost (SRMC), ie "energy only" or SRMC based markets, cannot properly reward future investment. This can be a problem not just for generation per se but for any facility that provides additional capacity. This includes storage, transmission and interconnection. Nor can energy only markets ensure adequate capacity and security. Any remedy for this problem requires administrative intervention in some form and is a decision inseparable from that of setting security standards. However, simple definition of a security standard will in itself become increasingly challenging, another factor affecting future approaches to consumer issues and regulation. While a regulator set security standard may remain, increasing ability of consumers to choose standards for particular applications will reduce the importance of the issue.

[13] Indeed this has often been expressed as a serious criticism of such proposals by proponents of fully liberalised markets. It is an issue at EU level where the Commission has generally supported "energy only" markets, which of course avoid the difficult issue of setting a Community wide security standard.

Implications for investment. Cost of capital.

Taken as a whole these considerations explain both historic organisation of energy utilities as vertically integrated and "regulated rate of return" monopolies, and current policies for long term contracts or "feed-in tariffs" with long term guarantees.

The clear lesson of this analysis is that getting the necessary investment at the lowest, or any reasonable, cost requires finding ways to reassure investors, a view frequently confirmed by the infrastructure investment community (mainly pension and sovereign wealth funds). The known solutions are combinations of a secure regulated monopoly structure that allows cost recovery (including a return on capital), long term contracts with a secure counterparty, and government guarantee.

Consideration of this aspect of investment risk also leads directly to consideration of the cost of capital as an issue. There is potentially a major discrepancy between a supposed social cost of capital, appropriate for use in appraising major issues of public policy, and the market cost of capital sometimes required for the actual financing of individual investment projects. This is discussed more fully in Annex 1, but its resolution is clearly a necessary condition for funding and financing of transformative infrastructure at a manageable cost. Resolution of the investment problem is a necessary condition for our ability to ensure that investments in a low carbon energy sector can be made with an appropriate cost of capital, and a major contribution to affordability.

2.3 Optimising or coordinating generation and other energy production under complex constraints.

This is primarily an operational issue, although operational issues can feed back into strategic investment choices, and it also has implications for prices and tariffs, and hence for allocative efficiency. **Conventional wholesale markets applied to low carbon systems will not deliver either efficient system operations or meaningful price signals.** The reason is that most low carbon technologies have cost and operating characteristics that are very different from fossil generation and are incompatible with the assumptions behind current wholesale markets. It may be possible to remedy this problem in certain well-defined conditions, but theoretical considerations suggest it will often not be possible.

The issue starts with the power sector, but may affect other sectors, eg the operation of heat systems, both through the effects of peak or back-up pricing and also through potentially complex questions in system operations. It is a novel and largely unexplored problem for the power sector, and deserves explanation in more depth. A brief further exposition is provided in Annex 2. The issue is also important because it has the potential to invalidate much of the conventional wisdom on how to organise market structures across the board. It is an issue separate from but additional to that of zero marginal cost and "missing money", and a deeper and possibly more intractable problem.

Implications for operation of a low carbon energy sector

Merit order operation is unlikely to be an adequate approximation for efficient operation of future low carbon systems, which incorporate substantial inflexibilities (eg nuclear plant and possibly CCS[14]), substantial storage or time shifting options (including the demand side), and stochastic supply (eg wind power).

These are new issues in that they are greatly accentuated in systems that do not have the flexibility of fossil plant, in systems where both storage and demand shifting play a large role, and in systems with large stochastic components. It has often been claimed for example that BETTA has penalised inflexible plant, not necessarily fairly.

These issues will also be exacerbated by, and possibly exported to, new generation technologies and vectors linked to electricity, in ways that deserve more analysis. These may include combined heat power, generation with CCS, hydrogen production, heat storage, batteries in electric vehicles, and other means of storing electricity. These will all need coordination with power system operation, even if there is no longer a reliable signal, or even any relevant signal, from a wholesale market. In these circumstances reliance on spot market pricing to reward flexible generation, storage and demand side management may also be a much more difficult task than is recognised in the ETI discussion of market mechanisms[15].

These complications predispose to a contract based command and control system in which the system operator (SO) seeks to optimise and balance choices, including those related to system security. In a later section it will be argued that there is a counterpoint to the strengthening of existing real time "command and control" by the SO, in the form of much more consumer involvement through innovative approaches to competitive supply, and a larger role for retail competition.

Implications for progress in achieving investment for a low carbon energy sector.

It is impossible to quantify the impact of this factor on operational efficiency and costs without modelling complex and entirely hypothetical counterfactuals of what alternative market "fixes" or optimisation routines might be put in place to deal with hypothetical future low carbon power systems. There must however be serious doubts as to whether important features of such systems, including the demand side, would operate or develop at all in such an environment, for the reasons discussed above and in Annex 2.

More important for investment, perhaps, is the fact that merit order type wholesale markets have been the intellectual and practical lynchpin of liberalised electricity markets as a whole. Increasing irrelevance of easy to understand wholesale markets will make it much harder for generators to anticipate the likely operating regimes for their plant or to have confidence in its fairness. Combined with the zero wholesale price issue, this will make generators much more likely to rely on contract terms both to cover capital costs and to govern their operating requirements.

2.4 Broader coordination issues at the investment stage.

This relates primarily to the investment domain but in a context that has to take into account future balancing and compatibility problems in system operations.

[14] It has been suggested that this is also a factor that should influence choice of CCS technology. Post consumption capture has been claimed to allow for more flexible operation of plant. Operating inflexibilities will tend to be associated with the chemical process aspect of CCS rather than combustion/ generation per se.
[15] UK scenarios for a low carbon energy system transition, ETI. p.47 of this briefing refers to this requirement.

Significant investment coordination has always been argued to be necessary, for example with respect to transmission network planning in the power sector, so this is not a new idea. The ETI has correctly presented this as of central importance, and also indicated that it will be amplified by cross-vectoral issues. Previously the implicit assumption has been that there was less need for coordination in activities that were essentially market driven. Indeed in a competitive market any formal coordination might from a regulatory perspective be seen as a contravention of competition law.

Future Issues

In a fossil fuel dominated generation sector, all plant is, at least in the essential respects of how it responds to being part of a complex power system, very similar. Past absence of coordination on generation investment has not been an issue. Competition has successfully driven sourcing of cheaper fuels, and improving thermal efficiency and plant availability. Limited coordination, primarily in relation to transmission, is implicit in regular forward looking statements from the National Grid.

However the assumption that the market can in future sort out coordination issues to provide workable combinations of technically very different forms of generation needs to be questioned and tested. There has for example been substantial debate over practical problems in managing systems with substantial volumes of intermittent wind and/or inflexible nuclear. Moreover potential new or greatly increasing loads, like battery charging or storage heating, also transform the possible choices, but their impact depends heavily on exactly how these demand side options themselves are developed. These are the kinds of issue identified by the Institution of Engineering and Technology (IET) in their recent call for a “system architect”. Choice is not just about comparative costs of technologies, but about what combinations are technically feasible and offer synergies.

The power sector illustrates the problem of achieving coordination through simple bidding processes that focus on a theoretical levelised cost. In a system context this means little, as the economic benefit of an investment in a new plant can only be assessed in the context of the system it is entering. In principle this is exactly what markets should be able to anticipate, and in principle they may work well for technically less complex choices dominated by fossil plant where average wholesale prices are reasonably stable and predictable. In practice it is more difficult, not least given the issues in 2.3 above. The problem of comparing alternatives across vectors with differing rules and structures may be even greater.

Major government decisions are currently determining the percentages of renewables, and of nuclear, and there are a number of comparable decisions on CCS generation and storage, smart metering, electric vehicles, and domestic heating, which will also have major implications for what constitutes a viable and sensible mix of generation technologies. These are decisions within government and elsewhere, but would benefit from serious technical consideration within the power sector itself, for example by the National Grid or by the major generators.

Low carbon energy systems will produce many new coordination issues. Some of these may be capable of resolution through familiar market mechanisms that include cost reflective pricing, but others will not. The following agenda raises examples, some of which are addressed in more depth in later chapters.

- Siting of wind turbines. Geography has a major effect on the economics of a wind facility, most obviously in the quantity and reliability of the wind and in the cost of construction, particularly offshore with different depths and sea conditions. However "firm" wind capacity in aggregate, and hence reliability, is improved through geographical diversity, so that concentration in a few favoured locations is not necessarily the best choice.

- The percentage of intermittent generation consistent with a workable power system, and its operation with differing combinations of other plant, load management and storage, is a fundamental system question.

- Carbon capture and storage will require a new network of CO2 gathering pipelines. The financing and operation of this network will be intimately linked to the requirements of, mainly, the power sector, with options for industrial CCS as the network grows, and the coverage of the network will have to reflect the choice of locations for fossil fuel generation constructed for use in CCS mode.

- Compatible mixes of different initiatives in demand management, storage and generation technologies in order to bridge both diurnal and seasonal variations. There are also questions over whether different forms of storage are better located locally or even at household level, or to capture economies of scale with a grid location and under direct system operator (SO) control.

- Electric vehicle choices will have a profound influence on storage needs and the potential for load management through possible battery charging regimes. In particular the extent to which re-charging will take place "overnight" on domestic premises, or as "rapid re-charging" at motorway service stations, will have major implications both for overall load balancing, and hence the mix of generation technologies, and for the reinforcement of local distribution networks.

- Hydrogen infrastructure. Hydrogen has multiple facets, but its essential feature is that it is not a source of primary energy. One potential source of its utility is as an outlet via electrolysis for spilled production from inflexible or surplus sources of power, ie essentially about storage of primary electricity. ETI scenarios[16] indicate production through other processes requiring carbon capture, but this also implies close linkages with and dependence on features of the power sector, notably the siting of CCS plant and the CO_2 gathering network. Hydrogen's potential for multiple applications as an intermediate or final use vector include use as a transport fuel, reconversion to electricity, eg as back-up, and conversion to another chemical store of energy (eg natural gas or diesel).

[16] The October 2015 E4Tech report for the CCC, *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets* indicates a much larger role for electrolysis, suggesting in one scenario that electrolysis will be produced largely by electrolysis until 2030.

- The long term maintenance, with declining sales, of gas distribution networks and their role as peak load support covering winter heating demands placed on the power sector. This raises questions both in aggregate, for the overall volume of the gas sector, and more locally for gas and electricity distribution networks.

- The development of local or city-wide district heating schemes based on combined heat and power. This implies a link between the development of local heating networks, including selection of preferred cities for early roll-out of heat schemes, and generation and other choices in the power sector.

Implications for progress to a low carbon energy sector

Some of the above challenges can in principle be met by a combination of market and price signals, eg through network charges, and a degree of informal coordination or indicative planning within the power sector. In other instances more formal coordination and policy direction may be required. New technologies will continue to throw up new questions. The need therefore is for structures that are sufficiently robust to adapt to and resolve a range of as yet unforeseen problems.

One difficult to resolve question is that of the different levels at which a coordinated approach is required. This paper focuses on a national level, but it is possible to envisage developments that transfer many of the big challenges, discussed here as national issues, down to a much more local level, and lower voltages. Equally no attention is devoted here to interconnection issues, other than implicitly, but these also raise major questions for coordination, and indeed for markets and for choices on security standards[17].

2.5. Communicating cost structures as tariffs and incentives for consumers.

This is an issue of allocative efficiency but with operational implications. Its most obvious manifestation is in the power sector but consumer reactions mean electricity tariffs are intertwined with other vectors and particular uses of electricity, including the heat sector, hydrogen production and battery charging for electric vehicles.

Current market structures do not provide for complex interactions between choices on supply and storage, and demand side options open to smaller consumers. Future low carbon scenarios will require cost and price signals to be consistent, cost reflective and supportive of demand side management. This will be true both in terms of aggregate supply and demand and also at smaller scales, eg within local distribution networks (LV for the power sector).

UK liberalisation made distribution a function separate from supply, which became a competitive market. Dissatisfaction with supply competition has arisen on two counts. The first is a public reaction. Existing competition formats have not been an

[17] In a single EU market a security level set in one jurisdiction affects energy markets throughout an interconnected EU.

unqualified popular success, and competition has not always prevented exploitation of consumers, notably through marketing policies which exploit consumer inertia. [18]

The second failing is much more fundamental in terms of future requirements. It is the lack of innovation on metering and related matters that arose from adoption of load profiling. With load profiling, all consumers of a particular type are assumed to have the same time profile in their consumption pattern, implying a homogenous mix of peak/ non-peak, day/night and winter/summer loads. The supply business is then essentially commoditised. All suppliers provide the same product, with differentiation only on price. This undermines, or rather excludes from the market, any competitive benefit from offering consumers a truly differentiated service. Profiling inhibited UK development of sophisticated metering and control systems and tariffs, arguably for a generation[19].

Technology change is now forcing re-examination of these issues and transforming the way that we look at the market. Just as new generation technologies with very different operating characteristics and cost structures should cause us to re-examine optimisation and wholesale markets, so should developments in metering, telecoms and control systems lead to re-examination of the way consumers use electricity and control their own usage, and hence the whole nature of the supply business.

Developments in communication and control technology have created an explosion of possibilities in metering and service provision. They allow for the application of sophisticated TOD metering – even for real time pricing – previously seen as impractical or impossibly expensive, as well as sophisticated remote control of individual appliances. Given the interactive nature of these possibilities, utilities need to consider how end use should be incorporated into processes for the secure and efficient operation of the system.

If markets are to produce efficient outcomes then they must contain the means for complex cost structures and network/ system characteristics, in production and distribution, to be combined and integrated with the right incentives for the many forms of decentralised contribution to balancing and stabilising the system. This includes appropriate tariffs for consumers engaged in demand management, for “prosumers” (who both produce and consume), and “prostumers” (who produce, consume and store). However even simple versions of “real time pricing” face major practical obstacles, mainly because consumers generally show little appetite for time or effort intensive economic calculations in relation to what they will continue to regard as an “on demand” utility service. There is also a potential for dynamic instabilities if simple peak load pricing just shifts peak to another period rather than managing and shaping load. A more sophisticated and radical approach is required.

Distribution engineers have identified further questions for the medium and low voltage distribution networks, if they have to handle substantially greater volumes of

[18] *The true cost of energy. How competition and efficiency in the energy supply market impact on consumers' bills.* Institute for Public Policy Research. April 2012.

[19] The CALMU credit and load management unit was pioneered by Fielden and Peddie, then an Area Board (ie state industry) Chairman, in the 1980s, and has enjoyed worldwide success. It died in the UK with privatisation and the adoption of profiling.

electrical throughput, with new types of load, and possibly with very different dynamic characteristics. So there are likely to be future problems of local load balancing, as well as aggregate demand/ supply management at higher or national system levels. These too may need to be reflected in the design of network use of system charges and in control measures to manage local stability. Network tariffs are another major area where cost recovery may have to be done differently in future, and not simply by averaging total costs over total units sold.

There are happily many technical and other options for managing these interactions more effectively while at the same time moving towards a "service" rather than a commodity approach. These include the automation of responses within individual appliances on the consumer premises, to respond either to price signals or to remote control by a supplier/provider. These are discussed in more depth below.

Future Options

The conventional utility model has consumers able to treat electrical energy supply as "on tap", with limited or no differentiation between applications (e.g. as between lighting, heating or mechanical power). Tariffs and prices for the most part approximate to an averaging of the costs of supplying electricity, with limited ability to differentiate on grounds of differing incremental costs.

This model needs to change, primarily because future developments in the nature of the load (eg battery charging or heat storage), and in control technology, will render it inefficient. In consequence it may be a high cost or even, given the less flexible nature of low carbon generation, an infeasible model. Consumer behaviour needs to be incorporated as a much more active element in the system. This goes well beyond much current thinking which, insofar as it addresses these issues, remains focused on time of day or even real time tariffs. Consumers may or may not welcome these, and, in practice, they may or may not be able or willing to respond. Potential for real time pricing needs to be qualified by an appreciation of future difficulties in generating real time SRMC prices as described in 2.3 above.

What is needed is to redefine the "consumer offering", defining electricity as a set of services, rather than a homogeneous commodity. This requires starting with a clean sheet in defining the nature of the services that consumers will want, and the basis on which they pay. So, for example, a consumer wanting to charge electric vehicle batteries might request 75 kWh to be delivered in a specified period, over several hours or even several days (eg a weekend), and the consumer's contract might specify that this requirement will be met in full but with timing that is "at the supplier's discretion". Corresponding but different arrangements could apply to the purchase of power for heat, for refrigeration, and some other uses, reflecting in each case the nature of the load. Commitments to individual consumers would be made by energy service companies who would be able to aggregate consumer requests and feed them in as part of the SO's system optimization routines. Such services might even be packaged with the provision of appropriate equipment (eg storage heaters).

The role of suppliers is then to act as aggregators, and their essential function will be to manage the complex interaction between consumer loads and system balancing requirements, including shaping and managing the pattern of consumption. This provides a major opportunity for a much more innovative approach to all aspects of metering and for the terms on which consumers purchase power. Suppliers could at the same time enter into individual contracts with generators, or a system operator or other central agency, which would reflect the economic benefits of their ability to shape consumer loads. They would also take responsibility for managing loads within network constraints at lower voltages, ie within local distribution networks.

This would have some powerful advantages. First it would allow consumers to purchase power for particular usages in ways more akin to their purchase of other goods and services, as opposed to perpetuating the "instantaneous commodity" characteristics that have hitherto been a unique and constraining feature of the power sector. This would also correspond to what consumers actually want and need from the utility. At the same time it would help make the services more affordable. Consumers could still choose to take some power "on tap" and would normally pay a higher price for this.[20] But many of the issues associated with administrative setting of security standards would become much less significant. To a much greater extent security levels would be chosen in a market.

This change is enabled by one set of technologies – those that surround metering, separate identification of different loads within each consumer household or business, and remote control. But it also helps to resolve the problems posed by another set of technologies, those linked to intermittent or inflexible sources of non-fossil generation and distributed generation.

<u>Implications for progression to a low carbon energy sector</u>

We can envisage a future with the following important characteristics.

In terms of the technical possibilities, there will be the option of remote control of individual circuits or appliances on consumer premises. Most obviously this will be for space heating, water heating and battery charging.

Consumers can in principle choose different standards of security and reliability for different parts of their load, with different standards on offer from different suppliers. It will be a straightforward matter for consumers to take different components of their load from different suppliers; ie separate circuits can be separately metered. Major programmes to roll out metering changes across UK households should be "enabling" of a wide range of such possibilities, as this will reduce the need for future investments by consumers and utilities.

Suppliers will have as their main function to aggregate the contracts and service agreements that they have with their customers, and match these with the purchase agreements they themselves enter on wholesale markets. They may also be

[20] "Electricity Markets and Pricing for the Distributed Generation Era", John Rhys, Malcolm Keay and David Robinson. Published as Chapter 8 in *Distributed Generation and its Implications for the Utility Industry***,** ed. F. Sioshansi, Elsevier, August 2014.

responsible for matching consumer loads with the constraints of local distribution networks.

3. POWER SECTOR GOVERNANCE. COMMITMENT AND COORDINATION. POSSIBLE MODELS FOR THE FUTURE.

Our criteria for a well-functioning electricity market and industry structure are that it should meet the challenges in Chapter 2 above and fulfil three key functions in investment, operation and retail supply.

For **investment** this means inducing and financing the investment the sector needs, getting sufficient investment to ensure a secure supply, and making sure that investment is financed at a reasonable cost of capital (eg by making sure investors are not forced to carry risks outside their own control). In **operational** terms this means making sure the most efficient use is made of a given stock of generation assets. This can be through a merit order operation induced by the wholesale market, or by a systems operator (SO) optimising scheduling and dispatch of any plant that is contracted or otherwise available. It also requires **allocative efficiency in retail supply**. This means attention to tariff signals, and to the new possibilities available to consumers. This is increasingly important with a large renewables sector and the need to manage consumer loads more pro-actively.

The problems and market challenges are largely covered in Chapter 2.

- Almost axiomatically, markets cannot deliver a policy objective, like low carbon, when they are not given an adequate signal to do so.
- Regulatory and policy uncertainty is now endemic. This inhibits any form of investment that depends on revenue streams over the long term. Even if forthcoming, it is likely, unless remedies are found, to impose a very high cost of capital for risks that can only be controlled by government/ regulators.
- Coordination issues, without any obvious market-based solution, will be increasingly evident both in terms of system operations and the need for balance in the mix of investments; these issues are exacerbated by the nature of low carbon technologies.
- The capacity issue and system security. There is no clear incentive for the market to provide adequate capacity. In fact existing operators may benefit from keeping the market tight.
- Current market structures and assumptions, notably assumptions for load profiling, place a wall between physical production choices and consumer behavior. There is general agreement on the importance of demand response but no coherent strategy to make it effective.

The essential strategic choice is a binary one, between reliance on a series of ad hoc “fixes” to correct real or perceived deficiencies in existing market structures, on the one hand, and a fundamental re-think and redesign of how markets should operate in the power sector. The second choice may require introduction of formal and mandatory obligations to provide adequate security and meet emissions targets.

Experience and analysis suggests that the first approach has several deficiencies: the general problem of trying to second guess markets, the potential proliferation of complex additional rules, schemes and instruments, and failure to address the implications for market structure of major technology-driven change in the sector. All these add to investor uncertainty and increase the risks of failing to meet objectives.

For the power sector, it may be observed that many of these issues, especially in relation to getting new low carbon investment, are already fully recognised by UK governments. This recognition is implicit in the nature of interventions to promote and support renewables or new nuclear investment with long term contracts, government guarantees and feed-in tariffs. There have also been examples of the National Grid, as system operator (SO), offering long term contracts for particular niche capacity requirements. Reliance on the grid in this context can be seen as historically the alternative approach to the investment problem, reliance on a degree of vertically integrated monopoly to support investment.

The most obvious danger of the current approach is that it risks falling into exactly the trap of uncoordinated ad hoc “fixes” described above, with each “solution” giving rise to a new set of problems. There is no clear line of responsibility to a body with engineering and industry expertise, and no explicit attempt to find a balance between very different and complementary technologies. Interventions also appear to be confined to a simplified objective of finding adequate low carbon capacity, and do not take into account any future issues that may arise in operating future systems, or in the involvement of the demand side, ie consumers, in an effective way.

As argued earlier this all suggests that movement towards some form of centralised approach is both necessary and, in a very real sense, already taking place. In the UK the Institution of Engineering and Technology (IET) has recently made a similar call for a “system architect”.[21] This is not necessarily a trend to be resisted. French experience in decarbonising their power in the 1980s and 1990s demonstrates the effectiveness of a combination of political commitment[22] and a high level of technical competence in the industry.

An important conclusion of this paper is that such a combination is now required for the UK industry. This leads us to the second approach of more formal mandatory or interventionist approaches. There are a number of possible approaches. One possibility that has been canvassed is to start by mandating generators or suppliers, as an absolute requirement, to meet low carbon targets and ensure adequate capacity according to some specified criterion. Suppliers, conscious of the range of coordination issues involved, would have a strong incentive to cooperate. This might, assuming some relaxation of competition law, lead to a jointly owned agency or agencies to coordinate the process of meeting these obligations at the different levels - investment, operational and consumer focused.

[21] http://www.theiet.org/factfiles/energy/pnjv-page.cfm?type=pdf

[22] NB This was done to reduce oil dependency on the Middle East, not for climate objectives, but the lesson applies. French decarbonisation was achieved in less than two decades, incidentally giving France some of the cheapest power in Europe.

How to best achieve an ideal institutional architecture with these features deserves a much longer discussion. However a main proposition in this paper is that some form of central agency is a necessary measure to address the challenges. It offers the most certain prospect not only of securing an adequate quantum of low carbon investment, as well as supply security, but also of securing a balance of different types of capacity and load management options compatible with secure and efficient system operation, and coordinating that with necessary infrastructure investments.

In order to simplify consideration of other power and cross vector issues, we assume that this more radical approach takes the strong form of a separate central procurement agency, with real commercial responsibilities, and a specific obligation to deliver on carbon objectives and system security. A fuller discussion of how such an agency might be created, alternative formats, what its functions would be, how it might operate, and other questions, is provided in Annex 3. As a further simplification, and for the purposes of exposition, we assume that such an agency would likely combine this role with the existing function of system operator (SO).

Such an agency would in effect become the major purchaser and wholesaler for the sector, inviting tenders for new capacity, and coordinate its programme with associated infrastructure investment by the transmission operator. With properly designed and implemented tendering procedures and contracts, this would retain both competitive pressures in building new plant and incentives for efficiency in operation. Its obligations would encourage a diverse balance of capacity types technically compatible with maintaining supplies, including decentralised generation, and maintaining reserve margins to ensure adequate security[23].

One further question is how the agency, as the dominant purchaser of wholesale power, would then sell on to suppliers who would in turn supply retail customers. One simple traditional answer is to create a bulk supply tariff that is sufficiently well designed to encourage allocative efficiency. This is certainly practical, but it might well be improved by a framework in which suppliers also contract with the agency for the amounts of capacity they require at different times to manage the needs of their own consumers. This has in the past been described as a “contracted capacity” approach. It has the advantage of reducing the demand forecasting onus on the central agency, so that it can concentrate on its primary procurement function. This also has the potential to create a new market framework within which one might expect greater opportunities for decentralisation and innovation in retail supply.

It is clear that this proposal has the potential to resolve all the market challenges identified earlier in 2.1 through to 2.5.

1. The agency is charged with implementing policy through its procurement decisions. Carbon pricing may be a useful adjunct, not least in reducing demand, but the agency provides a realistic underpinning for achieving the low carbon objective. Agency decisions can be much less dependent on tax or cap and trade decisions that may be subject to regular political intervention.

[23] A necessary qualification, as we argue later, is that this may prove to be quite difficult to define.

2. The agency has government and/or regulatory backing, and is able to offer secure guarantees or long term contracts to cover infrastructure investment, overcoming a main barrier to investment and securing a lower cost of capital.

3. The “missing money” problem is removed by long term contracts containing, inter alia, payments to reward capacity and availability to meet peak loads.

4. The technical problem of managing the complex operating characteristics of low carbon plant becomes the responsibility of the SO, calling on plant on terms included in the contract with the agency. The SO, not a defective wholesale market, has responsibility for optimisation in real time.

5. Investment coordination is now possible between procurement, system operation and the transmission function, to ensure that the mix of generation plant is compatible with secure operation of the system.

6. The agency will have a responsibility to include demand side measures in the equation, as well as decentralised initiatives for generation and storage. Innovative ideas and competition in retail supply to offer new services can be encouraged by appropriate use of bulk supply tariffs, purchase tariffs and contracts to manage aggregate loads.

7. As well as the above specifics, the agency can be a vehicle to deal with windfall profit problems, or stranded assets, through “cost of service“ regulation or a contractual equivalent. Mostly these are transitional issues.

8. The agency would be regulated, in purely commercial terms, on a conventional basis – one of the many possible variations or developments of the traditional rate of return approach, and reflecting the lessons learned since privatisation in 1990.

9. The more challenging aspects of its regulation would relate to scrutiny of its conduct and performance – how procurement was conducted, even handed treatment of suppliers, and progress in meeting low carbon objectives. One can therefore envisage some formal involvement of other parties, including competition authorities and the Committee on Climate Change.

This can resolve power sector investment and coordination issues because:

- The central agency enjoys the downstream security of revenues, ultimately from some combination of government guarantees (if necessary) and a monopoly or quasi-monopoly position, together with the market strength of the suppliers whose needs it is contracted to supply. This enables it to offer “bankable” long term contracts to low carbon generation investors; the viability of these contracts is not dependent on a highly uncertain carbon price. The outcomes include a lower cost of capital as well as greater attractiveness to the community of infrastructure investors.

- the contracts can if necessary be framed as power purchase agreements, and include provision for the central agency, or the system operator (SO), to dispatch output as required, subject only to the constraints, commitments and rewards/penalties set out in the contract. The agency can therefore, if necessary, and through the SO, optimise generation over much longer periods, eg a month or even a year. This resolves the wholesale market issues in a low carbon system where simple merit order stacking is no longer possible or appropriate. In other words it provides a structure within which the optimisation of more complex "low carbon" system operations can take place.

- It can also deal with the broader coordination issues in a simple and less complex way, negotiating directly with the transmission operator and with suppliers and local networks. Many of the coordination issues such as selection of a technically compatible mix of plant types, can be handled within the central agency itself. The central procurement model also offers a variety of ways in which the SO/ suppliers/ customer interface can be managed to accommodate demand response, and an undiminished role for distributed generation and local networks. It actually enhances competition and the potential for innovation in the supply function.

In the UK it is clear that movement towards more central and strategic direction is taking place, but to date this has been largely driven by events and on the basis of individual and ad hoc government decisions which only partially address the difficult questions involved. The case for change therefore is partly explicit recognition of what is already taking place. But what is required is a more complete identification of the challenges, with follow through to a consistent strategic approach.

A key advantage of this proposition is that it provides an instrument for coordination over all timescales with agencies or firms engaged with other key components in the ETI scenarios, including the development of heat networks, CCS pipe networks, and others, as well as some external linkages such as interconnectors.

The remit given to the CPA is also an important factor in determining the pace and direction of change outside its direct control. This is very relevant in considering patchwork or clockwork approaches to the low carbon objective. While the logic of the above arguments implies the need for a CPA-style entity under either set of scenarios, a CPA for power can to a significant degree also influence the path that is followed. It could clearly have a role, for example, in promoting early CCS development, in influencing the direction and shape of a hydrogen economy, in relation to decarbonisation of transport, and assisting in the difficult task of promoting heat networks.

4 HEAT SECTOR

4.1. Features of the heat sector. Collective or individual solutions?

Relevant options for low carbon development of the heat sector are conditioned largely by geographical factors. For heat networks, or "district heating", these factors include proximity to geothermal heat sources, population densities, sufficient scale to deploy heat networks economically, and, under some scenarios, proximity to gas or CCS networks. Heat networks, in which heat is distributed from a common source, raise a number of diverse practical questions, but will necessarily operate essentially at local authority or city levels rather than as units within a unified national body.

Very large numbers of households will continue to make their own choices of heating system, independent of any local heat network, and their most important low carbon options are likely to be heat storage and electric heat pumps. Each of these has important, but very different, implications for the power sector, both at the level of balancing generation and load at aggregated levels, and for providing adequate capacity within local distribution networks.

Strategy for the heat sector therefore has to cover two types of development which will give rise to very different regulatory and practical challenges, in one case a "collective" solution typically initiated at a municipal level, and in the other case solutions mainly chosen and installed by individual consumers, but which may pose significant wider coordination and network problems of a different kind.

The scale of the heat sector is also a major factor. Decarbonisation of the heat sector is widely assumed to require a very substantial ability to use electricity as an important element in substituting for the direct consumption of fossil fuels such as gas. This is a big challenge primarily because meeting existing UK heat loads from electricity generation alone would require a very large expansion, even up to a doubling, of current kWh generation, and, given the seasonal and temperature dependent nature of UK heat loads, a proportionately larger expansion of capacity. Thermal demands of domestic and public/commercial buildings are estimated in a 2012 CCC report[24] at about 450 TWh pa; this compares to current total electricity consumption of about 300 TWh pa.

The same CCC report indicates future heat loads, taking into account UK population growth, of over 400 TWh pa in the period from 2030 to 2050, even on the assumption of high efficiency achievement. More modest assumptions on efficiency require much higher amounts, of up to 550 TWh by 2050. Ambitious energy efficiency rollout projections are therefore a very important part of strategy, but the scope for reducing UK buildings' thermal demands will ultimately be limited, leaving a remaining heat supply requirement that is still very large. Such a change in scale of kWh supply is likely, a priori, to have very significant implications for local power distribution networks as well as for meeting aggregate demands.

Even if some of the heat need can be met through non-electric routes such as geothermal heat or biomass, and notwithstanding the useful energy gain from heat pumps, the interplay with the power sector is likely to remain substantial, with the possibility that heat choices, collective or individual, could be a dominant factor in the design and operation of power systems.

A further challenge is the potentially high cost of providing heat either through on premises electric heating methods, or through district heating networks, compared to

[24] *Decarbonising heat in buildings: 2030–2050*. Committee on Climate Change. April 2012.

"on premises" gas boilers. Although costs might be lower in favourable conditions, eg for heat networks in high density locations, or for further exploitation of current troughs in conventional electric load curves, low cost options are likely to be location constrained or supply limited. The high cost per kWh of heat energy is mainly due to the capital cost of additional generation capacity and/or new heat networks. This factor is accentuated by the strongly seasonal and temperature dependent nature of heating requirements, and further fuelled by the risk (for renewables) of low output at the seasonal peak. For electricity, these factors require an increase in kW capacity even larger than in kWh energy production, in order to meet heat loads.

A simple analysis of monthly long term averages for recorded degree days[25] suggests that even if within day and within month heat storage were adequate to spread consumption evenly over days and months, heat load factors would still only reach about 54%[26]. This is before taking into account the need for significant margins to cover severe cold spell conditions, or imbalances within the day or the week. A 54% figure reflects a possibly optimistic assumption that short term variations in heat load can be quite easily accommodated.

A poor load factor matters a lot due to the impact on unit costs of capital intensive low carbon electricity generation. Electricity generation facilities (hypothetically) dedicated to providing the main or only means to heat provision would be likely to operate at most at 50% load factor, even for non-intermittent options. There is substantial scope for "in filling" of existing electricity load profiles through, for example, the established heating option of night storage radiators. But, although this is a potentially valuable contribution, it is ultimately limited; and other applications, such as electric vehicle re-charging, may be in competition for some of this "space" in the daily load pattern. It does not in any case deal with the seasonality factor. Poor load factor substantially increases the contribution of electricity capital costs, the dominating element in low carbon systems, to average kWh costs associated with meeting heat demand.

Reflecting the above considerations, some alternative low carbon or electric options for the heat sector are set out below, leading on to consideration of network, commercial and regulatory issues. All pose some specific challenges for regulation and for a coordinated approach to heat and to the energy system more widely.

4.2 The Collective Solution. Local Heat Networks.

Heat networks, for distribution of heat in order to warm buildings, are in an energy efficiency context often associated with options for combined heat power (CHP) operation, but historically and internationally they have also been associated with other formats, eg conventional boilers fired by oil, coal or gas[27]. In principle future development could be in association with, for example, biomass or fossil fuel input

[25] Heating degree days are the number of degrees by which average temperature falls below a "base", eg 15.5° C, summed over all days for a given period. A similar measure, cooling degree days, can be applied

[26] Degree day statistics are readily available in official UK weather statistics .

[27] The widespread adoption of domestic gas condensing boilers has dramatically improved the efficiency of domestic gas heating, to a significant extent weakening the efficiency arguments for CHP.

with CCS, biomass without power generation, use of hydrogen fuel, dual firing, geothermal sources, or possibly as part of wider large scale heat storage.

Non-electric low carbon options include geothermal energy, where lower cost options are likely to be geography specific. A second is use of conventional fossil fuels but with CCS. This in turn may be limited initially to sites adjacent to a relatively small and undeveloped CO_2 gathering network, and carries the burden of the higher capital costs associated with CCS. A third is use of biomass or waste with CCS for firing district heating boilers. Once again biomass is likely to be supply limited and additionally has an important and possibly higher value in a competing use as input fuel for peaking or back-up plant[28] against renewables intermittency. Each of these non-electric options is therefore exposed to some form of supply limit.

The electricity linked solution for local heat networks is some form of combined heat and power production (CHP), with distribution of hot water as the heat vector. In this instance the source of the heat energy is thermal power generation plant. It is low carbon only for nuclear or for fossil plant with CCS. Biomass is a theoretical option, but as noted above, is subject to supply limitations and competing use constraints.

A general feature of district heat distribution is the large volume and large mass of water at relatively low temperatures, the last accentuated for CHP. This implies high capital and operating costs of distribution. In most circumstances, the most cost effective means of transporting and delivering energy over significant distances are likely to be electricity by wire, gas by pipe, or through a hydrocarbon store as a liquid fuel, rather than as low grade heat, with a low energy density, distributed through pipes to carry hot water. This factor is accentuated when the gas or electricity network is already in place or will be required anyway.

So the likely development of heat networks will be as local entities, without the development of national or large scale bulk transmission of heat. This strongly conditions approaches to developing and regulating heat networks. All district heating schemes will face the challenge of local capital costs in heat distribution and connection costs for individual households. A main problem is the cost and other issues associated with building new networks to distribute the heat.

The hard questions derive from the very obvious economies of scale in setting up a district heating network, and the alternative choices that consumers may want to make, if they have a free choice of heating method. Universal or near-universal participation may well be essential to the economics of many or most schemes. This is not necessarily a problem for "new build" situations. The equivalent of district heating schemes exist on a small scale, for example, in many large London apartment blocks, with an attendant lack of choice for residents. Typically they pay a fixed charge and their heat consumption is not metered (although this is changing). But residents in this case have "chosen" this form of heating when they moved in.

Implementing larger schemes that involve major retro-fitting is much more problematic, and, in addition to technical and engineering considerations, depends either on an element of compulsion or on making the district heat option significantly

[28] This is dependent on the implicit price of carbon and whether the target is 90% or 100% CO_2 reduction.

more attractive than alternatives in terms of household heating costs, a matter whose economic and political ramifications need to be considered in setting out a strategy for the heat sector.

4.3 Compulsion or choice in the context of heat networks

If we assume near universal participation as a necessary condition for the viability of most heat networks, then we have to confront the problem that many consumers will be reluctant to incur the disruption or other “transaction costs” of joining a heat network. These are in many ways akin to the problems of implementing programmes for raising insulation to a high level across the housing stock as a whole.

Insulation of buildings and energy efficiency is usually assumed in longer term projections. The benefit is clear – lower aggregate heat and electricity requirements, and lower capital outlay and running costs. The negatives are issues relating to the retro-fitting of the existing building stock, chosen policy instruments, and transaction and disruption costs to consumers. Increasing take-up may be achieved by simple economic incentives and subsidies but administrative measures, amounting to a degree of compulsion, have also been proposed by some commentators.

There is therefore a case for finding ways to link the two initiatives in the public perception, not least to reduce the element of discrimination that might be felt in areas where a heat network was being imposed.

Compulsion in a formal sense is unattractive, although comparable historical examples might be cited, such as the imposition of smokeless fuel requirements to combat city pollution in the 1950s. In practice some combination of “carrot and stick” is likely. This might for example be a selection from or combination of the following:

- Consumers are put on notice that existing services, eg unrestricted mains gas supply, will not be available after a certain date, or only available at a substantially higher price.
- A direct subsidy towards the capital cost of retro-fitting to the consumer’s own premises.
- Partial funding of the heat network through local taxes, so that householders recognise they are already paying part of the cost anyway.
- A guarantee that total future running costs will not exceed those of some benchmark calculation for the alternatives available to the consumer, eg electric storage heating.
- Ensuring that running costs for the alternatives fully reflect cost, including back-up energy per se. This would at least reduce the subsidies or the degree of compulsion necessary to induce near universal participation. Carbon pricing may be one element in this.
- Incentives through energy rating of buildings which might improve their value in selling, or be reflected in local property taxes.

4.4 Operations of CHP schemes and interaction with power systems

Issues in CHP operations reflect the fact that there is normally a trade-off between heat production, expressed as the temperature of output heat, and the thermal efficiency of electricity generation. One question is therefore whether CHP could or should be wholly subject to central dispatch, thus enabling the SO to call for extra power at times when the system is under stress and additional capacity is required. This is a potentially complex question. First it further complicates an already difficult task for the SO. Second it creates difficult conflicts of interest and duty within the CHP scheme, ie whether its primary responsibility is to heat customers or to the national power supply, or to meet a financial target. Third, reducing heat output in severe winter weather, in order to increase electricity output, could induce compensating use of direct electric heating appliances by individual households, defeating the purpose or even producing an adverse system feedback.

In theory there might be a case for comprehensive optimisation by a central overall system operator, but the problems of possible multiple objectives and excessive centralisation are much more apparent than the benefits. It should be clear that the primary duty attaching to CHP schemes is to provide a secure supply of local heat.

This does not need to inhibit purpose specific contracts between the CHP facility and the SO. The operator of the heat network would deal directly with the SO and the CPA, and the basis for kWh sales would be some combination of negotiated contract and tariff terms, analogous to those for retail suppliers of power. Contract terms would need to reflect technical constraints on the CHP plant, the priority attaching to heat output in winter, and CHP design should aim to maintain flexibility in operations.

4.5 Organisation and strategy for heat networks.

The heat network sub-sector is potentially diverse. It could include for example new schemes for isolated but concentrated rural communities with relatively small scale heat needs, conversions of established medium scale apartment blocks with communal heating, and larger and more controversial city wide schemes, including small scale nuclear generation. It is city schemes that are probably the most relevant to achievement of low carbon heat penetration in the ETI scenarios. A critically important factor is that of network economies of scale. Many schemes may only make economic sense with a sufficiently large number of dwellings at a fairly high density, possibly and controversially combined with near-universal participation.

In strategic terms, the intuitively obvious approach is to start with the “low hanging fruit”, where costs are lowest, and where consumers are less likely to be resistant to a potentially disruptive change. This increases the chance for early success and provides an opportunity to learn from the technical and other obstacles encountered in the first projects, before proceeding to more challenging schemes. After the more obvious “new build” opportunities, the next category would perhaps be areas with high density of dwellings and a high proportion of rented property, where a primary responsibility rests with landlords, public or private. This reflects an assumption, possibly misplaced, that owner occupiers will object more strongly to the disruptions associated with retro-fitting heat networks.

Many of the factors identified above, but especially consumer resistance, local disruption and "transactions costs", may make investment in and operation of the heat sector quite unattractive to private investors, including existing power generators. Moreover the expertise and experience required to construct and operate large scale heat networks, which does not currently exist in the UK, is quite separate from that of power generation. The division is even more marked if heat networks are to be associated with small nuclear plants. These factors mean it is improbable that heat networks will be "self- starters" in response to conventional market signals. Overseas experience suggests municipal involvement as one means of running and operating heat networks, but that does not prima facie correspond to UK historical approaches or to capacities in UK local government. The UK in any case has little recent experience of district heating and heat networks.

The ETI scenarios consider the role of heat networks in both patchwork and clockwork scenarios. However in either case we need to consider the question of what are the necessary conditions for heat networks to develop from a standing start. The general challenge to investment in infrastructure applies. There is not necessarily a need for a universal model but one plausible approach to large city-scale schemes might be the following:

- Establish a new "Heat Networks Authority" to identify the most promising candidate cities or other areas for early roll-out, to coordinate strategic planning with the power and other sectors, and to identify best practice from overseas experience.
- Government will almost certainly need to underwrite construction and other risks on early investments, but with the intention that these should rapidly become self-financing.
- The differences in culture and expertise requirements between generation (especially in the context of small scale nuclear plant) and heat network maintenance are such as to suggest separate ownership. Small scale nuclear plant would probably be owned and operated by one or a very small number of specialist companies, whereas the heat networks would be local, separate, and possibly under municipal ownership. The two parts would be bound together by clearly defined contractual obligations.
- The sector is also generally compatible with private sector ownership and management of facilities, but private sector ownership would probably require quite strong contractual commitments or other safeguards to underwrite the long term nature of the investments.
- Local authority operation and financing of heat facilities is another option. An important practical consideration is the financial capacity of local authorities to borrow with a low cost of capital.
- The generation operator will be contractually bound to supply heat as its first priority, and will also have contracts with the CPA and SO; electrical output may be varied up or down by agreement with the SO.
- Heat networks will operate as de facto local monopolies. For city wide heat networks there is a case for subjecting them to more formal and effective regulation, with OFGEM as perhaps the natural choice of regulator.
- Outside the large city schemes, there will be far more scope for local initiatives, and less obvious need for national support. All heat networks will

have significant monopoly characteristics, as they already do within London apartment blocks. The latter have a degree of regulation, through ownership and resident associations, providing a basic but not necessarily ideal model; the legal foundations for smaller local schemes may need re-examination.

4.6 Non-network Heat Sector. Consumer Choices and System Constraints.

Even in the longer term, heat networks will still leave a very substantial part of the population dependent on individual heating choices. For these consumers the main low carbon choices are the following.

Heat pumps can in principle reduce electricity requirements by multiplying the kWh of electrical input to produce up to 3.5 times the kWh of heat output. One drawback is that, for air source heat pumps, theoretical coefficients of performance (COP) of 3.5 can deteriorate badly in cold weather. This further lowers load factor and does little to resolve system peak load problems. A related issue is that heat pumps in low density environments may be a high percentage of local load and hence pose reinforcement or load balancing problems for local networks.

Household costs, if tariffs reflect both peak load pricing for the system as a whole, and local network reinforcement costs, are also a potential issue. Household specific installation costs are also likely to be substantial, since they include the heat pumps themselves, and are possibly higher than those for heat networks. Nevertheless they are still likely to have a comparative advantage for areas of lower population density, even if this may also be where network reinforcement problems are most acute. An attractive feature is that their installation and operation represents individual consumer choices rather than collective decisions and responsibilities.

Direct resistive electric heating, for use in household storage radiators, is a well established but niche market. Even though it accounts for a small percentage of total heat, it is already a significant contributor to winter night electricity load. As a relatively easy and low cost solution to improving the daily load factor in winter it has a potentially useful role in most scenarios, subject only to the qualifications and limitations above. However once the existing “load troughs” have been filled, the incremental cost of supplying heat through this route will necessarily start to reflect additional capital costs. “Full cost” electricity is an expensive form of heating. Policies and practices on consumer tariffs, and in particular any “promises” made to existing and early adopters of storage heating, will be an issue.

DASH. Resistive electric heating, for use on demand, is sometimes called direct acting space heating or DASH. Most households typically own some form of DASH, since its capital costs are negligible. Its occasional use is convenient but expensive (on a full rate tariff) and would most likely become even more so in any tariff system moving towards better reflection of the cost it imposes on the system. Even so it will continue to create peak problems if it is used as the fuel of last resort in cold weather or when the main household system is under pressure. It is therefore an important part of any analysis of the overall system problem.

Residual use of the gas network as a back-up or peak supply of heat to households or commercial consumers is certainly an important transitional option. Its longer term significance depends critically on overall emissions targets, and on whether conversion of primary electricity to hydrogen and its inclusion in mains gas supply becomes viable.

Issues different from those of heat networks arise for this less collective aspect of the heat sector. The biggest single issue may well be the potential rate of take-off for electricity based load, as heat pumps enter the steeper parts of the S-curve for market penetration. Given the potential scale of the load this could out-pace the growth in generation and in local network infrastructures. Likewise the "availability" of low price "off peak" electricity for storage radiators is probably less than 25 TWh and could also be exhausted quite quickly.

This may imply some quite sophisticated commercial and marketing calculations, on how to price the services associated with these forms of electric heating, and how to promote them to consumers. This would be primarily a responsibility of suppliers and depend on the volume of suitably shaped contracts secured from the CPA.

Marketing this type of heat also poses some awkward questions. There is a clear benefit to selling off-peak electricity from the current system load curve, at least if one assumes low carbon generation at night. However this may rapidly reach a supply limit, after which any incremental demands will face higher costs. Storage heater terms may therefore be on offer only for a limited period, but the customers will need to be assured of the continuation of their tariff for the life of their property.

Similar issues may arise in the local availability of both storage heating and power for heat pumps, to keep load within local network limits. These factors may imply some geographical differentiation in availability and in the terms on offer. The industry and the regulator will have to manage the fact of actual discrimination "by post code". These questions will clearly be bound up with finding a rational approach to network pricing that moves beyond simple cost averaging, and sequencing will be of significant importance in encouraging the development of individual consumers moving towards electric solutions for heat requirements.

4.7 General Strategic and Policy Considerations

Seasonal heat storage. Implicit in much of the above discussion is the high value that attaches to effective forms of seasonal heat storage. It does form part of the ETI scenarios in the context of hydrogen and possible injection into the gas network or conversion to gas or liquid fuel, but the dependence on primary electricity or CCS may make these relatively expensive options, other than for peak or back-up. Low cost seasonal storage of heat per se, rather than energy, would be a very welcome option for reducing capital costs. It is sometimes referenced in the context of ultra-low energy or "passive" houses, but there is little evidence as yet that it could be a significant element in retro-fitting for the UK housing stock. Much of conventional analysis is therefore posited on the assumption that it will not play a major role in our timescales. It has not therefore been covered here in any depth but clearly deserves further examination for the longer term; it has the potential to alleviate or remove a number of the operational and cost/ low load factor problems discussed. As such it is also a potential "game changer", a disruptive technology option posing a risk to other investments under consideration in the heat and power sub-sectors.

Roll-out of heat network development in tandem with programmes to improve energy efficiency of the building stock. There are a number of common issues, identified above, that suggest possible advantages in linking these developments. This provides one argument for considering the option of a broader Heat Authority to promote a balanced overall development of the sector.

Energy pricing and the rebound effect. There is an extensive literature on the rebound effect, essentially analysing the phenomenon in which a varying but sometimes high proportion of efficiency gains is used to support higher consumption. Given the scale of what a low carbon heat sector requires of the power sector, this is a potentially major issue. The main policy instrument to counter rebound is to ensure that the generally higher cost of low carbon heating through electric methods is reflected in higher prices. The proportion of household income spent on heating is much more likely to be stable.[29]

It follows that the implementation of policy for the heat sector would benefit in the transitional phases from higher levels of carbon prices, and in the longer run from ensuring fully cost reflective pricing. The second point is particularly relevant in the context of pricing back-up or peak load supplies and possibly in relation to local network balancing.

A rising marginal cost curve, windfall gains, and equity between consumers. The analysis above has identified a number of situations in which there are potential sources of low cost heat but in which these are all supply limited. These include geothermal energy (geographically limited), biomass for local CHP schemes (probably supply limited), and the initial infill of the winter load curve for storage heating. There will be some interesting regulatory questions, to which there is not necessarily a consistent and uniform answer, as to how this should be reflected in passing costs through to consumers.

4.8 Role of a heat authority.

The main purpose of a National Heat Authority (NHA) would be to act as a stimulus to the development of large heat networks, although it might be considered appropriate for it to have a slightly wider advisory role in relation to the heat sector as a whole. It would not have any significant commercial or operational responsibilities on a day-to-day basis. Its functions would be essentially strategic and advisory, in identifying suitable models from overseas experience, identifying most promising UK locations – primarily city-scale with the most favourable geographies. This could extend to a role in setting standards of good practice, and possibly in building links with the financial community.

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[29] Some energy economists have made a much more general observation of a similar nature, namely the remarkable similarity in energy expenditure as a percentage of GDP, as between countries with higher and lower energy prices.

The NHA could sit within government or could be an arms length body. In order to avoid duplication and reduce costs, it would be worth looking at existing bodies deemed to have general expertise in heating buildings, such as existing CHP bodies, trade associations and the Carbon Trust, to see what functions could be assumed by, delegated to or absorbed within those bodies.

5. CORRESPONDING CHALLENGES FOR OTHER ENERGY NETWORKS

This chapter explores a few of the major questions arising for different technologies and other networks, both in themselves and in relation to the power sector. The list is by no means exhaustive, but the discussion reflects the perspective we have taken: that of concentrating on some of the specifics arising from the different market challenges and actual or potential market failures, and also of examining critical interactions with the power sector.

5.1 Markets or intervention and regulation. Contrasting the energy sub-sectors

This paper has argued for approaches based on the fundamental characteristics and challenges of the sector. In the power sector these included substantial network characteristics, very high fixed costs, absence of alternative uses or markets (scale and immobility of assets), economies of scale, extreme real time complexity, and the transactions costs of involving consumers more directly in real time operation of the system. The last can also be described as the inconvenience of frequent decision making. These factors supported the case for more central coordination, long term commitments, and a single body with commercial responsibilities at the centre of decision making for investment and operations, as well as a much more innovative approach to supply competition. Moreover the power sector will be characterised by continuing technological innovation of a fundamental nature, another factor tending to promote the case for selective intervention.

Heat networks share the first four of these characteristics, but not the real time complexity, or the incorporation of the demand side in real time operations, or the degree of technological innovation in electricity generation. Moreover heat networks are essentially decentralised and local monopolies providing a commoditised supply, with much less scope for product differentiation, non-price competition and product or service innovation. In order to build momentum in the sector, the suggestion was for a national authority charged with promoting and coordinating low carbon development of the heat sector but without a commercial or operational role. In consequence the degree of centralisation is much less for heat networks although aspects of monopoly regulation, appropriate to local monopolies, are likely to remain.

Turning to some of the other sub-sectors and networks with which we are concerned, it is generally the case that the key factors listed above are either absent or weaker, or other considerations predominate. In addition, low carbon vehicle technology, for example, is not contained within national or local frameworks. In consequence while there are still a substantial number of coordination questions, especially in relationships with the power sector, there is less need and scope for central direction and control, or for underwriting of investments.

5.2 Hydrogen

The idea of a "hydrogen economy" confronts the multiple possibilities associated with future hydrogen production, movement and use. It is not a primary energy source, and viable means of production in a low carbon economy depend on an electricity input or association with carbon capture and storage. The CCC report cited earlier[30] suggests strong policy support will be needed to develop hydrogen options, and a good deal of uncertainty clearly exists on major features of its possible deployment. These are not debated here, but this paper considers instead one possible view of what a hydrogen landscape might imply for coordination and regulatory issues.

Key economic characteristics are, on the positive side, relatively low capital costs for its production (at least compared to power generation), some economies of scale in production, and perhaps most importantly in strategic terms, its potential versatility in different uses. These include:

- its potential convenience as energy storage, particularly for example if it also serves as a spill for periods of surplus power. Compared to batteries, storage costs (especially the capital element) may be relatively low, making it more competitive as a potential vector for seasonal storage.

- multiple options for "re-conversion" or use, directly (eg in vehicles), or through conversion to conventional vectors such as diesel fuel or natural gas, or in peak load power generation (accepting the energy loss in reconversion),

Negative features constraining its utility include its low energy density and hence, combined with high liquefaction costs, higher costs of transportation and storage, relatively high costs of electricity (other than when based on cheap surplus or off-peak power) if this is the main form of production, combined with a further loss of energy efficiency in conversion and re-conversion.

The biggest strategic questions for a hydrogen economy, at least in terms of future organisation and regulation, are perhaps the extent to which production should be large scale, to exploit economies of scale, or local to minimise the high costs of transporting hydrogen, and to avoid the need for a new network. If the main forms of production depend on carbon capture then proximity to a new CCS CO2 gathering network may be an important constraint. The following is one prima facie plausible set of answers, although without fuller examination, it must be seen as tentative.

Unless production economies of scale, or the constraints imposed by new CCS networks, dictate otherwise, its low energy density and high liquefaction costs predispose against tanker delivery for retailing to owners of hydrogen vehicles. Some other potential applications – conversion to diesel and power generation - are mostly compatible with relatively large scale production facilities, and do not obviously require a large piped transmission network. Retail requirements for

[30] The October 2015 E4Tech report for the CCC, *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets.* This report also tries to explore some of the preconditions for hydrogen development. We have already noted that its assumptions differ from the ETI scenarios. This paper remains neutral on these differences.

hydrogen vehicles or small scale back-up generation facilities might also be managed by decentralised production, possibly within much smaller local networks. There may therefore be a potential presumption against a new large scale hydrogen network, although this is not excluded in the E4tech analysis[31]. Hydrogen might "move by wire" (pre-production from primary electricity), but otherwise only after conversion to fuel such as gas or diesel, with established means of distribution.

If this presumption is broadly correct, a hydrogen economy does not of itself create any new natural monopolies for the economy as a whole, and is potentially a naturally competitive part of the energy sector, creating few new regulatory problems (beyond the mandatory health and safety issues of any new energy technology).

In this eventuality interaction with the power sector will be indirect and hydrogen production, power generation and storage can be treated, conceptually at least, on the same basis as other industries, and other means of generation or indeed forms of consumption. Clearly siting and other issues might predispose towards the integration of hydrogen production, storage and reconversion, and generation needs set out by the CPA would be a major influence on the overall development of the hydrogen sector. But even though hydrogen production and re-conversion to power might be a valuable grid facility, it would not necessarily be owned by the grid. Any hydrogen production reliant on electricity might use its own on-site renewables, and some production might go to uses other than back-up generation.

For decentralised production, it would be open to the producers to negotiate for off-peak or surplus power for production, and again there might be a degree of integration with decentralised energy and electricity networks.

In strategic terms this suggests that a developing hydrogen economy will not necessarily require a new physical infrastructure of pipes as a transmission network for hydrogen, and that there may be numerous options for combining production and reconversion or retailing within a single site. If this is correct then hydrogen will not necessarily pose some of the issues identified earlier for fixed infrastructure investment in power and heat. Options might be kept open by siting hydrogen facilities at preferred locations on the main HV network, minimising transmission losses and maximising the benefit of use in back-up or ancillary services. Additionally they could be close to suitable gas network connections, or to a CCS pipe network, should it be developed.

5.3 Carbon capture and storage (CCS)

The largest single issue for CCS appears to be the difficulty of establishing pilot schemes and building commercial momentum.[32] In part this reflects some of the obvious "market failures" identified earlier, including the absence of a carbon price that would prima facie support such an investment in an environment where wholesale prices, when not depressed by low carbon plant, are still set by fossil plant that does not carry any CCS cost. But inertia is probably compounded by the fact that it represents sets of expertise that straddle two very different industries, with

[31] Op cit. *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets.* October 2015

[32] A problem accentuated by recent decisions to cut support for CCS developments.

pumping and deep sea storage a natural role for the oil industry but not for owners and operators of conventional thermal generation.

So the question becomes that of who should or might take ownership of initial (and subsequent) CCS projects and provide a “kick start” for the technology. If a strong enough case to support CCS could be made to government, then the CPA mandate could include a responsibility to enable CCS development and invite tenders for a minimum quota of CCS generation. This would not necessarily require a Treasury subsidy, since, as with some other low carbon sources, costs would otherwise inevitably pass through to consumer prices.

The new questions in this instance relate first to the development and financing of any new gas gathering pipe or networks of pipes for CO_2 collection, and for the movement of gas to onshore or offshore storage facilities. Since most of the latter will be associated with older oil or gas fields, there may be opportunities to share or take over facilities previously operated by the oil companies.

Important matters to resolve will include the following: ownership rights over the storage and associated facilities and possible economic rents arising from these, the planning and financing of a gas gathering network to service the needs of multiple power generation facilities operating in CCS mode, and possible constraints on power plant operation and CO_2 transmission imposed either by the characteristics of carbon capture as a chemical process or by the need to operate the injection into storage facilities in particular ways.

The financing issue for a CCS gas gathering network is particularly intense. It requires construction of a fixed asset with no other obvious use beyond allowing the operation of CCS electricity generation further upstream. So if it is not owned collectively by the CCS generators, it will require secure long term guarantees from those generators to provide a revenue stream, over many decades, to pay for the investment. Those generators, in turn, cannot provide that guarantee, unless they have an equivalent guarantee that their output will earn a long term revenue stream, to meet not only their generation costs but to pay for the CCS network. So the future of the CCS gas gathering network depends, ultimately, on the ability of the CPA to provide the necessary assurances. This reinforces the argument for a strategic body in the power sector with the ability to offer long term financial commitment.

It also exemplifies the need for coordination in planning the physical investments, as with the coordination of transmission line planning, which is also inter-dependent with the location of new generation assets. The question here is who would or should undertake this coordinating role in developing CCS. It is likely that initiatives would in the first instance come from the CPA, making a strategic choice to develop CCS. Early CCS generation would be concentrated in a few sites close to preferred storage locations, and network issues might be relatively unimportant. But it would seem prudent to put in place a legal, regulatory and licensing framework to anticipate some of the planning, ownership and access issues that could arise.

The coordinating role could be another responsibility for the National Grid and/or CPA who already cover the power system, but the arguments are not convincing as these are essentially separate networks, with issues that are also largely separable.

Regulation of the gas gathering network should be relatively straightforward. One option would be a small specialist team, as part of the much larger sector regulator OFGEM. But since there is no obvious need for conventional price regulation or consumer protection, there is no strong case for this. Regulation could be in the hands of a small specialist body which would also deal with any specialised health and public safety issues. The other possibility is that of a CCS network jointly owned and managed by CCS generators, self-regulating or regulated by contract.

5.4 Gas distribution as back up

One of the issues raised in the ETI scenarios is the question of how to manage a gas system in which gas, distributed through national and local pipe networks, is no longer the primary source of domestic or commercial space heating, but is still required as a back-up to cope with winter seasonal peaks, or eventualities such as a prolonged shortage of renewables output. This requirement is amplified by the particular features of air-source heat pumps, whose coefficient of performance deteriorates when the external temperature falls. The main policy interaction with the electricity sector, in this context, is the relationship between gas back-up requirements, and the nature of electricity use for heating. This in turn may depend on the standard of security and capacity adequacy for the latter.

The key economic issues here are around tariffs. One question is the economic viability of a very substantial gas grid, when future consumption will be very small. The gas distribution network is at serious risk of becoming a stranded asset. A second is that the distribution costs (ie the costs of the pipes) already amount to a high proportion of the charge to consumers. At present that cost is recovered through tariff charges that are largely averaged over total units of energy consumption (expressed as cubic metres of gas or kWh equivalent), perhaps with a small standing charge. But continuing that tariff design has some problems. It exposes the gas distribution business to massive volatility in its revenues. It also exposes consumers to a corresponding volatility in their outgoings.

The most satisfactory solution to this issue is twofold. First, part of the solution may be acceptance of much smaller and concentrated gas networks, with gas available only to major centres of population, or perhaps other areas fortuitously contiguous to a main pipeline. More remote areas with low population density would be provided either with an alternative back-up or could even be given the opportunity to purchase priority allocations of power in the event of a shortfall in generation.

Second, the basis for tariff charges for gas supply would be much more strongly oriented towards fixed charges. This would stabilise both consumer payments and utility income. The fixed charges themselves might be differentiated according to location to be more cost reflective and reduce urban to rural subsidy. They might also be differentiated, for example, by size of dwelling or actual peak usage, not least for reasons of equity and to avoid a regressive tariff structure that excessively penalised the poorest.

There is a further general reason for looking very careful at charging structures. It is to make them sufficiently cost reflective so that when consumers make choices it is on a basis of true reflection of the total costs that those choices imply. Network charges will increasingly be a major component of that.

These ideas pose some serious challenges to current orthodoxies on the regulation of the sector, for example in terms of non-discrimination in charging, and also raise questions about how consumers might respond. For example, faced with a fixed charge some consumers might opt either to install their own alternative form of back-up, eg though local heat storage; this would generally be easier in more rural and wealthier areas. Or they might prefer to dispense with back-up altogether. In either case their decision would further undermine the economic viability of the local gas network. A different question, under certain conditions, is therefore whether gas connection should in some areas be compulsory.

None of these challenges are obviously insoluble, but they will raise quite complex questions, for which the above are simply an introduction.

5.5 Petrol/ diesel distribution networks

Under some scenarios for electric vehicles, there will be very substantial reductions in consumption of the current major transport fuels, petrol and diesel, essentially reduced to a back-up role for plug-in hybrids, or a small number of traditional vehicles. In some respects this might seem analogous to the potential problem of stranded assets in gas distribution, but in most respects it is quite different.

Most importantly there is no real equivalent of pipes or wires, long-lived fixed assets with high installation costs that have no alternative use. It is not a monopoly activity and the investments were made voluntarily in a competitive market So many of the obvious network infrastructure questions do not really apply, and it is hard to see why smaller sales of these fuels should justify treatment different from that of any other goods dependent on a distribution network. The much lower volumes may well imply higher costs per gallon, and like other products these may be higher in rural areas, but this would be in a context of much lower total expenditure by consumers on these fuels.

Since this will most likely continue to be a competitive market it seems unlikely that this would create new regulatory, operating or commercial problems, or the need for significant new investment. It is unlikely to require formal regulation, although the shrinkage in demand is obviously a commercial issue for the energy companies engaged in these markets. It is also possible that the number of refineries and companies engaged in distribution might shrink dramatically, but in this case any resulting problems would fall within the scope of the competition authorities, just as would happen now. There is no obvious public policy case for compensating the companies for stranded assets.

5.6 Biomass generation

The primary role of biomass, although not the only possible role, is defined in the ETI scenarios as a primary fuel for power generation. So to a large degree its interactions will be with the power sector. Combined with CCS it provides a negative carbon opportunity. Unlike conventional fossil generation it may well be viewed as primarily fuel supply constrained rather than MW capacity constrained.

In order to maintain lower cost CCS options, there is clearly a strong economic case for biomass generation to be in proximity to other CCS plant. This sits easily with an initially small CCS gas gathering network, unless other factors and cost calculations necessitate smaller units at locations closer to the biomass source.

Biomass does not prima facie pose distinctive problems at the investment stage, over and above the general problems discussed earlier. In relation to system operation, its most significant characteristic may sometimes be limited supply in relation to MW capacity. In this respect it simply poses a timing question for the SO, ie how quickly should a limited supply be depleted in response to load balancing or peak security needs. It is just one of the facets of low carbon generation technologies that do not fit neatly into the merit order model.

5.7 The transport sector. Electric or hydrogen vehicles.

A useful anecdotal example from Norway, where 23% of new car sales are for electric vehicles, is the incidence of peak loads at weekends. Even though EVs, mostly all-electric rather than hybrids, are still only 2.5% of the total vehicle fleet, concentrated load is starting to pose problems. Many Norwegians drive to their country retreats at weekends and on arrival seek to re-charge their vehicles. Since a Tesla can require a charge of around 75 kWh, or about a full week of typical household consumption, its delivery over a few hours has the potential to constitute a major and problematic peak load even at national level. As there are also high geographic concentrations, this has major implications for reinforcement of local networks. This immediately poses questions for the local as well as national management of such loads. Is the answer to attempt to meet demand by banks of local batteries, to sell the right to this kind of service at a premium price, to ration demand by local peak charges, or to organise pre-booking of charging slots?

Since transport is such a premium use of fossil fuel, currently highly taxed, the cost and affordability implications of these problems may seem less important than the practicalities of transition. It may therefore be worth considering how future transport demand might be shaped. It is immediately evident that the shape of the future motor industry will not be determined nationally, but in international and global markets.

However if, as now seems likely, we can foresee a future that includes widespread adoption of both battery and hydrogen vehicles, the commercial behaviour of the power sector, particularly in the nature of the recharging and refuelling services on offer to consumers, and their prices, will play a big role in influencing consumer choice and hence in shaping the mix of vehicles within the UK.

The CPA is likely to have a role in this process, not least because it will need to take into account the transport sector as a further substantial source of future consumer load. It is likely that the evolution of this sub-sector will be largely market driven but the balance between hydrogen and battery vehicles, and the between, for example all-electric and hybrids will be strongly influenced by the way in which electricity network infrastructure is developed, both nationally and locally, and the way in which such services are priced. For economic efficiency, and to avoid perverse outcomes, this needs to be strongly cost reflective.

6. SUMMARY AND CONCLUSIONS.

Policy priorities and particular features of low carbon technologies combine with the fundamental features of infrastructure investment as driving forces for major changes in organisation and governance – and a "system architecture" – across the energy sector. This will transform how energy markets can and should work in the future. The following list attempts to summarise and list both general principles and specific suggestions arising from the analysis in the preceding chapters.

<u>General principles and observations</u>

- Any strategy associated with the developments envisaged by ETI requires attention to well understood issues of infrastructure investment, but also to shaping the treatment of operational considerations and the consumer interface (allocative efficiency).
- The analysis identifies numerous complex coordination questions. The choice between market and regulatory/ interventionist answers is a pragmatic one, driven by the essential characteristics of each sub-sector and the nature of potential market failures.
- Analysis confirms the core role of electricity in shaping low carbon futures.
- Consistent with this, organisations within the power sector can play a significant role in shaping pathways consistent with the ETI scenarios, particularly in relation to CCS, the heat sector, transport fuel and hydrogen.
- Carbon pricing may be a transitional issue, but even if imperfect can play an important medium term role, not least in incentivising low carbon operation of the existing plant stock, and limiting the "rebound effect" on energy efficiency.
- Carbon pricing, and pricing principles generally, should be consistent across vectors, both in framing policies and in application.
- There is a general infrastructure investment problem, which tends to create a bigger role for some combination of long term contracts, vertically integrated monopoly (with regulation) and government guarantee. Recognition of this is implicit in much of recent policy. It needs to be more explicit and less ad hoc, and to be reflected in the institutional architecture of the sector as a whole.
- Satisfactory resolution of the infrastructure investment problem is of critical importance to financing investment with a reasonable cost of capital. Cost of capital is of fundamental importance both in determining strategic choices and for future affordability in the energy sector.
- It will be sensible to seek consistency in investment conditions across the sub-sectors, including investments made by municipal or local authorities, with comparable costs of capital for comparable investment opportunities.
- Opening and maintaining options ought to be an important element of strategy, given the many technological and other uncertainties.

- Analysis of the sectors into which electricity is expected to penetrate, heating and transport, suggests that there are also significant sequencing issues, to ensure that infrastructure and consumer decisions can move together.
- Network pricing will play an important enabling and shaping role in the future, and needs substantial re-examination to be more cost reflective, with much less cost averaging and possibly more location specific charges.

Power sector specific

- As well as general infrastructure investment problems, the power sector has some specific problems in relation to wholesale markets and retail supply.
- The need for new system architecture, and possibly a "system architect", is now widely recognised.
- Current energy wholesale markets based around merit order operation are unlikely to remain fit for purpose and will need major reform or replacement. Wholesale markets are likely to give way increasingly to central dispatch optimised by one or more system operators (SOs). SOs will optimise on the basis of technical and other parameters set down in the contracts.
- Long term contracts, with secure counterparties or government guarantees, are likely to be a major feature for most new capacity. Contracts (PPAs) should allocate risks according to ability to manage them, and incentive structures, market based where possible, should correspond to this.
- A central purchasing agency (CPA) for the power sector is suggested as one route to resolution of the major investment and operational challenges for the power sector.
- Underwriting the long term financial strength of a CPA, either directly or through the regulatory structure, provides a strong base for financing infrastructure investment. Some form of long term support or guarantee for such investment will be necessary.
- The National Grid is one natural contender for the CPA function which it might in principle combine with its existing functions as system and transmission operator, although these functions could also be separated.
- A CPA would coordinate generation, transmission and storage investment. It could also play an important role in the implementation of specific policies for the power, such as "kick starting" CCS, and in shaping the pace and content of electricity penetration in heat and transport.
- The CPA will sell to supply companies who will in turn sell to retail consumers. The supply companies will act as aggregators, offer innovative ways to buy electricity services, and contract for future supplies with the CPA.
- The CPA will also offer bulk supply and purchase tariffs, but most of its transactions for sale of power will also be on the basis of individually negotiated contracts.
- Suppliers will have as their main function to aggregate service agreements that they have with their customers. Suppliers will contract with the CPA, responding to price and other terms on offer, and shaping their loads to converge with system balancing needs.

- They will also have a de facto responsibility for working with local distribution companies and to keep consumer loads within any LV network constraints.
- A key proposal is to improve competition and innovation in the supply function. The "consumer offering", ie how consumers buy electricity, will change a lot, reflecting advances in metering and control technologies.
- Consumers will have the ability to buy different services, eg for purposes such as storage heating or battery charging, from different suppliers.
- Concepts of security need to be redefined, and will not necessarily be identical across all usages, even for an individual consumer. In principle it may be possible to choose between alternative levels of security and back-up even for particular applications such as heating.
- Network charges will be an important element in the functioning of the sector, and will need substantial, possibly controversial, re-design and rebalancing.

<u>Heat networks and the heat sector</u>

- It is useful to distinguish the areas of collective choice (district heat) and individual choice. Both present distinctive practical and strategic questions.
- Scale is a critical factor for heat networks, so near universal participation may be essential to the viability of city wide schemes; the paper offers a number of suggestions to help this process and overcome consumer inertia and reluctance, especially in retro-fitting.
- There is also a case for rolling out heat network programmes in tandem with programmes to retrofit the building stock for higher energy efficiency, since these programmes face some of the same consumer acceptance issues.
- There is a case for a Heat Networks Authority (HNA) or a Heat Authority to enable, promote and coordinate development of large city-wide schemes and other components of a low carbon heat target. It may be possible to associate this with some existing institutions and trade associations, but the HNA does not need to have direct commercial or operational responsibilities.
- An initial task for the HNA is to identify the most promising locations and cities in which to promote heat networks, taking into account densities and other social and geographical factors
- Real time central optimisation of power and heat sector operations is not recommended. The complex trade-offs between heat and power should be managed through contracts that CHP operators negotiate with the CPA.
- Generation and heat facilities will generally need to be under separate ownership, and this is compatible with private sector ownership and management of facilities. CHP scheme priorities will be for heat.
- As elsewhere contractual arrangements or equivalent measures will be needed to underwrite the long term nature of the investments. Government may need to underwrite construction and other risks on early projects, but with the intention that these are or rapidly become self-financing.
- Heat networks will operate as de facto local monopolies, requiring formal regulation, perhaps under OFGEM, and at least for larger schemes.
- Outside the large city schemes, there will be scope for local initiatives, and less obvious need for national support from a HNA.

- General issues for heat include its relation to the power network (for CHP), and electricity and gas network and back-up charges. This is particularly important with respect to consumer choice. Network charges and other tariffs applicable to competing heating options are critical to avoiding perverse incentives for consumers. In particular they need to be fully cost-reflective in respect of back-up and additional network costs.
- Some thought needs to be given to sequencing and forecasting issues for take-up of heat sector products such as storage heaters and heat pumps to make sure these are consistent with the rate of development.
- Local LV distribution constraints and policies affecting these heating options may feature much more highly than they have done historically.
- Low cost seasonal scale heat storage, if feasible, would be a game changer, and open up many more options across the energy sector as a whole.

Hydrogen and Transport

- The lesser nature of scale economies in production mean that a hydrogen economy will not necessarily need an extensive pipe network. If so it does not create any large new "natural monopoly" network or new regulatory problems.
- Given the different modes of production and use for hydrogen, current uncertainties over its preferred role, and the possible need for future flexibility, there are strong arguments for as much private sector and competitive market reliance as possible in this sector, at least after the innovation stage.
- The CPA, and the power sector generally, are nevertheless likely to have an important role in shaping future pathways that accommodate or rely on hydrogen based technologies.
- The motor industry is a global industry and developments will not be influenced significantly by policies adopted within the UK
- Development of power sector infrastructure, including at the local level, will however shape and possibly constrain UK consumer choices for low carbon transport, including choices between battery and hydrogen vehicles.
- As with heat, local LV distribution constraints and may turn out to be a very significant factor for transport options.
- Policy may therefore need to address sequencing issues, with infrastructure development of the power sector pursued in harmony with the penetration of electricity into new markets.

Gas Distribution Network

- Falls in gas volumes may require the gas distribution network to shrink, and to provide back-up only in large concentrations of population.
- Key factors in terms of allocative efficiency in this context will again be the structure of network charges for both gas and electricity (as substitutes).

Distribution of other road fuels

- Falling volumes do not establish an argument to create new regulatory, operating or coordination structures. The main issues are simply commercial questions for the companies. This is a sector that operates in a competitive market for a well established product, and should continue to operate without additional regulation or public support. The main sources of market failure in other sub-sectors – real time coordination, innovation, new infrastructure investment, etc - are absent here.

<u>Some general issues for regulation and governance.</u>

There are important corollaries for regulation and governance, and for the duties and obligations placed on distribution companies (and on suppliers and the CPA).

- A low carbon power sector, and the development of control technologies, will end any residual “predict and provide” approaches to utility operation in the power sector. Suppliers will provide a range of different “services” on different terms, with different standards of security on offer. To an increasing extent the level of security consumers want will be determined in a market. There will in consequence be new challenges for regulating “quality of supply”.
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- More discrimination between consumers will develop, with network prices and availability of service for particular applications more differentiated by geography. This will be so for power, but also in different forms for heat and gas supplies. Notions of universal service obligations will largely disappear.

- Most of the current structure for price regulation of the network elements of the energy sector will remain essentially unchanged, although it will obviously need to develop to reflect the changing nature of the sector and different cost issues. There will in this respect be substantial continuity.

- A significant issue less fully covered in general discussion above is that of general purchase tariffs, beyond those currently on offer as inducement to particular renewable technologies. Basing these on avoidable costs is logical, but often appears to discriminate against small supplies. Historically this has been a power sector issue, but in principle could occur elsewhere, eg in gas.

- Other substantive regulation issues will be about performance in relation to low carbon objectives, quality of service and “fairness” in treating consumers and suppliers, especially small independent suppliers.

- Economic regulation will also address competition issues, relating both to discrimination between consumers and conduct of tendering procedures.

- We should view the Committee on Climate Change as an essential part of system architecture for the power sector. With or without a formal role it will need to review regularly progress in power, heat and transport as part of its existing remit of monitoring progress towards low carbon targets.

ANNEX 1. COST OF CAPITAL.

It is worth reiterating some of the principles of capital theory as commonly deployed. The conventional CAPM model equates the cost of capital (CoC) to a risk-free rate plus a risk premium. In this context CAPM ignores project specific risk and defines a "beta" risk premium in terms of correlation with the movement of the market as a whole. Since investments in mitigating or adapting to climate change can be deemed to be essential there is no reason to suppose any market correlation. As with public utilities, which also have a very low correlation with the market, and hence a low beta and cost of capital, the CoC should be close to the risk-free rate.

The discrepancy arises from confusions between how to treat risks attaching to construction and commissioning, often of untested technologies with difficult site conditions, which are likely to be high but project specific, on the one hand, and how to treat the risk to the value of the investment once in place. In a regulated context the latter should be very low.

The answer is financing structures that separate these two dimensions of risk. Risk in the pre-commissioning phase may well need what appears as a high return, not least to allow for contingencies and appraisal optimism, and this will be reflected in the capital value at the commissioning. The return on that capital, however, needs to be much closer to the risk-free rate and, on the assumption that regulatory and policy risks can be eliminated, will be much closer to the social cost of capital used in policy appraisals.

Some major infrastructure projects in recent years[33] have not been managed or financed in a way that accurately reflects what should be the very low risk of utility-type activities, and achieving a low cost of capital from the point of delivery should be an important objective. Given that energy projects may be financed by a variety of parties, national, municipal and private sector, one objective should be to try to ensure a degree of consistency across the board in terms of risk exposure and the cost of capital, and the return on capital available to investors. Aiming at consistency in decision making and choice across vectors, as with consistency in CO_2 valuation, ought to extend to access to financing and the resulting cost of capital.

However, the biggest source of risk for potential investors remains that of policy and regulatory uncertainty. The cost of this risk is borne by consumers, under any market or regulatory structure; if imposed on investors it will be reflected, if investment is forthcoming at all, in a much higher cost of capital. As this risk sits almost entirely within the control of governments and regulators, its imposition on infrastructure investors is entirely self-defeating in terms of efficiency or value for money.

Analogies. Pension funds, who diversify "contract specific" risk across millions of individuals, are often required to value future liabilities at a risk-free rate ie government bonds. Similar practice is often applied to nuclear liabilities, which are not discounted at 10% over a 100 years. The reason in each case is that the liabilities are certain rather than market correlated risks.

[33] In June 2009 the National Audit Office estimated that failure of the Metronet PPP contract cost the taxpayer up to £410m. The project delivered high private sector returns even though the risks remained in the public sector.

ANNEX 2. MERIT ORDER, WHOLESALE MARKETS, AND SYSTEM OPERATIONS IN LOW CARBON SYSTEMS

Optimisation. As well as ensuring the technical integrity of the system, we need to consider the market processes that should optimise the use of a ***current stock*** of generation assets, so that electricity is generated at least cost. This is conventionally described as ranking plant in ascending order of short run marginal cost (SRMC), or simple stacking by fuel cost, and then calling on plant to operate in order of merit. In a "command and control" framework this is known as merit order operation; we could equally describe it as a short term "supply curve" for generation. In a market context this assigns a primary function to prices in optimising system operation, although wholesale market prices are also often seen as important signals for investment.

The merit order is therefore replaced in liberalised markets, eg the UK, by wholesale markets which, in principle at least, replicate (more or less) exactly what would happen in a perfect but centrally calculated optimal dispatch of plant. This happens when price is set equal to "system marginal cost" (SMC); this is the price that is just high enough to provide an incentive to generate for the highest SRMC plant required to meet the actual load on the system. In principle the SRMC of each individual plant is "discovered" through processes[34] which encourage plant operators to reveal their true SRMC in their bidding; this is the intention in setting a wholesale price equal to SMC, the highest SRMC, and allowing each generator to profit from the resulting margin. Wholesale market price, in principle, performs exactly the function that we should expect in promoting efficient production. It provides an incentive to generate for everyone whose marginal cost is less than the market price, and conversely discourages any generation if SRMC is above the market price.

The concept was developed in contexts with limited demand side response, and an objective to allow least cost satisfaction of whatever demand consumers chose to place on the system. But the principle extends easily to the demand side, as consumer needs can be similarly expressed as willingness to pay a certain price in each period and bid in their requirements accordingly (the "demand curve").

The central characteristic of conventional wholesale markets built around an SRMC-based price is that the "market" price drives an optimal dispatch of plant, and conversely a theoretically optimum dispatch based on merit order based can be used to determine a price equal to SRMC. Market prices for different periods can in principle be determined independently without considering possible linkages. Note that this is not just a matter of optimisation per se. It provides a rational basis for wholesale price formation in a pool based system, and for balancing charges under bilateral trading. Serious deviations from merit order in choice of plant that actually generates would be a negative indicator of the health of the market.

At a theoretical level, the validity of this model depends on the simplifying assumptions that (fossil) plant is wholly flexible, and that each period can be

[34] In the 1990 Pool this took the form of, in principle, cost reflective bids and payment at system SRMC. Modifications under BETTA to bilateral trading and a "balancing price" are generally regarded as consistent with the same theoretical underpinning, although the transparency of the wholesale price is reduced.

considered independent of all past and future periods. Although not wholly correct even for fossil plant, this is considered a good enough approximation to the truth for most current fossil-based systems. The very simple algorithm of a merit order automatically promotes a price consistent with least cost dispatch. Stochastic factors, inflexibilities and storage options are ignored within the conceptual framework of conventional market models, or are treated as exceptions.

<u>The future in low carbon electricity sectors.</u> The link between efficient market prices and system marginal cost provides an illustration of how a real market works to replicate exactly the result of the decisions that would be made by a theoretical central planner who was both benevolent and had perfect information. Defining the conditions for this replication to works is of great interest to economists, not least since it helps to define possible market failures. There is an extensive general literature, but we can try to explain why it has appeared to work so well for merit order operation, and consider whether the same conditions will apply in the future.

The essential assumptions of merit order optimisation in fossil based systems are:

- that each optimisation or price setting period, can be considered to be independent of all past and future periods.
- that the only relevant costs in deciding whether to generate from a particular plant in that period are its short term operating costs, essentially fuel costs.
- that those costs vary continuously and are linear in relation to level of output.

In reality it is well known that these assumptions are not strictly accurate even for fossil plant. In many US systems much more sophisticated cost structures are accommodated, but the many caveats are recognised not to make much difference to outcomes, and the assumptions above are a sufficiently close approximation to the truth to allow our explanation above to hold water. Moreover non-fossil plant has hitherto been either sufficiently small scale or intra-marginal to a point where it does not have any practical impact on the merit order principle. That is changing.

Treating the theory in a rather simplified way, one of the necessary conditions for the theorem that "decentralised prices can replicate perfect central planning" [35] to hold is that the set of feasible "solutions" represents, in mathematical terms, a convex set. In a linear programming formulation[36], this allows, inter alia, the conclusion that a binding constraint has a unique "dual" value which corresponds to a market price that has been "discovered" in a functioning market. The merit order is essentially a very simple example of a linear programme, with the main binding constraint being that current demand must be satisfied. In more complex optimisations the problem solves for multiple constraints; convexity of the set of feasible solutions, linear constraints and the absence of indivisibilities are conditions that guarantee a linear programming solution.

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[35] The meaning of this statement is generally taken to be ***either*** that a set of "shadow prices" can be issued which will give rise to the optimal outcome as local agents respond to the price signal, ***or*** that the market can and will discover these prices for itself.

[36] There are more general formulations, in terms of the Kuhn-Tucker theorem or Kuhn-Tucker conditions

What can be indicated very briefly here is that the previous satisfaction of these conditions has been very dependent on the particular and comparatively simple characteristics of fossil fuel plant, and on the nature of systems without either the benefit of extensive storage capability or the constraints of generating plant with complex operational characteristics and/or non-linear (short run) cost structures. If we are progressing to a world which is based primarily around other types of plant, and also embodies both actual storage and storage-type characteristics on the demand side, then the following complicating factors will need to be taken into account in calculating the optimum efficient scheduling and dispatch of plant.

- Some plant will have very complex constraints and cost structures. These include "must run" characteristics for plant that is genuinely inflexible. Nuclear, for example, is or can be capable of load following, but much less so than fossil plant, and typically with a much higher cost penalty. There appear to be similar issues with CCS, depending on whether it is pre- or post-combustion, and the nature of the associated chemical processes required for carbon capture.

- Demand side innovations are likely to lead to situations where operational decisions have to be taken on the basis that they need to ensure particular consumer demands are met, not necessarily in real time or a given half hour, but over a significantly longer and well-defined period required by individual consumers and their particular needs. Potentially or actually, this applies for example to loads for water or storage heating, or for battery charging. So some demand can be postponed, at least for a few hours, but possibly much longer. This provides the equivalent of storage capacity on the supply side.

- Similar storage options, such as large scale pumped storage, batteries, or thermal storage, will also grow in importance on the supply side.

- Some plant, notably wind, has an essentially stochastic character, even with improved weather forecasting, and this too needs to be embodied in the operational decisions to instantaneously balance supply and demand.

Some of these new constraints, inter-temporal considerations, stochastic elements and non-linearities, may well be capable of expression in a form that remains consistent with convex solution sets, but others clearly will not. [37]

These considerations are an obstacle to the continued operation of conventional wholesale markets that are separate from but additional to the problem of zero SRMC in energy only markets. Taken together they provide a powerful case for fundamental reform.

[37] Non-convexity arises in a great many situations, the simplest examples being economies of scale, "either ... or ..." situations, and conditionalities such as "this ... only if that".

ANNEX 3. HOW WOULD A CENTRAL PROCUREMENT AGENCY WORK?

The idea of central procurement in power is as follows. The agency buys generator output and sells on to other parties. These include large individual consumers, but will also include companies that purchase power in order to re-sell to smaller retail consumers. The agency does not itself own or operate generating plant.

It is possible to envisage such a procurement agency being created through more than one route. The simplest path is its creation by government as an agency charged with the general task of managing the power sector's generating capacity, and also ensuring that the low carbon objectives for the sector are met.

A second alternative, not discussed here, would be to mandate the existing supply companies, collectively, to meet specified carbon intensity targets. The companies would, subject to relaxation of competition rules, be likely to seek a coordinated approach to finding the means to meet individual and collective targets.

There are alternative ways to set up such a central procurement function more directly and without assuming it to be a result of mandating intensity targets.

<u>Establishing the procurement function in a new or existing agency</u>

The main choices are: a government department (DECC), the energy regulator (OFGEM), a new agency, or National Grid.

We should dismiss the idea of the agency as a government department. This option would provide neither the expertise nor the independence required, and expose important issues of technology choice and portfolio balancing to short term political whims and influences. Nor is the energy regulator, despite its sector expertise, a credible option, since regulation should be separate from management of the sector.

A new entity, as an "arms length" public body or a new private company regulated on a "cost of service" basis, is possible, but it would need to create or re-create a very substantial sector expertise from scratch.

The preferred alternative would be National Grid. It already has a substantial body of sector expertise. Coordination with system operation and transmission planning and operation within a single organisation would be straightforward, and this would avoid creating a new public sector body. It would also simplify commercial relationships, since a single body could then be responsible for procurement and contracts, operational decisions, and buying and selling of power on a day to day basis. This alternative is assumed, for simplicity, in the following sections, but it may be noted that more complex unbundled structures are also possible.

<u>On what basis does the CPA buy and sell?</u>

This could and probably should include a combination of contracts and published tariffs (inter alia providing a default position) for both buying and selling.

The CPA remit would be to take ultimate responsibility for provision of sufficient capacity to maintain a national power system, using a balanced and hence more robust mix of capacity types, and to meet carbon-reduction targets laid down by governments, all to be done in a cost effective manner. It would contract with all generation connected to the HV network, including all the main generation types – nuclear, fossil with CCS, large scale and remote renewables, and residual fossil plant required during transition to very low or zero carbon power sector. This would typically be on the basis of long term contracts specifying in some detail both payments for capacity and output, with appropriate incentives, and the basis on which the plant could be scheduled and dispatched by the SO.

The CPA remit would also need to take into account the potential for substantial growth in more decentralised arrangements for the power sector, including technical and commercial interaction with essentially independent parts of the system, where the main function of the grid is to provide both back-up in periods of local power deficit and the means to dispose of surplus most economically.

The CPA would therefore need to deal wholesale with a number of different types of buyer and seller. These could include local entities which were entirely integrated as between production, distribution (wires) and supply. They would include retail supply businesses, as currently understood, although these would tend to have fewer direct links with generators, and there would be less incentive for vertical integration. They could also include very large industrial consumers, mainly connected to the HV network. There would be significant interfaces with other parts of the energy sector, including combined heat power, gas networks, district heating and hydrogen facilities. Finally the CPA would be responsible for transactions across inter-connectors, governed by the relevant contract terms or international protocols.

Power purchase agreements (PPAs) with HV connected generators would generally be on a long term basis, although transitional period arrangements, required to keep open some non-CCS fossil plant, could be for shorter periods. These PPAs would provide the basic underpinning for the system as a whole. Purchase and selling agreements with the other categories might also be long term, but generally might be expected to be for shorter periods and subject to more frequent adjustment and renegotiation. Power purchase agreements would be defined with a view to enabling the SO to call on generation as required to meet demand. Contracts for the sale of power to suppliers would be defined to assist in shaping demand, ie the load curve, to enable supply/demand balance.

The larger part of all transactions would probably take place under contracts, but bulk tariffs for both purchase and sale would be in place as a default, and as a market signal of the current value of output at different times. The default bulk supply tariff for purchase would be constructed around the principle of pricing at avoidable cost, while the tariff for sales would need to cover the cost of providing capacity back-up. Generally parties transacting with the CPA would be able to secure a more favourable deal under contractual terms, but in exchange for offering greater certainty or ceding greater control over their output and/or taking of power.

This broad spectrum of arrangements, taken together with the future need for retailing suppliers to help shape consumer load and act as aggregators, should allow the CPA to shape the overall future of a low carbon system, and to meet the various challenges involved in balancing production, consumer loads and storage.

One intention of this structure is to ensure that the CPA does not automatically establish an outright monopoly position as a buyer of generation, especially decentralised generation. This could be reinforced by requiring a different agency, eg the Committee on Climate Change, to produce the forecasts of future load and future decentralised contributions on which the CPA would make and justify its plans.

Another possible variant is that the CPA would operate on the basis of procuring the necessary level of capacity to meet long term contracts placed by a number of dominant supply businesses, each with a secure revenue base. This option is not pursued here, not least because it could inhibit competition further downstream, where there is a clear need for more effective competition and genuine innovation.

Tendering Processes

This is potentially a controversial subject because it is sometimes assumed that tendering processes can be made technologically neutral. This is fairly obviously not so, since different types of generation have very different technical and operating characteristics, and a power system will require a carefully balanced mix.

To this problem can be added the very limited number of competitors and choices in certain technologies, notably nuclear and CCS, the economies from scale and scope, benefits of progression beyond “first of a kind”, and the many other complexities of tendering and awarding contracts for large engineering projects.

The CPA might however be subject to a number of normal requirements to seek out the best providers, to avoid undue discrimination (eg under EU Law governing public projects) and could to some degree be monitored and regulated in this respect.

Concern is often expressed that a single buyer such as the CPA would get tied in with well-established technology options, and that this would limit innovation, competition and the potential for new technologies. However generation technology is an international market, with very few barriers. It has in recent years seen massive innovation in low carbon technologies driving down capital costs and driving up performance substantially. Innovation is not primarily dependent on the structure of the power sector in one country.

Power purchase agreements with generators. Structures and principles.

The relevant economic principles for contract formation can be very simply stated. First, risks should be divided so that each risk rests with the party best able to “manage” or control that risk; that party then has the incentive to manage it effectively; incentives may be implicit or they may be the subject of explicit incentive arrangements in the contract. Second, the payment structure should be consistent with encouraging the most efficient use of resources. In particular, from the perspective of system operation, it means that the contract should be consistent with the SO being able to "call the contract" in the way that minimises overall cost. This may mean dispatch of plant in merit order, but is more likely to depend increasingly on more complex calculations. Third, performance incentives and penalties are geared to the market price or economic value of output or service provided.

These principles have to be applied to the actual cost structures and technical characteristics of generation plant. For fossil plant this is usually, in simplified form, a large fixed capital cost component associated with construction, expressed as a value per GW, MW or kW of capacity and a large fuel cost which varies directly with output and is expressed as a value per GWh, MWh or kWh. For low carbon plant other than CCS the capacity element will generally be a much higher proportion.

Finally the contract and/or licensing arrangements need to deal with the relationship between the individual plant and the system operator (SO), and with the implications of any particular technical features of the plant.

Capacity or MW payment. The owner/investor, and its financial backers, will want a high degree of certainty about the long term basis of their revenue stream under the contract. So a contract under which the investor builds, owns, operates and sells the output of a plant, as opposed to merely building (with immediate transfer of ownership to a buyer), will normally include a large payment element intended to cover capital costs, including financing. One would expect this to be spread over the life of the contract, since the generator is delivering capacity over a long period, and to be expressed as a price per MW. The risks associated with construction are born by the investor, since the buyer can do little to influence or control construction costs.

The investor's risk bearing will normally extend to plant availability, since the buyer will not want to pay for capacity that is not available, and availability risk should properly be managed and controlled by the plant operator, and may also be determined in part by the quality of the initial construction. The MW component of the contract payment is therefore likely to be subject to achievement of a target availability, typically measured either by output, for baseload plant, or availability testing, for peak-load plant. There could be incentives for above target availability.

However the generator will not carry demand risk, since this would normally be deemed to be more capable of management by the buyers, who will be responsible for forecasting demand and anticipating market conditions; the latter may build or enter into contracts for additional plant, which would automatically reduce the need for actual output under the contract with which we are concerned. So subject to satisfactory availability performance, the generator will get paid the MW payment regardless of how many hours it is actually called upon to generate.

Energy or MWh payment. In addition there will need to be a payment for actual MWh generated to cover the variable fuel costs of the generator. However if the contract payment exceeds the actual variable costs, then the buyer, eg a central purchasing agency, will no longer have accurate information on what plant to use first, and this will result in seriously inefficient operations and major departures from least cost. So the MWh payment under the contract will not normally attempt to build in any of the reward to the initial capital expenditure; nor should it contain elements other than those linked to short run operating costs.

The actual definition of the MWh contract price will however need to be specified in a form that allows for movement in actual fuel prices, eg through an index for the fuel type on which the plant runs. This means that fuel price risk is born by the buyer. It is possible to argue that neither party can control fuel price risks. However the buyer under the contract will be dealing in a wholesale market in which the overall level of prices will tend to reflect fuel price changes, and also has an opportunity to pass on fuel costs to consumers, the real ultimate repository of fuel price risk.

The actual costs of generation depend not only on fuel prices but on the thermal efficiency of the plant; this depends inter alia on maintenance and is managed by the seller. So the seller should continue to bear/ gain the risk/ reward associated with operating efficiency, if it differs from what is anticipated in the contract.

Incentive structures. To some extent this type of contract already has a number of broadly correct incentive properties for the plant operator – to meet availability targets, to improve on contracted thermal efficiency and hence lower its fuel costs.

However if we assume that there is still a residual spot market associated with dispatch, whether a conventional pool with demand side participation or a "generators' pool", incentives can be set up to be directly related to the market price as it manifests itself in system marginal cost or SMC. Generators can be rewarded for extra output, or penalised for failure to meet contractual targets at SMC, if they are allowed to sell into this market any output surplus to their contract commitments/ targets, and to meet their targets by "buying in" amounts to cover any deficits. This means their direct incentive to improve operational performance at the margin is driven by market conditions rather than complex incentive structures in the contract.

If for example a generator has contracted to supply 1000 MW over a particular period, but has temporarily reduced availability or fuel efficiency, it may be more efficient to meet that target by buying in power from other generators rather than advancing maintenance expenditure.

Summary. Overall this kind of contract structure, with a pool or wholesale market linked to dispatch, results in the correct allocation of risks, each risk to the party best fitted to carry it, and also retains the "market" disciplines to maximise operational efficiency in meeting daily demands for energy at the lowest possible cost. It meets the need for the purchasing agency to be able to call on plant in merit order.

<u>Regulation of the Central Purchasing Agency</u>

The key aspects of regulation, accountability and oversight for the CPA would normally be defined as:

- whether it is on course to deliver its remit and is making the right kind of choices; this might be subject to regular review by a body such as the Committee on Climate Change, which already monitors overall progress on carbon targets and carbon budgets.

- whether it is delivering adequate quality of performance at a reasonable cost; this could continue to be subject to monitoring by OFGEM as the industry regulator. OFGEM already monitor and regulate transmission.
- whether it is treating its customers and suppliers fairly and without undue discrimination, while fostering competition in the industry; here it might be subject to ordinary competition law, although there would almost certainly be issues of detail to consider in this respect.

System boundaries. High voltage or medium voltage. Decentralised activity.

We have made an implicit assumption in this paper that the national (UK) level is the natural level for the decision taking with which we have been concerned. This depends on several assumptions. The first is the degree of interconnection. It is plausible that very high degrees of interconnection could result in the power sector's centre of gravity moving to mainland Europe, but neither this nor the question of Scotland are included in our discussion.

Another question is the potential growth in decentralised production and decision making on demand management, together with growing interest in some cases in going "off grid". It is worth considering the situation of a substantial area of the country expressing the desire and ability to essentially separate itself from the rest of the network. The relevance of the national system, from such a perspective, would be confined to occasional trading possibly during readily identified time periods, together with provisions for back-up.

In this case, we should simply note that many of the general issues raised as challenges in 3 above just migrate to a different level. Smaller networks will face the same problems of securing investment and operational and investment coordination. In some respects these may be easier, but diseconomies of small scale may also make it harder to preserve elements of competition and consumer choice.

Comparison and contrast with pre-liberalisation experience.

One objection to this proposal is that government agencies, or state industries and the public sector more generally, are not good at managing large projects. However the only example to date of the successful transformation of a major developed economy from a fossil based to a largely decarbonised power sector is France. This was carried out by a technically competent state owned power company EdF, over a period of about 10 years. The outcome gave French consumers among the cheapest power in Europe, without bankrupting the French economy, and demonstrating the benefits of clear objectives, technical competence and political commitment to a course of action. EdF, owning and operating generation, transmission and distribution, was a far more monolithic company than the procurement agency proposed here.

We can also contrast this proposal with the pre-1990 operation of the power sector under a Central Electricity Generating Board. The most fundamental difference is that the CPA will not, in general, own or operate generation assets, although an argument could be made for putting certain assets, such as pumped storage, under the direct control of the SO. This immediately reduces the monolithic nature of the CPA to a more easily manageable and focussed role. Notwithstanding the success of EdF, recreating the CEGB would be an additional and hard to justify undertaking.

Financing

Another argument frequently made against such a proposal, and other elements in this paper is that risk, which ends up as a cost, is transferred to and has to be borne by consumers, rather than by investors in a market. This is a serious misconception.

The fundamental components of commercial risk in the sector do not go away because they are born by investors; the latter typically charge a risk premium, or require a higher rate of return on capital to cover the risks they face. So in the end the cost of irreducible intrinsic risk within the sector will end up with the consumer by one route or another, except in circumstances where some third party, such as government, is willing to cover them.

What is important is that the sector's structure, regulation and contracts should allow the risks to be managed as efficiently as possible. This means that where risks can be reduced and controlled by good management, this should be reflected in the incentive structures built into the commercial arrangements.

For the irreducible elements of risk which really are outside the control of any of the actors (eg oil prices), either investors charge a premium on cost of capital, the cost of which will pass through to consumers, or a regulated pass through of costs to the consumer leads to a lower cost of capital. The latter approach is more cost-efficient, avoids additional risk mark-ups and will result in lower prices.

The real issue is the allocation of risks to the parties according to their ability to control and manage those risks. The key risks for investors in this context are policy and regulatory risks, and these are best managed by the people who determine them, ie regulators and governments. Imposed on investors they merely raise the cost of capital, a self-defeating approach.