The role of future energy networks

A REPORT PREPARED FOR OFGEM

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Executive Summary

The energy sector will need to adapt to meet the needs of a low carbon economy and deliver security of supply. Both generation and electricity use will change as low-carbon technologies are introduced and customers become more energy efficient and use energy in different ways. The precise nature and timings of these changes, however, are difficult to predict.

Networks, as the physical link between supply and demand, are likely to need to adapt to support this transition. Responding to the changes, and the fact they are uncertain, presents new challenges for network regulation. In particular, a secure low-carbon energy system may offer new opportunities to actively manage demand and supply of energy. In turn, this may mean there are more options for networks to trade-off investment in network assets with active management of demand and supply.

As part of its RPI-X@20 project, Ofgem wants to understand whether the current structure and role of electricity and gas networks could be a barrier to effective and efficient regulation of future networks, given the changes that may occur. If barriers are identified, it wants to understand the options for change. This is the focus of our report.

Drivers for change

In order to meet the UK Government's long term greenhouse gas emissions' targets, the use of energy in the economy will need to be transformed.

- **Decarbonisation of the sources of electricity generation:** To meet climate change targets, emissions per unit of electricity are expected to fall by around 90% by 2030.[1] To achieve this, the share of coal and gas-fired generation will fall while nuclear and renewable generation, particularly wind, will expand.

- **New and more controllable demand:** Total electricity demand could rise, at the expense of gas and oil based fuel sources, as it is increasingly used to power heating and transport.

- **New storage technologies:** The economic case for electricity storage will improve with developments in battery technology and a rise in the value of solutions that mitigate the increased intermittency of generation.

The main implications of these changes for electricity networks are as follows.

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1 "Building a low-carbon economy – the UK's contribution to tackling climate change", Climate Change Committee (December 2008).

- Electricity networks are likely to **require increased capital expenditure** to connect new generation that may be located in different places to current sources.

- Networks may have to **manage more variable network flows**. This change may impact DNOs, given that flows on the distribution networks may cease to be uni-directional.

- There may be **more options to manage flows** if heat and transport use has characteristics that mean there will be discretion in its time of use. Technological innovations such as automatic load limiters and smart meters may make it easier to exploit the potential for managing demand as an alternative to network investment.

- There may be a **change both in the number of participants with which electricity networks have to interact and the nature of the interactions they have**.

- There appears to be a step change in the uncertainty that networks face about the extent, and location, of future demand and supply. This may mean there is **increased value in keeping options open.**

The situation in gas is different. Over the past 5-10 years, there has been a period of uncertainty about the ideal pattern of new gas network investment caused by:

  - the rate of decline of the production capability of UK Continental Shelf fields;
  - the scale, timing and location of new pipeline links to the UK from continental Europe; and
  - the scale, timing and location of new LNG import facilities.

Network investment has already been undertaken to accommodate many of these new supply sources. There do remain uncertainties in relation to the future development of the gas network such as:

  - the rate at which our reliance on imported gas will increase;

- the potential for the gas network to be used to transport renewable forms of gas such as biogas or landfill gas[2] or to be used to transport CO_2 as part of a Carbon Capture Storage scheme; and
- the future profile of gas demand, which will be influenced by a range of factors including lower CCGT load factors following renewables growth, the need for gas back-up generation for intermittent renewables and the rate at which space heating is decarbonised.

However, looking forward, the need for new investment, and its uncertainty, is likely to be lower than it is for the electricity sector. Our focus in this report is therefore on the electricity networks, although a number of the issues may also be relevant to the gas networks.

Transmission network issues

Energy flows across the transmission network are complex and require management. This is why there are the two separate activities of System Operator and Transmission Owner.

- The **System Operator (SO)** is responsible for ensuring that demand and supply for energy on the network is balanced, and that the resulting planned physical production and consumption is consistent with network capability.
- The **Transmission Owner (TO)** is responsible for the efficient maintenance and development of the network.

The exact division of responsibilities between these two activities, whether they are under common ownership, and the regulatory framework applied to them, will all have an impact on whether the trade-off between network investment and management of congestion is likely to be undertaken efficiently.

Although this issue is not new, future changes to the energy sector that increase the nature and volatility of energy flows and require the connection of generation in new locations will be expected to make this trade-off more important. Ofgem has asked us to consider whether the current ownership and responsibilities of the transmission owner (TO) and system operator (SO) encourage efficient choices between new capacity and constraint payments.

An overview of current industry structure and regulatory arrangements that apply to the electricity and gas transmission networks is presented in Table 1.[3]

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2 In "The Potential for Renewable Gas in the UK", (January 2009) National Grid estimates that biogas could contribute 5.6bn cubic meters of gas, or 5% of total UK gas demand by 2020. Their stretch case suggests there is "technical potential" to deliver 18.4bn cubic meters, or 18% of total demand. This suggests that biogas could make a contribution to UK heating in future but is unlikely to require a substantial increase in network capacity.

Table 1. Overview of characteristics of gas and electricity transmission sector

	Electricity	Gas
Ownership of TO and SO	Unified in E&W Separate in Scotland	Unified in GB
Licenses	NGET: combined GBSO/TO SPETL & SHETL: TO	NGG: combined GBSO/TO
Duration of "main" TO control	5 years	
Duration of internal SO control	5 years	
Duration of control covering congestion costs	1 year (SO control)	5 years (TO control)
Duration of remainder of SO external cost control	1 year[4]	Largely 1 year

Source: Frontier Economics

Based on the current arrangements, we identified three potential barriers to efficient choices being made between new capacity and constraint payments, at least for the electricity sector.

- The combined ownership of the SO and TO could lead to inefficient investment decisions being made. This could result in either too much investment (if the regulated WACC was higher than the TSO's actual WACC) or too little investment (if the TSO believes it can consistently beat any congestion forecast set by the regulator even if it invests at sub-optimal levels.)

- The SO TO Code may not appropriately incentivise the interface between National Grid as the GB SO and the Scottish Transmission Companies as the TOs.

- The financial incentives provided by the price control framework may not be equal between the options for active management of congestion and investment in network assets.

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3 We describe the arrangements for onshore transmission assets. There are some differences to the arrangements for offshore transmission assets.

4 The length of this control is currently the subject of consultation.

Continuing the *status quo* may therefore result in increased costs to customers if the trade-offs between investment and congestion management are not being optimised. We look at options to address these barriers.

On balance, we think structural change involving the unbundling of the TO and SO functions is unlikely to be an effective solution. Although it would remove the influence that the SO has on TO activities, such separation could create problems. First, failure to optimise between load and non-load related capex could increase total investment costs. Second, an independent TO might ignore SO costs associated with taking out lines at peak periods. Third a fully independent SO would have few assets, and hence little regulated equity return could be put at risk through an incentive scheme. This would make it difficult to ensure the SO was sufficiently financially incentivised to make optimal decisions.

There may be benefits from increasing the use of competitive tenders, although such opportunities may be limited given the requirement for investments to be discrete if they are to be effectively tendered. However, it is not clear to us that ownership separation of the TO and SO will be a requirement to get these benefits. Given the costs that would be incurred in any separation, leaving the ownership structure as it is and undertaking sufficient regulatory oversight of the tender process may be a better solution.

Licence and code changes (in particular to the SO TO Code) could help to improve the interface between National Grid as the GB SO and the Scottish Transmission Companies as the TOs. This is most likely to have an impact on the optimisation of within year activities such as the scheduling of maintenance by the TO. This means that the changes are worth considering but do not represent a solution to wider problems of ensuring appropriate trade-offs are being made between network investment and management of congestion.

The incentive framework is the main area for potential change. Simply unifying the TO and SO price controls would not be desirable by itself, as the TSO[5] would be exposed to too much risk of congestion cost volatility that is outside its control. Instead, the most appropriate solution appears to be one where only relatively controllable risk (i.e. that related to congestion volume, not price) is left with the TSO for a longer period (e.g. five years). There are two possible approaches to achieving this:

- indexing target SO costs to an external cost benchmark; or
- making the TSO face a cost of congestion at a predetermined price.

Both solutions take away cost price volatility and provide a five year volume incentive.

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5 We use TSO here to mean the company that undertakes both TO and SO functions for a part of the transmission network.

Assuming an index could be found, further changes may still be required. This is because the very different durations of a long-term investment and a short-duration contract make it hard to equalise risk and return in a price control framework. Ofgem has already taken an important step to address this issue within a price control period in DPCR5, with the equalisation of incentives between opex and capex. However, networks will also consider the costs and risks associated with the treatment of particular costs at the time of regulatory review. Once network investment has been made and allowed into the Regulated Asset Base (RAB), they may view its recovery as essentially guaranteed,. This may be seen as less risky than shorter term contracts for active management of supply or demand given they will be subject to more frequent reviews.

The answer may depend on a view of how well placed the TSO is (and will be) to judge the future usefulness of assets in which they invest. Transmission investments are by nature lumpy, infrequent, and subject to scrutiny by many parties (including both Ofgem and planning authorities). The ability of the TSO to make sound judgements on investments can therefore be considered on a case by case basis. While this may represent an increase in regulatory intervention, it may be justified by its effect on overall incentives towards efficiency.

Distribution network issues

Unlike the transmission networks, Distribution Network Operators (DNOs) typically operate passive networks today, with relatively straightforward flows of electricity. They do not have a history of making trade-offs between network investment and active management options.[6] Ofgem is therefore interested in answering the following questions.

- Are DNOs able to take on SO roles[7], to the extent required, to allow for more active demand management and the potential for smart grids?
- Will the current roles and relationships of DNOs and suppliers support active demand management and the effective use of smart meters by networks?

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6 Active management for DNOs could include controlling the inputs onto the network from generators or storage owners (supply-side options) or the offtakes from the network by customers (demand-side options).

7 As described in the section on transmission networks, there is no single definition of an SO, but the activities that an SO may undertake include responsibility for ensuring that demand and supply for energy on the network is balanced, and that the resulting planned physical production and consumption is consistent with network capability.

The extent of the SO role that DNOs may need to develop will depend on how the industry develops in response to the drivers for change identified above. Depending on the outturn scenario, the types of active management could be quite different, from something close to existing responsibilities around managing constrained connections through to regional balancing markets operating in real time. The driver that seems most likely to lead DNOs to undertake a SO-type role would be if there was a large increase in discretionary domestic demand. The most likely driver of this will be the mass adoption of electric vehicles.

We identify three potential barriers to DNOs taking on SO roles.

- **Securing supply-side response:** Will DNOs be able to secure a supply-side response of sufficient robustness to act as an alternative to network investment?

- **Securing demand-side response:** Will DNOs be able to secure a demand-side response of sufficient robustness to act as an alternative to network investment?

- **DNO incentives:** Do the current regulatory arrangements incentivise DNOs to make the right choice between network investment and active demand management options?

It is the last of these that we think Ofgem should address first. As we discussed above in the context of transmission network investment, the very different durations of a long-term investment and a short-duration contract make it hard to equalise risk and return in a price control framework, although the incentive equalisation proposed in DPCR5 is clearly an important step in the right direction.

Treating network investment as effectively guaranteed once it has entered the RAB without detailed regulatory scrutiny may be appropriate when a network investment is likely to continue to be used and useful throughout its life. If this approach is to be continued in a period of increasing uncertainty, Ofgem would need to be satisfied that the investments were appropriate. Since distribution investments tend to be small in scale and numerous, it may be impractical for Ofgem to review them all. However, it is also not clear that DNOs would be able to manage the risks associated with predicting where assets will be used and useful in future and so it will be inefficient for them to bear such risks. The regulatory focus may therefore be best placed in ensuring DNOs plan appropriately for future uncertainty, rather than rewarding or penalising them based on outcomes that they are unable to predict. This is something the RPI-X@20 project should look to take forward.

There are then some other options that seem worthy of further consideration to ensure DNOs are able to take on appropriate SO roles and can utilise active demand management and make effective use of smart meters.

- **Smart meter updates:** The way in which the smart meter mandated roll-out will happen is still uncertain. As part of this process consideration will need to be given to the DNOs' requirements, both in terms of the initial meter specification and industry processes, but also how these will evolve over time.

- **DNO ownership of supply side response:** Consideration should be given to whether DNOs should be able to invest in small scale supply side activities (such as storage) as an alternative to network investment.

- **Contractual separation on change of supplier:** If customer specific connections become more common there may be a case for seeking to make this part of the contract transferrable on change of supplier. This should be investigated once there is more clarity about how energy efficiency measures may be financed over time.

- **Differentiation of structure of charges:** Ofgem will need to look at whether DUoS charges can be differentiated to provide a balance between the cost of additional complexity and providing price signals to customers that will be sufficient to generate efficient responses.

These barriers to DNOs making an efficient trade-off may only become an issue when such decisions need to be made at a local level. This is more likely to be an issue if domestic demand is increased through the use of electric vehicles or heat pumps.

1 Introduction

The energy sector will need to adapt to meet the needs of a low carbon economy and deliver security of supply. Both generation and electricity use will change as low-carbon technologies are introduced and customers become more energy efficient and use energy in different ways. The precise nature and timings of these changes, however, are difficult to predict.

Networks, as the physical link between supply and demand, are likely to need to adapt to support this transition. Responding to the changes, and the fact they are uncertain, presents new challenges for network regulation. In particular, a secure low-carbon energy system may offer new opportunities to actively manage demand and supply of energy. In turn, this may mean there are more options for networks to trade-off investment in network assets with active management of demand and supply.

As part of its RPI-X@20 project, Ofgem wants to understand whether the current structure and role of electricity and gas networks could be a barrier to effective and efficient regulation of future networks, given the changes that may occur. If barriers are identified, it wants to understand the options for change.

A comprehensive assessment of all the potential energy sector changes and their implications is outside the scope of this project. Further, we do not attempt to predict which outcomes are most likely to develop. Instead, Ofgem has asked us to focus on whether the network companies can be expected to make efficient choices between network investment and active management of connected generation and load.

- **Transmission networks** already face a trade-off between new investment and congestion management. We look at whether the current ownership and responsibilities of the transmission owner (TO) and system operator (SO) encourage efficient choices between new capacity and constraint payments, and how this may change in the future.

- **Distribution Network Operators** (DNOs), by contrast, rarely actively manage demand and supply today. Under some scenarios, this may not continue to be optimal. We look at what might prevent them making efficient trade-offs between network investment and active management. For example, could DNOs take on an SO role to allow for more active demand management?

Ofgem is not undertaking a detailed review of market structure as part of this project. Rather, the intention is to identify any obvious areas where the effective delivery of the regulation of future networks would be undermined and identify the options for change.[8]

To inform our thinking, we talked to a selection of stakeholders involved in the transmission, distribution and supply of energy. They were pleased that Ofgem was looking at these issues and we found these meetings extremely helpful. Meeting notes are provided in Annexe 1.

The rest of this document is structured as follows.

- Chapter 2 provides an overview of the changes that networks might face in moving to a low carbon economy and ensuring security of supply.
- Chapter 3 looks at whether the current ownership and responsibilities of the TO and SO encourage efficient choices between new capacity and constraint payments over the transmission networks, and how this may change in the future.
- Chapter 4 considers whether there will be barriers to DNOs making optimal trade-offs between investment and active management in future and what options there are for reducing these barriers.

8 The Government's recent UK Renewable Energy Strategy also reflects on these issues. It states that "over the longer term, the regulatory framework may need to adjust to allow the electricity system to contribute to our target of an 80% reduction in greenhouse gas emissions by 2050." Available at http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx.

2 Drivers for change

Both generation and demand are likely to change as low-carbon technologies are introduced and customers use energy in different ways. This will have consequent changes for networks. In this chapter we briefly summarise the drivers of change and consider the implications for networks. Further background is provided in Annexe 2.

2.1 The implications of climate change policy and security of supply for networks

The UK Government has a target to reduce greenhouse gas emissions (as defined by the Kyoto protocol) to at least 80 per cent below 1990 levels by 2050. In order to meet the long term targets, the use of energy in the economy will need to be transformed.

- **Decarbonisation of the sources of electricity generation:** To meet climate change targets, emissions per unit of electricity are expected to fall by around 90% by 2030.[9] To achieve this, the share of coal and gas-fired generation will fall whilst nuclear and renewable generation, particularly wind, will expand.

- **New and more controllable demand:** Total electricity demand could rise at the expense of gas and oil based fuel sources as electricity is increasingly used to power heating and transport. This demand is potentially discretionary in terms of the exact time at which it needs to be consumed. This, combined with the roll-out of smart meters, will provide new options for active demand management.

- **New storage technologies:** Developments in battery technology and a rise in the value of solutions that can mitigate the increased intermittency of generation can be expected to improve the economic case for electricity storage. One proposed solution is that the batteries in electric vehicles could be used as a source of energy storage.

These changes will affect electricity and gas networks differently. We look at the implications for the electricity networks first.

[9] "Building a low-carbon economy – the UK's contribution to tackling climate change", Climate Change Committee (December 2008).

Electricity networks

- Electricity networks are likely to **require increased capital expenditure** to facilitate decarbonisation alongside continued security of supply. New generation may be located in different places to current sources. For example, transmission network upgrades may be required to connect wind generation located at the extremities of the country or at sea. The Working Group of the Electricity Networks Strategy Group (ENSG) has estimated that by 2020, reinforcements on the transmission level could cost up to £4.7bn.[10] Further upgrades would be required to meet increased electricity demand associated with transport and heat use.

- Networks may have to **manage more variable network flows**. This may be the result of an increase in the use of wind generation, an increase in distributed generation or because domestic electric vehicles are used to provide storage. If flows on the distribution networks cease to be uni-directional, DNOs may need to take on a greater SO role to manage flows.

- There may be **more options to manage flows** if heat and transport use does turn out to have characteristics that mean there is discretion in its time of use. Technological innovations such as automatic load limiters and smart meters may make it easier to exploit the potential for managing demand as an alternative to network investment.

- There may be a **change both in the number of participants with which electricity networks have to interact and the nature of the interactions they have**. For example, if the current roles and responsibilities are maintained, distribution companies may need to engage more with suppliers to secure demand side response.

- There appears to be a step change in the level of uncertainty that networks face about the extent of and location of future demand and supply. This may mean there is **increased value in keeping options open.** Within a context of increased uncertainty as to what the "optimal" capital expenditure plan would be, alternative ways of managing supply and demand on the network may become more attractive, particularly if they can be used to buy time to reduce uncertainty and avoid stranding network assets.

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10 ENSG (2009) p5.

The increased uncertainty facing electricity networks was highlighted in Ofgem's recent Long Term Electricity Network Scenarios (LENS) project. This developed five very different scenarios for electricity networks in Great Britain in 2050.

- **Big Transmission and Distribution**, in which TSOs are at the centre of networks' activity.
- **Energy Service Companies**, in which energy service companies (ESCOs) are at the centre of developments of networks, doing all of the work at the customer side. Networks contract with such companies to supply network services.
- **Distribution System Operators**, in which DSOs take on a role in managing the electricity system. DSOs would take more responsibility for system management.
- **Microgrids**, in which customers are at the centre of activity. Microgrid SOs emerge to provide the system management capability to meet customer needs.
- **Multi Purpose Networks**, in which network companies respond to emerging, and potentially changing, policy and market requirements. The TSOs retain the central role in developing and managing networks, but distribution companies have a more significant role to play.

The roles of the electricity networks would be very different depending on which scenario emerges.

Gas networks

The situation in gas is different. Over the past 5-10 years, there has been a period of uncertainty about the ideal pattern of new gas network investment caused by:

- the rate of decline of the production capability of UK Continental Shelf fields;
- the scale, timing and location of new pipeline links to the UK from continental Europe; and
- the scale, timing and location of new LNG import facilities.

Network investment has already been undertaken to accommodate many of these new supply sources. There do remain uncertainties in relation to the future development of the gas network such as:

- the rate at which our reliance on imported gas will increase;
- the potential for the gas network to be used to transport renewable forms of gas such as biogas or landfill gas[11] or to be used to transport CO_2 as part of a Carbon Capture Storage scheme; and
- the future profile of gas demand, which will be influenced by a range of factors including lower CCGT load factors following renewables growth, the need for gas back-up generation for intermittent renewables and the rate at which space heating is decarbonised.

However, looking forward, the need for new investment, and its uncertainty, is likely to be lower than it is for the electricity sector. Our focus in this report is therefore on the electricity networks, although a number of the issues may also be relevant to the gas networks.

[11] In "The Potential for Renewable Gas in the UK", (January 2009) National Grid estimates that biogas could contribute 5.6bn cubic meters of gas, or 5% of total UK gas demand by 2020. Their stretch case suggests there is "technical potential" to deliver 18.4bn cubic meters, or 18% of total demand. This suggests that biogas could make a contribution to UK heating in future but is unlikely to require a substantial increase in network capacity.

3 Transmission network issues

Energy flows across the transmission networks are already complex and require management. This is why there are the two separate activities of System Operator and Transmission Owner.

- The **System Operator (SO)** is responsible for ensuring that demand and supply for energy on the network is balanced, and that the resulting planned physical production and consumption is consistent with network capability.

- The **Transmission Owner (TO)** is responsible for the efficient maintenance and development of the network.

The exact division of responsibilities between these two activities[12], whether they are under common ownership and the regulatory framework applied to them will all have an impact on whether the trade-off between network investment and management of congestion is likely to be undertaken efficiently.

Although this issue is not new, future changes to the energy sector that increase the nature and volatility of energy flows and require the connection of generation in new locations will be expected to make this trade-off more important.

This chapter looks at whether the current ownership, responsibilities and incentive frameworks encourage the most efficient joint operation of the TO and SO roles. The principal questions are whether the:

- ownership of the TO and SO creates good incentives for joint optimisation;

- current industry codes encourage efficient working between the TO and SO where they are separate; and

- current incentive mechanisms, which are set in different ways for the TO and SO roles on electricity and gas networks, encourage efficient joint operation.

We start with a brief overview of current arrangements before looking at what could drive a requirement for change. We then consider whether there are barriers to the optimal trade-off between operational and investment activities, before evaluating some options for change.

12 The exact split of responsibilities, and the potential for making changes to the split, is something we discuss in this chapter.

3.1 Current industry structure and regulatory arrangements

This section provides an overview of current industry structure and regulatory arrangements that apply to the electricity and gas transmission networks. These are summarised in Table 2.[13]

Table 2. Overview of characteristics of gas and electricity transmission sector

	Electricity	Gas
Ownership of TO and SO	Unified in E&W Separate in Scotland	Unified in GB
Licenses	NGET: combined GBSO/TO SPETL & SHETL: TO	NGG: combined GBSO/TO
Duration of "main" TO control	5 years	
Duration of internal SO control	5 years	
Duration of control covering congestion costs	1 year (SO control)	5 years (TO control)
Duration of remainder of SO external cost control	1 year[14]	Largely 1 year

Source: Frontier Economics

We describe the current arrangements in the gas and electricity networks for:

- the ownership of the TO and SO functions;
- the way in which the SO manages congestion and the TO makes investment decisions; and
- the regulatory framework.

3.1.1 Ownership of TO and SO functions

There is a distinction in the ownership arrangements between the electricity and gas networks.

13 We describe the arrangements for onshore transmission assets. There are some differences to the arrangements for offshore transmission assets.

14 The length of this control is currently the subject of consultation.

- **Electricity:** Transmission assets are owned by National Grid Electricity Transmission (NGET) in England and Wales and by Scottish Power and Scottish and Southern Energy in Scotland. NGET undertakes System Operation activities in relation to the entire GB electricity network.

- **Gas:** Transmission assets are owned by National Grid Gas (NGG) which also undertakes System Operation in relation to the entire GB gas network.

These differences in structure are largely the result of history. At privatisation, the England and Wales Regional Electricity Companies (RECs) originally jointly owned the England and Wales transmission system operator, while the Scottish electricity companies were separate and vertically integrated. While the RECs sold the England and Wales transmission assets to form National Grid Company, the assets in Scotland have been retained by the Scottish companies.[15]

By contrast, the GB gas transportation network was originally part of the integrated British Gas. It was privatised as a single vertically integrated entity in 1986 and the GB network was separated and then subsequently demerged in 1997.

In both electricity and gas, National Grid holds only one transmission licence for both TO and SO activities. Therefore, to the extent that the transmission licences legally require the development of an efficient and economical system, National Grid is already under an obligation to act in an integrated manner.

3.1.2 Congestion and incentive management and trade-offs

We now consider how the SO manages congestion, how the TO makes investment decisions and how the two activities interact.

How does the SO manage congestion?

Gas and electricity transmission networks already actively manage congestion and experience multidirectional and changeable flow patterns. The details of the approach taken to managing network congestion and the nature of the associated costs are different across the two sectors.

In electricity, generator and supplier trading is national and undertaken on a half hourly basis. Generators (supply) and load (demand) typically have network access rights equal to their installed capacity or their peak load and can bid to supply or receive power on that basis. The outcome of this bilateral trading may be a set of physical production and consumption plans that are not consistent with network capability.

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15 The implementation of BETTA in 2005 integrated the operation of the GB network (by appointing National Grid Electricity Transmission to be the GB SO) but did not affect ownership.

In order to deal with this potential inconsistency, the SO may have to sell back electricity to generators in export constrained locations and buy electricity from generators in import constrained locations. The cost of managing congestion is the cost of these loss making trades.

Today, most congestion on the GB network is short term but is specific to particular locations. This means that there are a limited number of parties who can be asked to change their production or consumption patterns to resolve the problem. Combined with volatile short term electricity prices, this means that the overall cost of congestion is volatile.

In gas, shipper trading is also national although it is on a daily, rather than half hourly, basis. Shippers book capacity at entry and exit points but the release of capacity by the SO is not necessarily consistent with network capability. Therefore, as with electricity, the outcome of bilateral trading may not be aligned with network capability.

Unlike the electricity market, the SO manages most congestion through trading in capacity. The SO can buy back network capacity to ensure that the levels of capacity held by shippers are more consistent with the network capacity expected on any given day. Shippers are subject to penalties if they flow above their capacity holding levels, and therefore buying back capacity places the onus on shippers to rebalance their portfolio to meet demand in a way that is consistent with network capability.

In a competitive market, the prices that shippers will quote the SO to sell back capacity should be linked to the profit they would have made through using the capacity to flow gas. Therefore, like electricity, the cost of managing network congestion is still linked to commodity wholesale prices. However, at least in the short term, gas prices are less volatile than electricity prices and the SO typically has more options available to manage congestion. The overall cost of capacity management for gas is therefore likely to be less volatile than for electricity.

How does the TO make investment decisions?

For both gas and electricity, network investment decisions are made by the TO and are funded through the price control. Investment is split into non-load related (e.g. replacement) and load related (e.g. reinforcement, new connections) capital spend. The major impact of decarbonisation will be on load-related capex and we therefore focus on this.

Decisions as to where to invest are driven by TO forecasts of the likely future demand for network capacity.[16] One motivation for this investment is the level of current constraint costs. However, investment decisions are also driven by the need to continue to meet security standards and other assessments of the best

16 TOs may also use other instruments, such as derogations against security standards.

way of meeting demand. The regulatory and contractual framework aims to help TOs make forecasts of investment.[17]

The timing of investment is also constrained by broader regulatory processes, such as that associated with securing planning approvals. This is likely to be more of an issue for overhead power lines than for gas transmission pipes.

What are the interactions between congestion management and investment?

In this project we are interested in how the choice is made between long term investment in new network capacity and payment of constraint payments. As a result of the structural differences described above, the answer is different in the electricity and gas sectors.

- **Gas:** NGG, as both TO and SO, is responsible for making decisions between investment in new network capacity and "constraint payments". Therefore, NGG is solely responsible for optimising between the two with reference to the various incentives and constraints placed on it by the TO and SO price controls, and the other constraints that it may be under (e.g. HSE requirements, planning regulations etc.)

- **Electricity:** In England and Wales, the position is the same as that in the gas network: NGET is solely responsible for the decision. However, the position in Scotland is more complicated. The interaction between the SO and the Scottish TOs is governed by the SO TO Code. Under the provisions of this Code, the SO has the right to comment on the TO plans and suggest changes. Within year, the SO can also pay the TOs to complete work in different timescales (for example by paying overtime to ensure a line returns from outage faster) although this is infrequently used. However, the final responsibility for network development lies with the network owner (again, subject to other regulatory processes such as the TO price control and planning regulations).

Regulation

For both gas and electricity, Ofgem sets a five year price control that covers:

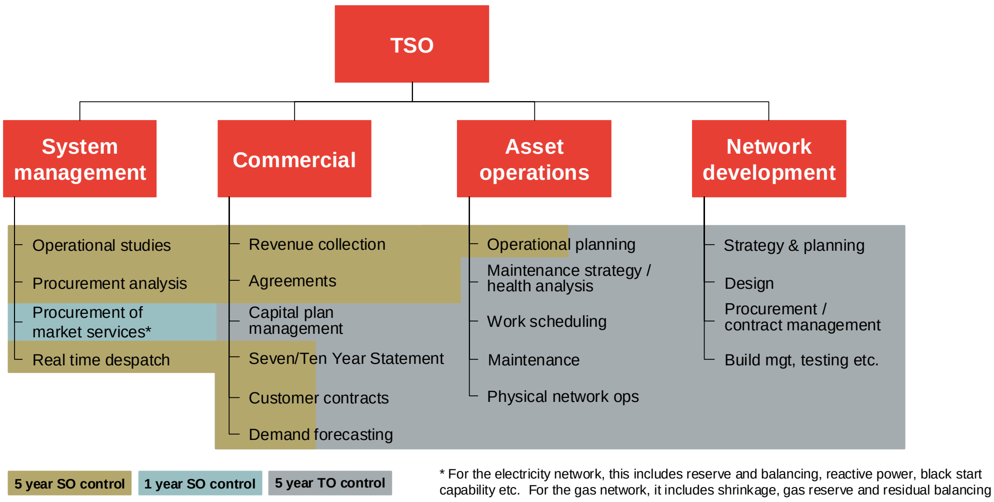
- network opex and capital costs (the TO control); and
- the "internal" costs of the SO activity (the cost of the resources internal to NGG and NGET which undertake system operation).

17 For example, the user commitment process which improves the signals provided from users to the TSO in relation to planned entry and exit dates from the network.

Both sectors also have a separate one or two year SO price control that covers some elements of "external" costs (the cost of procuring various energy or capacity services from energy market participants).

The regulation of the activities of a TSO is summarised in Figure 1 which indicates the range of tasks undertaken by the TSO and the way in which they are remunerated.

Figure 1. TSO tasks



Source: Frontier Economics

The activities are roughly ordered in terms of the timescale to which they relate: shorter term activities are on the left hand side and longer term activities are on the right. There are two particular points to note.

- Several network operator tasks, like operational planning, are neither funded uniquely through the TO control or uniquely through the SO control. These tasks require input remunerated from both controls.

- While the task of buying external services from energy market participants is a small part of the overall task of a TSO, it represents a material part of total costs. For electricity, these costs totalled £571m in 2007-08 or 27% of NGET's total regulated income.

However, arrangements vary between gas and electricity in relation to the trade-off between investment and constraint payments, which is the focus of this chapter.

- **Gas:** Funding to resolve some level of network congestion is provided through the TO price control. It associates baseline network capital expenditure with pre-defined capacity output measures. NGG receives incremental revenue if there is a market demand for further capacity (as signalled by auctions for short and long term capacity at network entry points). The price control funding also includes fixed amounts to allow NGG to buy baseline capacity back from shippers should network constraints arise.

- **Electricity:** Funding for resolving network congestion is not provided through the TO control, but is instead funded through the separate short term SO control. Recovery of costs associated with congestion is dealt with separately. The TO price control associates baseline network expenditure with pre-defined output measures (in this case, the balance between zonal generation capacity and peak demand).[18] This means that if more generation than expected connects in an export-constrained area, NGET automatically receives more revenue to fund the capex required to accommodate the connection[19].

For both gas and electricity, the short term SO price control ensures that (subject to caps, collars and sharing factors) the SO gets a benefit for balancing the system at a cost lower than an *ex ante* agreed target and is penalised if costs are higher. The target is reviewed periodically, based on historical performance and forecasts for network use, flow patterns and energy prices.

Overall, the electricity SO control is more holistic and deals with almost all elements of external costs. By contrast, the gas SO control is narrower in scope and, in particular, does not cover the cost of buying back capacity to manage congestion.

Arguably, this difference relates to the volatility of the underlying congestion management costs (and in turn to the underlying volatility in commodity prices). Under current market arrangements, the costs of managing congestion in electricity are more volatile and hence, to date, the SO has been less willing to take on a longer term incentive scheme.

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18 This revenue driver is present in NGET's price control. The Scottish TO price controls include revenue drivers of a slightly different form, reflecting the smaller geographic scale of the networks.

19 Separate allowances are provided for local connection works and for main system reinforcement.

3.2 Drivers for change over time

The level of uncertainty in relation to appropriate network development is likely to be higher for the electricity transmission grid in future. This is in response to several drivers, summarised in Table 3.[20]

Table 3. Drivers for change

Driver	Implications for network
Increase in renewable generation	High levels of capex required to connect new renewable generators, as renewable energy-rich areas are different from the current location of existing thermal generators.
	Need to manage unstable network flows given intermittent renewable generation (especially wind). This will require extra capacity or more active management for networks.
Switching in the thermal merit order	Changes in the carbon price and new technologies (like Carbon Capture and Sequestration (CCS)) may change the existing transmission-connected thermal plant merit order, with coal plant becoming price setting much more of the time. This will also tend to change the pattern of flows around the transmission network and potentially creates the need for new network investment.
New non-renewable generation	New grid investments will be required to support replacements for the UK's ageing nuclear fleet and interconnections with neighbouring markets. The financial, regulatory, planning and political issues associated with new nuclear power plants make the timing and location of the investments uncertain. While there may be less uncertainty in relation to the timing of new interconnector build, there is more uncertainty around the way in which new links will operate and the likely timing of import and export flows.
Growth in demand from new uses	In order to achieve the ambitious 2050 CO_2 emission reduction targets, a significant part of the transport and heating sectors will need to be decarbonised. This is likely to be achieved through greater use of electricity, both to charge electric vehicles and to provide space heating, which will in turn increase transmission system loading and potentially investment requirements.
Take-up of demand management	The roll-out of smart meters will provide more scope for demand management. This could both reduce overall consumption and reduce consumption at peak hours, potentially in turn reducing the need for new transmission investment. It also offers more options for the SO.

Source: Frontier Economics

[20] We focus here predominantly on load related capex driven by factors related to decarbonisation. There will clearly be other drivers (e.g. asset conditions) for non-load related capex. Equally, there would have been load related capex needed absent the drive for decarbonisation.

In the light of these drivers, it will be important to ensure an efficient trade-off is made between network investment and the management of network congestion. Failure to do this could result in additional costs to the customer:

- network investments could be made on the basis of a "central case" view of the future that turns out to be wrong, resulting in the assets being subsequently underused;
- capital investments could be made too soon, where it would be better to rely on operating measures to "buy time" until some uncertainty has been resolved; and
- generators could be paid constraint payments over long periods of time when it would have been more efficient to invest in the network and remove the congestion.

Further, unless significant volumes of electricity storage connect to the grid, the increased volatility of physical network flows is likely to result in increased volatility and unpredictability of congestion costs. This will make understanding the efficient trade-offs more difficult.

3.3 Potential barriers

Our analysis and discussions with stakeholders have identified three potential barriers to efficient and effective decision making.

- **Structural barriers:** Is the combined ownership of SO and TO part of the problem?
- **Licences and codes:** Do the licences and codes under which the SO and TOs operate create barriers to efficient decision making?
- **Incentives:** Does the current structure of the price controls (and in particular the interaction between the financial incentives created by the TO and SO price controls) present a barrier?

3.3.1 Combined ownership of the SO and TO

It has been suggested that a single party undertaking both SO and TO roles, as NGET does in England and Wales, may not have the right financial incentives to consider the investment/constraint payment trade-off efficiently.

This would only be the case if two conditions are met:

- common ownership would need to create opportunities for financial gain from sub-optimal decisions that would not be available if the activities were under independent ownership; and
- there would be insufficient offsetting benefits that could accrue to the customer as a result of combined ownership.

Common ownership could lead to sub-optimal decisions that result in either too much or too little investment.

- The TO may invest too much if its regulated WACC is higher than its actual WACC. In that case, it would invest rather than buy out congestion.
- The TO may invest too little if it believes it can consistently beat any congestion forecast set by the regulator. Note that common ownership only contributes to this problem if it helps the SO consistently make the regulator over-forecast the level of congestion (perhaps due to greater awareness of the likely maintenance activity). Otherwise, the SO would have an incentive to out-perform targets, regardless of ownership.

We look at historic data relating to the investment / constraint payment trade-off in the electricity sector in Annexe 3 of this report. The data does not indicate that there has been clear evidence in relation to NGET (and latterly the Scottish TOs) being able to trade-off the cost of future constraint payments against future network investment in the past. However, this should not be taken as an indication that further consideration of this issue is not required. Looking forward, it is likely that the trade-off will become more significant, and so making sure that the regulatory arrangements encourage efficient decision making is important.

3.3.2 Licence and Code arrangements

The Licence and Codes arrangements that govern the SO and TO functions aim to facilitate efficient trade-offs between SO and TO activities. However, there may be barriers relating to the specification of the interface between NGET as GB SO and the Scottish Transmission Companies.

This SO TO Code specifies the rights and responsibilities of both parties in relation to day to day network operation, maintenance and network development plans. It is predominantly an operational contract, delineating responsibility rather than attempting to govern commercial outcomes. These are instead determined largely by the price controls that are set independently for NGET and the Scottish Transmission Companies.

National Grid noted that the interface is not very contractualised. While there was scope, for example, for the SO to pay more to the TO to work in a different way (e.g. to complete work faster than foreseen in the year ahead outage plan) this option is rarely offered to them by the Scottish TOs and therefore rarely used.

If this interface does not allow each counterparty to indicate to the other the financial implications of particular courses of action, each will make their decision on the basis of their own costs and profits, without considering the impact on the other party. Inefficient trade-offs may therefore result.

3.3.3 Interactions between SO and TO price control incentives

If the financial incentives provided by the price control framework are not equal between the options for active management of congestion and investment in network assets, the regulatory framework may itself impose a barrier to efficient decision making. Even within a single price control, two key issues may affect the optimal trade off between capex and opex (for constraint management) efficiency.[21]

- The first is the risk of **price volatility during review periods:** The price volatility associated with the buying out of constraints (within year) is higher than that associated with investment projects, which will tend to encourage over-investment. Additionally, once capex projects are complete, the costs are generally fixed which means the pricing risk is resolved sooner than for opex.

- The second is **differences in the level of information asymmetry:** Utilities will tend to favour spending categories with greater information asymmetry, as the scope for outperformance against (benevolent) targets is greater. In this case, the information asymmetry between the SO and the regulator is arguably greater than that between the TO and the regulator. This is because of the large number of complex and interdependent external transactions undertaken by the SO each day, and the interaction between these short term transactions and the longer term reserve option contracts.

The greater potential barrier is the different timing and duration of the separate price controls. Because the SO is exposed to highly volatile energy market related costs, the SO control has a shorter duration. The shorter period may have two further impacts on incentives.

- **Reduce the extent to which the utility perceives a trade off between capex and congestion costs:** The SO only incurs the adverse impact on congestion costs of underspending TO capex for one year, after which the control comes up for review. The constraint target is then reset in the light of current information. Similarly, ongoing frequent reviews remove within a year or two the benefit to the SO of the reduction in congestion costs resulting from delivery of TO capex.

[21] This assumes actual and allowed WACCs are broadly in line and the strength of the incentives for cost efficiency are similar across controls. We note that the initial proposals for the current electricity DPCR equalise incentives for most opex and capex categories. However, features of the SO control such as caps and collars on SO profit can create short term differences in incentive strength.

- **Increasing regulatory risk:** As a result of the short term nature of the control relative to that for the TO, the SO has to justify constraint payment opex much more frequently than the TO has to justify constraint relieving investment projects. Other things being equal, this should mean that there is more regulatory risk of disallowance in relation to opex then capex.

The short duration of the SO price control means that the combined owner does not often directly face the financial incentives of the investment/constraint trade-off. In undertaking the vast majority of transmission investments, there is unlikely to be an effective payoff for the utility through the SO control as the constraint target will be reset one or two years following the investment (passing any benefit through to customers). Similarly, the utility is likely to be protected from the constraint cost of any underinvestment.[22]

3.4 Options for change

In the previous section we identified certain barriers that may distort DNOs' incentives to make an efficient trade-off between network investment and active management of demand and supply. In this section we look at the options for change that could address these barriers. We break these options into three different types.

- **Structural:** The roles and responsibilities of different industry participants could be changed. For example, responsibility for an activity could be transferred to another party (e.g. activities currently undertaken by the TO could be transferred to the SO) or ownership rules could be changed (e.g. NGET could divest its SO activity). Some of these changes would require a change to primary legislation while others could be done via licence changes.

- **Licence and codes:** For any given structural arrangement, licences and industry codes set out obligations including those that govern industry interactions. For example the arrangements governing the relationship between the TO and SO could be changed.

- **Incentives:** There are then a set of specific financial incentives that attempt to ensure that the behaviour of networks are efficient and consistent with a competitive market. For example, changes to the risk and reward of different activities within a price control could be made to influence network behaviour.

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22 While the revenue drivers described at the outset in relation to the TO control would reduce TO revenue allowances (and hence the scope for underinvestment) if there were to be less generation connected to the system relative to peak demand than forecast, this driver does not address incentives to invest to manage constraints for a given level of generation.

We evaluate options to address each of the barriers identified in the previous section.

3.4.1 Unbundling ownership of the SO and TO

The previous section identified the potential for a common owner to face distorted incentives when trading off between constraint payments and network investment. Ownership unbundling would remove the influence that the SO has on TO activities and *vice versa*, and so may be beneficial.

Ownership unbundling would need to be accompanied by a clear definition of the allocation of responsibilities between the SO and TO. While there is a reasonably clear definition in relation to the Scottish TOs (since they already have separate ownership from NGET as SO), the definition "within" NGET is not explicit.

There are a range of potential different allocations which could be put in place (frequently described as involving different "thicknesses" of SO roles). Different models exist internationally where the SO and TO roles have been separated and placed in different organisations. The most likely concern that would lead to separation of the SO and TO in GB is that it could remedy the possibility that the allowed WACC for the TO business may exceed its actual WACC, giving it an incentive to overinvest. Therefore, in thinking about the allocation of responsibilities, we consider a relatively "thick" SO which has responsibility for making (load related) investment decisions.

There are some generic problems created by such an allocation of responsibilities.

- First, this would split the responsibility for undertaking load and non-load related capex. Given that the transmission network is an integrated system, there is often scope to optimise capital investments to address both non-load and load related requirements simultaneously.[23] This may increase total investment costs.

23 For example, replacement is often on a better than like-for-like basis.

- Second, the independent TO would not consider SO-related consequences relating to their approach to the operation of the network.[24] For example, the TO might ignore SO costs associated with taking out lines at peak periods if it avoided incurring overtime for maintenance crews. Likewise, the TO might not incur additional costs to carry out maintenance when generators are going on outage anyway, making it cheap from an SO perspective. This may increase total operating costs. We discuss this further in the context of the separation of SO and TO functions in Scotland in section 3.4.2 below.

- Third, the incentive arrangements for the SO would need to be considered. A longer duration of SO price control would almost certainly be required (as otherwise the SO would only bear high congestion costs resulting from underinvestment for a single year). However, since a fully independent SO would have few assets and hence little regulated equity return to be put at risk through an incentive scheme, it may be more difficult to provide it with strong incentives in relation to its performance. This could result in overinvestment, as it might prove difficult to ensure the SO was financially responsible for transmission capacity that, at some point in the future, becomes underutilised.

The key question is therefore whether greater independence in investment decision making would create benefits which outweigh these problems. The answer to this will depend in part on the extent to which the SO's decision making is constrained by the TO's funding arrangements.

If the TO continues to be subject to a five year control set by Ofgem covering opex and capex, the SO is likely to be limited to redefining priorities or delaying particular schemes within an overall exogenously defined programme. It would have relatively little scope to exercise broader influence. This problem has been identified in a number of jurisdictions where the SO is independent from the TOs.[25] We note it would be open to Ofgem to rely more strongly on the SO's indication of investment priorities when it set the price control, and this may

24 In theory, it may be possible to put in place a contract between the SO and TO to ensure that each took account of the impact of its actions on the other. We discuss the difficulties associated with this below in relation to the current SO TO Code.

25 In a detailed review of arrangements published in January 2007, the Energy Reform Implementation Group (ERIG) in Australia recommended that there needed to be direct links between the recommendations on investment of the SO (NEMMCO) and the revenue allowances of the TOs as set by state regulators. Similar issues have frequently been raised in relation to RTO expansion plans in the US.

bring benefits[26], although we do not think these would be sufficient to compensate for the problems identified above.

Instead of retaining existing TO funding arrangements, alternative arrangements could be considered. In particular, the delivery of investment could be opened up to competition via the increased use of competitive tenders, similar to those being proposed for offshore transmission. The SO could define discrete reinforcement projects that would then be awarded on a competitive basis, with the TO being awarded a "life of asset" regulatory deal. Under such a framework for TO funding, there may be more scope for an independent SO to guide the level and timing of load related investment. Using a competitive process to determine the asset owner could bring benefits. In particular, it should help to reveal companies' actual cost of capital (at least in relation to particular projects) and would potentially encourage innovation in design, planning and construction.

A competitive tendering approach will work best when the delivery of the capacity is not strongly dependent on other activities of the existing network owners since it relies on the identification of discrete projects that can be put out to tender. As we noted above, the transmission network is an integrated system and the scope for the definition of discrete capital projects may be limited. Some projects, such as the development of offshore networks for windfarms, or potentially the north-south "bootlaces" currently being discussed, may be suitable. More often, however, onshore reinforcement relates to upgrade of existing assets rather than completely new lines. In these cases, there will be significant interactions with the existing network provider and often an interaction between load and non-load related capex. In trying to identify discrete investments in an integrated network, there is a risk that uneconomic substitution from old to new assets results.

Further, getting benefit from the increased use of competitive tenders does not necessarily require unbundling of the SO and TO, as the proposals for offshore transmission demonstrate. The main additional benefit from ownership unbundling is increased transparency that the TO does not have an information advantage in bidding for the investment opportunities tendered by the SO. However, providing regulatory oversight of the tender process is effective, it is not clear to use that ownership separation would deliver sufficient incremental value to justify incurring the costs of separation.

Therefore in summary, we think there may be benefits from increasing the use of competitive tenders, although such opportunities may be limited given the requirement for investments to be discrete if they are to be effectively tendered. However, it is not clear to us that ownership separation of the TO and SO will

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26 We discuss the benefits of similar arrangements on an EU level in our report "Improving incentives for investment in electricity transmission infrastructure", published by the EC in June 2008.

be a requirement to get these benefits and, given the costs that would be incurred in a separation, it is not clear the solution would maximise net benefits.

3.4.2 Changes to licences and Codes

As noted above, the SO TO Code may not provide sufficient scope for NGET to financially incentivise the Scottish transmission companies in relation to the impact of their actions on system operation costs. This may have an impact on the trade-off between constraint payments and capex. However, it is more likely that the principal cost of separation today is the failure of the TO and SO to coordinate activities within year.

National Grid gave the simple example that the Scottish TOs rarely offered the option to accelerate TO maintenance work to address the SO cost implications. There may be several reasons why this flexibility is not offered. For example, contractors carrying out maintenance may charge high costs for changes to the timings and scope of planned works which the Scottish companies assume outweigh the potential SO benefits to NGET. Equally, however, as part of vertically integrated groups, the Scottish TOs may be considering both the incremental costs from a transmission network perspective and the potential for generation business profits as a result of compensation for network constraints.[27] We are not able to estimate the impact on constraint costs of each of these explanations.

However, the lack of an offer from the TOs may not be the core issue. Even if an offer to accelerate or move maintenance works were made, it is difficult to see how anything approximating a competitive negotiation on prices could be achieved, because both NGET and the Scottish TOs are monopolists. Even the validation by one party of costs quoted by the other would be difficult, because the interactions between SO and TO relate to daily ongoing operations, with individual cases having specific costs and benefits. While it may be plausible for the SO to validate the cost of *accelerating* works (e.g. through paying overtime or working at weekends), *moving* works with the associated knock-on effects on the rest of the year's outage plan would be much more difficult to evaluate.

Given this, it is likely to be difficult to replicate entirely the effect of a single TSO optimising its activities within year. However, given the importance of Scottish constraints in overall constraint costs both now and in the future, it may be worth considering if improvements to the scope for financial incentives across this interface could be made to encourage a more efficient trade-off. For example, an *ex ante* specified menu of prices for accelerating or moving works,

27 Given the geography of the network in Scotland, the TOs would not need to breach any business separation requirements to realise that there would be potential for generation business profits.

while inevitably inaccurate, may result in more opportunities for trade-offs between maintenance and congestion management.

3.4.3 Changes to the incentive framework

This section sets out a conceptual framework for considering an efficient incentive regime for managing costs that have different levels of volatility. We then apply this framework, and consider three examples of possible alternate TSO regulatory regimes:

- a single five year TSO control modelled on the current TO control (to overcome the barrier of the different duration of the controls);
- indexing external costs, either within a TSO control or a separate SO control (if the combined TO/SO is better able to manage congestion volume risk than the price risk); and
- including a congestion volume driver in the TO control (for similar reasons).

Conceptual framework for an incentive regime

Under any incentive regime, a combined TSO would consider its costs and risks both within regulatory periods and between periods, taking into account its likely treatment during regulatory review. For example, even with a single five-year control covering both network investment and congestion management, a TSO may prefer to invest in the network. This is for two reasons.

- **Within period:** Under current market conditions, the process of managing constraint costs is likely to expose a TSO to more risk than an equivalent solution involving network investment. If this is not reflected in the determination of allowed revenue, TSOs will favour network investment.

- **Between periods:** Once network investment has been made and allowed into the Regulated Asset Base (RAB), TSOs may view its recovery as essentially guaranteed, through the recovery of depreciation and rate of return in future controls. TSOs may seen this as less risky than a continued review of the alternative solution involving the management of constraints.

For both reasons, TSOs may perceive less risk from reinforcing the network than from managing congestion through the market. This would bias them towards over-investment from a social perspective (i.e. where the total expected costs of investment are greater than the total expected costs of constraint management). In this regulatory framework, the trade-off between congestion management and investment would not be optimal.

This barrier to making an optimal trade-off can be addressed by either:

- reducing the risk associated with constraint management costs within period; and/or
- increasing (or at least making clearer) the risk associated with network investment across periods.[28]

In deciding on the appropriate approach, it is important to consider the efficient allocation of risk between the TSO and customers. In principle, risks that fall under management control should be borne by the company while risks outside management control are best passed on to customers. So, the ability to manage risk efficiently should help guide the balance between reducing constraint management cost risk and increasing investment risk.

A single five year TSO control

One option to overcome the different durations of the TO and SO controls is to merge them. We consider a single TSO price control modelled on the current TO approach, under which all SO costs are simply treated as another part of controllable opex.[29] The principle concern with this scheme is how the TSO would manage constraint price risk, which, at least to some degree (i.e. energy price volatility), is outside its control.

One way to mitigate the risk would be to have very low incentives on opex (for example, a high sharing factor). However, this would create risks in relation to efficiency in other opex areas.

A second way could be for the TSO to limit their exposure to price risk by constraining the compensation paid to generators.[30] While it is not clear that the current allocation of rights to generators is optimal, this would inevitably pass some risk back to generators, which in turn would affect incentives to invest in generation.

Without such changes, the TSO would need to be compensated for the price risks. This compensation could come through:

- a higher cost target for external costs relative to those seen historically; or
- a premium on the regulated WACC.

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28 While theoretically possible, Ofgem has not so far disallowed investments on the basis of their subsequent degree of usefulness

29 They are subject to an *ex ante* defined target and are not passed through

30 This would require a change in the current codes, for example, by constraining the way in which generators can bid into the Balancing Mechanism in order to limit high claims for compensation.

Unless the TSO does have the capability to manage price risk, this would mean customers were bearing more cost than necessary as they would be insuring the TSO for risks it could not manage. The key questions are therefore:

- how do you create a regime that incentivises the TSO in relation to those elements of congestion cost it is able to control; and
- having done so, is the current level of risk associated with network investment between periods appropriate?

We consider two regimes that might offer a solution to this.

Indexing external SO costs

One way to reduce price volatility in congestion costs could be to index some SO costs to external benchmarks. This would require an index that both reflects the non-manageable risks and is outside the control of the TSO. If such an index can be found, a decision would still be needed on whether SO costs should:

- be bundled with other opex within a TSO control; or
- continue to be dealt with separately, in order to allow separate sharing factors or caps/collars to be implemented.

The former is preferable from the perspective of ensuring efficient trade-offs between network investment and congestion management. However, whether this would be efficient depends on the extent to which the remaining risks (both volume and residual price risk resulting from imperfections in the indexation) were fully within the TSO's control.

Finding an appropriate index would require some research. However, since a substantial amount of price volatility in SO external costs (for example reactive power and constrained on costs) is linked to electricity market prices, it may be possible. Other costs (for example, constrained off payments) may be reasonably well correlated with other fuel prices.

Assuming an index could be found, the remaining question is whether the level of risk associated with network investment between reviews was appropriate. The answer to this question depends on a view as to how well placed the TSO is (and will be) to judge the future usefulness of assets in which they invest.

- If the TSO is well placed (in terms of information and analytical capability) to make such judgements, and is able to take actions today to mitigate the risk of stranding assets in future, then it would be reasonable to expect it to bear some financial risk in the event that an asset turned out not to be useful before the end of its economic life.[31]

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31 Such an approach would be consistent with some of proposals being made in relation to the enhanced TO incentives regime, under which the TO would take investment decisions ahead of users being ready to commit and in doing so would bear some risk associated with the future utilisation of those assets.

- Conversely, if the TSO has insufficient information or competence to make such judgements, or if it has made investments at the request or suggestion of other authorities (like government) the current regime under which TSOs face little risk once assets enter the RAB may continue to be appropriate.

In this context, it is important to note that transmission investments are by nature lumpy, infrequent, and subject to scrutiny by many parties (including both Ofgem and planning authorities). The ability of the TSO to make sound judgements on investments can therefore be considered on a case by case basis. While this may represent an increase in regulatory intervention, it may be justified by its effect on overall incentives towards efficiency.

Including a congestion volume driver in the TO price control

An alternative solution that would remove the price volatility risk would be to include a congestion volume incentive within the five year TO price control at a pre-defined price level. In this case, the allowed capital expenditure set at the time of the price control would be associated with a defined volume of congestion or network capacity.[32] If the TO made fewer investments and congestion levels were higher than forecast, the TO would incur a financial cost.

The level of this cost would need to be defined by Ofgem. It could either relate to an estimate of investment costs such that the benefit of underinvestment is clawed back, or it could relate to an *ex ante* estimate of the cost of congestion, in order that the TO faced a cost that reflected the cost incurred by the SO. The incentive could be symmetric, such that if the TO were to invest more than planned and reduced congestion, it would receive incremental revenue.[33] Under such arrangements, the SO would then need to be incentivised separately (over short periods) in relation to the price at which congestion relieving trades were made.

It is worth noting that this type of scheme would *not* be the same as the current control, which has a revenue driver providing the TSO with incremental revenue if new generation connects. This is because no account is taken within the current driver as to whether the connection of new generation actually results in

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32 The approach to defining the volume of congestion or the level of zonal boundary transfer capacity would need further consideration. It is likely to be imprecise, since both clearly vary significantly over time with system conditions. Equally, we note that it would be difficult to separate short term congestion (caused principally by the short term changes in the dispersion of generation and load) and longer term less transient congestion (caused by insufficient transmission infrastructure relative to conditions across a large number of time periods).

33 This would be more difficult to achieve with a capacity as opposed to congestion volume measure, as there would also need to be a test to verify that the capacity was actually valued by the market.

increased congestion volumes during the period, despite new investment.[34] If a congestion volume driver were implemented, continuing the current revenue driver may be less important.

Again, the remaining question would be whether the level of risk associated with network investment between reviews was appropriate. The same considerations would apply as noted above in relation to the indexation solution.

3.5 Conclusions and timescales

In recent years, there has been an ongoing debate about whether regulation incentivises efficient decisions between network investment and constraint management. While analysis of historic data does not provide strong evidence of problems in the past, the issues are likely to become more important in future. Continuing the *status quo* may therefore result in increased congestion costs borne by customers as the need for new investment to resolve congestion increases.

There may be benefits from increasing the use of competitive tenders, although such opportunities may be limited given the requirement for investments to be discrete if they are to be effectively tendered. However, it is not clear to us that ownership separation of the TO and SO will be a requirement to get these benefits and, given the costs that would be incurred in a separation, it is not clear the solution would maximise net benefits.

Licence and code changes (in particular changes to the SO TO Code) are most likely to have an impact on the optimisation of within year activities between the GB SO and the Scottish TOs. This means that the changes are worth considering but do not represent a solution to other problems.

The key area for change is therefore the incentive framework. The simplest solution of a unified TSO price control would not be desirable as the TSO would be exposed to too much risk of congestion cost volatility that is outside its control (at least without significant rule changes to allow the TSO to mitigate its exposure to energy market price related risks).

The most appropriate solution, therefore, appears to be one where only relatively controllable risk (i.e. that related to congestion volume, not price) is left with the TSO for a longer period (e.g. five years). There are two possible approaches to achieving this:

- indexing target SO costs to an external cost benchmark; or
- making the TSO face a cost of congestion at a predetermined price.

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34 While they are likely to be related, the volume of congestion need not be fully correlated with the volume of new generation connected.

Both solutions take away cost price volatility and provide a five year volume incentive. The residual question is whether the TSO faces risks in relation to network investment consistent with their WACC so that there is no incentive to overinvest. If this is perceived to be an issue, it may be something best reviewed on a case by case basis, given the nature of the projects involved in transmission. However, it would only be appropriate to introduce additional risk into the regulatory framework if there is a commensurate ability on the part of networks to mitigate that risk by taking improved decisions around network investment.

4 Distribution network issues

In this chapter we look at how the changes associated with the move to a secure low carbon economy might impact on the regulation of distribution networks. Unlike the transmission networks, DNOs typically operate passive networks today with relatively straightforward flows of electricity. They do not have a history of making trade-offs between network investment and active management options.[35] Given this, there may be barriers to DNOs taking on more of an SO type role[36] if required in future, given existing industry structures and roles and responsibilities. Ofgem is therefore interested in answering the following questions.

- Are DNOs able to take on SO roles, to the extent required, to allow for more active demand management and the potential for smart grids?
- Will the current roles and relationships of DNOs and suppliers support active demand management and the effective use of smart meters by networks?

Our focus is on the electricity distribution networks. As discussed in chapter 2, although there will be challenges associated with the changing use of gas, the stakeholders we spoke to did not think they were as significant as those facing the electricity sector. The main driver of the requirement for electricity DNOs to take on an SO role comes from the potential for a large increase in domestic consumption where there is discretion in the time of day it is required. This is not something forecast for the gas sector.

We start with a brief overview of current arrangements in respect of DNOs undertaking active management on their networks before looking at what could drive a requirement for change. As we discuss, there are ways that DNOs could make more trade-offs between investment and active management without taking on the same SO role as the TSO does today. We then consider whether there are barriers to DNOs making optimal trade-offs between active management and network investment and evaluate some options for change.

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35 Active management for DNOs could include controlling the inputs onto the network from generators or storage owners (supply-side options) or the offtakes from the network by customers (demand-side options). This could be done via price signals or contractual obligations. We discuss these further in this chapter.

36 As described in the section on transmission networks, there is no single definition of an SO, but the activities that an SO may undertake include responsibility for ensuring that demand and supply for energy on the network is balanced, and that the resulting planned physical production and consumption is consistent with network capability.

4.1 Current arrangements

In this section, we provide a brief overview of the current industry arrangements in respect of:

- the need for active network management by DNOs;
- the relationship between DNOs and the TSO; and
- relationships with customers and the supplier hub principle.

4.1.1 Active network management

Electricity flows on DNO networks are, at present, relatively straightforward. Power is injected into networks at high voltages from a small number of connections to the transmission network and distribution-connected generators, and is then distributed to a much large number of points where power is consumed. Some distribution points are at high voltages (e.g. industrial users) but the majority by number are small users at low voltages (e.g. households). As a result, power flows are typically uni-directional and relatively predictable.

DNOs generally build networks on a "fit and forget" basis. This means networks are designed to require little active management of either electricity generation or demand. They ensure that there is sufficient network capacity available to cope with all likely demand at any point in time. This is in contrast to the transmission networks that take explicit operational measures to manage inputs and offtakes on the network on a regular basis.

To make this work, DNOs rely on the fact that not all customers will consume electricity at the same time. The DNOs develop statistical models of likely peak demand across the customer base as a whole, and then build sufficient capacity to meet that peak demand (with a margin for unusual events). The same is true for generation connected to the distribution network, where DNOs will make sure there is sufficient capacity for generators to export the power they have agreed to sell.

In this environment, regulation has generally incentivised DNOs to provide network assets that meet this "fit and forget" approach at least cost. To date, there has not been much expectation that more active management would create greater system stability or reduce costs for the consumer. This is in part because distribution system stability through network investment can be delivered at relatively low cost, with typical Distribution Use of System (DUoS) charges around £60-£70 a year for a domestic customer.[37]

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[37] "Household energy bills explained", Factsheet 81, Ofgem (August 2009). Distribution charges make up 15% of the average electricity bill of £445.

However, although the DNOs are generally passive, there are some aspects of network operations that begin to take on a more active role.

- **Customer contact and emergencies:** In unusual events (like floods or power cuts) DNOs will be in contact with major customers to manage power loads to stop demand overloading the system. More generally, DNOs will contact large customers on an "engineer to engineer" basis to inform them about network outages or maintenance work and to anticipate potential problems.

- **New connections:** Before connecting new customers, DNOs will try to identify any potential network constraints. They will often offer larger customers (especially those with generation) constrained connections where customers can only import and export up to a given maximum capacity or have capacity constraints at certain (pre-specified) times. However, once connected, the DNO will not actively manage the electricity flows.

- **Scottish Hydro Electric (SHE):** SHE already takes on more aspects of active management on its network in the north of Scotland. This is a result of a thin demand base spread over a large geographic area and with a relatively high degree of penetration of distributed generation. Further it directly manages heating loads for some domestic customers via dynamic teleswitching, in order to manage local network constraints. Ofgem is currently investigating a "DSO incentive mechanism" option for SHE to cover the island of Shetland as part of DPCR5.[38]

In summary, DNOs typically operate passive networks at the moment, with relatively straightforward flows of electricity. They are used to anticipating and working around network constraints, but this is more in network design than in day to day operations.

4.1.2 The relationship between DNOs and the TSO

DNOs' relationship with the TSO reflects their role as primarily passive networks. For example, the TSO is able to call upon centrally dispatched generation that is connected to distribution networks and the DNO will make sure that network capacity is available. However, the TSO does not manage flows across the distribution networks. Instead, as discussed above, under most circumstances the distribution networks are built with sufficient capacity so that no active management of flows is required.[39]

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38 "Electricity Distribution Price Control Review, Initial Proposals – Allowed Revenue – Cost Assessment", Ofgem (August 2009), p. 89.

39 Some aspects of the TSO role will also affect electricity on the DNO. For example, the TSO's measures to stabilise frequency will ensure that frequency on all the DNOs will also be stable, but in general no further active management of electricity flows is required.

DNOs do undertake a number of technical measures in response to requests from the TSO, but these are generally activities required to maintain balance on the transmission network. For example, DNOs can be instructed to reduce voltage on the network by 3% or 6% in order to reduce overall demand at times when the system is under stress.[40]

4.1.3 The supplier hub principle and customer relationships

Within the GB electricity market, the primary relationship with customers is held by the supplier. The supplier is responsible for securing all the services needed by customers. This includes procuring wholesale electricity in the wholesale market, paying transmission and distribution network charges and contracting with other market participants, like meter providers. There are two main aims of this model:

- to provide an incentive for the supplier to get best value for customers throughout the supply chain in a way that meets customers' objectives; and
- to minimise transaction costs for customers who may prefer to have one contractual relationship.

Suppliers therefore have a role as the mediator within the supply chain. They need to identify and package propositions that are attractive to both customers and to other parties in the supply chain. For example, suppliers will offer long-term fixed price deals to customers where they can both lock-in long-term energy prices from wholesale suppliers and price the energy at a level attractive to consumers.

4.2 Drivers for change over time

There are two main reasons why DNOs might be required to take on a greater role in actively managing their networks.

- **Technical stability:** If network flows become more complex or variable, DNOs could be required to take on a more active role managing their networks[41], simply to ensure that system stability is maintained. This would be the case if continuing with passive management resulted in unacceptable fluctuations in voltage.

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40 DECC "Delivering secure low carbon electricity: a call for evidence" (August 2009) p. 16.

41 The actions that the DNOs would need to undertake to ensure system stability include managing the flows on the network by either requiring an increase or decrease in input flows (e.g. from distribution connected generation) or output flows (e.g. via demand side management).

- **Economic incentives:** The current "fit and forget" model requires building a network to cope with all expected demand. It therefore requires significant spare capacity to be in place for most of the time when the network is not being used at its peak level. But it may be that active management could reduce the peak load required on a part of the network, thereby limiting (or at least delaying) the need for additional reinforcement. If it is cheaper to manage the network constraints rather than reinforce the network, then this is the more economic option. Further, given uncertainty about how the low carbon economy may develop, there may be value in the optionality that active management could deliver. Essentially, it is a way of buying time, during which uncertainty may be reduced, at a lower cost than investing in a long lived asset that risks being stranded.

The four main developments that are likely to change the technical and economic incentives for active management over time are:

- **smart meters**, which will make active demand management technically possible and will be rolled out over the course of the next decade;
- **electric vehicles** (and to a lesser extent heat pumps) that could lead to a significant increase in the level of peak demand, but with a high potential for load shifting, beginning towards the end of the next decade;
- **variable generation**, such as wind power, which will create an incentive for more flexible demand management; and
- **distributed generation** (which may be predictable like CHP plants or may be variable like windmills) and **storage solutions** (such as electric vehicle batteries), which could lead to greater complexity of flows on the network.

We discuss each in turn.

Smart meters

Smart meters will make demand management technically possible over a much wider range of customers than today. Smart meters will allow suppliers to introduce time of use tariffs that encourage customers to consume electricity at different times, either through static or dynamic tariffs. Smart meters should also provide a platform for remote load management, whereby external parties (suppliers or others) can switch on or off some appliances within the homes at particular times.[42] DECC is still consulting on the form of roll-out, but it is expected that smart meters will start being introduced in the next couple of years with a full roll-out to domestic customers being completed by 2020.[43]

However, while smart meters may facilitate change, they are not likely to drive it. Smart meters will not threaten technical stability, nor will they require additional network capacity. Smart meters instead provide an option for greater demand management to avoid incremental network capacity. With current domestic use of electricity, this is unlikely to be significant, as there is relatively little domestic load where there is an option to time-shift demand.[44] Further, given total DUOS charges are a relatively small part of a customer's bill, it is unlikely to be driven by a desire to ease any existing constraints on the distribution network. Nevertheless, smart meters remain an important enabler for demand management that may become more important over time.

Electric vehicles and heat pumps

Electric vehicle use could easily double the total and peak electricity demand of a domestic customer. A typical car battery might have a capacity of 22kWh, or around twice the daily consumption of a typical household.[45] Fully charging this battery from a standard 13 Amp household mains socket delivering 3kW would take over 7 hours. Many households are likely to be interested in higher capacity connections which offer faster charging when needed. A 10kW connection would reduce the minimum time needed to recharge by around two-thirds, but would significantly increase household peak demand.

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42 These do not necessarily need to be externally controlled. For example, frequency detectors can be installed in fridges during manufacture, which would then respond automatically (see National Grid "Operating the Electricity Transmission Networks in 2020: initial consultation" (June 2009)).

43 DECC "The UK Renewable Energy Strategy", (July 2009) p. 86.

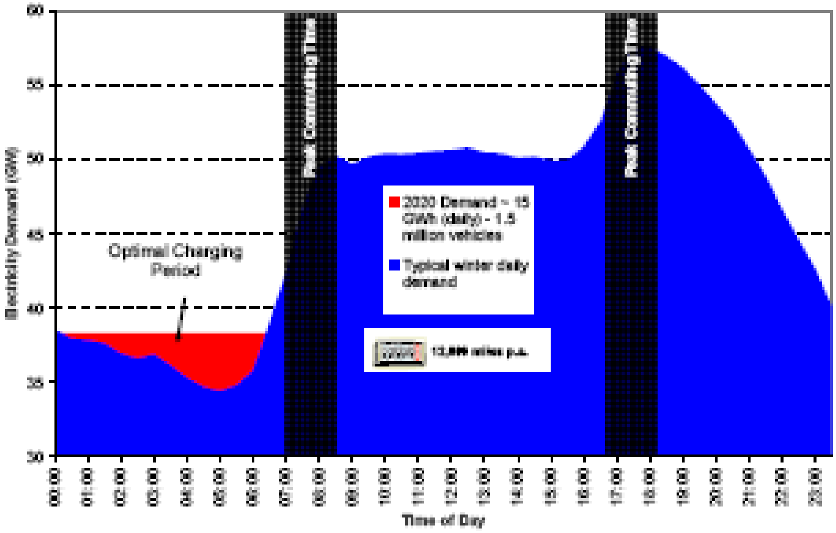
44 See "Demand Side Market Participation Report for Department of Energy and Climate Change", HIS Global Insight (July 2009).

45 National Grid "Operating the Electricity Transmission Networks n 2020: initial consultation" (June 2009), p. 25 A typical household consumes around 3,300 kWh per year, or just under 10kWh per day. An electric car would use just over 10kWh per day, based on driving 12,000 miles per year and a vehicle that can travel 3 miles on one kWh of charge.

Even without high capacity connections, only around 300,000 cars (or 1% of the current stock of cars) would have to be charging simultaneously to increase overall demand by 1GW. National Grid is projecting 1.5 million electric cars could be on the roads by 2020. If they were all charged simultaneously, overall demand would increase by nearly 5GW. Total generation capacity in 2009 was just 79.2GW, so even relatively small numbers of cars could add materially to peak demand. As a result, in the absence of any demand management measures, a rollout of electric vehicles would require significant network reinforcement.

However, unlike most existing domestic electricity demand, there is likely to be discretion in the time of day it is required: many customers will not mind exactly when their electric vehicle is charged, providing that it happens within a certain window. Since this window will generally be when people are asleep, it should include the period from midnight to 6am, currently the time of lowest demand.

Figure 2. A typical winter demand profile and optimal charging period for electric vehicles



Source: National Grid "Operating the Electricity Transmission Networks in 2020: initial consultation" (June 2009), p. 26

Wholesale generation prices will provide a strong incentive to avoid consumption at peak demand. Suppliers would therefore be encouraged to provide tariffs and demand management techniques to customers with electric vehicles in order to minimise electricity purchase costs.[46] The same type of motivation would also be likely to encourage an expansion of the TSO role, where the TSO makes much

46 Assuming that settlement changes so that the charges suppliers pay for electricity on behalf of customers with electric vehicles reflects the time at which they consume power.

more use of active demand management in order to limit the impact of this variable demand (which may involve encouraging consumption when the wind is blowing as much as reducing it at traditional peak periods).

However, electric vehicles could cause a shift away from pure "fit and forget" networks for DNOs for three reasons:

- Network constraints will not necessarily occur at the same time or to the same intensity as generation constraints. For example, at times of high wind, generation prices could be relatively low and the network could provide the main constraint on the system. DNOs will not be able to rely on generation prices alone to provide sufficient certainty that demand will be reduced to avoid network investment.

- Network flows could become more complex if vehicles are used for storage. Electricity would no longer flow in one direction from the transmission grid towards households but would flow in different directions depending on whether cars were charging or exporting energy.

- At the start of any electric vehicle roll-out, there may be local clustering of take-up, reflecting the social demographics of certain areas. During this period, DNOs may not be able to rely on the averaging of customer behaviour over their network if localised effects emerge. Further, it will take time for DNOs to get sufficiently robust statistical evidence about customer use of electric vehicles to optimally apply such averaging.

In summary, any rollout of electric vehicles would be likely to have significant impacts on distribution networks, even at relatively low levels of penetration when only a few per cent of customers have such vehicles.

Variable generation

If generation does become more variable in response to greater reliance on wind, there would be strong incentives to find ways to create a more flexible demand response that allows active demand management. However, by itself, this would not necessarily create any greater role for the DNOs, as long as the new generation is transmission connected. Instead, the primary motivation for the demand response would come from suppliers (who would seek to avoid imbalance charges) and from National Grid, as the TSO matching demand and supply at a national level. If demand and supply is matched at a transmission level, electricity flows are likely to still be uni-directional on the DNO network, limiting the response needed from the DNO.

Distributed generation

As we discuss in Annexe 2, the amount of distributed generation is likely to increase. However the scale of increase is uncertain and depends on factors such as the kind of policy support given to CHP[47] (which offers lower carbon emissions than equivalent sources today but is not compatible with a decarbonised electricity sector) and the planning regime for onshore wind (that will often be distribution connected) compared with offshore wind (that will more likely be transmission connected).

An increase in distributed generation may increase the complexity that DNOs have to deal with, particularly if it is variable. Connection costs may also rise although such connections may allow less reinforcement of the rest of the network to meet demand.[48] Our meeting with the Energy Networks Association indicated there a certain amount of generation could be connected to the distribution network before constraints were faced, although this could be exhausted if CHP schemes took off in town centre locations.

4.3 Implications for network responsibilities

The extent of the SO role that DNOs may need to develop will depend on the importance of each of the drivers discussed above. Depending on the outturn scenario, the types of active management could be quite different, from something close to existing responsibilities around managing constrained connections through to regional balancing markets operating in real time. To understand the drivers of this, it is helpful to think about the change in responsibilities on two dimensions.

- **Geographical dimension:** There are scenarios on both the demand-side (electric vehicles and heat pumps) and supply-side (small scale LV distributed generation) that could result in a requirement for active management on low voltage networks, potentially down to street level. However, if these do not take-off, or are most efficiently managed by others in the supply chain, the balancing function of DNOs could be similar to today, although perhaps involving some within-area regional balancing.

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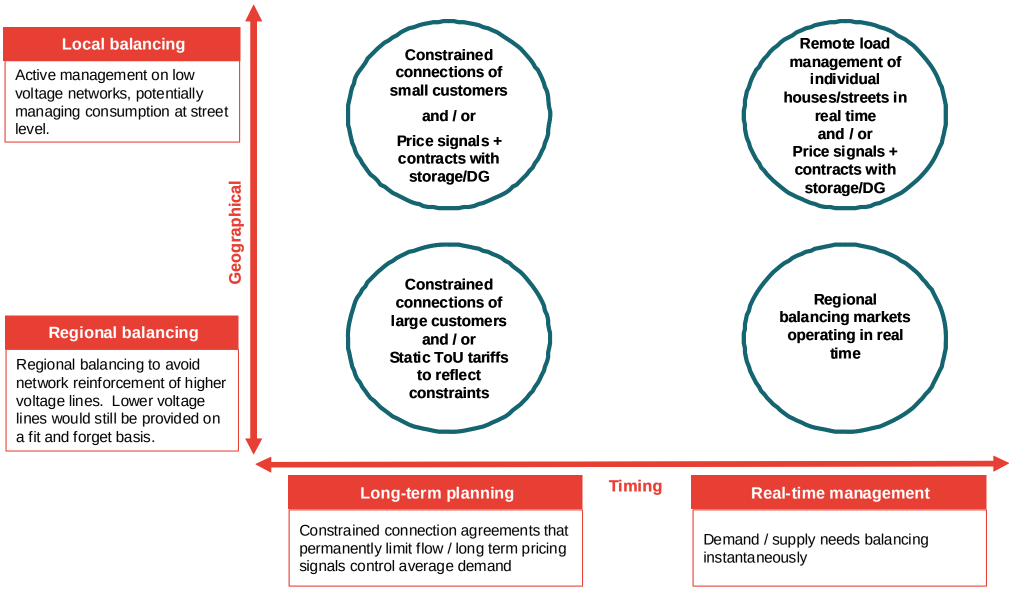
47 The policy in respect of feed-in tariffs will be relevant since it will set the value for any sale of electricity back onto the network.

48 The output from the plant could be used to provide electricity to customers on a part of the network that, in its absence, would require the network to be upgraded to allow the supply to come from an alternative source.

- **Time dimension:** A real-time response could be required if DNOs will need to instantaneously manage demand to ensure system security. However, there are other scenarios where any response can be maintained by long term arrangements, as they are with constrained connections.

Depending where the industry ends up on these two dimensions, this could lead to different requirements for DNOs to take on SO type activities. This is illustrated in Figure 3 below.

Figure 3. Potential requirements for SO-type activities



Source: Frontier Economics

The driver that could move DNOs to the sort of SO role identified in the top right hand corner would be a move to higher discretionary domestic electricity demand. As discussed above, the most likely driver of this will be the mass adoption of electric vehicles.

4.4 Potential barriers

In the previous section, we have seen that there may be an increased SO-type role for DNOs in the future, particularly if local balancing is required on a real-time basis. Given these types of activities do not currently take place, we look to see whether there may be barriers to them developing in an optimal way.

However, we first set out the features active management must have for it to be a substitute for network investment.

- **Certainty of response:** The DNOs must ensure that the network has sufficient capacity to allow customers to receive their contracted service. This certainty is reflected in the network planning standards (e.g. P2/6). By investing in network assets, DNOs essentially obtain certainty that a level of service can be provided, subject to unexpected failures. Active demand management options will need to replicate this certainty. This could be delivered in one of two ways:

    - each contract could specify a guaranteed response (i.e. that the DNO instruction will always be met); or

    - the DNO has sufficient options to call on that it can be satisfied to a high enough probability that the response it requires will be met.

  There may be merit in reviewing whether the planning standards need adjusting in the light of expected market developments. Similarly, a review of the quality of service standards may be warranted to test whether customers' willingness to trade-off quality of service against cost has been affected by the change in use, and cost of delivery, of energy. However, the basic principle that a contractual approach will still require certainty against whatever level of standard has been set will not change.

- **Length of response:** Network planning can have long timescales: to minimise overall network cost a view is taken about expected flows over long periods. This also reflects that network capex is characterised by long-lived assets. However, in other cases, planning may take place over a shorter time frame and, even with long-lived assets, there may be options for re-scheduling it by using shorter-term active management options instead. Further, given uncertainty about how the industry will adapt to a low carbon future, it may be optimal to plan over shorter time horizons until there is more certainty. In these circumstances, shorter active management solutions may provide a better option than a long lived asset.

With this in mind, we identified four potential barriers to DNOs taking on SO roles, which we discuss below.

- **Role conflicts:** Will a DNO's SO activities conflict with those of the TSO?

- **Securing supply-side response:** Will DNOs be able to secure a supply-side response of sufficient robustness to act as an alternative to network investment?

- **Securing demand-side response:** Will DNOs be able to secure a demand-side response of sufficient robustness to act as an alternative to network investment?

- **DNO incentives:** Do the current regulatory arrangements incentivise DNOs to make the right choice between network investment and active demand management options?

4.4.1 Role conflicts

If transmission and distribution companies are both operating SO-type activities, we need to consider whether there is a potential for them to conflict. We split this into consideration of technical and incentive conflicts.

Technical conflicts

Most conflicts currently take place where the distribution and transmission grids connect at the 132kv level. When we spoke to National Grid (NG), it considered that one of the main reasons for these conflicts was that DNOs did little active management, and instead left it to NG to take action. Therefore, providing DNOs invested in the necessary monitoring devices and equipment, it did not see why they could not jointly ensure the technical stability of the grid.

Indeed, this is already essentially what happens in Europe in relation to highly interconnected national and regional transmission systems. Clearly, information protocols and specification of responsibilities would need to be resolved. However, there does not seem to be any particular regulatory barrier to this arrangement working.

Incentive conflicts

There was a concern amongst some of the stakeholders we spoke to that the TSO would "overrule" the DSO and require actions to be taken that could conflict with its own commercial objectives. For example, that it would require the despatch of a distributed generator that the DNO was relying on constraining off to avoid network reinforcement.

As we discussed above, for active demand management to act as a substitute for network investment, the DNOs would need a level of certainty about the response in order to meet their planning standards. If the TSO can unilaterally invoke rights that will result in sub-optimal behaviour on the DSOs networks, then this will need to be addressed. We are not aware that this is currently the case but, if it is, it could be picked up as part of the overall review of protocols that will be required to ensure that the TSO and DSO functions can be aligned. Similarly, if the incentive strength within the regulatory frameworks provided to the TSOs and DNOs differ in respect of active management options, this may distort optimal trade-offs being made between the two parties.

4.4.2 Supply-side barriers

In this section we look at whether there are any barriers to DNOs being able to make use of a supply-side response. A supply-side response may involve DNOs instructing generators or storage providers to reduce or increase flows onto the network. This could be from either distributed generation or, in the longer term, electricity storage solutions. The FENIX project[49] has researched the options for creating Virtual Power Plants (VPPs) to provide services that can act in a similar way in aggregate to centrally dispatched generation. It has shown that it can be done in principle, although it is easier where the industry structure is more vertically integrated.

Some stakeholders challenged whether they will be able to get a sufficiently firm response via a contractual arrangement with these facilities to avoid network investment. They instead thought that removing the barrier to networks owning such assets would be beneficial. In the absence of this change, there was a concern that there would be a bias towards network investment over active management solutions.

In principle, if there was a service of value that a distributed generator or storage owner could provide to the DNOs, it is not clear why the contractual solution would not work. The DNO could issue a tender for the service it wanted to the level of certainty it required. If there was no response to the tender, this would indicate that the value to the DNO for system management purposes was not of sufficient value compared with alternative arrangements the owners could make. However, there may be circumstances where this is not the case.

- **Localised active management:** In cases where the response needs to be location specific, the number of options open to DNOs to deliver a supply-side response might be small. If the DNO is reliant on a small number of facilities to ensure technical balance of its system, there is a question whether the facility could hold the DNO to "ransom" when it needs to call on the capacity.

- **Size of facility:** There may be many small scale facilities increasing the contractual costs of the DNOs and reducing the likelihood that the active management option will be cost effective. However, specialist aggregators may emerge that can manage and co-ordinate numerous small-scale generators/storage providers at lower cost than the DNOs.

These barriers will be bigger if the SO role is required at a very local level. If they are not addressed, we would expect DNOs to favour network reinforcement at the expense of active demand management, at least on the Low Voltage (LV) network. We therefore consider options for addressing this barrier below.

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49 See www.Fenix-project.org.

4.4.3 Demand-side barriers

This section looks at the potential barriers to DNOs securing a demand-side response from customers as an alternative to network reinforcement. Our conversations with network stakeholders raised concerns that can be grouped into two areas.

- First, the current industry structure means that suppliers, rather than DNOs, would be responsible for the smart meter, and this could limit DNOs options for utilising smart meter functionality.

- Second, DNOs did not think suppliers would provide them with the type of services that they would require.

We discuss each of these potential barriers below.

Control of customers' meters

Under the "supplier hub" model, suppliers are responsible for providing metering services to their customers. The first point to note is that this does not preclude DNOs installing their own smart meters on their premises, such as the local substations. This may provide network benefits to them (for example in the management of network faults and optimal use of the network given outturn demand). However, such a solution will not be sufficient to provide DNOs with the ability to secure a demand-side management response. For that a direct link to individual customers' premises would be required. We therefore need to look at how DNOs will be able to interact with suppliers to access the functionality of smart meters.

The terms of the proposed mandatory smart meter roll-out are not yet known. However, it is likely that the following criteria will be met.

- **Type of meter:** Since the roll-out will be mandatory, there will be a process for agreeing the minimum meter specification. If DNOs have a business case for requiring a particular functionality, it is hoped that the process to agree the specification will accommodate it.

- **Access to data:** The model of roll-out that looks most likely to be adopted is known as the "Central Communications" model. This provides centralised access of data that, we understand, will be available to DNOs.

- **Speed of response:** The communications technology has yet to be specified and so the speed of communication to and from the meter is not yet known. As far as we can ascertain, the speed of communication between the DNO and the meter will not be materially impacted by the addition of a third party (the supplier) in the chain of command. For example, it is unlikely that the technology will provide sufficient speed for domestic customers to contribute to frequency response services, regardless of whether there is an additional party in the chain. For services that do not require such an instantaneous response, the additional time taken for the supplier to act as the intermediary is less likely to affect the viability of the service.

Since the terms of the smart meter roll-out have not been announced, these assumptions will need to be revisited when there is more certainty. Even if they do, there is still a question how any upgrades to the original meter specification will occur and whether this could act as a barrier.

- **Contractual cost of securing upgrades:** The DNO will have to negotiate with all suppliers operating in its area. As well as the cost of having to deal with multiple parties, it is unlikely that exactly the same terms would be agreed with all suppliers. This would therefore increase the ongoing costs of managing multiple contracts.

- **Potential unwillingness to innovate:** Suppliers may not want their meter bases to have different functionality in different regions. This could restrict their willingness to change meter specification for DNOs unless they all agreed.

- **Monopoly meter provision:** Short of installing a separate meter in the customer's premises, DNOs have no choice but to use the supplier's meter. This could mean that they are held to ransom over the cost of an upgrade.

If nothing is done to address this barrier, we would expect DNOs to contract at below optimal levels with suppliers for innovations to smart metering for network reasons. We look at whether there are options for removing this barrier later in this chapter.

Will suppliers want to sign these contracts?

For larger customers, DNOs could contract directly with customers to secure demand-side services. This is something ENW is trying to implement and is described in our meeting note. However, this will not be possible for domestic and SME load, where customers are unlikely to want to engage with multiple counterparties to govern use of their energy supplies. For those customers, DNOs will need to contract for the services with suppliers.

In our meeting with British Gas, it said that it did not see this as a problem and it would look to find opportunities to offer active demand management services with DNOs. However, other DNO stakeholders were sceptical. Of the arguments put to us, the following appear worthy of further consideration.

- **Length of contracts:** Customers can, and do, frequently change supplier. In 2007, over 5 million customers switched supplier, which is almost 20% of the total customer base.[50] This may not matter if the active demand management that is being sought covers a sufficiently large geographic area, thus allowing averaging effects to be relied upon. In this case, suppliers may assume that they will always have enough customers of the type to offer the service (e.g. prepared to install automatic response equipment) for a contract of sufficient duration to be of use to the DNOs. In contrast, if a local response is required suppliers may be less certain that they would maintain sufficient coverage to offer the service. It may be that the only suppliers with sufficient coverage in such localised areas will be the incumbent supplier. If this was the case, being the only supplier able to offer such a service could serve to make the incumbent's position stronger.

- **Localised pricing:** Even if DNOs tendered for contracts with suppliers, there are reasons why suppliers may be reluctant to take them up:

  - **National brands:** Suppliers have national brands and may not want to offer localised pricing as it would increase the costs of marketing and they may not want to justify why prices vary between different areas.

  - **Complexity:** Suppliers will need to make sure their billing systems can handle such differentiated pricing, something that has been an issue affecting supply competition in Scotland for customers with dynamic teleswitching.

  - **Price discrimination:** The licence changes made in response to the supplier probe may lessen suppliers' willingness to engage in regional price differentiation.

The more localised the requirement to secure a demand response, the more likely it is that DNOs will fail to secure appropriate contracts with suppliers and invest in network assets instead.

4.4.4 Equalisation of incentives

The price control framework needs to equalise incentives to allow DNOs to optimise the choice between network investment and active management alternatives. If these alternatives are limited to contractual arrangements (assuming ownership of supply facilities is not permitted) then it will require a balance between long-lived network capex investments against contractual opex alternatives, potentially lasting for much shorter periods.

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50 "Switching rate hits 5.1 million in 2007", Ofgem press release (April 2008).

It is easy to state that incentives should be equal but, as we saw in chapter 3, the reality of achieving this is challenging. The changes that are being proposed as part of DPCR5[51] to equalise the incentives between opex and capex spend go some way to addressing this problem.[52] However, the very different durations of a long-term investment and a short-duration contract make it hard to equalise risk and return in a price control framework. The same issues will therefore apply in a DNO control as those we discussed for the TSO control. Unless the differential risk of each option under the regulatory framework is correctly set, DNOs will not be expected to make the optimal trade-off.

4.5 Options for change

In the previous section we identified certain barriers that may distort DNOs' incentives to make an efficient trade-off between network investment and active management of demand and supply. In this section we look at the options for change that could address these barriers. We break these options into three different types.

- **Structural:** The roles and responsibilities of different industry participants could be changed. For example, responsibility for an activity could be transferred to another party (e.g. metering responsibility could be moved from suppliers to DNOs) or ownership rules could be changed (e.g. DNOs could be permitted to own distributed generation). Some of these changes would require a change to primary legislation while others could be done via licence changes.

- **Licence and codes:** For any given structural arrangement, licences and industry codes set out obligations including those that govern industry interactions. These obligations could be changed, for example by including an obligation in the supply licence to require them to offer terms to DNOs to upgrade the meter.

- **Incentives:** There are then a set of specific financial incentives that attempt to ensure that the behaviour of networks is efficient and consistent with a competitive market. For example, changes to the risk and reward of different activities within a price control could be made to influence network behaviour.

We evaluate options to address each of the barriers identified in the previous section.

51 The latest electricity Distribution Price Control Review.

52 "Electricity Distribution Price Control Review – Initial proposals", Ofgem (August 2009).

Meter upgrades

If the responsibility for providing meters in customer premises is with the supplier rather than the DNO, there may be a barrier to the DNO securing upgrades to the metering equipment.

A structural solution could involve the transfer of responsibility for metering services from suppliers to DNOs. However, this would merely move the barrier from DNOs to suppliers, who will also have a legitimate requirement to use the meters to incentivise customer behaviour. It may be easier to regulate DNOs' behaviour with respect to access to the meters, given the regulatory framework for networks is necessarily more comprehensive. Yet we do not think this reason would be sufficient by itself to warrant such a structural change to meter ownership.

In the absence of a structural solution, if suppliers retain responsibility for metering it will not be possible to deal with the barrier by adapting the incentive framework on DNOs[53]. Instead a condition could be inserted into the supply licence, requiring all licensees to negotiate with DNOs who request a meter upgrade, with possible Determination by Ofgem in the event of a dispute. However, this would go against the move to simplify the supply licensing framework to prevent it acting as a barrier to supply competition.

Given it is not clear how much of a problem this barrier would be, there is a case for waiting to see if it becomes an issue before seeking to add a new supply licence condition. Also, further avenues for dealing with meter upgrades may be revealed as the process for delivering the smart meter mandate is finalised.

Supply-side response

There may be barriers to DNOs securing supply-side services at a local level given the contracting costs involved in managing multiple small scale schemes and the potential for monoposony rents to be earned by the owners of such facilities.

A structural solution would be to relax the ownership rules and allow DNOs to own and operate distributed generation and/or storage facilities. This would act directly to address the barrier and would increase the likelihood that DNOs would make an efficient trade-off between network investment and investment in supply-side solutions. However, there are risks with this approach.

- It might bias DNOs towards ownership of such facilities, even when there are economic contractual options.

53 An option could be to bias the incentives in favour of DSM solutions to overcome the barrier created by supplier ownership of meters, however, this will involve a cost to customers that will be greater than an option that addresses the supplier behaviour directly.

- DNOs could exploit insider knowledge about the location of the best sites for such facilities.
- For certain schemes, particularly distributed generation, the provision of services to DNOs may be a relatively small part of the overall services offered by the facility. This could create problems about appropriate cost allocation when determining allowed costs during DPCR.

DNOs' licences could be changed to provide them with a requirement to tender for active management services before making network investment. However, this will raise costs particularly if it covered small schemes connected to the 11kV network and below and would not address the potential monopsony issues identified above. Since there is no requirement to tender for other network assets, we do not see it being an economic solution in this case.

It is not clear there is a solution involving a change to the incentive framework. If the incentives have been equalised between investment and active management options, DNOs will respond to the barriers to active management by over-investing in network assets. It is not clear that over-compensating the active management option to overcome the barrier would be in customers' interest.

It may be that DNOs are able to obtain sufficient demand-side response, so that supply-side response is not important. However, if it does not materialise, and local level balancing is required, Ofgem may wish to give further consideration to relaxing the rules on ownership of small scale supply-side options, should these provide a more economic solution to providing capacity than the more traditional approach of investing in wires.[54] This could be limited both by size of scheme and voltage connection on the basis that the problem will be most acute at local level. Such an approach has clear parallels with the gas regime that allows the gas network operators to own gas holders.

Demand-side response

There may be barriers to DNOs securing demand-side services given high levels of customer switching and potential reluctance on the part of suppliers to offer differentiated service offerings by region of the country.

A potential structural solution to this barrier would be to allow DNOs to contract directly with customers. However, there are two reasons why this may not work.

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54 There is a question whether this is allowed by the Third Energy Package. However, if they own storage that is used solely for the network and do not take title to the electricity (i.e. it does not count as sale or resale of electricity) then it should be possible. Ofgem should seek legal confirmation of this.

- People move house almost as often as they change supplier. The median length of residence of owner occupiers is 11.6 years, whilst for private renters this drops to 1.7 years.[55] Although energy contracts could be linked to the property rather than the owner, it is not clear this would be a welcome innovation to customers.

- DNOs are not set up to bill small customers on an individual basis. It would be costly to adapt billing systems to implement this change.

Instead it may be preferable to allow part of the contractual relationship to be transferrable to the new supplier. This could be done by extending and adapting the part of the contract that relates to the connection agreement. Similar issues are being discussed in the context of the Heat and Energy Saving Strategy consultation.[56] Any solution to the problem of financing energy saving schemes that emerges from this consultation may also be relevant in this context.

Even if contracts were transferrable, it would not address the barrier to suppliers being reluctant to offer multiple tariffs that vary on a regional basis. If DNOs were allowed to reflect all of these differences in their structure of charges, a supplier would be forced to trade-off the cost of reflecting such price differentials within its charges against the increased marketing and billing costs that might result. This would raise the costs of being a supplier and, if there are fixed costs to managing the complexity, could have a detrimental effect on entry into the retail market. Further, if suppliers chose not to reflect the costs in final tariffs, no price signal will be seen by customers and therefore no change of behaviour would occur.

An alternative to using price signals to generate response would be to have automatic controls installed in customers' homes with the ability to directly control use, rather than relying on a price signal. For example, some expect that the ability to charge electric vehicles will be demand-managed by the supplier or National Grid, via a plug / socket controlled by radio teleswitch.[57] If this was the case, DNOs could expect to get the demand result they required if they could strike a contract with a supplier to manage this process to meet network constraints. Suppliers would be expected to do this provided customers were willing to make the price/convenience trade-off. However, unless network charges are reflective of the costs of individual use (e.g. to reflect the cost of wanting a connection sufficient to fast-charge two electric vehicles), customers will not face the correct price signals to make the trade-off.

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55 "Housing Statistics 2008", Communities and Local Government (2008), Table 8.2.

56 "Heat and Energy Saving Strategy: a consultation", DECC (February 2009).

57 HIS Global Insight (July 2009) p 31.

Equalisation of incentives

If DNOs are to make the right trade-offs between network investment and active management, the price control needs to make sure it does not distort this trade-off. As we discussed in chapter 3 in respect of the transmission price control, this is not easy because the activities may have different risks both within a control period, and because of the regulatory treatment at the time of review. DPCR5 has taken an important step to equalise the strength of incentive for opex and capex efficiency. However, it may be that further changes will be needed to ensure the trade-off between active management opex and investment capex is optimised.

- **Within-control period risks:** It is not yet clear how volatile the contracts for active management options will be. It may be that the price volatility is of a similar order to that currently faced by TSO. However, if options such as domestic demand management and the output from small scale distributed generation / storage solutions are available on standard tariffs, there may be less risk.

- **Between-control period risks:** As we set out in our discussion of transmission networks, the regulation of capex to date has meant that once it is included within the concept of a RAB, the DNO sees little risk to it of recovering the investment cost. Whilst this is appropriate when the investment is likely to continue to be used and useful throughout its life, it may not be appropriate given the increased uncertainty about the future use of networks caused by the changes discussed in chapter 2. Instead, there may be more opportunities to make use of active management contracts rather than invest in long-lived assets, until there is more certainty about how the industry will develop.

There are two broad approaches that could be used to create the right incentives for between-control period risks:

  - an ex ante approach, based on evaluating whether an investment appears appropriate at the moment at which it is made; and
  - an ex post approach, based on remunerating asset owners depending on the actual use that is made of their investment in future.

The current regulatory framework is closer to the ex ante approach: once an investment has been allowed into the RAB, asset owners do not expect the investment to be removed for the remaining life of the asset. However, if this approach is to be continued, it would rely on Ofgem being satisfied that the investments were appropriate. Although this approach may be feasible for transmission investments that tend to be large and low in number, distribution investment projects tend to be smaller in scale and more numerous. It may therefore become impractical for Ofgem to review them all.

The ex post approach is closer to what takes place in competitive markets: asset owners make an investment and then receive the market value of the output from that investment in future. In almost all industries, however, the market value is typically less certain and the asset owner is therefore exposed to more risk or is able to mitigate the risk in different ways (for example through up front recovery of investment).

Whether there will be benefits to moving to an ex post approach depends on two issues.

- Network owners would need to be remunerated based on measures of "usefulness" of assets that are observable and objective and these measures would need to be agreed in advance. This could be challenging, given assets can last for many years and the uncertainty about future use of assets is, looking forward, high.

- Network owners would need to be best placed to manage the risks associated with predicting where assets are likely to be used and useful in future as it will not be efficient for them to bear risks that they are not best placed to manage. It is unlikely that DNOs could develop better forecasts of major economic trends (for example, the speed at which electric vehicles are deployed) than other sources, nor do they have much control over the pace of developments (which are likely to be driven by technological progress and government policy). But DNOs will have the best information and control about the steps that can be taken now to build networks that would be robust to a range of different development scenarios. It may therefore be that the regulatory focus should be on ensuring DNOs plan appropriately for future uncertainty, rather than rewarding or penalising them based on outcomes that they are not well placed to predict.

As with the TSO discussion, Ofgem will need to look at whether the current differential spread in risk between active management opex and investment capex needs adjusting, given DNOs ability to manage risk and what will result in best value for customers. We think this would be an important area for further work within the RPI-X@20 project.

4.6 Conclusions and timescales

It is too early to be precise about all changes that may need to be required to address the changes that will result from the move to a low carbon economy and ensuring security of supply. However, incentives need to be equalised between network investment and active management options so that DNOs will make the right trade-offs. Ofgem has already taken an important step to address this issue in DPCR5 with the equalisation of incentives between opex and capex. However further development may be possible and this is something the RPI-X@20 project should look to take forward.

There are then some other options that seem worthy of further consideration to ensure that DNOs are able to take on appropriate SO roles and can utilise active demand management and the effective use of smart meters.

- **Smart meter updates:** The way in which the smart meter mandated roll-out will happen is still uncertain. As part of this process consideration will need to be given to the DNOs' requirements, both in terms of the initial meter specification and industry processes, but also how these will evolve over time.
- **DNO ownership of supply side response:** Consideration should be given to whether DNOs should be able to invest in small scale supply side activities (such as storage) as an alternative to network investment.
- **Contractual separation on change of supplier:** If customer specific connections become more common (e.g. reflecting the number of electric vehicles able to charge at any point in time) there may be a case for seeking to make this part of the contract transferrable on change of supplier. This should be investigated once there is more clarity about how energy efficiency measures may be financed over time.
- **Differentiation of structure of charges:** Ofgem will need to look at whether DUoS charges can be differentiated to provide a balance between the cost of additional complexity and providing price signals to customers that will be sufficient to generate the efficient response.

If the incentives can be equalised between network investment and active management options, the other barriers to DNOs making an efficient trade-off may only become an issue when such decisions need to be made at a local level. This is more likely to be an issue if domestic demand is increased through the use of electric vehicles or heat pumps.

Current projections are that there will be few, if any, plug-in electric vehicles rolled out commercially before at least 2015.[58] But a roll out could begin in the second half of the next decade. Given the development cycle of new cars involves prototypes and market testing, there should be at least a three to five year notice before any mass roll-out takes off.[59] The funding of trials that has been proposed as part of DPCR5 should be used to start testing some of these solutions. If trials can start within the next price control period, this should provide adequate time for development to see whether active demand management at the local level is a workable solution.

58 "The UK Low Carbon Transition Plan – National strategy for climate and energy", HM Government (July 2009), p141.

59 On average, about 10% of the car stock is replaced each year, so to reach a 5% penetration rate of electric vehicles in the stock of the car fleet would require a penetration rate in new vehicles being purchased of roughly 15-20% of new cars for three years.

Annexe 1: Discussions with stakeholders

Meeting with Energy Networks Association (ENA)

Organisation:	ENA
Attendees:	Andy Phelps (ENA), Stephen Andrews (LowerWatts Consulting) Sarah Deasley, Richard Bradley, Radhika Chaudhry (Frontier Economics)
Date:	3rd August 2009

Will DNOs be able to take on an SO role?

The future role of networks is uncertain: the LENS scenarios may imply very different behaviours for DNOs depending on which one materialises. The biggest changes are likely to be the result of much more widespread distributed generation. Within this, Stephen Andrews highlighted two points:

- the complexity of contracts that could be required in order to achieve all the benefits associated with distributed generation; and
- the need to manage potential conflicts between SO requirements at transmission and distribution level.

Complexity of contracts and implications for ownership

Distributed generators could be required to sell services in several ways:

- selling electricity into the wholesale market;
- receiving ROCs or other support for renewable generation;
- decreasing power to meet local network capacity constraints; and
- other roles, like frequency response

This creates the potential for significant complexity. For example, at times a generator might wish to increase generation to get high prices for electricity and ROCs but be constrained off by local networks. Without a consistent set of contracts, the DG owner would be exposed to compensation claims for not providing electricity (and receiving ROCs) at times when they are constrained off by the DNO.

DNOs would only be able to avoid network reinforcement in areas where they can guarantee a response from network users (Engineering Recommendation (P2/6)). However, this would not necessarily be required for the whole life of an asset as even a delay in investment would still have value, even if it cannot be avoided altogether.

Under the existing regulatory framework, generation owners would need to solve the coordination problem by having a series of back to back contracts. The contracting process would get complex and expensive, and may still leave DG owners exposed to risks, limiting the uptake of DG.

As an alternative, the UK market may need to reconsider the constraints on ownership. If DNOs were able to own their own generation, they could internalise some of the conflicts (although the DNOs would still have the same potentially conflicting economic incentives to increase or decrease generation, and would have to sign consistent back to back contracts with other parties in the supply chain).

Potential conflicts between TO and DNO requirements

National Grid has suggested that distributed generation should be required to meet technical requirements, needed for the transmission SO but not for the DNO alone. For example, DG could be required to meet the same technical requirements as centrally dispatched generation.

The motivation for National Grid is to avoid some of the operational risks that would come from large amounts of distributed generation working to different technical standards. NG has argued that events of 27th May 2007 in Germany (and other European countries) which nearly led to a widespread network failure and major blackouts, would be harder to manage without such technical standards. If DG is unable to cope with frequency fluctuations like that of 27th May 2007, more plants could have shut off triggering further frequency changes and problems. However, making DG robust enough to cope with this type of change is expensive and NG has other options (e.g. increasing the technical reserve) in some cases. To some extent, the requirement for DG to meet the standards required for centrally dispatched generation is an attempt to get the technical reserve requirements for free.

One further consequence of managing local generation to meet TSO requirements is that the generation is then not available to the distribution SO, and the DSO has to perform "backflips and somersaults" in order to manage demand on the local network. (N.B. this is only likely to be an issue in a world in which DNOs have already taken on an SO role – if DNOs are still operating on a "fit and forget" basis, the technical problems are reduced at the cost of extra network reinforcement.)

However, it would not necessarily need to be the DNO that takes on the local SO role. It could be that National Grid could take on the SO role throughout the whole electricity network – DO and TO – especially if the SO services were needed at the level of regional balancing, rather than more local levels. In this case, the SO would take on the role of an asset owner, with National Grid as SO.

Timing: when would DNOs need to take on an SO role?

The primary driver for DNOs to take on an active role would be DG. This is the main driver that would cause it to be cheaper for parts of the local network to be actively managed and harder to rely solely on fit and forget.

On most local networks, there is scope for additional generation before network reinforcement would be required. At the very local level, on average around 40% of houses could fit a 1.5kW micro CHP plant before the network would face problems (likely to be voltage control in the first instance). However, an 8kW electric car would be a "different ball game" and networks would likely face problems at considerably less than 40% penetration. At higher voltage levels, there tend to be similar levels of headroom. So a typical local 11 kV network could support maybe 1-2MW of generation capacity, while a typical 33/132kV line could support 30-40 MW. But this is an average, and DNOs might face constraints sooner (for example, from CHP in town centres, although this is not a problem yet).

Scottish Hydro is already taking on many aspects of an SO role. This reflects the distributed generation on the network with lots of wind and few customers to soak up the demand.

How can DNOs rely on active demand and supply management

With more distributed generation, there will be a need to reliably aggregate large numbers of small users to provide services (like balancing power) that can only be provided today by large individual users or generators.

The FENIX project has researched the options for creating Virtual Power Plants (VPPs) to provide these services, and act in a similar way in aggregate to centrally dispatched generators. This has demonstrated that it should be possible to provide VPP-type services based on disaggregated providers. However, this would be easier in a more integrated, less fragmented market than that in the UK. Importantly, any trials of VPP services should cover the regulatory/commercial arrangements as well as the technical requirements. Finally, in relation to what role other industry players may have in the future, it is uncertain whether suppliers are interested in the long-term relationships needed by DNOs in some instances. One option to trial would be third party agents, similar to the role of meter providers today.

Telecon with Energy Northwest (ENW)

Organisation:	Energy Northwest (ENW)
Attendees:	Paul Bircham (Energy Northwest) Sarah Deasley, Richard Bradley, Radhika Chaudhry (Frontier Economics)
Date:	30th July 2009

Incentives for the TO and SO

One option to help mitigate the problems associated with the TO/SO split may be to re-evaluate the role of the System Operator (SO). The role of the SO has two components: a technical role (operating the network to ensure balance, frequency response etc.) and a commercial role (securing contracts with different parties prepared to balance up or down or provide other services).

The commercial role of the SO could potentially be in conflict with the TO's functions. As a result, it may be possible to separate the commercial activities of the SO from the TO, while leaving the technical activities with the TO, so resolving most of the commercial problems.

Need for more active demand-side management by the DNOs

Demand-side management potentially has a considerably larger role to play in future networks. The key drivers for a shift in this direction could be greater variability in generation as a result of increased generation from renewables and also a lack of adequate capacity.

Demand-side management trial

ENW is currently conducting a demand-side management trial to investigate whether reinforcement investment in a specific area can be delayed or avoided by reducing peak demand. The aim of the trial was to see whether an agreement could be reached that was attractive to both ENW and its customers. The trial involved negotiations with eight large consumers and considered three alternative contracts:

- A contract where the customer's energy supply may be halted during pre-defined time-periods (for example, during peak time) probably with several weeks' notice.

- A contract where the customer's energy supply may be halted at short or no notice, for example in the case of faults on the network or due to security concerns.

- In the event that the customers possess a back-up generator, a contract where the customer would be required to run the generator at certain times and potentially feed in to the system.

After some negotiations, it looks like there would be a set of contract terms that would be interesting to both ENW and the customers, and ENW is looking to take the trial forward to implementation stage with three to four customers (out of eight customers that ENW initially approached). The most attractive of the three contracts was the first: with advance notice of capacity being withdrawn. While the length of contract has not been confirmed yet, the tentative period is expected to be a "single digit" number of years. This type of contract would not require a real time SO role from ENW, but would still require it to manage demand more than it currently does.

The project would be attractive to ENW if it can earn a rate of return equal to the money that would have been required had the network reinforcement gone ahead – i.e. equivalent to the rate or return plus depreciation for the avoided capex that would have been allowed into the RAB. This would require some changes to the current incentive structure but should be possible under DPCR5, and ENW will require consent from Ofgem before the trial can go ahead. ENW also needs to clarify whether a contract for intermittent supply would be allowed under the Electricity Supply Continuity Regulation. ENW has a meeting scheduled with Ofgem to discuss these issues.

Within the trial, ENW is contracting directly with final customers, with a new type of agreement (rather than a revised connection agreement). This is partly for reasons of administrative simplicity (including suppliers would have meant more parties to try and coordinate/educate within the trial). The fact ENW looks to be able to contract directly with customers to secure such a deal does start to challenge the supplier hub principle. However, if ENW were to extend the trial to smaller customers, it would be more likely to use suppliers, although including more parties makes trials harder to run and more cumbersome: you would either need a supplier with sufficient customer saturation within the particular geographic area you were targeting or you would need to contract with multiple suppliers. It is further complicated by the fact customers can change supplier at short notice.

ENW recognises that the changed relationship could potentially cause problems for the customer's supplier. First, they will have to ensure they are not exposed to imbalance payments as a result of customers not consuming power when expected (although long notice periods should make this less of an issue). Second, some customers may use constant margin contracts where suppliers earn their highest absolute margin at times of high prices (when ENW is most likely to exercise the right to cut off customers).

Future SO roles

The need for greater system management is likely to depend primarily on two factors.

- More distributed generation would lead to a significantly complex network and thus increase the need for system management at the distribution level.

- Any change in demand patterns as a result of a change in technology (e.g. electric cars) could constrain the network capacity and again augment the need for an SO at the distribution level.

The level at which SO activities would need to be carried out remains to be seen. One option is that they would take place at a regional level. For example, ENW's network might naturally split into three areas: the region of Cumbria (generation dominated) and separate regions for Greater Manchester and Lancashire (where electricity flows from the grid to the final customer). If replicated across the country, this would imply 25-40 different balanced areas at the distribution level. But other scenarios are possible; if microgrids develop as per one of Ofgem's LENS scenarios, the DSO role would be much more local.

The first trigger point for a greater SO role is likely to be distributed generation. ScottishHydro already has to do some active management of its network, and this could spread further.

More generally, the existing regulatory framework is likely to be robust to new generation as long as it is "big generation", such as nuclear power or large offshore wind farms. It would be more significantly challenged if either new generation is much more distributed or if there is a widespread roll out of electric vehicles which could operate as a source of storage.

Customer relationships and demand management

In order for DNOs to rely on demand side measures in place of network reinforcement, they need to rely on:

  - long term certainty, that there will be a customer response if they are to rely on a customer response rather than network reinforcement; and

  - an immediate customer response when required.

Since customers may change their supplier with a 28-day notice, for DNO's to rely on a response means they need to reach a certain saturation of customers with demand management technology/contracts. DNOs therefore either need to own the customer relationship (at least control of technology) or all/most suppliers need to provide the same deal. Otherwise DNOs would be exposed to risks that customers would switch to suppliers who do not offer demand-side management.

Whether it is better to contract directly with the customer or go through the supplier depends on the scale of the relationship. A direct relationship is potentially more reliable but it may be easier to contract through suppliers if the target customer group is large. Contracting through the supplier may become easier once the supporting systems and processes are in place. So suppliers could act as "aggregators" of demand, securing contracts with customers who are prepared to have their demand managed, but networks then operate at a technical level to schedule customers on and off, given the contracts agreed by suppliers.

It is also essential to remove any possibility of time-delay involved in communicating with the customer through a third-party (e.g. a supplier) if that is required. Again, this would require access to any equipment required to implement the demand response.

For current purposes, ENW's expectation is that the Central Comms model for smart meters is likely to provide access to the information they need today. As demand side management becomes more active, DNOs may need access to the meter (subject to the discussion above about whether a sufficient saturation of customers can be achieved via suppliers).

Development of local energy service companies

One way in which low carbon energy services could be provided is via local vertically integrated energy service companies (ESCOs). ENW thought the scale of activity could be a potential constraint on the development of ESCOs. The ESCOs have an incentive to keep their scale of operation low to meet the licence exemption criteria, but a high level of expertise would be hard to attain at a small but integrated level.

Under the current regulation the DNOs do not have much incentive to reach deals with ESCOs to, for example, lease parts of their network since the perception would be that Ofgem would immediately deduct any revenue received from regulated allowed revenues. But ENW have not actually been approached by any ESCOs so far.

Further, it would be hard for DNOs to offer tailored prices to ESCOs given the structure of charges and prohibitions against discrimination, in the absence of Regional Pricing Zones. ENW had explored a couple of RPZ options but it had not yet found an opportunity to use one.

Meeting with CE Electric

Organisation:	CE Electric
Attendees:	Phil Jones, John France (CE) Sarah Deasley, Richard Bradley (Frontier Economics)
Date:	22nd July 2009

Overview

The challenge for DNOs – and for the RPI-X@20 project is to work out what DNOs are meant to achieve. The current framework incentivises DNOs to achieve reliable networks which meet all agreed user requirements for the lowest possible level of capex and opex. Ofgem and DNOs now need to work out what it is that DNOs are meant to optimise. For example the primary aim could be to help generation optimisation, getting the maximum amount of renewable generation connected – and without constraints – in a short period of time.

System operator role for DNOs

Current SO roles for DNOs

Today, the SO role for DNOs, in the sense of active management of load along the network, is "virtually zero". The network is generally designed to be "fit and forget" with sufficient spare capacity that all customers can use the capacity they have agreed.

There is little need for an SO role as flows on the network are relatively predictable with power generally flowing from a few large input points to many (mainly smaller) output points; even if consumption by an individual household is unpredictable, a neighbourhood is not. So, DNOs have been encouraged to adopt an approach of building the network to cope with all likely demands it is likely to face, without active management of constraints.

To the extent that there is an SO role, this comes about in two ways.

- Decisions about new connections take into account the potential constraints that new customers would impose on the network. For example, large customers (e.g. industrial sites with local generation) may agree a constrained connection where the agreed maximum capacity is less than the projected maximum outflow from the site. In these cases, the capacity constraint is agreed upfront but not actively managed later.

- DNOs take on more of an SO role during emergencies, or other unusual periods. For example, CE will be in contact with large power users following network outages to try to agree short term reductions in their power consumption to prevent any network outages spreading. More generally, CE will be in frequent contact with large users to keep them informed about engineering work/system outages etc. While this is not really an SO role, it does start to include some features and types of contact that could be relevant for an SO role. However, it is nothing like what is usually meant by SO.

There is no separate payment for SO type roles within the price control at present. There are some allowed costs for e.g. liaising with National Grid and for the control room, but the costs are not separately allocated for SO-type roles as opposed to other purposes.

In general, thinking about constraints/need for stable network flows etc. would not be a major culture shock. What would be new, would be introducing the skills and systems needed to do it all in real time.

Potential for an SO role to be required in future

The need for an SO role in future would depend on developments that make electricity flows on the network more variable and less predictable.

With current patterns of electricity generation and supply, there is not much need for an SO role, even if smart meter technology made active demand management more widely available. (Similarly, DNOs do not generally use active demand management, even at large customers where smart meter-type technology is already available). This is because the potential gains from more active demand management to reduce distribution capex or opex requirements are relatively low at present – a few pounds per customer per year – and are likely to be insufficient to incentivise customers to respond in a way that could be relied on for network planning purposes.

So, if SO roles are required in future, it would be in response to changes in electricity flows. The two most likely are the following.

- More widespread distributed generation, which could lead to more complex two-way flows along the network, especially if the generation is unpredictable (i.e. wind power). At present, CE has only a few hundred MW of distributed generation (mostly conventional, e.g. CHP schemes), where the associated wires are based on a "fit and forget" principle.

- Electric vehicles, which would draw large amounts of power, sufficient to exceed existing system capacities, and which would be likely to have a high degree of discretionary load.

These two changes would lead to more complex network flows, but it is not yet obvious at what level an SO role would be required (i.e. which parts of the network can be fit and forget, and which parts of the network would need to be actively managed). For example, it would be hard to manage any flows below secondary transformer level (a few hundred houses) as the small number of customers would require very precise targeting. More likely is that customers would agree a constrained connection – e.g. whether they can charge one or two electric vehicles at a time. The active SO role could then come into play to manage flows above the secondary transformer, but potentially still at quite a local level.

A separate issue is whether DNOs could take more responsibility for managing the power inflows/outflows to the Grid. At present, it makes sense for NG to be the TSO and centrally dispatch generation capacity. If distributed generation becomes more widespread, it would get more expensive for NG to keep this role, centrally dispatching many individual generators and relying on capacity being available on the DSO network in order to carry the power to the Grid. At some point there may come a tipping point where it becomes cheaper to get the DNOs to manage the power on their own networks, and commit to providing certain in/out flows for Grid.

Interaction between DNOs and suppliers in active demand management

DNOs sometimes underplay the relationship they have with customers, and they already have a connection agreement with every customer. Although the contact with small customers is limited, DNOs know their big customers quite well and will be in regular contact on an "engineer to engineer" basis to inform about network maintenance/manage emergency situations and so on. But for smaller customers, most of the relationship is around emergency or routine connection or interruption scenarios (power cuts etc.).

The customer relationship for active demand management needs to reflect several factors:

- The amount of money involved per customer will often be pretty small. Typical DuOS charges are around £60-70 per customer, so the gains from active demand management are likely to be only a few pounds per customer in most cases. There is a limit to what domestic customers will be prepared to do in order to save a few pounds, and so there may not be much of a role before electric cars are introduced, when there is more load to shift, and less cost to shifting the load.

- Capacity decisions need to be based on long-term commitments from customers. DNOs could not be exposed to a situation where they limit their capex in new capacity on the basis that a customer has agreed a constrained connection, only for the customer to change supplier or change its commitment and want to consume more power, requiring a higher network capacity. One option would be to have a premises specific UoS charge (e.g. a one car/two car household) that continued irrespective of the occupant or of the supplier.

- This could mean that the type of customer relationship varies across the country, in the same way as only some parts of the country can receive broadband today. In urban areas, there would be scope for higher capacity networks, with active demand management used to smooth out differences between geographically concentrated customers. In rural areas, there is likely to be more need for longer-term capacity constrained contracts for electric vehicle use, as the additional network capacity will take longer to install.

In general, the more local the level at which the SO activity takes place, the more critical it will be for the DNO to have a relationship directly with a customer, or at least be able to communicate with a specific house. If the SO role needs to manage only a few customers, then the individual consumption patterns of those individuals will matter.

Finally, there is a make or buy decision for DNOs in the sense of: do they operate active demand management/storage themselves, or do they set up a price mechanism and encourage others to bid in? Assuming they set up a price mechanism, there is the question of whether DNOs would be able to take part themselves, or whether that would be seen as abusing their position. DNOs have privileged information about network use, demand patterns, predicted outages etc. which others would not.

Meeting with British Gas

Organisation:	British Gas
Attendees:	Philip Davies, Tim Dewhurst, Steve Briggs (British Gas) Sarah Deasley, Richard Bradley (Frontier Economics)
Date:	23rd July 2009

Incentives for the TO and SO

In the electricity sector, British Gas (BG) considers that the main structural problems in this area relate to the Scottish TOs.

- The coordination of the three TOs creates problems: a single GB TO could help.
- Vertical integration of the Scottish companies creates further problems.

The problems created by this structure have always been there. However, the scale of the problem is now more evident, given improvements in cost transparency.

On the issue of whether TO and SO should be under separate ownership, BG did not necessarily see this as a problem, and felt such separation could make it harder to make efficient trade-offs between the two. Instead it may be better to do the following.

- Make sure the roles and responsibilities of each are clear and decisions fully transparent. This could be done by increasing industry scrutiny of decisions and the TOs/SO engaging more in discussions with industry.
- Greater customer involvement in TO investment decisions. BG believes that there should be scope for some network investment that goes beyond strictly that which could be implied by user commitment (i.e. investment that anticipates user need). However, to limit the risk of such assets being underutilised, they believe customers should have an active involvement in the decision to invest in this way.

BG considers that the main problem with BSUOS is the difficulty in predicting its level with any degree of certainty. There may be ways Ofgem / industry could improve the stability of BSUoS by reviewing its structure (for example, enabling the smoothing of charges over time).

There was concern that it would not be possible to extend the electricity SO incentive arrangements for a period comparable with the TO price control, given the uncertainty in estimating congestion in electricity over a longer period. They felt this would be exacerbated by National Grid (NG) having better information than Ofgem would have when it tried to set such a control. They were therefore sceptical that a set of incentives that are specified for a duration longer than a year or two could deliver good value for customers, in light of the level of uncertainty facing electricity constraint costs.

BG had a further concern about whether the networks had the right personnel to do this activity optimally. If this was the case then even the best incentive mechanism would not produce an optimal outcome. Therefore before trying to adjust the incentive mechanism, consideration should be given to the wider policy framework, and the problems with the Scottish TOs addressed.

A system operator role for the DNOs?

BG did not consider there was a need for the DNOs to take a SO role. Instead demand management should be *proposition* driven. They felt this is best delivered by suppliers engaging in commercial arrangements with customers rather than being imposed by networks. BG believe that customers are more likely to engage more actively with their supplier (with whom they have a familiar relationship) than with networks. This will have benefits in terms of the volume and type of demand management that customers offer.

BG had a number of concerns about DNOs adopting an SO role.

- DNOs are currently (and have historically) been managed as passive networks. The networks do not have a culture that is conducive to innovation and creativity, and there seems to be little evidence that networks are willing to change this mindset. This is unsurprising given that networks are operated on a risk averse basis and therefore it is a leap to think they could be used as agents of transformation.

- The joint ownership of DNOs and Suppliers means that the supplier community is diluted: suppliers that are jointly owned follow the network line. This already causes problems in challenging network behaviour (e.g. in the debate about structure of charges and the ERA's reluctance to challenge the level of rate of return used to set network price controls). This joint ownership could lead to further problems if the DNOs took on a SO role. There was a concern they could operate the SO function in a way that acted to disadvantage competitor suppliers. If the structural solution to this is not possible (split distribution and supply), the Governance arrangements should be changed so that each jointly owned D and S entity was only entitled to one vote.

- There was a concern that having 14 separate SOs for each DNO network would not lead to the overall optimisation of the GB system.

If DNOs require additional balancing on their systems, they could incentivise suppliers to do this on their behalf. Suppliers were then best placed to find the best way of securing the required services from customers.

Interaction between DNOs and suppliers in active demand management

As mentioned above, BG considers suppliers are best placed to maximise the benefits of smart meters, given they 'own' the customer relationship. Suppliers will be better able to sell services to customers as part of an integrated package, rather than individually (e.g. they would not have to charge separately for remote load management alongside other services). This could encourage take up, and reduce costs. But this would also require networks to align their tariffs to the shifts in demand needed, so that peak prices match the timing and duration of peak loads on the network.

BG considers that the functionality of the smart meter put forward by the ERA will meet all of the DNOs' requirements. Further, if networks clearly required a certain functionality to be added to smart meters (and were willing to pay for the service that such functionality would enable) then it should be straightforward for this to be included in future releases of meters. It is then the information that comes from the meters, rather than the functionality, that is of most use to the DNOs. The 'central comms' model for smart meter roll-out will provide DNOs with the required access to data. BG did not know of any problems that would be caused due to a potential timing delay if DNOs had to communicate with Suppliers, rather than directly with customers, in the operation of demand management services.

BG thought there may need to be some changes to the incentive arrangements to fully optimise the use of smart metering information. One example that was given was in terms of incentives to reduce theft where currently electricity suppliers and non-domestic gas suppliers do not have clear incentives to report and address theft. The structure of network charges would also need to be adapted so that distribution network pricing signals that align with network peak demand could be reflected in tariffs.

BG thought that the problem of requiring a long term commitment from customers (e.g. when making decisions about network reinforcement) could be overcome. This was primarily because customers will still have an incentive to respond to the charges/tariff structures put in place which encouraged them to sign up in the first place. And suppliers will develop alternative ways to encourage customers to remain on particular contract types over time.

Development of local energy service companies

BG noted the link between this issue and Ofgem's consideration on distributed generation in 2007. BG's views on this issue were broadly in line with Ofgem's conclusions at that point. Beyond issues of aggregation and scale, BG did not think there were any obvious network-related barriers to the development of ESCOs.

They considered that the biggest potential barrier related to the financing of energy efficiency investment and debt recovery. In particular, how you recovered the large upfront investments required without incurring unacceptable risk of bad debt given disconnection of the service/removal of the investment were not possible. This is in contrast to Sky TV services where the value of the service sky provides is in the delivery content, which can easily be turned off where there is non-payment. BG provided us with a presentation given to Ofgem that looks at this problem in more detail and suggests extending the right to object on change of supplier as a potential solution[60].

60 "Facilitating Retail Competition in Energy Service – Extending the Right to Object" (9th April 2009).

Telecon with National Grid

Organisation:	National Grid
Attendees:	Paul Whittaker, Lewis Dale (National Grid) Sarah Deasley, Richard Bradley Radhika Chaudhry (Frontier Economics)
Date:	7th August 2009

Incentives for the TO and SO - electricity

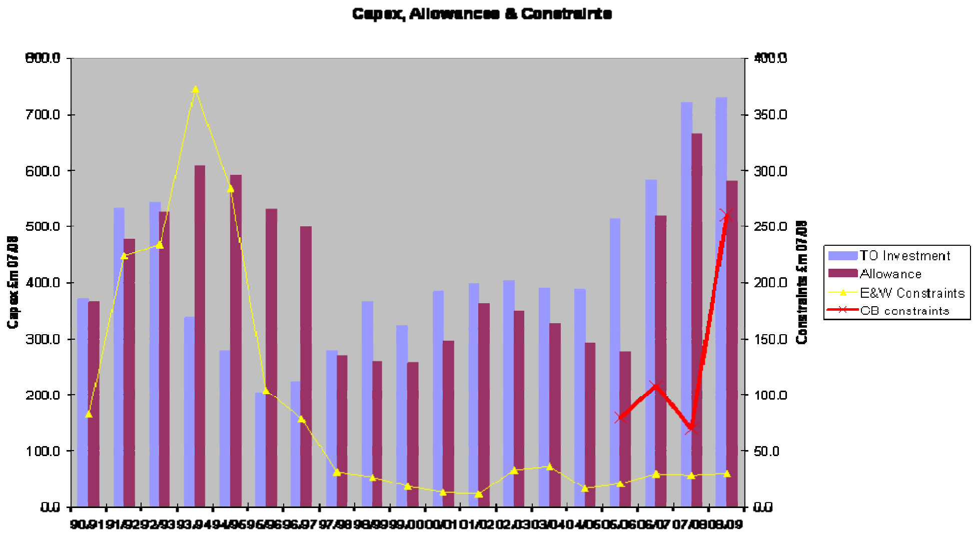
Although Ofgem sets separate incentive mechanisms for National Grid's (NG) SO and TO functions, NG is a single company with one licence. NG has a legal duty to undertake both functions together so that it meets its legal duty to develop and maintain an efficient and economical system. It internally co-ordinates the TO and SO functions so as to meet this objective.

To forecast constraints NG make volume predictions about constraints in particular areas and then they look at what plant is affected to determine likely costs. Forecasting the volume of constraints is intrinsically hard as it requires separating actions taken to address constraints from those taken to establish reserves (and NG will combine the two in order to manage the network effectively). However, the really difficult bit is working out the Balancing Mechanism impact. This "market" is not particularly liquid and the bids and particularly the offers are largely independent of any 'market price' and can be quite volatile. Regional pockets of constraints are likely to have few generators and so strategic bidding can occur. Nuclear, which is not flexible, is always likely to bid very high compensation requirements. Although they would like a longer SO incentive, the risks inherent in exposures to the Balancing Mechanism makes it hard to move to a longer term SO incentive. This might be addressed by a radical change away from the Balancing Mechanism to something like nodal locational pricing.

It is hard to split constraint payments between long term causes (where NG may be making a choice between network investment and constraint costs) and short term causes (where there is day to day management, for example to deal with maintenance requirements).

NG provided the following data about constraint payments and capex allowance and investment.

Figure 4. Capex, allowances and constraint costs

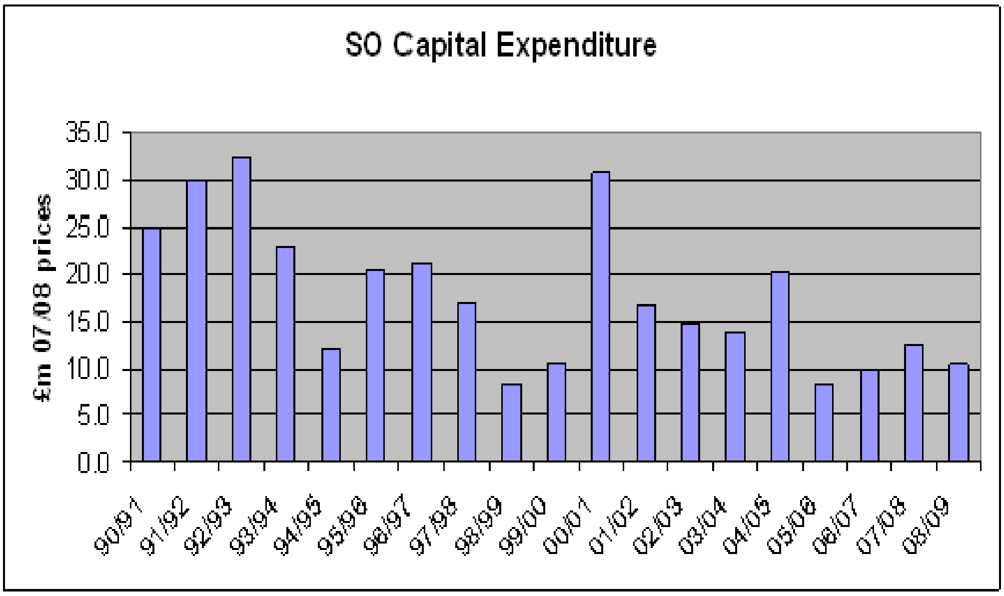


Source: National Grid

The data on the TO allowances up to 1996/97 is from Appendix 10, Transmission Price Control Review (Dec' 06). That for 1996/7 to 2000/1 has been taken from Ofgem initial proposals for the 2001 price control. Allowances for 2001/2 onwards come from Ofgem final proposals documents (including final proposals for the 1 year roll-over control for 2006/7). All of the numbers have been adjusted from the various price bases used in the final proposal documents to 2007/8 prices using RPI. The allowed revenue has not been recalculated to reflect issues such as the impact of outturn revenue drivers.

The data on TO investment has come from NG's regulatory accounts and is based on gross capex less SO capex and less any user capital contributions. These numbers vary from those in the transmission report (due to the inclusion of non-operational capex like vehicles and software) but allow a consistent definition back to 1990. SO Capex on the same price basis is shown below in the chart below.

Figure 5. SO capital expenditure



Source: National Grid

NG consider this shows that they have not been underspending on capex for the last few price controls whilst increasing constraint payments. Whilst there was a small bump in constraint payments when NETA came in, constraints in E&W has been fluctuating around £25-50m level since an SO incentive regime was first introduced. In E&W, most constraints are due to maintenance outages. NG considered that short term SO incentive schemes for a vertically integrated company owning TO and SO worked OK.

It is harder to manage the integration of the TO and SO roles in Scotland, with NG providing the SO role on transmission networks owned by others. The interface between the parties is not very contractualised and, while there is scope for the SO to pay more for the TO to work in a different way (e.g. pay overtime to get TO to complete work faster) this is rarely offered and so rarely used. NG already has the opportunity to comment on the network owners' plans, and this generally reaches an acceptable solution.

The increase in constraint costs in recent years has been for GB constraint costs. This increase has in part been because renewable generation is being connected before waiting for reinforcement at the E/S boundary (given the terms associated with the introduction of BETTA). The TAR may result in a move to a more "connect and manage" world. It would be expected that E&W's constraints would start rising if "connect and manage" is extended.

Looking further forward, in the period from 2020, a bigger nuclear base load together with an unpredictable wind load could lead to additional changes on top of the move to more "connect and manage" world. You would expect this to lead to a higher level of 'efficient' constraint payments. NG thinks that the overriding duty it has to manage the system will mean it will trade-off TO and SO in an efficient way to this new equilibrium. If the incentive mechanisms could further encourage transition to the new efficient equilibrium, that would provide further comfort that they would be meeting their fundamental duty.

NG also noted that quantified constraint costs were not a big driver of network investment, since constraint costs are hard to predict even a year ahead and investments can last up to 50-60 years. Investment decisions are primarily driven by security standards, in conjunction with NG's fundamental economic duty to act in an efficient way. So, while the general assessment of the robustness of alternative options and hence the likely avoidance of constraints is an important consideration, it is not a case of calculating an NPV of constraint costs over 50 years, compared with the capital investment that would otherwise be required.

Incentives for the TO and SO – gas

NG thought that the gas SO incentive arrangements were more complete than the electricity arrangements. This was because gas was easier to manage in this way (given buy back arrangements and reserve capacity). Further, the joint ownership of the SO and TO over the whole geographic region in gas meant that it was possible to use remuneration within the RAB as part of the incentive framework. This would be more complex in electricity given the ownership separation with the Scottish companies.

NG have already managed a massive change in the direction of gas flows across the network in the last five years without increasing constraint costs. They don't think it will get more difficult than this. Further, although they do not think that the gas network is on a path to obsolescence, they did not think that there would be particular problems with managing constraint costs during any wind-down.

A system operator role for the DNOs?

At the moment, DNOs operate largely passive networks. The wires are designed to meet statistically adjusted demand requirements. As soon as you put generation in a network, this "fit and forget" becomes difficult to do. Instead you have to manage flexible services in order to keep use of the network within capacity. The levels of Distributed Generation (DG) are not yet sufficient to require much of an SO role for DNOs.

The issues between T and D at the moment occur at the borders of the networks, particularly at the super grid transformer level. They have regular meetings to discuss these issues. A lot of the problems that occur now come from the fact that there is little DNOs can do to control their networks. The situation may therefore improve if DNOs make investment in technology to manage flows on their systems and have more options for undertaking actions on their networks. NG also thought the current DPCR5 proposals in respect of exit charge incentives would also help.

NG was involved with the FENIX project, which looked at how to harness DG into Virtual Power Plants (VPPs). NG felt the project initially did not give sufficient consideration to the role of suppliers and the fact that in GB the SO role was a relatively small role given that only c3% of capacity is not self dispatched. Although NG procure some services from DG, they are fairly niche services and may be aggregated by other parties. They thought it was network control services from distributed generators that DNOs should focus on while the wider despatch and sales role would sit better with suppliers.

NG thought the most likely scenario was for DNOs to undertake a role where they ensured technical stability on their networks rather than undertaking a commercial local balancing role. It felt this would most likely be met by S and G via self dispatch combined with NG's balancing responsibilities. They did not think that all of the LENS scenarios were equally likely (and Ofgem should focus RPI-X@20 on those that were more likely). In particular, NG considered that the microgrids scenario was unlikely. However, if the scenario did occur, then local balancing at DNO level would become more likely. In those circumstances, GB would look more like the interconnected networks of Europe where each country is largely self-sufficient but trades at the margin. However, NG thought it would be 2050 or beyond before such a scenario emerged. There would therefore be sufficient time for it to happened gradually, and, on the basis of what they know now, did not think they would face a cliff-edge point where there would be a sudden need for change.

Interaction between DNOs and suppliers in active demand management

One of the reasons NG signed up to FENIX is that they thought they would need more flexibility in the future (from VPPs) to make up for the decline in centrally dispatched generation. NG has not seen a lot of demand side participation in the Balancing Mechanism, although they have seen more in some of the short term tender arrangements. This is because suppliers are incentivised to get customers into balance and, to date, they have tended to compete on price rather than flexibility. However, NG thought this might change as smart meters go in.

NG did not think it was yet clear what the enduring role of DNOs should be. You would expect suppliers to do most of the activities, with DNOs undertaking similar niche roles to those of NG with specialist network/balancing services procured by tenders, etc.. Further, some solutions may just be legislated for rather than 'bought' (e.g. all new fridges would have to be sold with a chip in them that provided load management capability).

NG thought that using DPCR5 to provide funding for some proper trials was the right way to go. In general, active demand management was likely to develop gradually over time with no sudden "cliff edges". Regulation would therefore have time to adapt as pressures became clear, rather than needing to anticipate all potential problems now.

Development of local energy service companies

NG did not have strong views on vertically integrated ESCOs. They did note that if you were looking for much more innovative energy service companies, it did not seem sensible to prohibit networks from entering this market.

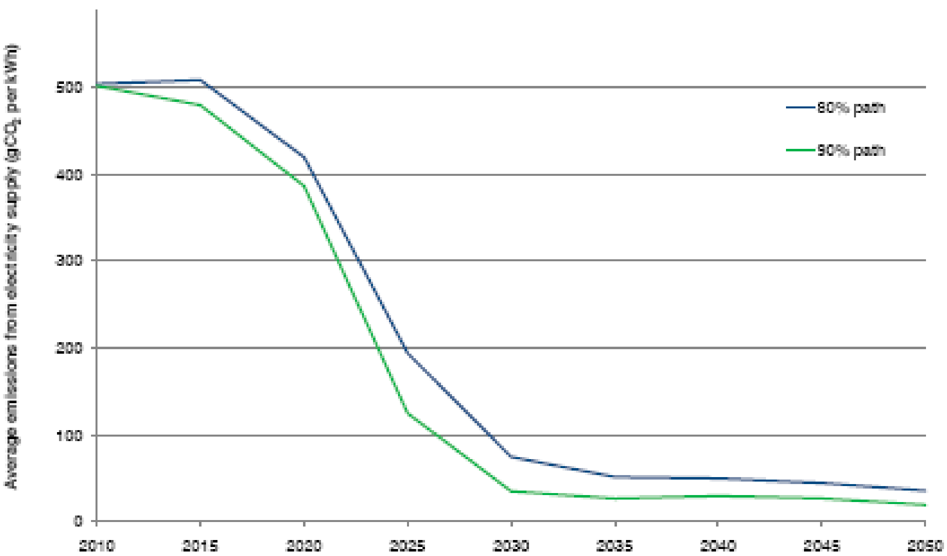
Annexe 2: Climate change policy and security of supply

This annexe summarises the drivers for changes in energy networks that are needed to ensure a low-carbon economy and security of supply. We focus on the changes that most directly affect the areas of interest in this report: namely, where there is a potential choice for networks between capital investment and actively managing networks.

4.6.2 Electricity generation

Coal and gas power stations currently account for 75% of electricity generation in the UK[61] and electricity generation contributes 28% of all greenhouse gas emissions.[62] To meet climate change targets, emissions per unit of electricity will need to fall by around 90%. Modelling carried out for the Climate Change Committee (CCC) suggests that this reduction will need to be achieved by 2030 if the 2050 climate change targets are to be met. Figure 6 shows the CCC's forecasts for the carbon intensity of electricity.

Figure 6. Carbon intensity of electricity generation



Source: Climate Change Committee "Building a low-carbon economy - the UK's contribution to tackling climate change" (December 2008)

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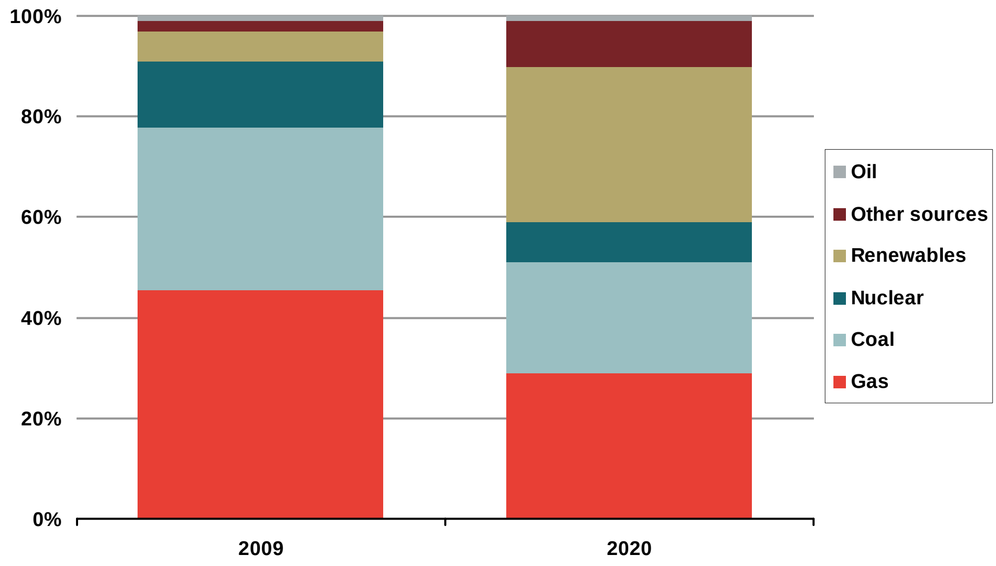
61 DECC, "The UK Low Carbon Transition Plan", July 2009 p. 54.

62 Source: Defra, data for 2007.

Although there is uncertainty about this timing, it is clear that decarbonising electricity generation is essential to meet the 2050 targets. In the next decade, the reductions in greenhouse gas emissions are expected to be achieved by significant changes in the mix of energy generation. This is partly driven by the fact that much of the existing generation fleet will need to be replaced by 2020. Sixteen major power stations are scheduled to close by 2020, including 12GW of coal and oil power stations under the Large Combustion Plant Directive and 7GW of nuclear power where plants have reached the end of their lives.[63] DECC's forecast change in generation mix is shown in Figure 7.

Figure 7. Electricity generation by source: DECC projections



Source: DECC, "The UK Low Carbon Transition Plan", July 2009 p. 54

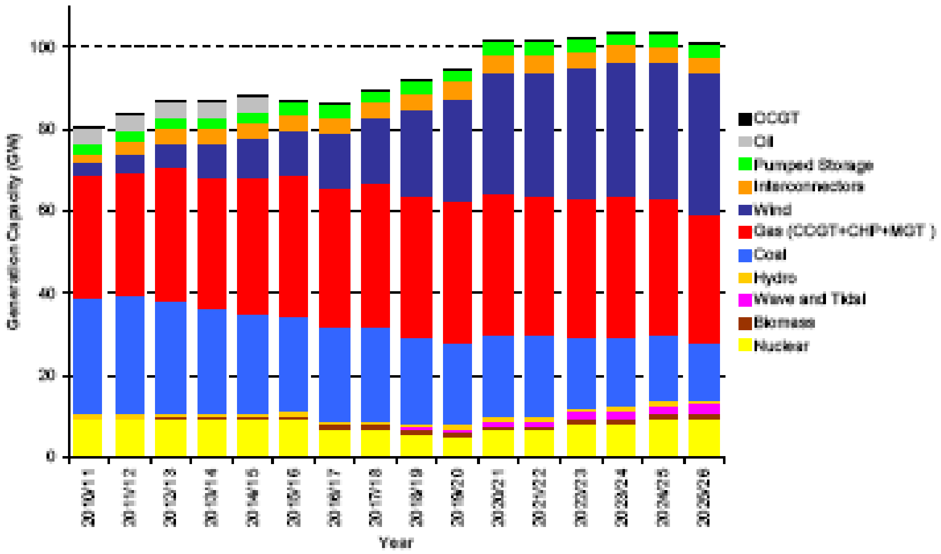
DECC projects that the share of coal and gas-fired generation will fall from over 75% today to around 50% by 2020. At the same time, renewable generation will expand five-fold from 6% today to just over 30% in 2020. The bulk of the additional renewable energy is expected to come from wind power (approximately 27 GW), with roughly equal amounts of onshore and offshore wind generation. The total installed capacity of wave and tidal power could be approximately 1GW, while small scale renewables could account for between 3 and 4GW.[64]

63 DECC "Delivering secure low carbon electricity: a call for evidence" (August 2009) p. 30.

64 DECC "The UK Renewable Energy Strategy", (July 2009) p. 44.

Other projections show similar views about how the generation mix could develop. Figure 8 shows National Grid's projections of generation mix in their "Gone Green" scenario. The scenario shows a steady increase in the total capacity of wind generation connected to the network, with decreases in gas and coal. Nuclear generation is expected to drop in the middle of the next decade as plants are retired, with a gap before the next generation of plants are built.

Figure 8. Electricity generation by source: National Grid projections



Source: National Grid "Operating the Electricity Transmission Networks n 2020: initial consultation" (June 2009), p. 15

Three types of technology are forecast to provide the bulk of electricity generation: wind power (both on and offshore), nuclear power, and coal or gas-fired power stations fitted with carbon capture and storage (CCS). These plants have different characteristics from the thermal generation used today and will have implications for networks.

- New capacity is likely to be **located in different places** from generation today meaning the need for new investment and the need to manage new flow patterns.
  - On the transmission system, wind power will mainly be located in the extremities of the country or at sea. Even future coal plants with CCS may be located differently if clustering becomes more important to minimise costs of a CO_2 transportation network.
  - On the distribution system, smaller scale generation, either of an intermittent or more predictable nature, could proliferate. This generation could either be connected as embedded generation currently,

or could even be located in individual domestic customer premises. This would mean that flows would cease to be predominantly unidirectional.

- Generation will be **more variable**, as wind generation will depend on the weather. Ensuring a geographically distributed portfolio of wind generation will help minimise the variation, but generation, and hence the pattern of flows over networks, will be less predictable overall. The electricity system as a whole needs to be resilient to periods of low wind, when there will be need for thermal backup plant, and high wind, where there will be a need for synchronised thermal plant that can reduce output quickly, or for sources of export demand or storage.

These changes will have an impact on security of supply. DECC and National Grid are both consulting on the steps that will help ensure security of supply in this environment.[65] Both expect that continuity of supply will continue to rely on flexible generation, but that active demand management will also have an increased role.

4.6.3 Energy demand

Over the next decade, overall demand is expected to be approximately the same as it is today. Improvements in energy efficiency and reactions to potential price increases are expected to be broadly offset by extra sources of demand and economic growth. But in the longer term, there may be changes in the mix of energy use. Total electricity demand could increase at the expense of gas and oil based fuel sources, if it plays a growing role in providing power for heating and transport. Figure 9 shows the CCC's projections for electricity generation to 2050, based on most domestic heating switching to electricity and a high penetration of electric vehicles.

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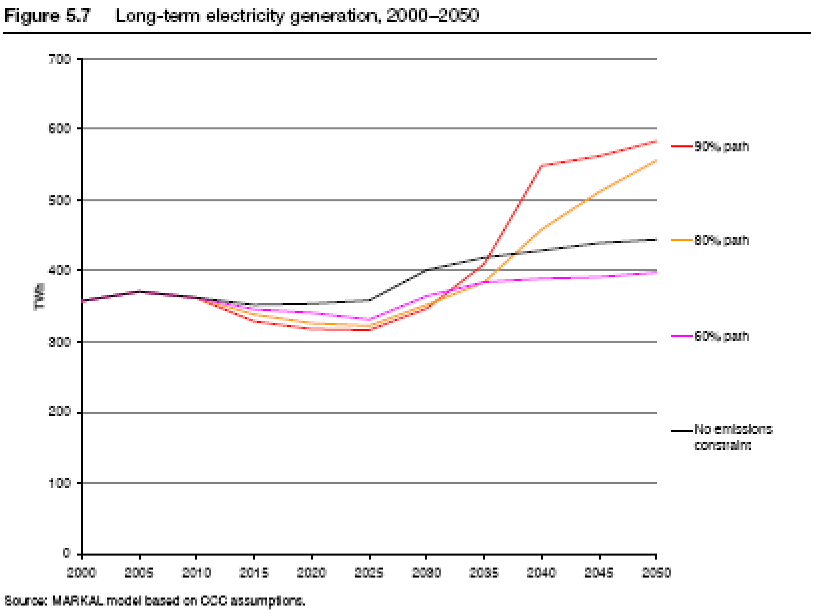
65 DECC "Delivering secure low carbon electricity: a call for evidence" (August 2009), National Grid "Operating the Electricity Transmission Networks n 2020: initial consultation" (June 2009).

Figure 9. Projected level of electricity generation required in order to meet climate change targets (60%, 80% and 90% reduction in emissions by 2050)



Source: Climate Change Committee "Building a low-carbon economy - the UK's contribution to tackling climate change" (December 2008), p. 179

In the long term, the future of the gas network is uncertain. For domestic and commercial customers, gas is mainly used for space heating and hot water. Since electricity can also provide such services, if the electricity sector can be decarbonised, it could replicate these uses with lower carbon emissions. Together with the potential reduction in gas fired generation, this means there is some uncertainty about the future of the gas network, unless it can be used to transport renewable forms of gas, such as biogas or landfill gas, or unless backup for intermittent generation is provided through alternatives to electricity space heating (e.g. continued use of gas boilers in individual premises).

The second area that could be transformed is the transport system. It will not be possible to rely on fossil fuels to power the transport system if the long-term climate change targets are to be met. Based on existing knowledge, it does not appear practical to capture carbon emissions from individual vehicles and, even with improvements in energy efficiency, carbon emissions would be too high without such carbon capture technology. Instead, road transport is likely to move to either battery-powered electric vehicles or vehicles using hydrogen fuel cells. The more likely of these options appears to be battery-powered vehicles, but that depends on developments in battery technology.[66]

66 See for example Climate Change Committee "Building a low-carbon economy - the UK's contribution to tackling climate change" (December 2008).

The use of battery technology in vehicles could prove to be one of the main methods to deal with the intermittency and variability of wind power to ensure security of supply.[67] Being able to draw on that power and export energy back to the grid at times when the system is short, would help to manage short-term fluctuations.

There are some niche examples of electric vehicles around today. However, most commentators do not expect the early stages of a mass-market rollout to start until 2020. National Grid assumes a rollout of 1.5 million vehicles in 2020 in their Gone Green scenario, or around 5% of all cars. Nevertheless, given the scale of electricity demand that could result from even a modest roll out, this could lead to major increases in electricity demand in some areas.

Combined with these changes to the demand for, and use of, electricity, the rollout of smart meters will provide a means to potentially enable demand side management. Smart meters will allow suppliers to introduce time of use tariffs, potentially encouraging customers to consume electricity at off-peak times. They should also allow suppliers or others to switch on or off appliances within homes in order to support the economic management of the overall power system. DECC is still consulting on the form of roll-out, but it is expected that smart meters will start being introduced in the next couple of years with a full roll-out to domestic customers being completed by 2020.[68]

The main implications of these changes for networks are the following.

- **New network capacity may be required** to meet the additional demands of heating and transport loads.

- **The new demand is uncertain:** On one hand, demand management facilitated by smart meters may reduce consumption at peak. On the other, however, the maximum demand required to charge an electric vehicle quickly could be a significant addition to current maximum demand for other current household uses.

- **Flows are likely to be more complex:** The flows on distribution network will cease to be predominantly unidirectional if there are changes such as an increase in distributed generation or if electric vehicles are used to provide electric storage and export power back to the Grid. This will mean an increase in the number and uncertainty of network events that will require DNOs to undertake active management by controlling flows onto and off the network.

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67 David MacKay "Without Hot Air" (2009).

68 DECC "The UK Renewable Energy Strategy", (July 2009) p. 86.

- **The demand is potentially quite discretionary:** Many customers may not mind when their electric vehicle is charged, as long as it is charged at some point overnight. The same is true of heating, as customers will generally care more about the temperature in their room than the precise time the heat is generated. This, combined with the roll-out of smart meters, provides an opportunity to manage network flows by controlling high volumes of demand at low cost, with large loads able to be moved in time. This means there is the potential for DNOs to avoid network investment by instead making use of demand management.

4.6.4 New technologies

As the intermittency of generation increases, the economic benefits of energy storage should improve. Equally, in parallel with other developments relating to decarbonisation (e.g. improvements in battery technologies), the cost of electricity storage may reduce.

At present technology levels, the most economic of the electricity storage facilities is likely to be Compressed Air Energy Storage (CAES), with estimates for capital costs in the range €700-850/kW for an asset likely to have a lifetime of around 30 years[69]. These costs are above current estimates of OCGT or part-loaded CCGT costs. However, with technological developments and the potential for use in new cavities, the cost of CAES may reduce to be competitive with conventional flexible generation. Equally, improvements in battery or fuel cell technologies may improve the economics of other storage solutions.

Over the long term, it is therefore credible to consider the connection of either centralised or distributed energy storage devices to the electricity network, with the following implications.

- **The possibility to invest in new technologies**. Particularly where energy storage technologies have no other users, it may be appropriate for DNOs to consider investment in storage technology instead of network capacity (as the gas networks did in relation gas holders and LNG storage facilities).

- **Flows are likely to become more complex**. As with the use of electric vehicles as a form of storage proving power back to the grid at certain times, flows on distribution networks may cease to be predominantly unidirectional.

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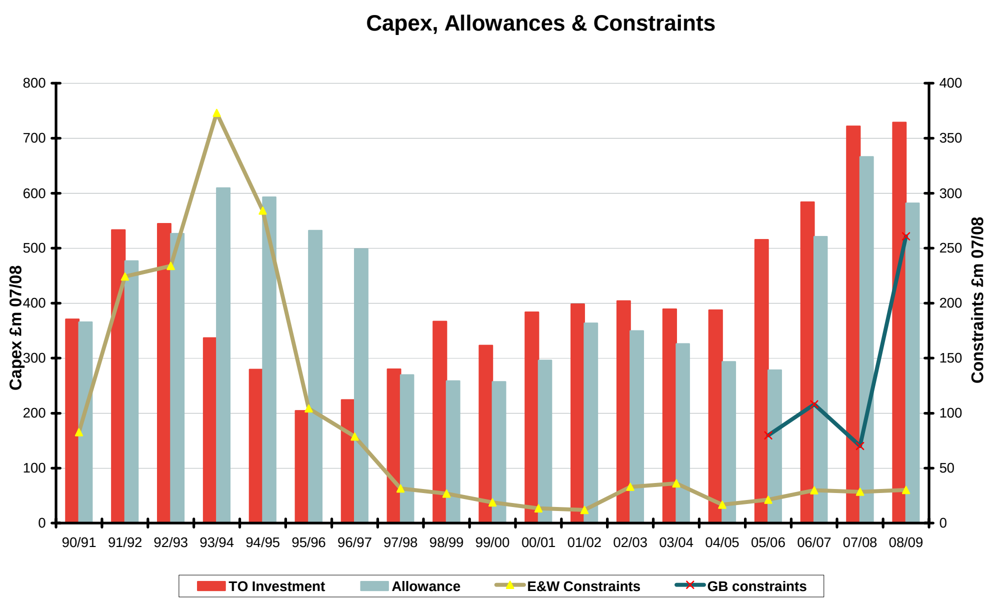
69 "Emerging Technologies to increase the Penetration and Availability of Renewables: Energy Storage - Executive Summary" (EPRI, 2008).

Annexe 3: Experience from electricity transmission SO incentives

To date, historical data does not indicate a clear issue in relation to NGET (and latterly the GBSO and the Scottish TOs) trading-off the cost of future constraint payments against future network investment, although the data available makes it hard to draw definite conclusions. Figure 10 shows the allowed and actual levels of capex on the electricity transmission network and the level of congestion costs incurred. Between 1990 and 2005, the congestion costs only cover the England and Wales network. Post BETTA, congestion costs are shown for GB as a whole.[70]

Figure 10. History of capex and constraint costs



Source: National Grid

70 The data contains several simplifications although we believe the graph is broadly representative of the overall position. In particular, load and non-load related capex is combined; the TO investment has been taken from NG's regulatory accounts and is based on gross capex less SO capex less any user capital contributions; and some data has been estimated from previous graphs where underlying data was not available. The meeting note with National Grid provides full data sources.

The chart shows that between 1992-93 and 1995-96, high congestion costs were incurred at the same time as the TO was investing significantly less than the allowances set in the price control. However, while this might at first sight indicate sub-optimal decision making in relation to the capex / constraint payment trade-off[71], it is arguably more likely to be the result of:

- generators exercising locational market power over constraint payments; and
- the absence of a financial incentive mechanism on the SO (at the time, constraint payments were simply passed through to customers).

In later years, up to the implementation of BETTA in 2005, congestion costs remained low and stable. The level of investment more consistently tracked price control allowances, with a slight tendency for overspends relative to allowances.

Since 2005, both congestion costs and investment levels have increased. While this may be evidence of the trade-off being realised, in reality the two are likely to be being driven by different factors.

- The growth in *investment* is being driven by a combination of non-load replacement spend, and the need to develop the network, particularly to connect more renewable energy in the north of the system.

- The growth in *congestion* costs is being driven by several factors, including the:
  - connection of renewables generation in advance of transmission reinforcement work, based on "connect and manage" decisions taken at the time of the introduction of BETTA[72];
  - failure to co-ordinate optimally TO and SO operational activities through the SO TO Code; and
  - potentially the exercise of locational market power.

However, the lack of evidence of a problem to date should not be taken as an indication that no further consideration of the issue is required. In future, the trade-off is likely to become more significant. For example, congestion costs between 2006-07 and 2008-09 would have been sufficient to pay for the cost of the Beauly Denny upgrade (estimated at £332m in 2004). Making sure that the regulatory arrangements encourage efficient decision making is likely to become increasingly important.

71 We note that, in any period, some congestion will be an efficient outcome of optimised TO and SO decision making and hence even without other factors, this evidence does not definitively point to sub-optimality.

72 Under a "connect and manage" approach as being discussed under the Transmission Access Review (TAR), it is likely that this trend would continue, with implications for constraint costs in both Scotland and England and Wales.

Annexe 3: Experience from electricity transmission SO incentives

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