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Energy and Climate Change Committee

The future of Britain's electricity networks

Second Report of Session 2009–10

Volume I

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The Energy and Climate Change Committee

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Summary

The creation of a low-carbon economy requires a new way of thinking about our energy system. The expansion of renewable energy will entail a greater number of generators connecting to Britain's networks, ranging in size from roof-top solar panels to large offshore wind farms. These sources of generation cannot respond to fluctuations in energy demand in the way households have been accustomed. At the same time, consumers' demand for electricity could increase as a result of the electrification of the transport and heating sectors. The only way Britain can respond cost-effectively to these challenges is by applying a smarter approach to managing the energy system. This could occur in a range of ways—from the household level with the use of smart meters to manage customers' energy consumption, through to the high voltage transmission network where generators may need to develop methods of sharing access to the grid.

The existing regulatory and policy framework, and industrial structure, is a product of the fossil fuel economy of the twentieth century. This Report examines the issues that will be integral to the development of a smart grid that is able to meet Britain's future needs. We note the progress the Government has made in developing a vision for the smart grid, and argue that it should take account of the following principles:

- The need to avoid locking the UK into a particular outcome for the future energy mix at an early stage;
- Integration and management of energy demand within the energy system;
- Minimisation of regulatory and policy uncertainty for network companies who must invest in network assets; and
- The possibility of a new industrial structure emerging over time.

Achieving a smart grid will have implications for the high voltage transmission network. We call for the Government to investigate the potential to make better use of the existing network, whilst acknowledging too that greater and more strategic investment is necessary in the coming years. We also recommend further work to develop a fair and open transmission access and charging regime. For the lower voltage distribution networks we welcome recent initiatives to improve innovation and call for these to be extended over time if there is demand. We also express concern at proposed changes to the network charging regime for small generators at a time when the Government hopes distributed generation will play a greater role in the future energy mix. Finally, we call on network companies and the regulator to do more to ensure the industry has the skills it needs to meet the future challenges posed by the smart grid.

1 Introduction

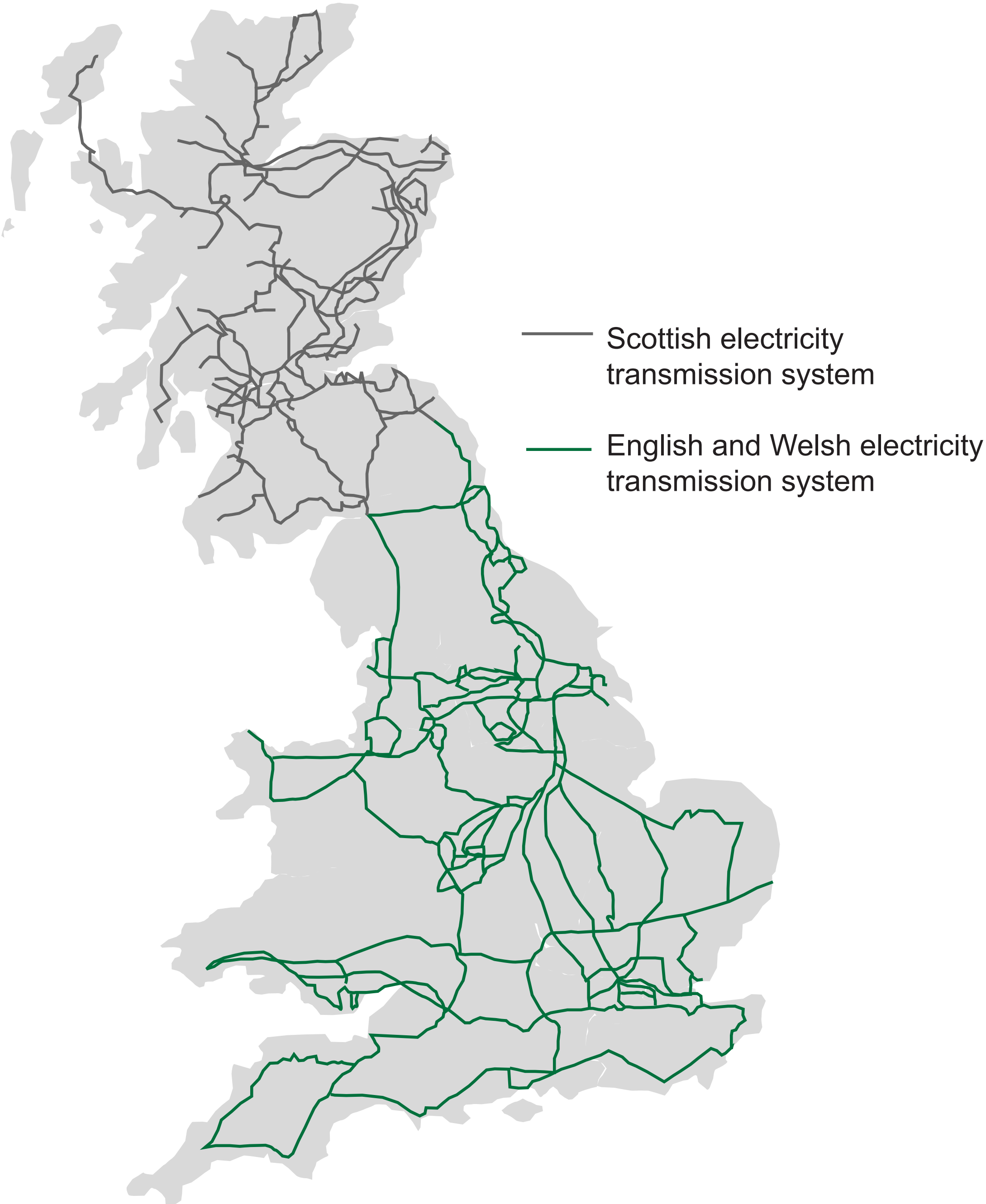
1. The 2007 Energy White Paper set out two long-term challenges for the UK's energy policy—the reduction of carbon dioxide emissions; and ensuring secure, clean and affordable energy supplies. Britain's electricity networks will play a crucial role in the delivery of both these objectives.[1] A large proportion of our network assets are now approaching the end of their useful life. The need for renewal, combined with the necessity to respond to future challenges, presents a once-in-a-lifetime opportunity for us to revolutionise Britain's electrical energy system and facilitate the transition to a low-carbon economy. This is why we chose to consider the future of Britain's electricity networks as one of our first inquiries.

2. Britain's current electricity infrastructure was designed to support post Second World War economic growth.[2] The system is characterised by a relatively small number of large fossil fuel-based and nuclear generators, which are connected to a high voltage **transmission** network—often referred to as the national grid. This allows the efficient transportation of electricity nearer to the sources of demand. It is delivered to consumers via 14 lower voltage regional **distribution** networks. These are almost entirely passive in nature with relatively little connected generation. Overall, power flows in one direction across the system from higher to lower voltage levels, as illustrated in Figure 1.

1 Throughout this Report we consider only the electricity networks of Britain—that is England, Wales and Scotland, though we will refer to the UK with regard to energy and climate change policy where appropriate.

2 Ev 264 (Prof Goran Strbac, Imperial College London)

Figure 2: the transmission networks of England and Wales, and Scotland



Source: National Grid

4. The 14 distribution networks across England, Wales and Scotland are owned and operated by seven companies known as distribution network operators (DNOs). These are shown in Figure 3. Scottish and Southern Energy and Scottish Power own both the transmission and distribution networks in their respective regions. Electricity supply companies pay the DNOs for consumers' use of their networks. In turn, suppliers pass these charges on to consumers through their bills.

available, historically, there has been a capacity margin over peak demand of around 20-24% to ensure security of supply.[4] Today's transmission system has been built to accommodate the simultaneous output of all power stations connected to the network. This approach has underpinned the development of Britain's electricity infrastructure in the modern era. As one witness told us: "nothing has fundamentally changed since 50 years ago".[5]

6. However, there is now a new challenge. If the likelihood of dangerous climate change is to be avoided, Britain and the rest of the world must drastically cut their carbon dioxide emissions in the next 40 years. To fulfil its part, the Government has committed the UK to an 80% reduction in emissions over 1990 levels by 2050. As part of the trajectory to this objective, the Government has also signed up to a legally-binding target for 15% of energy to come from renewable sources by 2020, as part of an EU target for 20% renewable energy. To achieve this, the Department of Energy and Climate Change's (DECC) lead scenario suggests more than 30% of electricity could be generated from renewables.[6] To meet the longer-term target the electricity sector will need to be almost entirely decarbonised by 2030, all the while maintaining security of supply.[7] The task is colossal, not least because demand for electricity may increase considerably through the electrification of parts of the heat and transport sectors. It is also ambitious by international standards. One witness said: "there is nothing on the scale that we are envisaging".[8]

7. Not only will the transition to a low-carbon economy entail massive changes in the sources of electricity generation, it will also necessitate a transformation in our networks. Indeed, the Institution of Engineering and Technology told us that: "Without the right networks, few of the UK's energy ambitions can be realised".[9] The Department described the electricity networks as "a key enabler" to future investment in generation capacity.[10] Without the physical assets in place and the right regulatory framework, there is a real danger of new generation being delayed, increasing the likelihood of the lights going out. Furthermore, the networks will be crucial in allowing consumers to play a greater role in managing their own energy demands. To achieve this, we need to become smarter at controlling the flow of electricity across the system—"Making energy cleverer" as one witness put it.[11] This is the overarching theme of our Report.

8. We received a large volume of written evidence for which we are grateful. We also took oral evidence from academics with expertise in energy networks—Dr Michael Pollitt from the Judge Business School, University of Cambridge, Professor Goran Strbac from Imperial College, and Dr Jim Watson of Sussex Energy Group; transmission network owners—National Grid, Scottish Power, and Scottish and Southern Energy; the sector skills council—Energy and Utility Skills; the main trade associations—the Energy Networks

4 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)

5 Q 47 (Prof Goran Strbac, Imperial College London)

6 HM Government, *The UK Renewable Energy Strategy*, page 8, July 2009

7 Ev 267, para 1.6 (Prof Goran Strbac, Imperial College London)

8 Q 63 (Dr Michael Pollitt, Judge Business School, University of Cambridge)

9 Ev 187, para 4 (Institution of Engineering and Technology)

10 Ev 147, para 8 (Department of Energy and Climate Change)

11 Q 48 (Prof Goran Strbac, Imperial College London)

Association, the Renewable Energy Association, the British Wind Energy Association, Scottish Renewables, and the Association of Electricity Producers; distribution network owners—CE Electric UK and Electricity North West Ltd; the Institution of Engineering and Technology; the regulator—Ofgem; and the Minister and officials at the Department of Energy and Climate Change.[12] We would like to express our thanks to all those who contributed to our evidence-gathering. We particularly thank Professor Goran Strbac and Dr Jim Watson who were specialist advisers on the inquiry, although we emphasise the conclusions and recommendations of this Report are the Committee's own.

9. The remainder of this Report is split into four chapters. Chapter 2 considers what a vision for Britain's electricity networks should take in. Chapter 3 analyses the various challenges faced by the transmission network. Chapter 4 looks at the changing role of the distribution networks. In particular, it highlights the importance of innovation in delivering networks fit for the 21st century. Finally, Chapter 5 asks whether the current networks sector workforce has sufficient skills to deliver the changes required in the coming years.

12 A list of those who gave evidence can be found on page 74.

2 Creating a vision for Britain's electricity networks

10. The transition to a low-carbon economy will require a fundamental change in the philosophy of power generation and supply, and the development and operation of a new, much larger and significantly more complex electrical energy system. The costs of achieving this will be huge—Scottish Power, for example, has estimated £37 billion for the required network investment between now and 2020.[13] The scale of the challenge, combined with the timeframe over which it is to be achieved, has led many within the industry to call on the Government to provide more strategic direction on how it expects the networks to evolve over time. In this Chapter we look at the progress to date in developing a vision for Britain's electricity networks and the potential key principles we believe should underpin such a vision.

Does Britain need a vision?

11. Several of our witnesses argued the Government needed to provide more leadership on the future development of the electricity networks. The risk that the market might otherwise fail to deliver in time, especially given the longer lead time for new network infrastructure, was a primary concern raised, for example by the Energy Networks Association.[14] Similarly, Electricity North West Ltd said that: "To make a change of this magnitude in the short timescales available requires the identification of a unifying strategic direction for the GB energy industry. To rely on hope and market mechanisms alone is doomed to failure".[15] Dr Jim Watson told us: "there is a need for more coordination and some semblance of a strategy, a plan of where we are going",[16] while the Institution of Engineering and Technology noted: "There is no vision document showing a joined-up transmission-distribution-end-user picture".[17]

12. In general, the view of many within the industry was that given Government policy is currently shaping the future low-carbon energy mix, for example through the Renewables Obligation and the facilitation of new nuclear build, it is therefore reasonable to expect the Government to provide some high-level guidance to ensure the networks develop in a way that is consistent with its overall vision for the energy sector.[18] As the British Wind Energy Association put it: "Government is the one that is setting the targets; […] it has to be the one that actually actively propels us forward".[19] Any vision for our electricity networks must therefore sit within a wider strategy for our future energy mix. It is important too that it is built on a consensus of stakeholders, rather than determined top-down by the

13 Ev 258, para 7.2 (Scottish Power)

14 Ev 164 (Energy Networks Association)

15 Ev 158, para 3.3 (Electricity North West Ltd)

16 Q 6 (Dr Jim Watson, Sussex Energy Group)

17 Q 279 (Institution of Engineering and Technology)

18 For example, see Ev 129, para 11 (Centrica)

19 Q 150 (British Wind Energy Association)

Department.[20] We note Ofgem's recent Project Discovery report, and we have arranged to take further evidence on this work.

13. **The transition to a low-carbon economy will transform the role of our electricity networks over the next 40 years. Whereas today the networks are seen as a means to an end in the transportation of electricity from generators to consumers, in the future they will play an integral and active role, enabling supply and demand to be managed in a much more complex and decentralised energy system. The market alone will not be able to deliver these changes—it requires strategic leadership from Government delivering a vision for the future that engages actively both consumers and the energy sector.**

Building a long-term vision

14. We believe the Government's strategy for the development of the electricity networks should contain four key features. It should: avoid locking Britain into a particular outcome for the future energy mix at an early stage; seek to integrate and manage energy demand within the energy system; minimise regulatory and policy uncertainty for the companies who must invest in new network assets; and be open to the prospect of a new industrial structure evolving over time. The following sections consider each of these in more detail.

Avoiding lock-in

15. The long-term vision for our electricity networks will to a large extent depend on the future generation mix, or as one witness told us: "we should not let the network tail wag the generation dog".[21] The Government believes the market should determine the contribution of different technologies to the energy mix, though in reality it is influenced by public policy through the target for 15% renewable energy by 2020, and the stated desire for nuclear power and carbon capture and storage to play a future role, albeit delivered by the private sector. In the short to medium term there is some certainty as to how the system will evolve. For example, in its *UK Renewable Energy Strategy* the Government stated that the majority of growth in electricity from renewable sources between now and 2020 will come from wind power, both onshore and offshore, with bioenergy making an important contribution.[22] National Grid also expects up to 14 GW of new gas-fired capacity to come on-stream in the next few years.[23]

16. Beyond 2020 it is more difficult to predict how our energy system will evolve. A useful example of this is Ofgem's *Long-Term Electricity Network Scenarios* (LENS) project.[24] This set out five plausible network scenarios for 2050, dependent on the direction of policy over time and the underlying energy mix. One potential outcome is for 'bigger' transmission and distribution networks to cope with the variability of large renewables. Another is a micro-grid based scenario, which would include higher levels of local renewable generation

20 Q 281 (Institution of Engineering and Technology)

21 Q 8 (Dr Michael Pollitt, Judge Business School, University of Cambridge)

22 Department of Energy and Climate Change, *UK Renewable Energy Strategy*, July 2009

23 House of Commons, *Official Report*, Col 1336W, 16 December 2009

24 Ofgem, *Electricity Network Scenarios for Great Britain in 2050*, November 2008

and less strongly interconnected local grids. A key conclusion of the study was that a large degree of uncertainty existed over what the final outcome might be, although all the scenarios posed a potential challenge to the status quo. Ofgem told us: "it is not clear whether we will need much larger networks or much smaller networks in the future".[25]

17. In the face of such uncertainty, some of our witnesses made calls for the Government to do more to narrow the range of options for the future.[26] Electricity North West Ltd told us: "it is now necessary to move the whole weight of the industry behind a clearly stated, preferred option if we as a nation are serious about achieving targets".[27] Similarly, Centrica said: "there is a need to recognise the overall direction—is it towards a 2050 'big' transmission, 'small' distribution network scenario or vice versa […]".[28] However, other witnesses took a different view. Dr Michael Pollitt told us keeping technological options open has benefits, noting that: "We just don't know at this stage what the best network configuration is for 2020 or 2050, not least because of price, policy and technological uncertainty".[29] Another cautioned: "Government and the regulator should not try to 'pick winners'".[30]

18. The primary disadvantage with adopting a single approach is that it risks locking the system into an outcome that is sub-optimal in the long run, either because it proves more expensive, or because it does not make the best use of emerging technologies. Moreover, Britain's existing electricity infrastructure is already highly centralised, built as it is around large-scale fossil fuel and nuclear plants. Dr Jim Watson of Sussex Energy Group told us: "The 'lock-in' of this system […] presents a challenge when government policies now require the system to change".[31] In other words, our existing model of 'big' transmission and passive distribution increases the likelihood of the same approach continuing in the future, unless regulation and policy allows for the possibility of other outcomes. As the Department put it: "We […] need to ensure that our policy framework is flexible and supports innovation in network development and operation".[32] Fortunately, in the short term it is possible for the existing networks to accommodate changes in demand and increased renewable generation without radically changing our energy networks.[33] This should allow some time to experiment with different technological options.

19. **Although we know with some confidence how the electricity mix will evolve in the run up to 2020, there is much less certainty over what a completely decarbonised energy system might look like in the long run. The Government's vision for the future of our electricity networks must take account of the range of possible scenarios for the evolution of the energy mix, ensuring it does not lock Britain into a particular outcome at an early stage.**

25 Ev 211, para 1.4 (Ofgem)

26 For example, Ev 174, para 3.5 (E.ON)

27 Ev 159, para 3.4 (Electricity North West Ltd)

28 Ev 130, para 20 (Centrica)

29 Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)

30 Ev 182 (Helius Energy)

31 Ev 270, para 4 (Dr Jim Watson, Sussex Energy Group)

32 Ev 147, para 10 (Department of Energy and Climate Change)

33 Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)

Integrating energy demand

20. Britain's current electricity system is demand driven. When a consumer increases their electricity use, somewhere generation increases by a commensurate amount to satisfy that demand. This is possible because our electricity mix includes a large amount of capacity that is able to respond to changes in demand. For unexpected demand fluctuations, National Grid can use pumped storage or call on reserve capacity.[34] In addition, gas and coal-fired power stations, which currently provide around 68% of electricity supply, can to varying degrees respond flexibly to changes in demand.[35] Historically, generation capacity has expanded as a result of increases in demand. As Professor Strbac told us: "The whole culture and philosophy of the system is based on a predict-and-provide mentality".[36]

21. The transition to a low-carbon economy, however, poses a challenge to this traditional *modus operandi*. In the next few years, the expansion of large-scale wind power will increase dramatically the amount of variable generation entering the system. Whilst the network system operator will be able to estimate the availability of wind power using weather forecasts, this form of generation cannot respond directly to changes in consumer demand. At present, and in the short to medium term, this may not be a significant issue for the networks because the level of wind-based generation will be manageable within the overall system. However, if in the longer term up to 30% of electricity comes from wind, this could pose major challenges for the networks, particularly as such variable capacity will operate alongside baseload nuclear power, which cannot be switched on or off to meet differing network load demands. Without mitigating action it is likely electricity supply will often exceed demand, for example during the night, or fall short, such as when the wind fails to blow.

22. If Britain were to maintain the existing approach whereby supply is entirely responsive to demand, then the solution to the inflexibility of wind and nuclear power would be to build more back-up capacity for when the wind fails, and curtail wind farms when their output exceeds demand. This option would, however, be very expensive. Furthermore, to achieve the Government's 2050 target for carbon emissions it is likely that it would also require the electrification of both the heat and transport sectors combined with a large increase in renewable generation, much of which would be variable wind. Accommodating these changes within the electricity system under the current approach would necessitate massive reinforcement of the transmission and distribution networks, and lead to very low levels of generation and network asset utilisation, and hence low utilisation of capital investment. Electric vehicles provide one example of why this would happen. If in the future they charged from the time they were plugged in, they would add significantly to the peak in electricity demand that occurs in the early evening each day when people come home from work. The approach Britain has at present would mean greater generating and network capacity would be necessary to meet this demand peak, though these assets would remain idle at most other times.

34 Pumped storage is a form of hydroelectric power generation where low-cost off peak electricity is used to pump water to a higher elevation, which is then used to drive turbines during peak periods when prices are higher.

35 Department of Energy and Climate Change, *Energy Trends*, September 2009

36 Q 47 (Prof Goran Strbac, Imperial College London)

23. Denmark, which relies on wind power for about a fifth of its electricity needs, has already begun to experience problems managing generation across its system.[37] However, its small size, combined with its interconnection with mainland Europe and the Nordic countries, enables it to export excess supply to neighbouring countries. Britain does not benefit, at present, from the same level of interconnection. Moreover, we cannot assume that closer linkage to European markets would bring the same benefits as it has for Denmark, given Britain's expected expansion in wind power will take place against a backdrop of similar drives to increase renewable energy across the Continent to meet the European Commission's 20% target by 2020. We consider interconnection in greater depth in Chapter 3.

24. The solution to the problem of inflexible supply lies in making demand flexible instead.[38] More intelligent demand-side management could take a variety of forms. For example, heating, refrigeration and air-conditioning systems could provide a form of energy storage to accommodate short-term variations in electricity supplies.[39] The mass deployment of electric vehicles could also offer such storage, charging up when there is enough system capacity and, if necessary, exporting electricity back into the system during periods of constrained supply.[40] The inherent storage potential from the electrification of the transport and heating sectors, therefore, presents the opportunity to decouple energy production and use.

25. Elsewhere, smart metering could allow customers to respond more dynamically to market prices, changing their demand profile through arrangements such as dynamic demand technologies so that they consume more energy when the system is less constrained. A blunter form of this already exists with Economy 7 (an electricity tariff which charges less for overnight usage), but it has the potential to be linked more closely to real-time fluctuations in the energy system. Integrating demand into the overall management of the energy system is a core part of the concept of what has become known as the 'smart grid'—"an electricity network that can intelligently integrate the actions of all users connected to it—generators, consumers and those that do both—in order to efficiently deliver sustainable, economic and secure electricity supplies".[41]

26. Creating a smart grid will require distribution networks to transform their current approach, moving away from their traditional passive role towards more active management of the potentially highly complex flows of energy entering their systems at all voltage levels.[42] This will only be achieved through the deployment of advanced information and communication technologies (ICTs), combined with a radical rethink of how the system is controlled, and the role of the electricity supply company in delivering energy services to customers. We discuss this more in Chapter 4. The potential benefits are huge. Revolutionising the relationship between consumers and electricity producers could foster greater public awareness of the relationship between energy use and the need for

37 Danish Energy Agency, *Energy Statistics 2007*, October 2008

38 See for example, Q 285 (Institution of Engineering and Technology)

39 Ev 185, para 3 (Institute of Physics)

40 Q 277 (Institution of Engineering and Technology)

41 EU SmartGrids Technology Platform definition, quoted by Ev 188 (Institution of Engineering and Technology)

42 Ev 164 (Energy Networks Association)

new energy infrastructure. Furthermore, the Centre for Sustainable Energy and Distributed Generation estimates the smart grid approach could halve the level of investment in generating capacity needed to meet future demand, compared to a scenario that assumes a continuation of the existing philosophy.[43]

27. **Whatever the scenarios for the future development of the electricity mix, it is likely that they will include a much higher proportion of generating capacity that is not able to respond easily to demand. The only cost-effective response is for demand itself to be more flexible and play a more active role in the management of our energy system. This should sit at the core of the Government's vision for Britain's electricity networks.**

Minimising regulatory uncertainty

28. The UK was one of the first countries to liberalise its energy markets 20 years ago. At that time the regulator's main objective for the electricity networks was to improve operational efficiency. It achieved this through an RPI-X regime that linked companies' allowed revenues to the rate of inflation (RPI), minus some factor 'X' calculated to incentivise them to cut costs in order to make a profit. Now Ofgem's primary focus is the efficient delivery of a low-carbon economy and continued security of supply both for present and future consumers.[44] This change in the objectives for the regulatory framework, therefore, requires a fundamental rethink of the regime itself. Accordingly, 20 years after privatisation the regulator is currently conducting a review of network regulation known as RPI-X@20. Due for completion later in 2010, the initiative should see a significantly different regulatory regime designed to meet the new challenges the networks face.

29. One of the key messages from our evidence was the need for the future regulatory framework to provide long-term certainty to market participants. Scottish Renewables told us: "a strong and long-term signal to the investors is absolutely crucial if a fit for purpose electricity network is to deliver a decarbonised and reliable electricity supply".[45] Similarly, Dr Michael Pollitt said: "it is important that network investments face a more consistent policy framework going forward than at present".[46] Elsewhere, ESB International Investments said: "Investors such as ourselves require a stable regulatory regime and policy framework".[47] The British Wind Energy Association also gave the example of how stability would be important for ensuring the increased cable manufacturing capacity necessary to ensure the future connection of offshore wind.[48]

30. **The regulatory framework will need to adapt to meet the new challenges of facilitating the transition to a low-carbon economy, whilst ensuring security of supply. As such, we welcome Ofgem's current RPI-X@20 review. At the same time as ensuring flexibility in the potential outcome for how the networks might evolve, it is important**

43 Q 47 (Prof Goran Strbac, Imperial College London)

44 Ev 211, para 1.1 (Ofgem)

45 Ev 260, para 12 (Scottish Renewables)

46 Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)

47 Ev 179, para 1 (ESB International)

48 Ev 116 (British Wind Energy Association)

that reforms arising from the review and the Government's vision for the electricity networks take account of the need for long-term regulatory and policy stability to give firms the confidence to make the investments required.

The industrial structure

31. The current industrial structure of the networks sector reflects the evolution of the GB market since privatisation. At present, five companies operate as distribution network owners, one firm—National Grid—is the transmission owner for England and Wales, while two firms have both transmission and distribution networks. These latter two—Scottish Power and Scottish and Southern Energy (SSE)—additionally own generating assets. National Grid is also the system operator for the whole GB system.

32. There are various ways in which the industry's composition could change in the future either as a consequence of regulation, or through the market response to developments in the networks sector outlined already. For example, the vertical integration of the Scottish companies was questioned by some of our witnesses, including the regulator, who thought it could constrain competition.[49] Dr Michael Pollitt told us: "the evidence, though fairly anecdotal, is quite strong that countries that have independent transmission companies do better and have more successful electricity systems".[50] Scottish Power and SSE disputed strongly any assertion their position gave them undue market power that was not compliant with EU law.[51] Whilst the Minister also supported this position, Ofgem told us third parties connecting to the Scottish networks felt "uncomfortable" about the current situation.[52]

33. Elsewhere, international experience points to different ways of managing transmission. For example, it is not clear whether there should be an onshore monopoly of new build for transmission assets, such as that held by National Grid in England and Wales, and regionally by the two Scottish companies. In Chile, Argentina and some US jurisdictions, the system operator role is separate to network ownership and run on a not-for-profit basis, thus allowing different firms to take responsibility for owning and maintaining the networks. The Government is already pursuing this approach for offshore transmission, which we discuss further in Chapter 3.

34. Finally, in the future there may be a more general debate over the separation of distribution and transmission. The development of a smart grid could lead to distribution network owners also becoming system operators for their areas, actively managing the flow of electricity between the distribution and transmission networks. In this situation the old distinction between the two types of network would become blurred. This could bring into question the need for separate asset ownership between the two sectors as is currently the case in England and Wales. The existing 14 distribution networks are a remnant of the pre-privatisation organisation of the electricity sector. It is conceivable that these could fragment or merge in the future depending on how the smart grid develops.

49 Qq 111 (National Grid) and 355 (Ofgem)

50 Q 26 (Dr Michael Pollitt, Judge Business School, University of Cambridge)

51 Qq 110 (Scottish and Southern Energy) and 111 (Scottish Power)

52 Qq 355 (Ofgem) and 422 (Minister for Energy)

35. **Britain's networks sector currently has a hybrid structure that is largely the result of the evolving regulatory framework since privatisation. Whilst it may be adequate for now, the transition to a low-carbon energy system may require a different organisation of the industry. The Government and the regulator should not be afraid to allow this to happen, whether through regulation or otherwise, so long as it provides transparent and fair access to natural monopoly network assets for both generators and consumers. In particular, we recommend Ofgem monitors closely the market behaviour of the two vertically integrated Scottish firms. These arrangements could be changed if they are found to be detrimental to consumers.**

Progress so far

36. During 2009 the Government made progress in developing a vision for Britain's electricity networks. In March the cross-sector Electricity Networks Strategy Group (ENSG) published *Our Electricity Transmission Network: A Vision for 2020*. This set out the strategic investment the transmission system could require over the next decade if the system is to have enough capacity to connect the large expansion of renewable energy, particularly wind power, needed to meet the Government's 2020 target. We discuss the case for such transmission investment in the next chapter.

37. In December 2009 the Department published *Smarter Grids: The Opportunity*. This set out a high-level vision of what a UK smart grid might look like. It highlights three main challenges to overcome for the successful deployment of the smart grid. First is the importance of engaging consumers who will play a key role within the future energy system, potentially as micro-generators, but also through the management of their energy demand, whether passively or proactively. Second is the testing and application of new technologies, particularly ICT, that are crucial components of the smart grid. Underlying both these challenges is a third, which is to ensure the regulatory and commercial framework evolves in parallel to facilitate the changes required. The report states: "The overall aim will be that smarter grid investments are increasingly seen as 'business as usual'". The Department has now asked the Electricity Networks Strategy Group to develop a road map for the delivery of the smart grid. DECC will combine this with its own analysis and will publish later in 2010 its views on the actions required to deliver the smart grid in Britain.

38. **We note the progress the Department has made in beginning to develop a strategic vision for how Britain's electricity networks will evolve over time. In preparing a road map for delivery of the smart grid, it should take account of the following principles:**

- **The need to avoid locking the UK into a particular outcome for the future energy mix at an early stage;**
- **Integration and management of energy demand within the energy system;**
- **Minimisation of regulatory and policy uncertainty for network companies who must invest in network assets; and**
- **The possibility of a new industrial structure emerging over time.**

3 Transforming transmission

39. Because we do not know yet what the energy mix of the future will look like, neither do we know with any certainty how the transmission network will evolve. We have already identified, however, that there is a risk of continuing Britain's 'lock-in' to a 'big' transmission system if the regulatory framework does not allow for the possibility of other outcomes. In this Chapter we consider a range of issues that have concerned policy-makers in recent years in determining transmission policy.

Investing in capacity

40. Ownership and operation of the transmission networks in Britain is permitted under licence, the terms of which restrict the revenue of the licensed network businesses.[53] The revenue allowed to transmission companies is based on a pre-determined programme of investment agreed between them and the regulator. It is reviewed every five years by Ofgem through what is known as a Transmission Price Control Review (TPCR). The current TPCR period runs from 2007 to 2013, having recently been extended by one year. In 2009/10 it will allow companies to recover around £1.5 billion in revenues. For households, the cost of transmission equates to around 4% of electricity bills.[54] Growth in companies' revenues is determined using the RPI-X framework. This approach has encouraged firms to reduce costs over time through efficiency improvements. The next TPCR will be based on a new regulatory framework, arising from the current RPI-X@20 review.

41. Ongoing investment in the transmission network is necessary to ensure the system remains operational, for example, through the replacement of ageing or obsolete assets. It is likely that a system of balancing supply and demand such as BETTA will continue to operate in the longer term, and therefore new investment will also be crucial to assist with the migration of less efficient and older plant towards a marginal supply position on the basis of continued availability as installed capacity. However, many within the industry now argue that further investment to expand the system is required in order to connect the expected growth in renewable generation in the coming years. In this section we look at the main barriers to expansion of the transmission network and the case for further investment.

The role of planning

42. The planning system is a fundamental determinant of whether investment in new transmission capacity is delivered on time, and was highlighted as a potential barrier by the Department, the regulator and the industry.[55] Past experience explains why this is the case. In the 1990s it took over six years to acquire planning consent for a 50-mile stretch of new

53 Ev 232 (Scottish and Southern Energy)

54 *Ibid.*

55 Ev 103, para 4.2 (ABB), Ev 111, para 15 (Association of Electricity Producers), Ev 149, para 33 (Department of Energy and Climate Change), Ev 164 (Energy Networks Association), Ev 175, para 3.16 (E.ON), Ev 179, para 6 (ESBI International), Ev 212, para 3.1 (Ofgem), Ev 232 (Scottish and Southern Energy), and Ev 237 (Scottish Chambers of Commerce)

high voltage power lines in North Yorkshire.[56] More recently, the upgrade of the 137-mile line between Beauly near Inverness, and Denny near Falkirk, replacing the existing 132 kV cables with high voltage 400 kV lines, entered the planning system in 2005. Seen as key to allowing the connection of new onshore wind farms in northern Scotland, the project was first conceived in 2001, and awarded funding by Ofgem in 2004. Consent was finally granted in January 2010, which means construction work could be completed by 2012, when projects would be able to connect to the new line. From conception to completion, the upgrade will have taken 11 years.[57] Smaller projects have also faced difficulties. Scottish Power told us about a 20 km wooden pole line it wished to build between Lostock and Carrington in Lancashire.[58] The company submitted its planning application in 2003, but is not expecting to receive consent until later in 2010.

43. Overall, many of our other witnesses were highly critical of the planning process. The Scottish Chambers of Commerce described it as “sclerotic”.[59] Another witness said that, left unaddressed “the planning system is likely to thwart aspirations for connecting renewable generation”.[60] Elsewhere, Scottish and Southern Energy told us: “The shortcomings of the planning systems need to be addressed if the UK is to meet the EU 2020 target and longer-term security of supply and climate change goals”.[61]

44. Several organisations, however, sought to defend the planning system. Scottish Natural Heritage, for example, told us the length of inquiry into the Beauly-Denny line was partly the result of the transmission companies having not undertaken sufficiently thorough exploration of alternative options, such as burying cables underground in areas of environmental sensitivity.[62] The Campaign to Protect Rural England (CPRE) noted that the delay to consenting the North Yorkshire line had been the result of the developer having to consider ways of lessening the impact of the line on the landscape that it had not fully addressed in its initial proposal.[63] Both organisations rejected the idea that the planning process should be considered a ‘barrier’ to network expansion—rather, as CPRE told us: “it is a vital means of ensuring that the future development of the transmission network takes full account of the public interest”.[64]

45. In order to address some of the concerns with the current planning system, the *Planning Act 2008* established an independent Infrastructure Planning Commission (IPC), which will operate a streamlined consenting process. Under the new arrangements Ministers will retain responsibility for the policy framework, which will be set out in National Policy Statements (NPSs). The IPC will make decisions on consents based on these NPSs, which will set out the need for the infrastructure and how the IPC should consider impacts. Consultation on applications will be required before they are submitted

56 Ev 111, para 15 (Association of Electricity Producers)

57 Ev 262, para 32 (Scottish Renewables)

58 Q 103 (Scottish Power)

59 Ev 237 (Scottish Chambers of Commerce)

60 Ev 179, para 6 (ESBI International)

61 Ev 232 (Scottish and Southern Energy)

62 Ev 252, para 9 (Scottish Natural Heritage)

63 Ev 120, para 10 (Campaign to Protect Rural England)

64 Ev 119, para 7 (Campaign to Protect Rural England)

to the IPC, and guidance given on what constitutes a good application. The hope is that this will mean the Commission can consider applications more quickly, which it will do within set timetables.[65] The Government published the draft NPS on electricity networks infrastructure in November 2009, as part of a suite of energy NPSs.[66] They are subject to consultation and parliamentary scrutiny, for which this Committee is playing a key role, before likely designation sometime in 2010.

46. Only planning applications for power lines in excess of 132 kV, or network infrastructure that is associated with a nationally significant power station, will be subject to approval by the IPC. This means that consenting for lower voltage distribution lines will still fall to local planning authorities. The new system applies only to England and Wales. In Scotland, reform has also taken place: measures announced in 2008 include the requirement for promoters of major developments to conduct a consultation with the community before submitting the planning application. A statutory four-month time period for a decision on applications will also be put in place. Other reforms in Scotland include: simpler and more transparent processes; quicker decision-making by councils on high-quality applications; a greater focus on matters of national interest; and up-to-date development plans to provide investors and communities with greater certainty. In 2009 the Scottish Executive also published its second National Planning Framework (NPF2), which designated 14 national developments of strategic importance to Scotland, of which electricity grid reinforcements was one.

47. The network industry broadly welcomed reform of the planning system.[67] There is a high level of expectation on the ability of the changes to speed up the planning process. E.ON UK told us: "The success of the new IPC planning process […] will be key to the delivery of major infrastructure projects".[68] Scottish and Southern Energy said: "The importance of the National Policy Statements cannot be overemphasised […] the NPSs must be clear and have sufficient depth to form the basis for authoritative decisions".[69] The Association of Electricity Producers noted its concern, though, that there remains a disjointed approach between the systems in England and Wales and Scotland, with varying timescales, considerations and processes. It believed greater consistency was needed.[70]

48. **Reform of the planning process is vital if network improvements are to be delivered on time to connect new generating capacity in the future. We note the recent changes to the planning systems in England and Wales, and Scotland, and are pleased to be playing a role in scrutinising the draft National Policy Statement for Electricity Networks Infrastructure. We hope the new system will lead to a faster decision-making process, but one that nonetheless will take account of the environmental concerns associated with new proposals. For this, developers have a duty to ensure their initial applications take adequate account of alternative options. The Government should also look closely**

65 Ev 149, para 33-35 (Department of Energy and Climate Change)

66 Department of Energy and Climate Change, *Draft National Policy Statement for Electricity Networks Infrastructure (EN-5)*, November 2009

67 For example, Ev 164 (Energy Networks Association) and Ev 203, para 13 (National Grid)

68 Ev 175, para 3.16 (E.ON UK)

69 Ev 232 (Scottish and Southern Energy)

70 Ev 111, para 16 (Association of Electricity Producers)

at the consenting process for applications in England and Wales that will not fall to the Infrastructure Planning Commission to see whether reform or improved guidance is necessary at this level as well.

Strategic investment in transmission

49. Under the existing TPCR framework investment is reactive—transmission companies do not undertake reinforcement or line extension work until individual generating companies have guaranteed they will meet the cost of those connections.[71] This approach, whereby network capacity is expanded only if there is a power plant ready to use it, has helped reduce the risk of investment capacity not being utilised, otherwise known as stranded assets.[72] However, this can cause problems for generating companies that are not able to guarantee their connection until they are confident their projects will proceed, for example, once they have received planning permission. We have already seen, though, that the consenting process for new grid capacity can take time. This can lead to a mismatch between when a project is ready to connect to the grid, and when the grid capacity is available to connect it. The problem is exacerbated by the fact that, as the share of renewables in the electricity mix expands, transmission reinforcement is being driven increasingly by a large number of relatively small projects.[73]

50. The existing regulatory framework is now affecting the ability of transmission owners to provide connections in the necessary locations.[74] For example, National Grid told us: "A more flexible mechanism is required to deliver the infrastructure investment in our vision".[75] This would also align better the construction programmes of the transmission companies and power station developers. Accordingly, a consensus has emerged within the industry in support of strategic investment in grid capacity—that is, investment ahead of individual projects being able to give specific financial commitment for their connections.[76] This is possible because the general geographical location of a significant amount of future renewable generation, particularly wind power, is already well known.

51. To identify where areas of investment were required, in 2008 Ofgem and the Government asked the Electricity Networks Strategy Group (ENSG)—a senior industry group—to consider what the transmission system would need to look like to meet the 2020 targets for renewable energy. The ENSG published the first phase of its work in March 2009. It identified reinforcement work for a range of projects in areas of Scotland, Wales, East Anglia, London and the South West. It includes potential high voltage subsea cables between Scotland and the north of England along both the east and west coasts. In total, the work could amount to £4.7 billion between now and 2020. This is in addition to network investments already approved to connect renewable generation and through the current transmission price control. Combined, the cost of this work would be equivalent to

71 Ev 227, para 9 (Renewable Energy Association)

72 Ev 149, para 29 (Department of Energy and Climate Change)

73 Q 154; Ev 227, para 9 (Renewable Energy Association)

74 Ev 131, para 33 (Centrica)

75 Ev 202, para 6 (National Grid)

76 For example, Ev 164 (Energy Networks Association), Ev 171 (Energy Technologies Institute), Ev 227, para 11 (Renewable Energy Association), Ev 258, para 7.3 (Scottish Power) and Ev 270 (Sussex Energy Group)

the asset value of the existing transmission system—potentially the biggest grid development since the Second World War.[77] It is also worth noting that this excludes the cost of connecting future offshore wind. The report notes that provided the work is taken forward in a timely manner, subject to planning consent, the reinforcements could be delivered within the required timescales. They would be phased over the next decade with the resulting network able to accommodate between 29 and 45 gigawatts of new generating capacity.[78]

52. The ENSG work has received widespread support from the industry.[79] E.ON called for transmission companies to be permitted immediately to commence with pre-construction work for the projects identified.[80] Scottish Renewables said: "It is important […] that work on these upgrades and reinforcements should start as quickly as possible".[81] Ofgem responded in April 2009 by approving up to £12.5 million of funding outside the current TPCR for the transmission companies to begin feasibility studies and preparatory work. Since then the regulator has been working with the firms to establish longer-term funding arrangements that will facilitate a programme of strategic investment. In January 2010 the regulator approved additional funding of up to £1 billion for construction work on specific projects.[82] Further investment will be funded through the next TPCR, due to begin in April 2013. A key part of Ofgem's work will be to ensure that additional funding does not lead to the construction of unused, stranded assets. In its evidence to us the regulator acknowledged that its new approach entailed making a judgement on the level of stranded asset cost that was reasonable to incur for consumers, and that this represented "a fundamental philosophical shift" in its regulation of network investment.[83]

How strong is the case for investment?

53. Although there was a consensus between the generators and network companies in favour of significant new investment in transmission reinforcements, this view was not shared by all who gave evidence to the Committee. For example, Dr Michael Pollitt told us a key concern should be "making sure that we do not […] give network incumbent companies a licence to massively increase capacity, which might not be necessary".[84] Prof Strbac noted too that the ENSG work presents a solution that involves a 'business as usual' response by the industry that is a direct consequence of the existing regulatory framework.[85] Although both acknowledged that investment in the network infrastructure will be needed, they also believed that, in addition to new capacity through network reinforcements, a range of other solutions that can release latent network capacity should also be considered. These include, for example, the application of a variety of operational

77 Q 3 (Prof Goran Strbac, Imperial College London)

78 Electricity Networks Strategy Group, *Our electricity transmission network: a vision for 2020*, March 2009

79 For example, Ev 110, para 11 (Association of Electricity Producers), Ev 113, para 10 (Arup), Ev 129, para 9 (Centrica) and Ev 232 (Scottish and Southern Energy),

80 Ev 174, para 3.6 (E.ON UK)

81 Ev 261, para 22 (Scottish Renewables)

82 Ofgem, *Transmission Access Review—Enhanced Transmission Incentives: Final Proposals*, January 2010

83 Q 307 (Ofgem)

84 Q 12 (Dr Michael Pollitt, Judge Business School, University of Cambridge)

85 Ev 268, para 2.5 (Prof Goran Strbac, Imperial College London)

measures, emerging local generation coming on stream, or allowing a greater role for responsive demand—all of which could substitute for network investment.

54. A further important concern raised by Phil Baker and Dr Bridget Woodman at the University of Exeter was that existing network assets should be fully utilised before making the case for further investment.[86] The GB Security and Quality of Supply Standards (SQSS) set out the criteria and methodologies that National Grid must use in the planning and operation of the electricity transmission system. In other words, they determine the level of transmission asset utilisation. Baker and Woodman told us there is scope to improve the utilisation of the existing transmission assets.[87] One example could be a move towards weather-related security standards. At present around 70% of transmission faults relate to weather conditions. However, the weather is not taken into account when operating the transmission system, even though it may be possible to relax operational security standards during fair-weather conditions, and so release latent network capacity. Such an approach could significantly decrease the external costs of operating the transmission system and reduce the need for investment without posing a risk to customer supplies.

55. Another way of releasing latent capacity from the existing network is through the use of special protection schemes. These are intelligent tripping systems that mitigate unexpected faults that could lead to a disconnection of a transmission line by automatically tripping generation or shedding demand load from elsewhere on the system. Although limited in scope at present, network operators already use some of these technologies to enhance the capability of their existing systems. Worldwide, there is growing interest in the development and application of such approaches, which entail more sophisticated system operation, but also minimise or avoid the need for network reinforcements. Solutions such as special protection schemes are more widely used in other parts of the world, including the US, Brazil, Chile, Australia and Taiwan, thus allowing system operators to achieve a higher level of network utilisation.

56. Prof Goran Strbac argued that the SQSS, which have remained largely unchanged since 1948, present a barrier to a range of other solutions that could release latent capacity from the existing network.[88] Among others, these include more sophisticated system operation, such as the application of advanced network control, protection and maintenance techniques and innovative decision-making tools.[89] They also include non-network solutions such as the greater role of demand in managing the electricity system as discussed in Chapter 2. This is important because these alternative approaches could not only enable the release of latent capacity from the existing transmission assets and facilitate the connection of greater amounts of wind power in the short term, but also in the longer term play a key role in the development of a smart grid.

57. Phil Baker and Dr Bridget Woodman also criticised the incentives in place for new transmission capacity.[90] At present the regulated income of transmission operators

86 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)

87 *Ibid.*

88 Ev 267, para 1.6 (Prof Goran Strbac, Imperial College London)

89 Ev 264 (Prof Goran Strbac, Imperial College London)

90 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)

through the transmission price control review (TPCR) is a function of the value of their asset base. This, therefore, places an incentive on companies to grow that base by building as much transmission capacity as they can justify, rather than actively looking for operational alternatives. In June 2008 the transmission companies began a fundamental review of the SQSS. This could provide a major opportunity to reform the Standards to maximise utilisation of the existing network and encourage the take-up of smart grid technologies. The review team's terms of reference set a target date of September 2009 to report and consult on detailed proposals.[91] These have not yet been published. We note that the ENSG work that proposes significant strategic network investment is based on the existing SQSS.

58. **To avoid delays in connecting new power stations a more strategic approach to investment in transmission capacity is necessary. We welcome the Electricity Networks Strategy Group's work to identify the reinforcements it believes are needed in the next ten years. We also note Ofgem's cautious approach in allowing funding to advance particular projects and we urge them to be more proactive in promoting ways of avoiding delays.**

59. **Given the costs involved, the resulting impact on customers' bills, and the risks of delay, it is vital the case for investment is as robust as possible and preferable to any alternatives. There is some concern that the existing regulatory framework is driving the case for transmission investment presented by the industry at the expense of other more cost-effective options that seek better to utilise the existing network infrastructure. The current fundamental review of the Security and Quality of Supply Standards (SQSS) presents a major opportunity to address these issues. However, the review, which had aimed to publish detailed proposals in September 2009, has not yet reported. Therefore, we are concerned that some of the currently proposed strategic network investment that is based on the existing SQSS may prove unnecessary. Furthermore, reform of the SQSS will be vital for the development of a future smart grid. It would be totally unacceptable if Ofgem failed to fulfil its duties to consumers by not ensuring the timely completion of this review, especially as the regulator has already begun to grant funding for additional investment. We consider it essential that consideration of new investment in transmission has the benefit of the outcome of the SQSS review and strongly recommend that urgent measures are taken to complete and publish the review.**

Network charging

60. On connection to the GB transmission system, generators are required to pay the following charges:

- Connection Charges: These enable National Grid to recover the costs involved in providing the assets that allow connection to the transmission system.
- Balancing Services Use of System (BSUoS): This charge recovers the cost of balancing demand and supply across the system.

91 National Grid, Scottish Power, and Scottish and Southern Energy Open Letter, *A fundamental review of the Great Britain Security and Quality of Supply Standard*, 24 June 2008

- Transmission Network Use of System (TNUoS): This charge recovers the cost of installing and maintaining the transmission network required to allow the bulk transfer of power between sites and to provide transmission system security.[92]

In this section we focus on current issues concerning the second and third of these charges.

Constraint costs

61. The transmission system has a finite capacity to transport electricity between power stations and consumers. Constraints can occur when the system is unable to transmit the power supplied at a particular location to where demand for it is situated. This may be because heating ratings on electricity lines have been exceeded, or because of an inability to maintain voltages on the system within the limits set out in the GB Security and Quality of Supply Standards (SQSS) discussed in the previous section. Constraints can also be exacerbated by transmission outages arising, for example, from network reinforcements, or unexpected generation failure. When such constraints occur National Grid, the system operator, will take action to reconfigure the system and/or go to the wholesale electricity market to increase or decrease the amount of electricity being supplied to the system at different locations.[93] If National Grid has to require a power station to reduce its output because of constraints on the transmission network, the generator is compensated for the reduction in the grid's capability to take their full output. The costs incurred are referred to as constraint costs. Along with all the other costs associated with keeping the system in balance and maintaining security of supply, these are passed onto users of the system through Balancing Services Use of System (BSUoS) charges. They are paid equally by generators and consumers, and do not vary by location.

62. In recent years the level of constraint costs have risen from £70 million in 2007/08 to £262 million in 2008/09 and are forecast to be £198 million in the current financial year.[94] Constraint costs have caused growing concern for Ofgem since the establishment of the British Electricity Trading and Transmission Arrangements (BETTA) in 2005. The Arrangements brought together the electricity markets for Scotland, England and Wales. Under the regime, generators self-despatch their plant. In other words, they have guaranteed access to the grid, except at times when they are constrained off by the system operator. Because the interconnection between England and Scotland, known as the Cheviot Boundary, does not have the capacity to always meet the demands placed on it by electricity flows between the two countries, Ofgem has issued the boundary a derogation from the requirement to comply with the Security and Quality of Supply Standards (SQSS).

63. Constraint costs are key to informing investment decisions in new network capacity.[95] Accordingly, an investment programme is underway to upgrade the Cheviot Boundary as this is seen as a main pinch-point on the network. It is important that constraint costs send the right signal of investment needs. The evidence we received suggest two factors have

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92 www.nationalgrid.com

93 Based on Ofgem, *Addressing Market Power Concerns in the Electricity Wholesale Sector—Initial Policy Proposals*, para 1.28-9, March 2009

94 Ofgem, *Locational BSUoS Charging Methodology – GB ECM-18*, para 1.13, December 2009

95 Ev 267, para 1.5 (Prof Goran Strbac, Imperial College London)

contributed to the level of these costs being higher than they otherwise could be—the inherent nature of BETTA and the alleged exploitation of market power by the Scottish transmission companies.

64. One of the key differences between the BETTA system and the electricity 'Pool' trading arrangements that preceded it is that the market does not explicitly reward companies for providing generating capacity. Indeed, the debate on the future of BETTA includes substantial argument that a new system able to cope better with variable demand may need, at least in part, to reward installed capacity. Phil Baker and Dr Bridget Woodman at the University of Exeter argue that this means firms must instead attempt to recover some of their investment costs through the BETTA market. However, in an efficient market constraint costs should only be driven by fuel costs—i.e. the relative difference it costs for, say, a coal-fired power station in southern England to generate, versus a similar plant in Scotland. They note that the costs of resolving transmission congestion are observed to be around £90 per MWh, whereas under an efficient market only costs of £10 per MWh should apply.[96] Similar work conducted by the Centre for Sustainable Energy and Distributed Generation demonstrates the same effect.[97] This implies that BETTA potentially overstates the true level of constraint costs and, therefore, the need for additional transmission capacity to meet these constraints may also be overstated.

65. Ofgem also believes constraint costs have been made artificially high in recent years through the exploitation of market power by certain electricity companies. In April 2008 it launched a formal investigation under the *Competition Act 1998* into the behaviour of Scottish Power and Scottish and Southern Energy. The complainants alleged that the companies may have withheld generating capacity from the wholesale forward market while using the same plant to supply balancing power to National Grid at excessive prices.[98] Ofgem closed the investigation in January 2009, stating that to continue would have been an inefficient use of resources given the low likelihood of making an infringement decision under the Act.[99] Nevertheless, the regulator estimates that up to £125 million of the £262 million of constraint costs incurred in 2008/09 could potentially have been the result of the misuse of market power.[100] Because of the difficulties Ofgem believes it faces in applying the *Competition Act 1998* legislation to the wholesale electricity market, it has argued in favour of being able to place a Market Power Licence Condition on generators that would strengthen its ability to carry out investigations.[101] The Energy Bill currently before Parliament includes provisions which would give the regulator these powers.

66. In February 2009 Ofgem wrote to National Grid highlighting concern at the level of constraint costs, and asked it to conduct a review considering possible changes in the way

96 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)

97 Ev 264 (Prof Goran Strbac, Imperial College London)

98 Ofgem, *Addressing Market Power Concerns in the Electricity Wholesale Sector—Initial Policy Proposals*, para 1.14, March 2009

99 Ofgem Press Notice, *Ofgem closes Competition Act 1998 case against Scottish Power and Scottish and Southern Energy*, 19 January 2009

100 Ofgem, *Addressing Market Power Concerns in the Electricity Wholesale Sector—Initial Policy Proposals*, para 1.15, March 2009

101 *Ibid.*

they are recovered. In May the company proposed a modification to the BSUoS charging methodology—referred to as GB ECM-18. This would see constraint costs that arise from the non-compliance of a derogated transmission boundary, such as the Cheviot interconnection, being levied on a locational basis to all exporting generators behind that boundary. Ofgem is now consulting on this proposal and expects to make a decision before the start of the next charging year on 1 April 2010.[102]

67. If implemented, GB ECM-18 will inevitably shift the burden of BSUoS charges from generators in England and Wales onto those in Scotland. Depending on how generators respond, it will also potentially reduce the level of constraint costs across the system by encouraging less generation north of the border and more in the south. National Grid also believes the reforms would reduce companies' ability to exercise market power when the system is constrained.[103] The proposals met with criticism from some our witnesses. Scottish Renewables told us: "It is conceivable that generators behind a number of boundaries will face significant additional […] charges which may cause the suspension of a number of projects".[104] However, National Grid's analysis suggests that though wind generators in Scotland would pay more, it would be marginal thermal (i.e. fossil fuel-based) plant that would be incentivised to generate less.[105] Scottish Power, which would be most affected by GB ECM-18, also expressed concern stating: "[...] we do not see ourselves as a cause of the balancing costs. We are unable to generate as much as we would like because the network is not strong enough".[106] However, others were in favour of greater locational pricing within the BSUoS charges, noting that the current system, which does not minimise constraint costs, creates incentives for inefficient investment in transmission assets.[107] Prof Strbac also argued that moving towards locational BSUoS charges would facilitate greater sharing of network capacity by, for example, encouraging conventional power stations in Scotland to reduce their output on windy days.[108] He also considered that, in the future, the sharing of network capacity between generators will be a key feature of the smart grid.

68. It is also worth noting that once the current upgrade of the Cheviot Boundary is complete it is possible that it will then comply with the SQSS and no longer require a derogation. Given the locational charges under GB ECM-18 apply to a derogated boundary, many of the concerns raised by the Scottish generators may prove unfounded in the long run. The debate may also be superseded by new charging arrangements that could arise from DECC's consultation on an enduring access regime for new generators, which we discuss later in this Chapter.

69. **Constraints occur on the transmission network when the system is unable to transmit the power supplied at a particular location to where demand for it is situated.**

102 Ofgem, *Locational BSUoS Charging Methodology – GB ECM-18*, para 1.13, December 2009

103 National Grid, *GB ECM-18 Addendum*, November 2009

104 Ev 260 (Scottish Renewables)

105 *Op. cit.*

106 Q 88 (Scottish Power)

107 Ev 268, para 2.10 (Prof Goran Strbac, Imperial College London) and Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)

108 Ev 268 (Prof Goran Strbac, Imperial College London)