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Dear Dr Finkel and the Panel

AEMC submission to the Independent Review into the Future Security of the National Electricity Market

The Australian Energy Market Commission (AEMC or Commission) welcomes the opportunity to make a submission to the Expert Panel's Preliminary Report on the Independent Review into the Future Security of the National Electricity Market (the Review).

Australia's energy sector is undergoing a significant transition. Changes are increasingly driven by new technologies, business models and consumer preferences, but also by various sector specific government schemes that operate outside the governance frameworks of the National Electricity Market (NEM), and usually designed to support renewable technologies or reductions in emissions.

The NEM was established to introduce competition in the wholesale electricity sector with the objective of decentralising operational and investment decisions to commercial parties who are better placed to bear the costs and manage the risks of those decisions. It also recognised the fact that the energy sector is not static. The governance framework was designed to, and does, evolve continuously. This can be illustrated through the 214 changes made to the energy market Rules, and 102 reviews or pieces of advice completed by the AEMC, since its establishment.

Recent years have seen a much more rapid transformation of the sector. New ways of generating electricity are challenging the physical security of the electricity system, and consumers are demanding more choice in the way they source and use electricity. This means that the sector and the regulatory framework underpinning it must be more flexible. It also means that policy objectives must be clearly specified and the mechanisms used to achieve them aligned and integrated.

The overall aim of the NEM and its governance framework is to provide a reliable, secure energy supply at the best possible price for consumers and it must continue to deliver this while the sector transforms in response to the other policy objectives of governments. Significant investment is needed to deliver these outcomes. However, without stable policy and regulatory frameworks, the NEM and its supporting framework will be unable to perform this role.

Effective policy leadership is needed to provide the investment certainty that is a prerequisite for the successful management of the transformation of the sector.

Maintaining a reliable power system in light of the structural changes involves co-ordinating a complex set of commercial and technological factors that result in a series of investment and disinvestment decisions - that is, moving people and capital from one place to another, moving from one business model to another, moving from one form of technology to another, and effectively managing the risks along the way. The co-ordination of these decisions and managing the risks involved is what workably competitive markets do best, given a credible policy framework and effective governance.

Mechanisms that drive emissions outcomes in the NEM must align with energy policy objectives of reliable, secure supply at the best price for customers. The design of any emissions reduction mechanisms must be resilient to changes in market conditions and not depend on today's expectations and assumptions. This will give investors and consumers confidence to invest and change behaviour.

Investments in technologies to maintain a reliable and secure system are crucial, and regulatory frameworks should set the pre-conditions, but not target specific technologies, so the market can coordinate and deliver outcomes in the most efficient way possible. Market and technological risks should be allocated to commercial parties with the strongest incentives and abilities to manage or mitigate those risks. This protects consumers from bearing the costs of mistakes.

The success of any framework also largely depends on how the people who operate the system and its many parts respond when something happens that they could not have anticipated.

There are three matters the Commission believes are critical in maintaining the future security and reliability of the NEM. These matters are the focus of the Commission's submission:

1. **Good governance** – The governance framework consciously allocates decision making responsibilities to a range of parties and gives those parties the tools and mechanisms to implement them. While the governance structure is generally sound, there are a number of opportunities to improve the effective functioning of the current arrangements to support timely, well informed decisions and inclusive processes. Pursuing these opportunities is crucial if the gap between issues emerging and being addressed is to be shortened. A number of suggestions to improve the effective functioning of the governance framework, including on the role of the AEMC's Reliability Panel, are set out in **section 1**.

2. **Effective integration of emissions reduction and energy policy** – While it is clearly the role of governments to determine an emissions reduction policy objective for the electricity sector, the design of the mechanism is critical in both achieving the emissions objective and maintaining and enhancing an efficient, safe, secure and reliable energy system that delivers the best outcomes for consumers. To this end, **section 2** sets out the policy design principles which must be considered when designing an emissions reduction mechanism to successfully integrate with the energy market. Poor design will put both objectives at risk - however, a mechanism designed to be consistent with these principles will help contribute to the regulatory certainty that is critical for all investors in the energy sector, including renewable energy, and hence system reliability.

3. **Giving investors and consumers confidence** – Appropriate investment signals, risk allocation and risk management tools are critical in achieving sufficient and timely investment in the technologies necessary to maintain reliability, security of supply and competition in the retail market as the sector transforms. The efficacy of the price signal is critical to market participants making efficient decisions. This is because short term dispatch and long term investment decisions are primarily driven by current, and expectations of, derivative prices in the wholesale contract market. If this market is influenced by external factors, for example, subsidies designed in a way that allows particular technologies to be financed by mechanisms that operate outside of the NEM, the ability of price signals and risk management tools to coordinate investment and divestment decisions, and hence to achieve reliability and security of supply for consumers, is undermined. The effective functioning of the wholesale and contract markets is therefore critical to maintaining reliable and secure supply to consumers, and in promoting competition in wholesale and retail markets for the benefit of consumers. This matter is discussed in **section 3**.

The idea of investment signals and certainty is further explored in a report attached to this submission prepared by Professor George Yarrow for the AEMC, titled *Energy and environmental policy: the GB experience* (2017)[1]. The report provides an account of the development of Great Britain (GB) energy and environmental policies over recent decades, with a focus on the extent to which they have worked together to bring about the achievement of best-feasible trade-offs between major policy objectives. As noted by the author, the story of GB responses to the challenges involved in coordinating energy policy and environmental policy is "for the most part, a narrative of failure." Some observations from the report are included in section 2 and Box 4 of this submission.

The Commission acknowledges that there are a range of other matters and a series of questions which the Review is considering. The AEMC has completed, or is currently progressing, a range of work that relates to the seven themes and supporting questions asked in the Expert Panel's preliminary report. Attachment A lists this work, and includes a brief description of how each Rule change process, review or piece of advice is relevant to each of the Panel's questions. This may be useful for the Panel in identifying what has been achieved to date.

Section 4 of this submission is then used to outline the key aspects of the AEMC's current work program. This includes an overview of the system security work underway which will deliver immediate solutions relating to power system emergency management. It will also develop medium to long-term changes to the market frameworks to support the entry of new technologies and new participants in a manner that delivers secure energy at the best price for consumers as the NEM transitions to a lower emissions future.[2]

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[1] The report provides a historical narrative of policy development in GB and provides an overview of the changes to the institutional and governance arrangements which have taken place. Importantly, the report also provides an overview of the major effects that GB energy and environmental policies have had on investment, innovation, energy prices, system security, institutions and on the overall performance of climate change policy. The report highlights just how significant the low degree of policy integration has been for the achievement of both energy and environmental policy objectives.

[2] The AEMC published its draft decision in respect of a proposal received from the South Australian Government to amend the National Electricity Rules in relation to Emergency Frequency Control Schemes on 22 December 2016. It also published an Interim Report for the System Security Market Frameworks Review on 16 December 2016. A Directions Paper for this review will be published in March 2017.

The Commission can provide the Expert Panel with any additional information in relation to the matters raised in each of the consultation questions, on request.

This submission draws on the AEMC's experience with energy market development matters. In making and amending the national energy market Rules in response to Rule change requests submitted by any party, and in providing advice to the Energy Council, the AEMC is guided by the three national energy policy objectives: the National Electricity Objective (NEO); the National Gas Objective (NGO); and the National Energy Retail Objective (NERO). These objectives focus on promoting the long term interests of consumers with respect to price, quality, reliability and security of energy services. Supported by effective engagement and strong relationships with stakeholders, the capability of the AEMC to provide well-considered analysis and advice to the Energy Council on emerging issues and policy solutions, and to deliver on the energy objectives, has generally proven to be robust.

More broadly, the national energy market governance arrangements have created an effective and transparent framework for implementing reforms on a national basis and continuously refining the energy market at all levels of the supply chain.

The final outcomes experienced by consumers are of course also influenced by factors operating beyond the remit of the NEM institutions. The Independent Review into the future security of the National Electricity Market provides a rare opportunity to establish coherent mechanisms for the achievement of the energy and emissions reduction policy objectives of the NEM jurisdictions.

If you have any questions or require further information please contact Anne Pearson, Chief Executive Officer, on (02) 8296 7800.

Yours sincerely

John Pierce
Chairman

Attachment A: AEMC work that relates to questions raised in the preliminary report

Attachment B: Regulatory Policy Institute, Environmental and Energy Policy Integration, the GB Experience, February 2016

AEMC submission – Key messages

- The NEM was established in the context of a national productivity reform agenda aimed at delivering markets that are competitive where possible, and well-regulated where not.
- The NEM was established to introduce competition in the electricity sector and to decentralise operational and investment decisions away from governments and regulators to commercial parties. It also recognised the fact that the energy sector is not static. Change in markets is not new, and the framework was designed to, and does, evolve continuously while still meeting the need for a stable investment environment.
- Regulatory and market arrangements can be thought of as primary mechanisms for allocating and managing risks. Diagnosing and responding to regulatory and market failures therefore demands both clarity of policy objectives and a deep understanding of the technical, economic and financial risks inherent to the energy sector.
- The success of any regulatory framework largely depends on how the people who operate the system and its many parts respond when something happens that had not been anticipated.
- When designing frameworks, consideration should always be given to the fact that consumers are best served by workably competitive wholesale and retail markets that allocate risks to commercial parties that have the strongest incentives and abilities to manage those risks. Changes in technology or market conditions should not require changes in frameworks; rather the frameworks should be capable of adapting and self-correcting.
- The overall aim of the NEM is to provide a reliable, secure energy supply at the best possible price for consumers and it must deliver this while the sector transforms. Significant investment is needed to support this transformation and regulatory frameworks must support investment in the broadest range of technologies possible in order to deliver the outcomes customers want, at lowest cost.
- A comprehensive system security work program is already underway which will help deliver technical solutions and regulatory and market framework changes necessary to maintain a secure supply of electricity for customers as the NEM transitions to a lower emissions future.
- There are three matters the AEMC believes are critical to maintaining security in the current environment of change:

1. **Good Governance -** there are opportunities to improve the effective functioning of the current governance arrangements to shorten the lag between when challenges emerge, and when they are acted upon.
2. **Effective integration of emissions reduction and energy policy -** the design of any mechanism to achieve emissions reduction objectives is crucial if we are to achieve both the required emissions reductions and the safe, secure and reliable supply of electricity at the best price for consumers. If the impact on how the electricity markets operate is not properly considered when designing a mechanism to drive emissions reductions in the electricity sector, then the achievement of both energy and emissions objectives will be at risk.
3. **Giving investors and consumers confidence -** appropriate investment signals, and the ability to respond to those signals, are critical to achieving sufficient and timely investment in the technology necessary to maintaining security of supply and competition in the retail market. Fundamental risk management structures within the NEM must be maintained so as to protect customers from bearing the risk of those investments.

- As the Australian energy market becomes more dynamic, it is more important than ever that all parties are committed to playing their appropriate role in supporting timely, national energy market development.

1. Good governance

The governance framework within which the energy market operates is fundamental to the successful delivery of energy market reform. As noted by the Expert Panel, effective governance will be critical in managing the transition currently underway, and in implementing any necessary reforms to market and regulatory frameworks.

The current governance framework was created by COAG over ten years ago to oversee Australia's energy markets. At the time of creation, competition policy was a national priority and a governance structure that could deliver effective competition and investment certainty in the energy sector enjoyed support from the highest levels, through the Council of Australian Governments (COAG).

Energy market governance was formalised in the Australian Energy Market Agreement (AEMA), an intergovernmental agreement signed by all state, territory and commonwealth government leaders. For most of this time, the governance arrangements have delivered successful market and regulatory outcomes, creating a stable investment environment and promoting growth in competition across the energy supply chain in the long term interests of energy consumers.

Since the energy market governance framework was formalised, key successes of the energy market reform agenda include:

- creation and oversight of the three national energy market institutions (that is, the Australian Energy Regulator (AER), the Australian Energy Market Operator (AEMO) and the AEMC)
- maintenance of stable and effective electricity wholesale market arrangements over time
- introduction of full retail contestability in electricity and gas across all NEM jurisdictions
- removal of electricity retail price regulation in most NEM jurisdictions where retail competition has been found to be effective
- the ability to develop and refine in a consistent direction the Rules[3] for the economic regulation of network service providers in response to experience and industry developments
- development and implementation of the AEMC's Power of Choice review recommendations to provide consumers with more choice in the way they use electricity and manage their bills
- implementation of the National Energy Customer Framework (NECF) in a majority of NEM jurisdictions
- creation of gas Short Term Trading Market (STTM) hubs in Sydney, Adelaide and Brisbane.

The Council's ability to deliver effective and long lasting reforms has required a commitment by jurisdictional governments to the overall benefits to consumers of a national approach, and having in place the structure and processes necessary to deliver it. While all jurisdictions are 'on' the Council, its success depends on the extent to which all governments 'own' the Council as an institution, its strategic objectives and national work program. It is crucial that the Energy Council remains effective as it is ultimately accountable for the performance of the national energy market.

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[3] In this submission, "Rules" is used to refer specifically to the National Electricity Rules, National Gas Rules and the National Energy Retail Rules, This is distinct from the term "rules" which may be construed as referring to any legislative instrument or regulation within the remit of governments, jurisdictional regulators or other technical bodies.

As the Australian energy market becomes more dynamic with new technologies, emissions policy and consumers increasingly driving market developments, it is more important than ever that the governance arrangements are clearly understood, consistently applied and receive a revitalised commitment from all parties in order to support timely and effective market development.

This section offers some observations on the evolution of the current governance framework, highlighting the strengths of the current arrangements. It also identifies a number of areas for improvement to the governance arrangements, including in relation to the effective prioritisation of tasks and the timeframes within which issues are progressed.

A number of observations are also offered on the AEMC's Reliability Panel and the opportunities that exist to strengthen its role in reporting on reliability, safety and security matters.

Evolution of the governance framework

Recognising the important policy role for governments in providing national leadership on energy issues, in 2001, three years after the official commencement of the NEM, COAG established a Ministerial Council on Energy (MCE) to "provide national oversight and coordination of energy policy development and to provide national leadership so that consideration of broader convergence issues and environmental impacts are effectively integrated into energy sector decision-making."[4]

Situated within the broader COAG structure, the MCE was responsible for providing policy leadership to the energy sector and provided the means for participating jurisdictions to coordinate nationally, on important energy policy issues.

At the time, there was a general level of concern regarding various aspects of the governance arrangements, including in relation to the following:

- The role of the National Electricity Code Administrator (NECA) versus the role of the MCE in terms of setting national energy policy.
- The potential for regulatory overlap due to a lack of clarity in the roles and responsibilities of key electricity governing bodies. This lack of clarity had already led to instances of duplication in consultation processes between the ACCC (the competition regulator) and NECA (the manager for change processes and compliance in relation to the National Electricity Code).
- The number of independent jurisdictional economic regulators pursuing different approaches to energy regulation. The multiple regulatory regimes was creating barriers to entry and increased compliance costs for market participants seeking to operate on a national basis, limiting choice and increasing prices for consumers.

COAG First Ministers subsequently commissioned an independent review of the energy market governance arrangements, referred to as the Parer Report (2002). Among other things, the Parer Report confirmed concerns that there were too many regulators operating independently across the jurisdictions, and that the key electricity governing bodies had overlapping responsibilities.

In light of the recommendations made in the Parer Report, the MCE recommended to COAG that NECA be abolished and two new statutory bodies be established:

[4] Australian Energy Market Agreement, Recitals, A(a).

- The AEMC replaced NECA as the Rule maker and was provided with an additional function of market development adviser to the Council.
- The AER replaced the ACCC and the jurisdictional economic regulators[5] as the national economic regulator, and NECA for Rule compliance.

The National Electricity Law (NEL) set out the roles and functions of the AEMC and AER, and the National Electricity Code was changed to the National Electricity Rules (NER).

The focus of the governance arrangements was threefold: to separate market development from broader energy policy setting, with the MCE being accountable for policy; to separate Rule making and market development advice from rule enforcement and compliance; and to bring greater clarity and transparency to the roles and objectives of the governance institutions, and to the decision-making processes.

A key feature of the arrangements was to consolidate a range of different market objectives into a single National Electricity Objective (NEO) focussed on efficiency and linked to the long term interest of consumers of electricity.

The relationship between efficiency and consumer interests within the NEO was expressed in the Second Reading Speech for the Bill that introduced the current governance arrangements in 2004. In this speech, the Minister explained:[6]

> "The long-term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long-term interests of consumers in respect of price, quality, reliability, safety and security of electricity resources will be maximised."

The arrangements also provided for a single process for developing the national energy Rules, in contrast to the varied approaches taken by jurisdictions, and the previous two-tiered approach which required both NECA and the ACCC to review changes proposed by participants. In addition, governments determined that it was not appropriate to seek authorisation by the ACCC of Rule changes under Part IV of the Trade Practices Act 1974 (Cth).[7] This was a significant decision.

The NEL (as well as the National Gas Law (NGL) and the National Energy Retail Law (NERL)) enables any person, apart from the AEMC, to initiate a Rule change proposal,[8] including industry participants, other institutional bodies, end users, as well as the Council. Previously, only NECA and industry participants (with agreement from at least six participants) could submit Rule change proposals. It is important to note that these arrangements did not remove any law making functions from any Parliament. The AEMC largely took on the Rule making functions that had previously been undertaken by NECA and other jurisdictional bodies.

Under these arrangements, the Council, subject to agreement by all its members, is able to initiate Rule changes without AEMC involvement. Given the broader mandate of the Council, this is

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[5] While the AER replaced these bodies as the national economic regulator, retail pricing functions remained the responsibility of individual jurisdictions. That said, the jurisdictions were given the option to confer these functions on the AER by agreement with the Commonwealth.
[6] National Electricity (South Australia) (New National Electricity Law) Amendment Bill (2005).
[7] This was renamed the Competition and Consumer Act 2010 (Cth), effective 1 January 2011.
[8] Limited restrictions exist under the NEL in relation to who can submit Rule change requests affecting AEMO's declared network functions and derogations.

completely appropriate and enables them to be ultimately accountable for Australia's energy markets.

The framework allows significantly enhanced participation from a range of stakeholders, including consumer groups, in the Rule making process (the significance of the role for stakeholders is discussed further below). Importantly, the AEMC is not empowered to initiate Rule changes, other than to correct minor errors or where the proposed change is non-material. The AEMC's role is to manage the Rule change process, and to consult and decide on Rule changes proposed by others. The arrangements consequently impose a strict level of policy control, which is the province of the Council, on market developments and establish well understood and transparent processes for policy and regulatory changes.

The involvement of stakeholders in the Rule making process supports better regulatory decision making and minimises the risk of inappropriate decisions being made. An independent decision making body, separate from industry and government but with a clear and consistent objective, is able to determine Rules that best align with the policy intent and governments' broader reform agenda.

A considered and consistent approach to reform is desirable as inappropriate regulatory or policy decisions, or policies that change too often have significant consequences for markets, undermining confidence in those markets and in the institutions that govern them. This can cause momentum for reform to slow or even retreat. The current institutional arrangements and processes minimise the potential for this to occur, ensuring a self-sustaining framework for ongoing market reform.

A key strength of the national energy Rules as regulatory instruments is the certainty of adaptability they provide in response to changes in the market. Compared with similar instruments like Acts or Regulations which would require changes to be made by Parliaments or Regulators of each jurisdiction, the national energy Rules are able to be continually updated by one national Rule-maker, based on proposals brought forward by, and consultation undertaken with, a range of stakeholders. The current consolidated version of the NER, for example, is version 88 which commenced on 1 January 2017.

In February 2015, an Expert Panel commissioned by the Energy Council commenced a review of the governance arrangements for Australian energy markets (Governance Review). The Governance Review was initiated in response to a COAG commitment to review the governance arrangements in the Australian energy market five years after the establishment of AEMO in 2009.[9]

In the final report delivered to the Energy Council in October 2015, the Panel concluded that the division of functions established by the current governance arrangements for Australian energy markets is fundamentally sound and that Australian energy market governance is amongst best practice internationally. It also made a number of recommendations to the Energy Council to improve transparency, timeliness, resources and clarity of functions and purpose, both for the Council itself and the other energy market institutions. These recommendations are at various stages of implementation.

The current national energy governance structure is set out in Box 1.

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[9] The Review Panel (the Panel) comprises Dr Michael Vertigan AC as Chair, Professor George Yarrow and Mr Euan Morton.

Box 1 – Energy Market Governance Structure

The current governance structure for Australia's energy markets was created by COAG. Separating the functions of broad policy direction, Rule-making and market development, economic regulation and compliance and market operations has resulted in independent expert decision-makers with clear accountabilities and objectives operating at the national level.

The COAG Energy Council was created in December 2013 and is the latest embodiment of the Ministerial Council on Energy (MCE).[10] It is accountable to COAG and brings together energy and resources Ministers from the commonwealth, states and territories to pursue a common set of objectives and coordinate priorities for the development of national energy and resources markets.[11] Specifically, the Energy Council is responsible for:

- facilitating national oversight and coordination of governance, policy development and program management to address the future challenges facing Australia's energy and resources sectors
- providing national leadership on key strategic issues and integrating these priorities into government decision-making
- enhancing national consistency between regulatory frameworks to reduce costs and improve the operation of the energy and resources sector.

The Energy Council's mandate in energy markets is limited to matters defined by the Australian Energy Market Agreement (AEMA), the key foundation document for energy market matters.[12] It is also subject to its Terms of Reference which are updated and approved by COAG from time to time. The Commonwealth serves as the permanent Chair of the Energy Council and an administrative secretariat sits within the Department of the Environment and Energy.

Although there is no formal delegation of decision making by the Energy Council, it is supported by the Senior Committee of Officials (SCO) which is composed of Senior Officials at Head of Department/Agency level from each of the participating jurisdictions. SCO advises the Energy Council and develops and progresses issues to achieve the Energy Council's priorities. The Commonwealth also serves as the permanent Chair of SCO, and by convention its decision-making processes and protocols mirror those of the Energy Council and are set out in its Terms of Reference.

Given the way in which legislative responsibilities are split between the Commonwealth, State and Territory Parliaments, the Energy Council has become the key institution in the governance architecture necessary to deliver energy market reforms. The multi-jurisdictional model has allowed for the development of a resilient national market framework, facilitated by discussion and agreement on national and jurisdiction specific policy priorities that support the long term interests of consumers.

The three market institutions are the main vehicles by which the Energy Council governs the Australian energy markets.

[10] The MCE is referenced in the national energy legislation (including the NEL, NGL and NERL).
[11] Specifically, coordinating governance, policy development and program management to address the future challenges facing Australia's energy sources; providing national leadership in key strategic issues and integrating these priorities into government decision-making; and increasing the consistency between regulatory frameworks to reduce costs and improve the operation of the energy sector.
[12] Its energy market functions are specifically referenced in clause 4 of the AEMA.

The **Australian Energy Market Commission (AEMC)** was established to oversee Australia's main energy markets. It is responsible for Rule-making and energy market development at the national level, including in respect of the National Electricity Rules, the National Gas Rules and the National Energy Retail Rules which govern the NEM, elements of natural gas markets and energy retail markets. The AEMC's strategic priorities guide its market development work and inform the advice it provides to governments.

The AEMC was established in 2005 under the Australian Energy Market Commission Establishment Act 2004 (SA).

The **Australian Energy Regulator (AER)** was established to replace the ACCC and the jurisdictional economic regulators as the national energy market regulator. It is responsible for the economic regulation of electricity and gas transmission and distribution networks, and retail markets (other than retail pricing), at the national level. It also enforces the National Electricity Rules, National Gas Rules and the National Energy Retail Rules made by the AEMC.

The AER was established in 2005 under the Competition and Consumer Act 2010 (Cth) enacted by the Australian Government. While the Commonwealth has responsibility for the AER, its governance, functions, powers and duties are established under agreement of the Energy Council and described in the national energy Laws.

The **Australian Energy Market Operator (AEMO)** is responsible for the day-to-day operation and administration of the power system and electricity wholesale spot market in the NEM, the settlement of retail electricity markets and the retail and wholesale gas markets. It coordinates the strategic development of the national electricity grid and, in gas, delivers strategic planning advice and forecasting to guide long-term investment and resource management.

AEMO was established in 2009, is a company limited by guarantee and has two types of members: government and industry, constituting 60 and 40 per cent respectively. Its corporate activities are governed by its Constitution and any obligations required by the Corporations Act 2001 (Cth).

Strategic priorities for the energy sector

In light of the unprecedented pace of change in the energy sector, the ability of the governance framework to deliver successful reform relies on the Energy Council clearly defining a set of focussed priorities for the energy sector, and communicating these to all parties. Effective and active leadership by the Energy Council in setting a strategic direction for the sector is critical if stakeholders are to unite behind a common set of priorities, or seek changes where they believe the priorities are not appropriate.

The AEMC currently undertakes a regular strategic priority process, designed to help it fulfil its role as the provider of advice to the Energy Council on market development matters, as well as to guide its approach to national Rule-making. Developed in close consultation with stakeholders, this process has facilitated the identification of a set of priorities to be addressed by both policy makers and the market institutions over the next few years.[13] The 2015 strategic priorities process, for example, defined three strategic priorities for the development of the energy market: a consumer priority, focused on enabling consumers to make informed decisions in competitive retail markets; a gas priority, focused on promoting the development of an efficient gas market; and a markets

[13] The development of the priorities should also encourage other stakeholders to submit Rule changes on the issues of most important to them.

and network priority, focused on ensuring market and network arrangements encourage efficient investment and flexibility.

In addition to the strategic priorities process, the AEMC's role as adviser to the Energy Council on market development issues, and the processes and approaches it utilises to fulfil this role, has allowed it to identify emerging issues and alert governments to them well in advance of the issues presenting challenges in the market. For example, the Review of Energy Market Frameworks in light of Climate Change Policies (2009) observed and reported that decreasing levels of inertia would make it hard to withstand disturbances in South Australia.

In December 2016, the AEMC received a Terms of Reference from the Energy Council tasking it with providing targeted strategic advice to inform the Energy Council's energy market strategy and priority setting process. The Terms of Reference for this advice ask the AEMC to provide its advice to the Energy Council in a report. Senior Officials are then tasked with developing specific proposals on policy and strategic direction, to be submitted to the Energy Council for consideration based on the advice provided by the AEMC.

The Terms of Reference require the AEMC to deliver its targeted strategic advice to the Energy Council in September/October every three years, commencing in 2017. They also indicate that the Energy Council will publish its strategic priorities for the energy sector in December, two to three months following the receipt of the AEMC's triennial advice.

Given the time-critical nature of energy market reform, it is imperative that the development of a strategic direction for the energy sector is supported by a robust framework and not frustrated by duplicative, time-consuming processes and delays in decision-making. In this context, there may be merit in establishing a formal, transparent process around the Energy Council's subsequent determination of the strategic priorities following receipt of the AEMC's strategic advice. This process could include the formalisation of timeframes within which the Energy Council will publish its strategic priorities following receipt of advice from the AEMC. It may also include public reporting on the progress of Senior Officials in developing specific proposals on policy and strategic direction to be submitted to the Energy Council for decision.

Implementing a transparent process would provide a formal feedback loop which allows the Energy Council and Senior Officials to communicate to the AEMC and other stakeholders how the strategic advice provided by the AEMC has been used by Senior Officials and the Council to inform its determination of the strategic priorities. Importantly, it will also provide clarity to stakeholders, including the three energy market bodies, market participants and consumers, on when to expect the delivery of the Energy Council's strategic priorities for the energy sector.

Once the strategic priorities have been set, there is an opportunity to then draw a clear linkage or 'line of sight' between the Council's strategic objectives and its work program. One example of how this might occur is by publishing and maintaining the up to date strategic objectives and supporting work program, including transparency in the assignment of tasks and timelines for deliverables, on the Council's website.

Clarity in the articulation of the Council's strategic objectives and its work program (including its purpose), supported by clear public communications of these matters and regular progress reporting against them, is essential for informing and obtaining broad support from stakeholders who are often tasked with implementing policy decisions within specific timeframes.

To maintain the momentum of the national energy market reform agenda, including broad stakeholder support, it may be timely to refresh the Council's communications of the national strategic objectives. On an ongoing basis, it is also important to continually draw the linkage between the reform program and the strategic objectives so that stakeholders understand the broader context for change.

The lag between when issues are identified and when they are considered by Ministers

The lack of a formal process around the Energy Council's efforts to determine and set strategic priorities for the energy sector is part of a broader concern around the lag between when emerging issues are identified, and when they are considered by the Energy Council. This time-lag has considerable influence over the ability of the regulatory and market frameworks to keep pace with the rapid changes underway in the sector.

As the Expert Panel is aware, new technologies and emissions policies are transforming the sector. Advances in low emissions generation technologies, metering, battery storage and solar PV (to name a few) are changing the way consumers participate in the market. However, these changes, and the impacts they are having on market and regulatory frameworks, have not been wholly unforeseen.

The AEMC, as part of its market development function, has undertaken independent reviews in response to requests from the Energy Council, and has self-initiated reviews where we have believed there to be an emerging issue in the market (for example, the System Security Market Frameworks Review (2016)). Where these reviews have identified deficiencies in the operation of Rules, the AEMC has made policy recommendations to the Energy Council for consideration, with suggested changes to the regulatory or market frameworks made in the form of proposed Rule changes which the Energy Council could then choose to submit (for example, the Power of Choice Review (2012)).[14]

We are aware of a perception held by some stakeholders that this process unnecessarily extends the time period before words (policy recommendations) are converted to action (rules), particularly where extensive analysis and consultation has already occurred as part of a completed AEMC review. However, matters that are considered in reviews are not trivial. They may involve multiple rules, proposed changes to the Law, affect multiple and diverse stakeholders, or have a non-energy policy component, such as understanding the potential consequences for financial markets in response to the failure of a large market participant.

The AEMC's review process is therefore comprehensive and ensures that the recommendations put forward to the Energy Council are born from detailed consideration of relevant issues, extensive stakeholder consultation and considered development of a robust rule design. This process seeks to minimise the risk of inappropriate decisions being made which could adversely impact on confidence in market arrangements. It also means that when the AEMC's advice and recommendations are presented to the Energy Council, they are ready to be considered and, if agreed, progressed by the Council immediately.

In an effort to streamline the AEMC review process, the Review of the Governance Arrangements (2015) recommended, and the Energy Council agreed, that the AEMC should develop a "staged

[14] In general, the AEMC cannot initiate Rule changes.

review process" proposal for broad and complex reviews[15], and a "single-step review" process proposal for reviews dealing with specific or contained issues.[16] The new review processes would provide the Energy Council with an opportunity to check in with the AEMC on a more regular basis in respect of complex reviews, while also enabling the Energy Council to progress more quickly the AEMC's recommendations and advice once received.

The new review processes do not require legislative changes to be implemented and can be easily progressed through the design of the relevant Terms of Reference for a review or piece of advice tasked to the AEMC by the Energy Council. The AEMC is committed to working closely with the Energy Council to ensure that the intent of the recommendations can be captured immediately.

While the revised "staged review" and "single step response" review processes establish a framework to support timelier decision-making by the Energy Council and the AEMC, the ability of the review process to achieve timely reforms in practice relies on the Energy Council, Senior Officials and the secretariat making changes to the way in which they consider and progress AEMC review recommendations. Overall, the recommendations and advice provided by the AEMC to the Energy Council need to be agreed (or otherwise) and progressed faster than has historically been the case.[17]

This requires the Energy Council and Senior Officials to recognise the AEMC's role as expert adviser to the Energy Council on market development issues, as well as the strength of the governance arrangements supporting this role. It also requires Senior Officials to facilitate, in a timely manner, the process of getting the AEMC's advice and recommendations to Ministers for consideration and decision.

As set out in Box 1, the Energy Council is supported by an administrative secretariat which sits within the Department of the Environment and Energy. We consider the secretariat is in a strong position to be able to drive the process of energy market reform substantially. This necessitates secretariat staff with the experience, skills and expertise necessary to actively manage and progress the Council's work program in order to deliver the strategic objectives.[18] It also requires secretariat staff to be fully committed to the timely delivery of the Council's strategic priorities.

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[15] These proposals were put forward by the AEMC in its submission to the Review of Governance Arrangements (2015). A staged review and Rule making process would allow the Council to consider the AEMC's analysis at a "check-point" and confirm the need and scope for a second stage of the review, prior to its commencement. The second stage would then consider implementation issues, including development of rules (and other instruments, if required). After receipt of the review final report, if the Council was able to submit a Rule change request to the AEMC within six months of receipt of the report, the AEMC would then commit to having the Rule change completed within six months.

[16] A single step response to an AEMC review would involve the Council making a decision to approve a Rule change request at the same time that it considers the recommendations set out in the final report for a review and forwarding the approved Rule change request to the AEMC with the meeting communiqué. The AEMC would commit to a six month Rule making timeline under these circumstances. The single step response approach could potentially save up to eight months if the Council considers and approves its response to AEMC review recommendations at the same time.

[17] In general, it takes the AEMC around nine months to complete a review (that is, from receipt of the terms of reference, to provision of the final advice). It can then take another eight months for the Council to respond to the review recommendations. This implies that it generally takes about 17 months before the AEMC considers a Rule change request, or commences an additional review or piece of advice, from the Council in response to an AEMC review recommendation.[17] This extended timeframe has a number of implications, including on the ability of the market and regulatory frameworks to keep pace with rapid changes occurring in the energy sector.

[18] This will be particularly important if the secretariat role is expanded in line with recommendations from the Review of the Governance Arrangements (2015).

We consider there is an opportunity to better equip the secretariat with, in particular, technical expertise, to help drive the timely delivery of the Council's priorities. This can be achieved by facilitating closer communications between the secretariat, each of the member governments and the market institutions on the respective work programs. This could be achieved by having a representative seconded from the AEMC (and from AEMO and the AER) to the secretariat.[19]

The secondee(s) would serve as the technical expert for their respective organisation, responding to any queries from Senior Officials or the secretariat on the organisations and their work programs, and responsible for following the passage of that work through the secretariat, to the Energy Council and (where agreed) back down again.

This opportunity would facilitate closer interactions between staff from the secretariat, member governments and the three energy market institutions. In addition to providing secretariat staff with an opportunity to learn more about the functions and every-day operation of the AEMC, AEMO and the AER, it would also contribute to an increased understanding of the realities of the interplay between the Energy Council, SCO and the market bodies, by staff seconded from these bodies.

Role of the Reliability Panel

The Reliability Panel forms part of the AEMC's institutional arrangements that support the national electricity system. The Reliability Panel's core functions relate to the safety, security and reliability of the national electricity system. An overview of the Reliability Panel is provided in Box 2.

Box 2 – The Reliability Panel

The NEL sets out the key responsibilities of the Reliability Panel which include:

- to monitor, review and report on the safety, security and reliability of the national electricity system
- at the request of the AEMC, to provide advice in relation to the safety, security and reliability of the national electricity system.

The Panel's work program is largely driven by specific requirements set out in the NER. Generally, the focus on the Panel's work is on determining standards and guidelines, which are part of the framework for maintaining a secure and reliable power system.[20]

The standards developed by the Reliability Panel specify information to market participants, such as generators and large customers. For example, they specify important requirements for connecting to, and operating under, the national electricity system, such as performance standards and operating frequencies.

The Reliability Panel must also develop the standard for a system restart which AEMO uses when procuring ancillary services to be used in the event of a total blackout of the power system. In December 2016, the Panel completed its latest review of the System Restart Standard, which was last set in 2012.

[19] This would be in addition to the recommendation of the Review of the Governance Arrangements (2015) to expand the secretariat by a small number of appropriately qualified officers seconded from the Australian Government and state and territory jurisdictions. The intention is to support the expanded role of SCO in terms of oversight and reporting on the delivery of the Energy Council work programme.

[20] The Panel must follow the consultation process set out in the NER in determining standards and guidelines.

Most of the Panel's guidelines are developed to assist AEMO to perform its power system security and reliability functions.

In addition to its ongoing obligations, the Reliability Panel may also be directed from time to time, by (only) the AEMC, to review or provide advice on a specific matter as it relates to the safety, security and reliability of the national electricity system. The Reliability Panel also actively monitors Rule change requests and reviews that the AEMC is conducting and makes submissions on projects that are relevant to its functions.

The Reliability Panel is comprised of senior members who represent a range of participants in the NEM including AEMO, generators, network businesses, consumers and large end users. In appointing a person to the Panel, it is the role of the AEMC to ensure the Panel is broadly representative of persons with direct interests in reliability of electricity supply under the market arrangements.

Many of the reviews and pieces of advice provided by the Reliability Panel form part of its periodic and ongoing obligations under the NER to review market parameters regarding power system security and reliability.

The Reliability Panel has, for example, a periodic obligation to review and provide advice to the AEMC on the reliability standard and settings once every four years.[21] This periodic review of the reliability standard and settings enables the Reliability Panel to consider whether the standards and settings remain suitable for current market arrangements and whether they continue to meet the requirements of the market, market participants and consumers. At the end of the review, the Reliability Panel makes recommendations to the AEMC as to whether the standard or any of the market settings need to change.

The Reliability Panel also undertakes an Annual Market Performance Review (AMPR) each year. This examines the performance of the NEM in terms of reliability, security and safety of the power system. This is done by reference to various power system security and reliability standards, policies and guidelines. The AMPR also provides an opportunity for the Reliability Panel to consolidate key information related to the performance of the power system in a single publication for the purpose of informing stakeholders. Among other things, this may assist governments, policy makers and market institutions to monitor the performance of the power system, and to identify the likely need for improvements to the various measures available for delivering reliability, security and safety.

In 2017, the Reliability Panel will be undertaking a range of work that will support the safety, security and reliability of the national electricity system. These projects include a number of periodic reviews that the Reliability Panel is required to undertake, as well as more proactive work. The 2017 work program includes (but is not limited to) a review of the Reliability Standard and Reliability Settings, the 2017 Annual Market Performance Review and a review of the Frequency Operating Standards.

Following the conclusion of the AEMC's current System Security work program (discussed in section 4), the Reliability Panel may be tasked with a number of additional responsibilities. Based on the AEMC's draft Rule in relation to the South Australian Government's request to amend the

[21] The reliability standard is the maximum amount of electricity expected to be at risk of not being supplied to consumers in a financial year. Referred to as the maximum expected unserved energy (USE), the current Reliability Standard is 0.002% of annual energy consumption. The reliability settings encompass the Market Price Cap, Cumulative Price Threshold and Market Floor Price.

National Electricity Rules in relation to emergency frequency control schemes and the AEMC's Interim Report for the System Security Market Frameworks Review (both published in December 2016), these responsibilities may relate to:

- developing a standard for emergency frequency control schemes
- defining the post-contingency operating state for protected events
- potentially developing standards relating to managing inertia, system strength and rate of change of frequency or other matters that may come out of the system security review.

The Reliability Panel has an integral role in setting the framework for maintaining the operation of a safe and reliable electricity supply system through its functions outlined above. As such, if through the course of progressing any Rule change or review, the AEMC identifies the need for a new standard relevant to reliability or security matters and which may involve the consideration of technical issues and/or a trade-off between costs and reliability/security benefits, we consider the Reliability Panel is ideally placed to set such a standard.

In addition, we consider there may be an opportunity to broaden the Reliability Panel's role in reporting on matters relevant to the safe, secure and reliable operation of the power system. Specifically, there may be merit in expanding the scope of the Reliability Panel's Annual Market Performance Review so that it becomes a more useful tool to the market. This could involve reporting on a wider range of issues impacting the power system, and potentially including some forward looking analysis to better equip stakeholders, including governments and policy makers, in forming expectations of future power system safety, security and reliability issues.

2. Effective integration of emissions reduction and energy policy

Greater integration of emissions reduction and energy policy is required to maintain and enhance an efficient, safe, secure and reliable energy system that keeps prices as low as possible for consumers. Effective integration helps to contribute to the regulatory certainty that is critical for all investors in the energy sector, including renewable energy.

Energy and emissions policies have different objectives and so it is important they are developed in a manner where any efficiency trade-offs and costs are well understood. Emissions reduction policies that are appropriately designed and integrated can achieve their objectives and minimise costs faced by consumers in energy markets.

Evidence from international markets suggests that if integration (that is, the maintenance of fundamental structures in the market that support investment and competition) does not occur, the impact on the efficacy of price mechanisms, together with uncertainty and policy risk, will likely require ongoing government intervention in otherwise well-functioning energy markets, transferring investment risk and costs onto consumers.

Such an outcome is evidenced through the GB experience of energy and environmental policy development over recent decades. As observed by Professor George Yarrow in his report appended to this submission:[22]

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[22] In this excerpt, DECC refers to the Department for Energy and Climate Change which was established in 2008 to bring together GB energy and environmental policy. DECC was subsequently closed in 2016 with its responsibilities transferred to the Department for Business, Energy and Industrial Strategy (BEIS). See: G Yarrow, 'Regulatory Policy Institute, Energy and environment policy: the GB experience', A report for the AEMC, February 2017, p. iv.

> "…in 2010 DECC concluded that the existing energy market arrangements, developed over a period of twenty years, would be incapable of meeting the carbon budgets it had adopted and set about redesigning the market itself, a programme it referred to as Electricity Market Reform (EMR). The result of that exercise is a set of arrangements in which virtually all generation capacity must acquire contracts that are settled via centralized procurement arrangements…
>
> A consequence of the new market design was accurately summarized in 2015 by the then Secretary of State at DECC when she said: *"We now have an electricity system where no form of power generation, not even gas-fired power stations, can be built without government intervention."* Since that was exactly the position pre-privatization, the implication is that GB has come full circle. The work of Ofgem and of earlier Governments has been undone and there is no reason to think that a policy approach that worked poorly in the 1960s, 1970s and 1980s will work significantly better now."

When contemplating the effective integration of energy and environmental policy, we consider that it is important to design a mechanism to achieve an emissions reduction objective which is consistent with the National Electricity Objective and thus preserves the means of exchange and allocation of risk in energy markets. In this respect, the following factors are worth considering:

- **Adaptable and sustainable design** – for an emissions reduction mechanism to be sustainable and effective, it needs to be able to meet its objectives in the face of a changing and uncertain future. Without this ability to adapt when the future does not turn out as expected, investors may begin to expect that a emissions reduction mechanism may be changed in light of the actual outcomes, for example if demand is lower than anticipated at the outset of the policy. This can lead to investors not having the confidence to invest in new generation capacity.
- **Flexibility to adapt** – if the mechanism design is predicated on one view of the future, then it may not be sufficiently resilient to respond to changes in demand, fuel prices, technology costs and other factors that influence electricity market outcomes. This will likely result in the emissions reduction objective and NEO not being met, along with pressure placed on governments to undertake reviews, resulting in investment uncertainty.
- **Technology neutral** – an emissions reduction mechanism that recognises abatement brought about through the greatest variety of technology options will help minimise the long term costs to consumers of meeting the emissions target.
- **Geographically neutral** – a mechanism that is indifferent to where generation or demand-side technology options are to be located in the NEM and that allows the locations selected to be an outcome of the trade-off between economic costs and benefits, is likely to minimise long term costs for consumers.
- **Contract market liquidity** – an emissions reduction mechanism that, through its effect on the technology of the generation stock, preserves or enhances contract market liquidity will assist participants to manage risks efficiently for the long term benefit of consumers.
- **Allocation of risk** – an emissions reduction mechanism that allocates risks to those parties best-placed to identify and respond to risks in an efficient manner will be consistent with the NEO. The NEM is designed in a manner such that generators make investment and retirement decisions based on price signals in the spot and contract markets, and face the outcomes of their decisions. If electricity demand, fuel costs, or other variables are higher or lower than expected, the primary implications for plant profitability are borne by generators, rather than consumers or taxpayers. This is appropriate because generation

businesses have the expertise, information and commercial incentives to manage such risks efficiently.

The current Renewable Energy Target (RET) policy provides an example of an environmental policy that has not been successfully integrated with energy policy. The design of the mechanism does not maintain appropriate price signals for investment, nor encourage efficient behaviour by market participants and thus has a greater likelihood of increasing the costs faced by consumers in energy markets.

The RET policy and some of the unintended consequences on outcomes in the electricity market are highlighted in Box 3.[23]

Box 3 – Implications of RET policy design on the electricity market

The principal policy to reduce emissions in the electricity sector is the Renewable Energy Target (RET). The RET is a policy designed to encourage investment in renewable energy generation.[24] It comprises the large-scale renewable energy target (LRET) and the small-scale renewable energy scheme (SRES). The LRET is the largest component of the RET policy and directly impacts the NEM.

The LRET provides an incentive for investment in renewable energy technology by requiring liable entities (mostly retailers) to source a proportion of their electricity from renewable sources. Eligible generators create large-scale generation certificates (LGCs) that retailers are required to purchase. It is the availability of LGC revenue (which can be earned in addition to revenue earned through the wholesale price) that encourages renewable generation to enter the market.

A key problem with the existing LRET is the impact of its design on risk allocation and incentives faced by existing generators, consumers and new entrant renewable generators.

Under the LRET, the wholesale market price is no longer the primary signal for new investment in renewable energy generation. Instead, the price signal is provided by the LGC price and the target amount (or percentage). In effect, renewable generation is compensated through payments from retailers and other large users, in addition to the wholesale market revenue.

These other price signals have meant that renewable energy generators have continued to enter the market, particularly in South Australia, despite lower wholesale market prices. The resulting exit of existing generators has resulted in two significant and, importantly, unintended impacts on wholesale market prices in both the energy and ancillary services markets:

1. **An increase in both the level and volatility of wholesale energy prices.** This is due to a combination of lower supply, increased reliance on more expensive gas generation (particularly in South Australia), and a greater share of intermittent generation in the generation mix. Higher and more volatile market prices have increased the price of forward contracts, and have also offset the short-term merit-order effect.
2. **A lack of liquidity in the forward contract market,** which has exacerbated the rise in forward prices. Retailers and generators are typically incentivised to enter into long-term contracts to

[23] See AEMC submission to the Review of the Renewable Energy Target (2014) for a more comprehensive overview of the implications of the RET design on electricity market outcomes.
[24] At the present time, Australia's policies for reducing emissions from the electricity sector at both the Commonwealth and jurisdictional levels are not consistent with emissions reductions as their primary objective. This is demonstrated by the design of the associated mechanisms, which have focused on directly or indirectly promoting the uptake of specific renewable energy technologies.

minimise price risk. However, generators that also receive LGC revenue have less incentive than other generators to enter into contracts, as the LGC revenues mitigate these generators' exposure to wholesale energy prices. Furthermore, as traditional generators retire, and more capacity comes from renewables, fewer generators are available to offer contracts, further raising the cost of forward contracts.

The exit of synchronous generators in South Australia has reduced competition amongst suppliers of frequency control and ancillary services (FCAS), raising the market price of FCAS. The exit of synchronous generators has also reduced the system's inertia, making it more susceptible to large changes in frequency from unexpected changes in electricity demand or supply. These impacts on risk management and risk allocation are unintended consequences of the existing subsidy mechanism used to achieve the government's RET policy.

In contrast, emissions reduction policies that are effectively integrated with energy policy will have a greater likelihood of achieving emissions reduction objectives in ways that support the efficient operation of the energy market and the long term interests of consumers.

In this context, at the request of the Energy Council, the AEMC explored the characteristics of alternative mechanisms for achieving the electricity sector's share of Australia's Paris Agreement emissions reduction targets. Our advice on the integration of mechanisms used to achieve energy and emissions reduction policy objectives was presented to the Energy Council in December 2016.

Consistent with the terms of reference for this work, the AEMC analysed the characteristics and impacts on the energy market of three emissions reduction policy mechanism, each designed so that they are expected to meet the electricity sector's share of emissions reductions by 2030. The three policy mechanisms considered were as follows:

- **A market-based mechanism** which would involve the establishment of a declining Emissions Intensity Target for the electricity sector.
- **A technology subsidy** which would involve extending the existing LRET subsidy mechanism for new renewable generation capacity.[25]
- **Government regulation** involving a staged approach to fossil-fuelled generator exit.

A business-as-usual (BAU) scenario was also developed as the counterfactual against which to compare the effect of the three emissions reduction mechanisms. BAU includes the existing LRET, which is a target of 33,000 GWh by 2020, with this target amount remaining the same through to 2030.

In considering the AEMC's analysis, it is important to note that electricity market modelling provides a simplified environment within which the impacts of emissions reduction policies on the electricity sector can be assessed. Market modelling is best suited to understanding factors such as changes in wholesale prices, resource costs, cost of abatement and investment and retirements from a counterfactual - in this case BAU. Because the modelling results are dependent on input assumptions, it is more reliable to assess the relative change in outcomes from BAU and not the absolute levels of the outcomes.

In this context, the Commission's analysis has shown that the EIT is the most cost effective, scalable, and robust emissions reduction mechanism, of the three broad pathways available to

[25] Based on 2015 forecasts of demand, the current LRET would need to increase from 33,000GWh in 2020 to 86,000GWh in 2030 to meet the 28 per cent emissions reduction target.

policy makers even when it was tested against three sensitivities - a high demand, low demand and high gas price sensitivity.

The EIT has the lowest impact on prices relative to the BAU scenario and the other emissions reduction policy mechanisms. EIT also has the lowest cost of abatement compared to the other emissions reduction mechanisms. The EIT is technologically-neutral and therefore encourages the least-cost form of abatement to be adopted by market participants. It self-corrects when future demand, technology costs and other factors inevitably turn out to be different to what is expected today. Under EIT, risks are allocated to those best placed to manage them, this includes maintaining access to risk management tools, such as hedging contracts. It can also accommodate changes in the emissions reduction target over time. These characteristics are important to maintenance of confidence in the mechanism resulting in stability of the policy mechanism over time.

In summary, it is unambiguously the role of governments to set environmental policy objectives and to consider the trade-offs between these objectives and energy policy outcomes. However, as has been a key theme of the AEMC's work on this matter, energy and environmental policies have different objectives and it is vital that they are developed in a manner where any efficiency trade-offs and costs are clearly understood by policy makers.

When contemplating the effective integration of energy and emissions reduction policy, we consider that it is vitally important that the mechanism to achieve an emissions reduction objective is designed having regard to the principles set out above. Doing so will help to preserve the means of exchange and allocation of risk in energy markets leading to more efficient energy market outcomes and lower costs to consumers over the long term.

Box 4 – Integration of energy and environmental policy in Great Britain – A cautionary tale[26]

Professor George Yarrow's report for the AEMC provides an account of the development of Great Britain (GB) energy and environmental policies over recent decades, with a focus on the extent to which they have worked together to bring about best-feasible trade-offs between major policy objectives.

The GB story is a cautionary tale for governments seeking to introduce mechanisms to achieve emissions reductions policy objectives without having regard to energy policy objectives, including the means of exchange and allocation of risk in energy markets. The key components of the GB narrative on energy and environmental policy integration are set out below.

1. Start with a well-functioning market and set of institutional arrangements

Energy market liberalisation in Great Britain gained momentum in the 1990's following the privatisation of British Gas in 1986, followed by most of the electricity supply industry in the 1990's. Importantly and at the same time, independent regulators were given market-development mandates in addition to their traditional price control responsibilities.

This process brought about a number of early successes including increased investment efficiency, improved operational performance of plant, reduced operational expenditures more generally, high levels of supply security and, after an initial lag, lower energy prices for consumers.

[26] See attachment B for the full report from Professor George Yarrow for the AEMC, titled *Energy and environmental policy: the GB experience* (2017).

2. **Consistent with its role, Government decides to achieve a new set of environmental policy objectives. However, there is confusion as to whether the new objective is to reduce emissions or to support a particular set of technologies (emission reduction policy versus industry policy)**

As early as the 1990s, the challenges of coordinating energy policy and climate change mitigation policy to achieve the differing policy objectives were recognised. However, despite growing international concerns about climate change, GB experienced a lagged response in terms of the introduction of explicit environmental policy measures into the electricity sector. When major schemes explicitly directed at carbon reduction within the electricity sector did arrive, around ten years later, they targeted specific levels of renewables penetration in the generation mix. This was at odds with the previously technology neutral approach to energy policy in the GB.

3. **Mechanisms to achieve the environmental policy objectives are designed outside the energy market institutional arrangements and without proper regard to the impact on energy market operations**

The Renewables Obligation Certificate (ROCs) scheme introduced in 2002 was the first major scheme explicitly directed at carbon reduction. Developed by the Department of Industry and Trade, the ROCs scheme specified target levels of renewable penetration in the electricity generation mix. This mechanism ran counter to the principles underlying energy policy at the time, one of which was technological neutrality.

In 2005, the European Union’s Emissions Trading Scheme (EU ETS) offered the prospect of a carbon reduction strategy that would have been consistent with GB energy market mechanisms. However, in 2007, a different approach for carbon reduction was taken by EU leaders. The new approach was based on agreement on both the level of carbon reduction to be achieved by each EU member state over a defined period, and on the means for achieving the reduction. The new approach was characterised by three targets, all to be achieved by 2020: a 20 per cent reduction in greenhouse gas emissions; 20 per cent of energy consumption to be supplied by renewables; and a 20 per cent reduction in primary energy use.

The mechanisms for achieving the renewables and energy efficiency targets that were imposed by the EU were not consistent with the market – which would have otherwise left the choice of how to best achieve the targets to market participants - and were therefore directly at odds with existing energy policy in the GB.

4. **When the energy market mechanisms begin to deliver outcomes which are not intended, the energy market mechanisms rather than the environmental policy mechanisms are blamed, leading to more intervention in the market**

The new carbon reduction strategy based on binding targets developed and agreed by EU leaders rapidly diverged from the market development path characteristic of the GB energy market. More specifically, the strategy quickly resulted in the emergence of a central planning approach to environmental policy, focussed on achieving the GB legally binding commitments to overall carbon budgets, and on the disaggregation of overall budgets into targets for particular sectors and technologies.

A major implication of these developments for the conduct of GB energy policy was the impact on the ability of the energy regulator, Ofgem, to deliver better outcomes for consumers through the development of competitive markets. All major decisions concerning market design, market development and rule making were taken over by central government in order to better fulfil the quantitative targets.

The Department of Energy and Climate Change (DECC) was created in 2008, bringing energy and environmental policy together in one department. While it was the policies that DECC pursued which drove up energy costs, DECC took an increasingly dim view of competition and pressed consistently for aggressive intervention in retail markets.

5. As more and more intervention occurs, investment in the energy sector stalls completely and the market reverts back to central control and planning as per pre-liberalisation - the difference being that this is now done by a government department rather than the Central Electricity Generating Board (CEGB)

In assessing the Government's approach to energy and environmental policy, investors recognised that their revenues would be influenced by the Government's carbon reduction mechanisms, and by political decisions following from comparisons of performance relative to the quantitative targets. In other words, investors recognised that policy uncertainty had increased substantially.

Recognising the investment problems, DECC concluded that the existing wholesale electricity market arrangements that had been successful for over 20 years would be incapable of meeting the carbon reduction targets it had adopted. DECC therefore set about redesigning the market through the Energy Market Reform Program. This program created a set of arrangements under which virtually all generation capacity needed to acquire contracts settled via centralised procurement arrangements. In effect, through Contracts for Difference and Capacity Payments for capacity availability, DECC was acting as a monopolistic procurer of wholesale electricity – it could control the quantities of electricity to be produced by different types of generation plant at different times in the future.

6. As prices rise and reliability is threatened, Government backs out of its commitment to reduce emissions

The developments in GB climate change policy have led to rapidly escalating costs of electricity supply. Estimates have been given that the effect of the government policies on household energy prices would be close to a 60 per cent increase in prices by 2020. In addition, because capacity markets have not worked as intended, investment in CCGT capacity has stalled giving rise to concerns about security of supply (although the likely effect is a further increase in energy costs and prices). Further, the environmental policies have only had a modest effect on GB's estimated carbon footprint, and the policy incoherence has had the effect of foreclosing potential innovative activity that does not fit with the carbon reduction strategy.

Since 2010, increasing costs and prices have led to a readjustment of environmental policy, starting with the Treasury attempting to take greater control over the escalating payment commitments being accumulated by DECC (and followed by cuts in support rates to small scale renewable generators).

In July 2016, DECC was closed and its responsibilities transferred to the Department for Business, Energy and Industrial Strategy (BEIS).

In January 2017, BEIS identified two future priorities for energy and climate change policies – (1) the affordability of energy for households and businesses and (2) securing industrial opportunities for the UK economy of energy innovation. Reference to achieving carbon reductions was noticeably absent.

3. Maintenance of risk management structures

In order to safeguard reliable and secure energy supply to consumers, the NEM must provide the appropriate investment signals so that sufficient and timely investment in various generation and demand-side technologies takes place. Price signals in the wholesale and contract markets are an important driver of new investment in the NEM. The effective functioning of these markets is therefore critical to maintaining reliability, security of supply and in promoting competition.

The NEM operates as a market where generators are paid for the electricity they produce and retailers pay for the electricity their customers consume. This implies that generators naturally have a 'long' exposure to the wholesale price and retailers are naturally 'short' the wholesale price. All energy traded through the NEM must be settled through the spot market, an arrangement referred to as the "gross pool".

Both generators and retailers face risk from being exposed to spot market prices which can, and do, fluctuate significantly on a 30 minute basis. This volatility reflects the complex and dynamic environment in which the market operates. Currently, prices in the spot market range from the Market Price Cap of $14,000 to a minimum price of -$1,000.[27]

To manage their exposure to the spot market, participants typically seek to enter into contracts settled by reference to the spot market price for the region in which their production or consumption occurs. Contracts allow generators and retailers to effectively convert uncertain future spot market prices into more certain wholesale prices to better match upstream or downstream obligations that are also relatively stable across time.

An overview of contracting in the NEM is provided in Box 4.

Box 5 – Contracting in the NEM

Market participants in the NEM have the possibility to hedge their risks against price volatility in the contract market. This has been an integral part of the NEM market design since its inception. Hedging risks can significantly reduce market participants' (and ultimately consumers') exposure to high price events.

By helping to smooth their future effective wholesale revenues or payments, contracts lower participants' risk profiles and increase the ease with which they can obtain equity and debt financing from suppliers of capital.

Generators face upstream obligations in the form of fixed costs and variable costs (costs that increase with their power output).

[27] The Reliability Panel is responsible for reviewing the level of the Market Price Cap, the Market Floor Price and the Cumulative Price Threshold (the "Reliability Settings") as well as the Reliability Standard, every four years. Its next review of the Reliability Standard and Settings will be undertaken in 2018, for the settings to commence from July 2020.

The absolute and relative magnitudes of these costs vary considerably by plant technology, fuel type and location.[28] However, these costs rarely vary on a half-hourly basis and are therefore more stable than the spot price.

For generators, entering into hedge contracts provides an opportunity for a steadier stream of income. Contracts allow them to underwrite or finance the purchase of fuel or obtain financing for capital investment. In addition, contracts can allow certainty of revenue around the operation of plant particularly if a generator cannot ramp generation up or down significantly to respond to the 30 minute price fluctuation.

Meanwhile, retailers typically enter into contracts to supply electricity to customers at prices that are fixed or vary in a pre-determined manner over a specified period of time. These often provide fixed pricing over a period of months or even years.

For retailers, entering into hedge contracts provides an opportunity to avoid sharp fluctuations in the electricity price. Contracts for wholesale electricity provide retailers with access to a consistent price for electricity which in turn allows them to write longer-term contracts with consumers, and therefore offer stable retail prices.

Contracted generators will bid into the spot market with the objective of being dispatched at a volume that matches their retail positions.

Contracts in the NEM are currently traded on the ASX (“exchange traded”) and traded bilaterally (“over the counter” (OTC)). The two core contract types are caps and swaps:

- **Swap** - A swap contract trades a fixed volume of energy during a fixed period for a fixed price (the strike price). The wholesale market spot price is, in effect, swapped for a fixed contract price (the strike price). The contract is settled through payment between counterparties based on the difference between the spot price and the fixed price.
- **Cap** - A cap contract trades a fixed volume of energy for a fixed price when the spot price exceeds a specified price. It provides insurance against high prices. The standard contract traded in the market is a $300 cap. This means the seller of a cap is required to pay to the buyer the difference between the spot price and the cap price every time the spot price exceeds 4300/MWh during the specified contract period.

In 2014-15, of the total volume (by MWh) of energy contracts traded, 84 per cent were traded on the ASX, with 16 per cent of energy contracts traded OTC. Of the OTC contracts (by MWh), 79 per cent were swaps, while 16 per cent were caps. The remaining 5 per cent were other more complex contracts.

While the contract market is distinct from the spot market, the prices of contracts are based on forecast spot market outcomes. This means that the expectation of high prices in the spot market will result in higher contract prices, which in turn allow potential investors to sell contracts and underwrite new investment in generation. Similarly, the expectation of low prices in the spot market will result in lower contract prices, which in turn reduces the ability of potential investors to sell contracts to underwrite new investment.

This interplay between spot and contract markets means that market outcomes need to be assessed by reference to both spot prices and contract prices.

The value of contracts in driving investment and delivering reliability[29]

[28] For example, coal-fired plant generally have higher fixed costs and lower variable costs than gas-fired plant. Most renewable plant technologies, such as wind and solar, have significant up-front fixed costs but very low variable costs.

As noted in Box 4, a crucial point when considering market outcomes - including reliability, security of supply and competition - is that the contract market is an integral part of the functioning of the NEM despite being completely separate from the NEL and Rules.

In the NEM, the reliability standard is used to indicate to the market the required level of supply and demand adequacy on a regional basis – that is, the minimum expected level of reliability.[30] To incentivise sufficient generation capacity and demand-side response to deliver the reliability standard, the NEM design includes three key reliability settings - the market price cap (MPC), market floor price (MFP) and the cumulative price threshold (CPT). The reliability settings form the key price envelope within which the wholesale spot market balances supply and demand and encourages sufficient capacity (on the supply- and demand-side of the market) to deliver the reliability standard.

The challenge of maintaining reliability in the NEM is therefore ensuring that the reliability settings are set at appropriate levels to incentivise sufficient generation capacity and demand-side response to deliver the expected reliability outcome, but no higher than consumers are willing to pay for that outcome.

The level of the reliability settings drives risk in the wholesale spot market and therefore impacts the strength of the incentives on retailers and generators to take a more or less cautious approach to hedging against spot market risk. The strength of this incentive is critical in driving reliability outcomes in the NEM both in the short and long term.

Generally, decisions on the amount of capacity to be contracted tend to be driven by retailers, who are best placed to understand the likely demand of their customers. Retailers are strongly incentivised to contract for a level of capacity that limits their exposure to extreme market prices, while also avoiding the purchase of excess capacity. The incentive on retailers to seek out contracts in order to fully hedge their customer load is strengthened the higher the level of the MPC.

Meanwhile, generators are strongly incentivised to ensure that their generating units are available and able to generate up to the contracted amount when extreme prices occur. For example, if a generator experiences an unplanned outage of one of its contracted generating units, it will be unable to earn the high revenue associated with the extreme price that will be required to compensate the contracted retailer. Such an event could come at a significant real financial loss to the generator. As such, contracted generators are incentivised to be available and generate at times of high prices.

The strength of the incentive on generators to participate in the market and ensure generation up to the contracted amount is available, is also influenced by the level of the MPC. Importantly, it drives reliability outcomes in the short term.

[29] System security is distinct from reliability. The concepts of 'reliability' and of 'reliable supply' have a consumer focus and describe the likelihood of supplying all consumer needs with the existing generation capacity and network capability. System security or "security of supply" is a measure of the power system's capacity to continue operating within defined technical limits, even in the event of the disconnection of a major power system element such as an interconnector or large generator.

[30] The reliability standard is set by the Panel in accordance with the NER. The current approach specifies the maximum expected unserved energy (USE) – or the maximum amount of electricity expected to be at risk of not being supplied to consumers, per financial year. Currently, the level of USE is set at 0.002 per cent of the annual energy consumption for the associated NEM region or regions per financial year.

In respect of the above, the hedge positions of both generators and retailers are a function of wholesale spot prices and hence the level of the MPC. The differing incentive on retailers and generators to fully hedge their exposure to extreme prices in the spot market also creates the signal for new capacity to enter the market – this, in turn, drives reliability outcomes in the long term.

For example, a retailer seeking to manage the risk associated with growth in customer load will look to enter into a contract with a generator to cover its exposure. In the instance existing generators are unwilling or unable to make additional generation capacity available in order to match the retailer's hedge, new generation will be incentivised to enter the market to meet the expected demand, confident it will be supported by a long term contract with the retailer.

More broadly, the ability of the wholesale and contract markets to deliver investment signals to ensure sufficient and timely investment in various generation and demand-side technologies takes place requires a number of conditions to be met. First, hedge contracts of sufficient size and duration must be available and agreed between generators and retailers, in order to provide a more certain revenue stream with which to underwrite investments.[31] In addition, spot market prices must not be subject to distortion by external factors such as investments that are not undertaken in response to market price signals, but are undertaken through interventions in the market. These matters are discussed further below.

The importance of well-functioning, liquid contract markets

A liquid contract market facilitates efficient generation investment and retirement decisions in two ways: by providing information on expected future market prices; and by providing a mechanism through which new generation can be financed. A well-functioning contract market obviates the need for an explicit capacity mechanism in the NEM.

Contract prices provide information about expected future spot prices, which in turn reflect participants' views of future wholesale market demand and supply conditions. Because expected future spot prices are not directly observable in the NEM, new and existing generation investors tend to look to the prices of contracts to help inform them about what are likely to be profitable and unprofitable decisions.[32] As long as the wholesale market is 'workably competitive',[33] decisions that are profitable will promote economic efficiency and the long term interest of consumers, other things being equal.

A liquid contract market is critical in supporting new entry and expansion in the upstream and downstream segments of the market. For example, long-term hedge contracts may be a material prerequisite for a potential new entrant generator to arrange for finance for the upfront costs of project development. The costs of financing may be substantially increased for a new entrant if they cannot obtain such a hedge contract or be confident of being able to access a relatively liquid contract market in the future.

[31] The alternative to this is that investors must be willing to invest on the basis of expected returns from spot market prices only, even though spot prices are expected to be highly volatile, with revenue expected to vary significantly from year to year.

[32] Specifically, investors will look at forward-dated swap contracts to provide an indication of market expectations of future average spot prices, and forward-dated cap contract premiums to provide an indication of the future level and duration of spot prices in excess of the cap strike price (typically, $300/MWh).

[33] In a workably competitive market it is expected that firms display profit maximising behaviour, seeking the widest possible margin between prices and their underlying costs. Pricing behaviour is disciplined by the threat of new suppliers entering the market in response to price signals and consumers exercising choice.

Similar considerations apply to actual and prospective retailers. A potential new entrant retailer (or an existing retailer looking to expand its retail portfolio) will need to be able to obtain hedging contracts to manage its exposure to risk in the spot market or have a balance sheet that enables it to build its own generation plant. A lack of liquidity in the contract market may create a barrier to entry and expansion in the retail market, reducing competitive pressures on existing retailers to charge prices that reflect efficient costs and improve their offers.

In the NEM, the existence of a contract market is akin to a capacity mechanism in so far as it guides decisions on capacity investment based on expectations of future supply and demand. However, capacity mechanisms (like the one found in Western Australia) tend to involve a central authority making decisions on when, where and how much generation capacity is required, based on its own expectations of future supply and demand. By necessity, the costs and risks of over or under building capacity is transferred to consumers.

In contrast, the NEM utilises prices signals in the contract market to guide participants in making their own decisions on generation investment. Importantly, generators determine the level of generation capacity in the market and face financial incentives to avoid over or underbuilding generation capacity. This is likely to be in the long-term interests of consumers because generation investors and their counterparties are likely to be better informed, better incentivised and better able to assess and manage these risks than centralised authorities.

As noted in Box 3, the government's existing LRET policy has had the effect of reducing contract liquidity and increasing contract premiums, making it more difficult for existing and prospective market participants to source and enter into contracts.[34] If generators and retailers are unable to enter into contracts of sufficient size and duration and are therefore unable to secure a more certain revenue stream in order to underwrite investments,[35] investor confidence is likely to be eroded, threatening security of supply and potentially reducing competition in the retail market.

Further, confidence in the market structure may also be eroded, making consumers, governments and their agencies more risk averse. Such effects could threaten the ongoing efficiency of the market itself and may substantially damage the long term interests of consumers.

Price signals, competition and reliability

An objective of introducing competition in the wholesale electricity sector was to decentralise operational and investment decisions away from governments and regulators to commercial parties. Generation businesses may be no better at forecasting the future than were governments, however, the important difference is that equity shareholders bear the cost of overinvestment, rather than consumers. This is a very different way of allocating risk and one which provides very different incentives for efficiency.

[34] Retailers and generators are typically incentivised to enter into long-term contracts to minimise price risk. However, generators that also receive LGC revenue have less incentive than other generators to enter into contracts, as the LGC revenues mitigate these generators' exposure to wholesale energy prices. This reduces the number of participants in the contract market, as well as the size and duration of contracts being offered. This effect is exacerbated by the retirement of traditional generators in response to lower wholesale prices from more capacity becoming available from renewables, leading to even fewer generators being available to offer forward contracts, further raising the cost of these contracts.

[35] We note that the alternative to this is that investors must be willing to invest on the basis of expected returns from spot market prices only, even though spot prices are expected to be highly volatile, with revenue expected to vary significantly from year to year.

Under competition, price signals guide participants as to how they should run their plant, when maintenance should be carried out and when and what type of technology to invest in. Profit, competition and capital market discipline provide incentives to manage risk. Under a regulatory approach, such as a capacity market or through technology subsidies, price signals are weakened and these decisions are taken by a central authority that does not have the same incentives or exposure to risk, which is allocated to consumers.

In the NEM, the efficacy of the price signal is critical to market participants making efficient decisions. This is because short term dispatch and long term investment decisions are driven primarily by wholesale market prices or derivative prices in the contract market. If prices are influenced by external factors unrelated to supply and demand, for example, subsidies that favour specific technologies, this can result in an inefficient mix of generation being dispatched. Over the longer term, it can result in an inefficient level of investment in capacity, increasing costs for consumers.

Changes to investment incentives and risk allocation can adversely impact the efficiency and sustainability of the NEM through:

- increased price volatility and the requirement to increase the price cap to ensure that peaking generators required for reliability can recover their fixed and variable costs
- continued closure of thermal plant, which may result in unforeseen system security and reliability implications
- the possibility of government intervention to ensure sufficient capacity is available due to a lack of investor confidence
- greater vertical integration due to energy market risks that are too costly or unmanageable to hedge against.

The ability of the NEM to deliver appropriate investment signals therefore also requires the delivery of spot market prices which are not subject to distortion by external factors such as investments that are not undertaken in response to market price signals, but are undertaken through interventions in the market.

As explained in section 2, if environmental policy is not effectively integrated with energy policy, the NEM may reach a point where participants do not have the confidence to make investment decisions in response to price signals. This is likely to result in a scenario where government intervention is always required, along with the consequent transfer of investment risk onto consumers and the likelihood of higher costs.

4. AEMC work program

Australia’s energy markets are undergoing a fundamental transition.

Driven by rapid technological change and emissions policy, the NEM is experiencing a significant shift away from conventional generators, powered by coal and gas, and towards new technologies, such as wind farms and solar panels. Due to their different technical characteristics, the widespread deployment of these new technologies has the potential to have major impacts on the maintenance of power system security.

At the same time, ongoing structural change in Australia’s east coast gas markets has been accelerated by the Queensland-based liquefied natural gas (LNG) export industry. Gas demand on the east coast increased threefold over the period 2014-2016 and this is having consequential impacts on the level and variability of gas flows and wholesale gas prices.

More broadly, competition in retail electricity and gas markets continues to evolve and is becoming more dynamic. Enabling technologies and the services they provide are creating opportunities for retailers to develop products and offers that better align with customer preferences; and for consumers to choose how their energy is sourced and used.

As a result of these significant transformations, Australia’s energy markets are more interconnected and interrelated than ever before. The AEMC’s current work program acknowledges this by focussing on ensuring the regulatory and market arrangements continue to provide reliable, secure energy at the best price for consumers.

That said, it is very difficult to predict what the future will look like. It is therefore imperative that market and regulatory frameworks are flexible and resilient enough to respond to whatever the future may bring in a way that is technology neutral, facilitates consumer choice and maximises efficiency.

The AEMC work program, which is discussed in more detail throughout this submission, has been focussed on four key areas of reform:

- **Promoting system security as the market transitions to new technologies and renewables.** Development of more sophisticated market and regulatory mechanisms to maintain power system security, including an AEMC review on the impact of renewables on system security announced in July 2016.
- **Redesigning the east coast gas market to free up gas trading.** A comprehensive reform package to redesign the east coast gas market; not just for gas users but to boost the ability of the power system to integrate renewables.
- **Integration of energy and emissions reduction policy.** Ongoing development of advice on integrating environmental and energy policy so we can answer the question: what mechanism will be used to move from the 2020 emission target to the 2030 emission target as part of Australia’s commitments under the Paris agreements?
- **Promoting and protecting consumers so we have more engaged and better informed energy shoppers**. Continued support for the energy services markets, including the AEMC’s Power of Choice work program that puts consumers in the driver’s seat so they can make the energy choices they want with appropriate consumer protections.

Reform in each of these areas will enable the market to develop and evolve to deliver secure and reliable energy services at the least cost to consumers.

Importantly, like the energy sector, these key areas of reform are interrelated - success in one area will almost always affect the success in another. The ability to efficiently maintain a secure electricity system, for example, will depend on how well we integrate emissions reduction and energy policy. In addition, reforming the gas markets to remove existing barriers to the use of gas in the electricity sector is also critical to cost effectively transition to a lower emission electricity sector while maintaining system security.

For this reason, any reforms to Australian energy markets must be designed in a way that is flexible and resilient and not dependant on any one view of how the future will look. This is best achieved by ensuring that the regulatory and market arrangements support energy markets that are workably competitive, such that risk is allocated to those best able to manage it.

4.1. Promoting system security as the market transitions to new technologies and renewables

Driven by technological development and climate change policies, the NEM is experiencing a significant shift away from conventional generators, powered by coal and gas, and towards new technologies, such as wind farms and solar panels. Due to their different technical characteristics, the widespread deployment of these new technologies has the potential to have major impacts in terms of AEMO ability to operate the system within defined technical limits, such as voltage and frequency.[36]

For this reason, new approaches and tools are required to manage system security as efficiently as possible. In addition, regulatory frameworks that govern the operation of the NEM need to be flexible and resilient in order that these newer types of electricity generation can be effectively integrated into the market while maintaining the secure operation of the system.

The AEMC is on the front foot in responding to these challenges through its comprehensive work program focussed on system security in the NEM. Working closely with AEMO, this work addresses the need for possible changes to market arrangements that lead to more efficient outcomes for energy consumers while delivering a secure operating system. The AEMC is also considering how the energy wholesale market frameworks can evolve to accommodate the change in generation and demand-side technologies needed to transition the NEM to a lower emissions future, while maintaining a secure supply of electricity for customers.

The System security work program involves two separate but related packages of work, each of which is discussed below.

In addition, the AEMC has been tasked by the Energy Council to review the factors which contributed to the 'black system' event experienced in South Australia on 28 September 2016. The AEMC's proposed approach to this review, consistent with the terms of reference received on 6 January 2017, is discussed at the end of this section.

Package 1 – Immediate reform package

The first package of reforms is focussed on the immediate actions which can be taken to refine and strengthen mechanisms to manage emergency frequency events.

It involves the progression of two Rule change requests which were submitted by the South Australian Government on 12 July 2016 (Emergency Frequency Control Schemes Rule change). The changes proposed to the National Electricity Rules were designed to address some of the more immediate concerns in relation to the governance and operation of emergency protection schemes, particularly as they apply to managing the impact of a sudden separation of South Australia from the rest of the NEM.

In accordance with the statutory timelines, the Commission published a draft determination and draft Rule for the two Rule change requests on 22 December 2016. The draft Rule will enhance the frameworks for emergency frequency control in the NEM, specifically by:

[36] The system is secure when technical parameters such as voltage and frequency are maintained within defined limits. Maintaining frequency requires balancing the supply of electricity against demand instantaneously. Large deviations or rapid changes in frequency can cause the disconnection of generation, potentially leading to cascading failures and ultimately a 'black system'.

- establishing an enhanced governance framework for the development of a national emergency frequency control scheme (EFCS)
- introducing a new category of contingency event, the protected event, and a supporting governance framework.

Emergency frequency control schemes are the last line of defence to protect against a major supply disruption and potentially a black system, following a significant disturbance to the power system.

The draft Rule will broaden the scope of technologies currently able to be used to control emergency frequency events, to include any available technology able to provide the most efficient solution to the event. The Rule will also formalise arrangements for the development of over-frequency schemes designed to limit the consequences of over-frequency events. This will allow for more effective management of these events.

The draft Rule also introduces a new category of contingency event, the protected event.[37] A protected event is defined as a non-credible contingency event whose occurrence is reasonably plausible and could lead to significant consequences if left to be addressed solely through the use of existing automatic under frequency load shedding schemes.

The new category of protected event will allow AEMO to use ex-ante actions to manage the power system on an ongoing basis, as well as undertake some load shedding/generation tripping to limit the consequences of a 'protected event' should one occur. This category would capture events that have a lower likelihood of occurrence than credible events, but which could have significant economic consequences if unaddressed.

The changes we have proposed will put in place emergency frequency control schemes, and frameworks to support them, which are appropriate in light of the changing generation mix in the NEM.

Submissions to the draft determination and draft Rule closed on 16 February 2017. A final determination and implementation of changes to the National Electricity Rules in response to these Rule change requests is expected by 30 March 2017.

Package 2 – Forward looking reform package

The second of the system security reform packages is more forward looking and focussed on adapting the market frameworks to complement the changing generation mix. This package of work is being progressed via our System Security Market Frameworks Review (System Security Review) which commenced on 14 July 2016. This review was initiated by the AEMC as a vehicle to coordinate the assessment of three additional Rule change requests relating to a number of similar and related power system security issues:

- AGL and the South Australian Government submitted requests to amend the National Electricity Rules to introduce new mechanisms for the provision of additional system security services to support power system frequency. These were received on 24 June and 12 July 2016 respectively.

[37] Currently, AEMO manages the power system to limit the consequences of reasonably possible events (known as credible contingency events). The consequences of all other events (known as non-credible contingencies) are limited through controlled load shedding and special protection schemes.

- The South Australian Government also submitted a request to amend the National Electricity Rules to address the reductions in system strength, on 12 July 2016.

Importantly, consideration of the Rule change requests in the context of the System Security Review will enable solutions which are identified through the review and are within the scope of the Rule change requests to be directly implemented by making changes to the National Electricity Rules based on these Rule change requests.

The AEMC's interim report for the System Security Review was published on 15 December 2016. This report outlined the key challenges to system security and some of the new markets and services that could be introduced to help maintain a secure system as the generation mix changes.

The preliminary view is that the changes required to maintain system security may include:

- New measures to obtain inertia for the system most likely via synchronous generators or other synchronous machines.
- Development of fast acting frequency response services, which might be provided via invertor-based generators such as wind turbines, by energy storage devices and by demand-response schemes.
- Possible changes to generator performance standards to improve the tolerance of the system to changes in frequency.

Innovation must be encouraged, which means rewarding the best options that may mature over time including those not even imagined today. Any new Rules or mechanisms need to be designed carefully so the best security outcomes can be achieved while keeping the prices that consumers pay as low as possible over the long term. Without careful design, customers and market participants will bear unnecessarily high costs over a long period, potentially stifling future innovation in other technologies and increasing the risk that system security challenges may not be addressed.

The AEMC is in the process of refining the range of potential options to deliver the new system security services. The different characteristics of these services may mean different procurement paths are taken for each. Stakeholder feedback will be sought on our proposed approach in a Directions Paper due to be published on 16 March 2017.

The ultimate output of the System Security Review will be a report to the Energy Council highlighting Rule changes and technical changes made in response to the Rule change requests received, and recommendations for further action where required, including possible changes to policy or legislative frameworks or recommendations in relation to potential future Rule change requests.

Review of the System Black Event in South Australia

At its meeting on 7 October 2016, the Energy Council agreed to direct the AEMC to review the factors which contributed to the 'black system' event experienced in South Australia on 28 September 2016. The AEMC has received the terms of reference for this review on 6 January 2016.

Consistent with these terms of reference, the AEMC will provide the Energy Council with a final report for this review within six months of the completion of both AEMO's investigation report, focused on the technical issues contributing to the event, and the AER's compliance report, focused on the compliance of market participants with requirements in in the NEL and NER.

The purpose of the review is to build on the work being conducted by the AEMC and AEMO in their respective system security work programs, by identifying any systemic issues that contributed to the system black event in South Australia, or affected the response. It is intended that the final report to the Energy Council will highlight:

- any recommended actions or amendments to the regulatory frameworks, whether the NEL, NER or other jurisdictional instruments, that should be taken to address these broader system issues
- how the recommendations will be addressed in the AEMC's ongoing work programme, to the extent that there are suggested changes to the NER.

On 31 January 2017, also consistent with the terms of reference, the AEMC advised the Council on how it proposes to conduct the review. In summary, in order to inform the preparation of its report, the Commission intends to undertake three phases of work:

- **Stage 1, developing a fact base**, drawing on, among other things, the incident reports prepared by AEMO and the findings of the AER's investigation.
- **Stage 2, assessing the issues**, starting with a critical evaluation of the findings of AEMO and the AER and including an examination of factors such as broader policy drivers and detailed operational arrangements, in additional to the frameworks specified in the NER.
- **Stage 3, developing recommendations to address the issues**, guided by the NEO and the factors set out in the terms of reference including the nature of the economic costs of disruption arising from system black events and the importance of secure and reliable supplies to high energy users.

AEMO's fourth and final report is due to be published in March 2017.

4.2. Redesigning the east coast gas market to free up gas trading

Increasing gas market efficiency is important for maintaining power system security. As renewable generation makes up a larger part of the energy mix, gas-fired generation is expected to play a more prominent role in supporting the intermittent nature of wind and solar power. This is true for a number of reasons:

- The carbon intensity of gas (approximately 0.5 tCO2/MWh on average) is considerably lower than black and brown coal (approximately 0.9 tCO2/MWh and 1.2 tCO2/MWh on average respectively).
- Gas is flexible and can be more readily ramped up and down in response to inherent variability in output of renewables compared to coal.
- Gas generation is synchronous, unlike wind and solar PV. Consequently, the use of gas powered generators helps to maintain the security of the system.

Reforming the gas markets to remove existing barriers to the use of gas in the electricity sector is therefore critical to cost effectively transitioning to a lower emission electricity sector, while maintaining system security.

The gas industry on the east coast of Australia is undergoing a structural change. This transformation has been accelerated by the Queensland-based liquefied natural gas (LNG) export industry driving a threefold increase in demand, with consequential impacts on the level and variability gas flows and wholesale prices. Coinciding with this transformation is the expiration of many long-term GSAs, with domestic users having to negotiate new contracts in a vastly different market. GSAs are typically now being offered at higher prices[38], for shorter durations and with more restrictions on volume flexibility.[39] At the same time, the pipeline transportation infrastructure has evolved from largely point-to-point pipelines into an interconnected network, supporting a series of increasingly interlinked wholesale gas markets.

While bilateral contracts will remain a fixture of the east coast market, more flexible and sophisticated means of managing gas portfolios are becoming increasingly important to participants, including to gas-fired generators.

Recognising these changes, in December 2014 the Council of Australian Governments (COAG) Energy Council established a set of principles, which it referred to as its Vision for Australia's future gas market. A key outcome for the Vision is the establishment of a liquid wholesale gas market, with a key outcome of this being an efficient and transparent reference price for gas.

The COAG Energy Council then tasked the AEMC to identify a roadmap to achieve the Vision. To do so, it requested that we review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia ("the East Coast Review"). Concurrently, the Energy Council, at the request of the Victorian Government, tasked the AEMC to undertake a specific, detailed review of the DWGM. The “DWGM Review” is discussed further below.[40]

The AEMC commenced the East Coast Review and DWGM Review in February 2015 and a Stage 2 Final Report for the East Coast Review was presented to the Energy Council in August 2016.

The Stage 2 Final Report set out a roadmap for gas market development on the east coast of Australia. A key feature of the roadmap is our recommendation that wholesale gas market trading should be concentrated at two points:

- a Northern Hub, based around the existing Gas Supply Hub at Wallumbilla, Queensland
- a Southern Hub, which would be established by enhancing the existing DWGM in Victoria.

We also made a number of other recommendations in the Stage 2 Final Report targeted at improving secondary capacity trading on pipelines outside of Victoria and enhancing the information provided to the market through the Natural Gas Services Bulletin Board. To implement the reforms, we further recommended the establishment of an independent, dedicated reform group.

Our recommendations were considered by the COAG Energy Council at its meeting in August 2016. The Council, in large part, accepted the Commission's recommendations and constituted the Gas Market Reform Group (chaired by Dr Michael Vertigan) as the implementation body for the

[38] The LNG industry has also presented a new risk in the form of prices in GSAs being linked to oil and increased spot price volatility.
[39] ACCC, *Inquiry into the east coast gas market*, April 2016, p. 18.
[40] The East Coast and DWGM Reviews have been structured over two stages. The reviews were carried out together in Stage 1 and then split into two separate reviews at the commencement of Stage 2.

Council's Gas Market Reform Package.[41] Importantly, the Council agreed to implement this package as a matter of priority.

Of particular note is the in-principle support given by the Energy Council for the establishment of the Southern Hub in Victoria, by transitioning the existing DWGM to the AEMC's recommended design. This support was subject to the delivery and outcomes of the Final Report for the DWGM Review.

The purpose of the DWGM Review has been to consider whether the DWGM: allows market participants to effectively manage price and volume risk; provides appropriate signals and incentives for investment in pipeline capacity; and facilitates the efficient trade of gas to and from adjacent markets. All these attributes are consistent with the Vision.

In considering the future role of the DWGM in the market development roadmap, we have assessed the current arrangements against the key elements of the Vision and, particularly, those attributes highlighted in the terms of reference. We have concluded that the DWGM does not meet these objectives, and therefore will not facilitate the achievement of the Energy Council's Vision for Australia's future gas market.

The changes underway in the wider east coast market present new challenges for the DWGM and expose shortcomings that previously obscured by its less interconnected operation and more benign market conditions. Given that the limitations result from features intrinsic to the existing market design, we do not consider that incremental changes could address the shortcomings effectively or durably.

To address the emerging challenges, we have made draft recommendations to substantial reforms to the DWGM to introduce new arrangements based on an entry-exit model that is applied widely across Europe. With the gas industry across south-eastern Australia now far more integrated domestically and internationally than it was when the DWGM was established, it is timely to update the market design to enable it to better reflect the more dynamic environment it now operates within. Importantly, the implementation of the Southern Hub will not compromise and should enhance those aspects of DWGM performance that have been positive to date - retail competition and gas system security.

The introduction of the proposed Southern Hub in Victorian is critical in putting downward pressure on the prices that Victorian consumers of gas will pay – including gas fired generators – thereby helping Victoria to replace brown coal with cleaner fuel sources while avoiding significant price increases. The proposed arrangements would provide significant benefits as follows:

- **Improved risk management:** Participants would have greater flexibility to trade physical products, either bilaterally, or through a low cost, anonymous trading exchange. This will enable participants to better manage price and volume risks. Liquid physical trading may also facilitate the development of financial derivatives, which would further enable participants to manage their risks.
- **Transparent and meaningful reference prices:** Prices on the southern hub exchange and the reporting of bilateral trades, including any liquid financial derivatives market that

[41] Informed by the findings and recommendations of the AEMC's East Coast Review and the ACCC's Inquiry into the East Coast Gas Market which was also submitted to the Council at the August meeting, the Energy Council agreed to launch its comprehensive Gas Market Reform Package. This broad reform package comprises 15 reform measures in four priority areas: gas supply; market operation; gas transportation; and market transparency. See: COAG Energy Council website at www.coagenergycouncil.gov.au.

might also emerge, would provide market participants with transparent and meaningful reference prices. This would be used across the supply chain to inform investment decisions.

- **Improved trading between hub locations:** The southern hub trading exchange would be the same as the Northern Hub exchange (proposed in the east coast review) to support low cost, anonymous and transparent trading for participants. Having similar characteristics should lower transaction costs and complexity for traders operating across both hubs, encouraging greater participation and trade across the wider east coast market and so facilitating gas going to the parties that value it the most.

Ensuring that the market arrangements enable gas to play a role going forward will support security of the national power system and reduce the need for, and costs associated with, the security mechanisms necessary to efficiently maintain a secure electricity system.

The AEMC published a Draft Final Report for the DWGM Review on 14 October 2016. Having received submission on this report, the Commission, in conjunction with the Victorian Government, is considering additional time to assess submissions and potential alternatives to the proposed recommendations made in the draft final report. While a final decision on this has yet to be made on the timelines, the Commission expects that the Final Report for the DWGM Review will be submitted to the Energy Council and the Victorian Government by 31 August 2017, with publication two weeks after.

4.3. Engaged and informed consumers

It is consumers themselves who are in the best position to decide what works for them. Accordingly, a significant part of the AEMC's work program over recent years has been focussed on supporting the development of the competitive retail services market and supporting more engaged and informed consumer choices.

This objective was at the heart of the AEMC's Power of Choice reforms, under which eight Rule changes were made in 2014 and 2015 to give consumers more options in how they use energy and encourage network businesses to adopt non-network alternatives where they are cheaper than investing in network assets. These Rule changes were based on recommendations in the AEMC's Power of Choice review and Rule change requests from the COAG Energy Council, the Total Environment Centre, IPART, Red Energy and Lumo Energy.

Key changes to the Rules included:

- new rules enabling consumers to access their energy consumption information from their retailer distributor, or authorise a third party to access it, with specified timeframes and data formats;
- cost-reflective distribution pricing;
- the introduction of competition in metering;
- a new "shared market protocol" to enable communications between parties wanting to access new services that can be provided by advanced meters;
- an expanded demand management incentive scheme and innovation allowance;
- increased powers for AEMO to obtain demand side participation information to improve its demand forecasting;
- new rules regulating embedded networks and enabling customers in embedded networks to choose their retailer; and

- ancillary services unbundling to enable new types of participants to provide ancillary services.

The AEMC also undertakes annual reviews of retail energy competition. As part of these reviews, the AEMC undertakes qualitative and quantitative research with individual consumers. The AEMC has also developed a blueprint for informing and empowering energy consumers.

A key issue that consumer stakeholders have raised with the AEMC is whether changes to consumer protections under the National Energy Retail Law and National Energy Retail Rules are necessary given the transformation of the energy market and the proliferation of new technologies and business models. The COAG Energy Council is currently consulting on this issue and the AEMC is engaging in this consultation.

The AEMC is also currently considering whether improved information and new distribution market models are required to more efficiently utilise distributed energy resources. The AEMC engaged closely with the Network Transformation Roadmap work being undertaken by the ENA and CSIRO. The AEMC is also currently consulting on a distribution market model research project.

ATTACHMENT A – AEMC work that relates to questions raised in the preliminary report

The AEMC has completed, or is currently progressing, a range of work that relates to the seven themes and supporting questions asked in the Expert Panel's preliminary report. The table below outlines the key pieces of work that relate to each question and includes a brief description of each piece of work. This may be useful in identifying what is being considered, or has been achieved to date.

Preliminary Report – Consultation Question	Relevant AEMC rule change, review, advice or submission
Chapter 1: Technology is transforming the electricity sector	
1.1 How do we anticipate the impacts, influences and limitations of new technologies on system operations, and address these ahead of time?	• **AEMC Strategic Priorities for Energy Market Development** (2015, 2013, 2011) have been prepared every two years to frame key issues for consideration in the market, encourage a dialogue amongst stakeholders and guide the AEMCs work program and its advice to the COAG Energy Council. This AEMCs strategic priorities work will be replaced by targeted strategic advice delivered in line with terms of reference provided by the COAG Energy Council in December 2016, to inform the Energy Council's energy market strategy and priority setting process. • **AEMC Technology work program** currently includes a project investigating the integration of storage (2015) into the energy market, and a 'distribution market model' project (commenced 2016) that will explore how the operation and regulation of electricity distribution networks may need to change in the future to accommodate an increased uptake of distributed energy resources. • **System Security Market Frameworks Review** (commenced 2016) will support the continuing transformation of the NEM by addressing a range of complex inter-related issues that have largely resulted from the change in generation mix. • **Energy Market Arrangements for Electric and Natural Gas Vehicles** (2012) found that energy market arrangements are generally robust to cater for the efficient uptake of EVs, and they should be treated as another form of demand side participation.

1.2 How can innovation in electricity generation, distribution and consumption improve services and reduce costs?	• **Review of regulatory arrangements for embedded networks** (commenced 2017) will identify and assess any issues for embedded network customers under the NERL and NERR and identify appropriate solutions. An Embedded Networks rule change (2015) reduced the barriers to embedded network customers accessing retail market offers. • **Alternatives to grid-supplied network services** rule change proposal (submitted, not yet commenced) seeks to overcome barriers to the use of some technologies that may not currently fall within the definition of 'distribution service'. • **AEMC submission to the COAG Energy Council Stand-Alone Systems** consultation (2016) which proposes the development of a consumer protection and economic regulatory framework to allow the efficient uptake, investment in, and supply and use of stand-alone energy systems. • **Electricity Network Economic Regulatory Framework Review** (commenced 2016) will monitor developments in the energy market and provide advice on whether the economic regulatory framework for networks is sufficiently robust and flexible to "continue to achieve" the national electricity objective in light of these developments. • **System Security Market Frameworks Review** (commenced 2016) – see above. • **Power of Choice Review** (2012) and 11 resulting rule changes (2014, 2015) provide more opportunities for consumers to make informed choices about the way they use electricity.
1.3 What other electricity innovations are you aware of that may impact the market in the future?	• AEMC Technology work program – see above
Chapter 2: Consumers are driving change	
2.1 How do we ensure that consumers retain choice and control through the transition?	• Review of the regulatory arrangements for embedded networks (commenced 2017) – see above • **Retail Competition Review** (annual) provides regular advice on the state of competition

	in energy retail markets. The 2016 review found that competition in retail energy markets is becoming more dynamic and delivering new types of retail deals and services to consumers as the market transforms, giving them greater control over how they manage and use energy. However, the review also found that there is a need to make it easier for customers to access the choices available to them. The 2017 review will deliver advice on the state (and likely future development) of competition in NEM; trends in retail markets over time; and recommendations to improve retail competition in electricity and gas markets across NEM jurisdictions. • Alternatives to grid-supplied network services rule change proposal (commenced 2017) – see above • Review of regulatory arrangements for embedded networks (commenced 2017) and Embedded Networks rule change (2015) – see above • Power of Choice Review (2012) recommended changes to improve consumers' awareness of their patterns of electricity use and enables them to make more informed choices about electricity products and services specifically: • **Expanding competition in metering and related services** rule change (2015) is designed to promote innovation and lead to investment in advanced meters that deliver services valued by consumers at a price they are willing to pay. • **Distribution Network Pricing Arrangements** rule change (2014) provides efficient and flexible pricing options to consumers to help them make informed consumption choices and manage their expenditure. • **Customer access to information about their energy consumption** rule change (2014) makes it easier for customers to access their electricity consumption data from their retailer or distributor in an understandable format and in a timely manner. • **Review of Electricity Customer Switching** (2014) and resulting rule changes make the consumer transfer process more timely and accurate by improving the accuracy of customer transfers (2017), and using estimated reads for customer transfers (2017).

2.2 How do we best meet the needs of vulnerable and hardship consumers?	• Review of regulatory arrangements for embedded networks (commenced 2017) - see above • Retail Competition Review (2016) – see above • **AEMC submission on Consumer Protections Behind the Meter** consultation (2016) sets out the AEMCs view that the consideration of energy specific consumer protections behind the meter must take a broad view of the products and energy services offered in the electricity market.
2.3 How do we ensure the needs of large-scale industrial consumers are met?	• **Demand Response Mechanism and Ancillary Services Unbundling** rule change (2016) unbundled the provision of ancillary services from the provision of energy opening up competitive opportunities for customers to offer services to help control the frequency on the electrical system. • **East Coast Wholesale Gas Market and Pipeline Frameworks Review** (2016) the Commission recommended a package of 15 key reforms to improve the efficiency of gas trading and access to pipeline transportation, forming a roadmap for the future development of the market. These are in the process of being implemented by the gas market reform working group established by COAG Energy Council. • **Review of the Declared Wholesale Gas Market** (commenced 2015) recommends changes to the Victorian declared wholesale gas market that would integrate it with the broader east coast market giving participants greater ability to manage price and volume risks, provide market signals for pipeline investment, and improve trading across the east coast market. • Power of Choice Review (2012) – see above
2.4 How can price structures be made more equitable when consumers are making different demands on the grid according to their energy use and their investments behind the meter?	• Distribution Network Pricing Arrangements rule change (2014) – see above

2.5 How do we ensure data sharing benefits and privacy are appropriately balanced?	• Expanding competition in metering and related services rule change (2015) – see above • Customer access to information about their energy consumption rule change (2014) – see above • Power of Choice Review (2012) – see above
Chapter 3: The transition to a low emissions economy is underway	
3.1 What role should the electricity sector play in meeting Australia's greenhouse gas reduction targets?	• **Integration of energy and emissions reduction policy** (2016) describes the characteristics of alternative mechanisms for achieving the electricity sector's share of Australia's Paris Agreement emissions reduction targets. The objective of this report is to equip Australian governments to assess the emissions reduction mechanism that is most capable of integrating with the National Electricity Market. • **AEMC submission to Emissions Reduction Fund Safeguard Mechanism consultation** (2015) outlined the AEMCs view that the ERF safeguard mechanism should be designed with a view to achieving both emissions reductions and energy policy objectives. Without an integrated approach neither the reliable secure supply of energy at the best price for consumers, nor the Commonwealth Government's emissions reduction objectives, are likely to be achieved.
3.2 What is the role for natural gas in reducing greenhouse gas emissions in the electricity sector?	• See section 4.2 of this submission. • East Coast Wholesale Gas Market and Pipeline Frameworks Review (2016) – see above • Review of the Declared Wholesale Gas Market (commenced 2015) – see above
3.3 What are the barriers to investment in the electricity sector?	• See section 3 of this submission. • Integration of energy and emissions reduction policy (2016) – see above • AEMC submission to Emissions Reduction Fund Safeguard Mechanism consultation (2015) – see above • **AEMC submission to Review of the Renewable Energy Target** consultation (2014) sets out the AEMC view that environmental policies that are appropriately designed and

	integrated can achieve their objectives and minimise costs faced by consumers in energy markets. It is important to design a mechanism to achieve an emissions reduction objective that preserves the means of exchange and allocation of risk in energy markets. The RET is an example of a policy that does not do this and therefore does not effectively integrate with the energy market. Several factors that should be considered when contemplating the effective integration of energy and environmental policy are set out in the submission.
3.4 What are the key elements of an emissions reduction policy to support investor confidence and a transition to a low emissions system?	• See section 2 of this submission. • Integration of energy and emissions reduction policy (2016) – see above • AEMC submission to Emissions Reduction Fund Safeguard Mechanism consultation (2015) – see above • AEMC submission to Review of the Renewable Energy Target consultation (2014) – see above
3.5 What is the role for low emissions coal technologies, such as ultra-supercritical combustion?	• Integration of energy and emissions reduction policy (2016) – see above
Chapter 4: Integration of variable renewable electricity	
4.1 What immediate actions could be taken to reduce the emerging risks around grid security and reliability with respect to frequency control, reduced system strength, or distributed energy resources?	• See section 4.1 of this submission. • **Emergency Frequency Control Schemes** rule change proposal (commenced 2016): the draft rule includes an enhanced emergency frequency control scheme framework to allow for the efficient use of all available technological solutions to limit the consequences of emergency frequency events, and a new classification of contingency event, the protected event, that in certain circumstances, will allow power system security to be managed by using a combination of ex-ante solutions, as well as load shedding. • System Security Market Frameworks Review (commenced 2016) – see above

4.2 Should the level of variable renewable electricity generation be curtailed in each region until new measures to ensure grid security are implemented?	• System Security Market Frameworks Review (commenced 2016) – see above • Emergency Frequency Control Schemes rule change (commenced 2016) – see above
4.3 Is there a need to introduce new planning and technical frameworks to complement current market operations?	• System Security Market Frameworks Review (commenced 2016) – see above • Emergency Frequency Control Schemes rule change (commenced 2016) – see above
4.3.1 Should there be new rules for generator connection and disconnections?	• **Transmission Connection and Planning Arrangements** rule change proposal (commenced 2015): a draft rule seeks to improve transparency, contestability and clarity in the transmission connections framework while maintaining clear accountability for outcomes on the shared transmission network that affect consumers. It also seeks to enhance the efficiency of existing transmission planning arrangements and promote a more coordinated approach to transmission planning.
4.3.2 Should all generators be required to provide system security services or should such services continue to be procured separately by the power system operator?	• System Security Market Frameworks Review (commenced 2016) – see above
4.4 What role can new technologies located on consumers' premises have in improving energy security and reliability outcomes?	• Review of regulatory arrangements for embedded networks (commenced 2017) – see above • Alternatives to grid-supplied network services rule change (commenced 2017) – see above • System Security Market Frameworks Review (commenced 2016) – see above • AEMC Technology work program – see above • Expanding competition in metering and related services rule change (2015) – see above • Power of Choice Review (2012) – see above

4.4.1 How can the regulatory framework best enable and incentivise the efficient orchestration of distributed energy resources?	• Review of regulatory arrangements for embedded networks (commenced 2017) – see above • Alternatives to grid-supplied network services rule change (commenced 2017) – see above • Electricity Network Economic Regulatory Framework Review (commenced 2016) – see above • AEMC submission to the COAG Energy Council Stand-Alone Systems consultation (2016) -– see above • AEMC Technology work program – see above • **Contestability of energy services** rule change proposal (commenced 2016) seeks to promote the development of competitive markets for new technologies that are capable of providing services in both contestable and regulated markets. • **Demand Management Incentive Scheme** rule change (2015) helps balance the incentives on distribution businesses to make efficient decisions in relation to network expenditure, including demand management.
4.5 What other non-market focus areas, such as cyber security, are priorities for power system security?	• Integration of energy and emissions reduction policy (2016) – see above
4.6 How could high speed communications and sensor technology be deployed to better detect and mitigate grid problems?	• Emergency Frequency Control Schemes rule change proposal (commenced 2016) – see above
4.7 Should the rules for AEMO to elevate a situation from non-credible to credible be revised?	• Emergency Frequency Control Schemes rule change proposal (commenced 2016) – see above

Chapter 5: Market design to support security and reliability	
5.1 Are the reliability settings in the NEM adequate?	• **Reliability Panel, Annual Market Performance Review** (annual) examines the performance of the National Electricity Market in terms of reliability, security and safety of the power system • **Reliability Panel, Review of Reliability Standard and Settings Guidelines** (periodic) this periodic review enables the Panel to consider whether the reliability standards and settings remain suitable for current market arrangements and to ensure they continue to meet the requirements of the market, market participants and consumers.
5.2 Is liquidity in the forward contract market for electricity adequate for the needs of commercial and industrial consumers and, if not, what can be done?	• See section 3 of this submission. • Retail Competition Review (2016) – see above • Integration of energy and emissions reduction policy (2016) – see above
5.3 Are commercial and industrial users experiencing difficulties in obtaining quotes for supply?	• Retail Energy Competition Review (commenced 2017) – see above • Retail Competition Review (2016) – see above
5.4 What impact will an increasing level of renewable generation have on the forward contract market and what new products might be required?	• See section 3 of this submission. • Retail Competition Review (2016) – see above • Integration of energy and emissions reduction policy (2016) – see above
5.5 Rule changes are in process to make the bid interval and the settlement interval the same, both equal to 5 minutes. Are there reasons to set them to a longer or shorter duration?	• **Five Minute Settlement** rule change proposal (commenced 2016) involves compulsory five minute settlement for generators, scheduled loads and market interconnectors. Demand side participants in the wholesale market, including retailers and large consumers, could choose to be settled on either a five or 30 minute basis.
5.6 What additional system security services such as inertia, as is currently being	• See section 4.1 of this submission. • System Security Market Frameworks Review (commenced 2016) – see above

considered by the AEMC, should be procured through a market mechanism?	
5.6.1 How can system security services be used as 'bankable' revenue over a sufficient period of time to allow project finance to be forthcoming?	• System Security Market Frameworks Review (commenced 2016) – see above
5.6.2 How will generators and retailers mitigate price risk in such a market?	• See section 3 of this submission • System Security Market Frameworks Review (commenced 2016) – see above
Chapter 6: Prices have risen substantially	
6.1 What additional mechanisms, if any, could be implemented to improve the supply of natural gas for electricity generation?	• Alternatives to grid-supplied network services rule change (commenced 2017) – see above • Electricity Network Economic Regulatory Framework Review (commenced 2016) • Contestability of energy services rule change proposal (commenced 2016) – see above • East Coast Wholesale Gas Market and Pipeline Frameworks Review (2016) – see above • Review of the Declared Wholesale Gas Market (commenced 2015) – see above
6.2 What are the alternatives to building network infrastructure to service peak demand?	• **Replacement expenditure planning arrangements** rule change proposal (commenced 2016) seeks to make network asset replacement decisions more transparent by explicitly requiring networks to include planned asset retirements and de-ratings, and options to address network limitations arising from these, in in their annual planning reports. It also seeks to extend the application of the regulatory investment tests to replacement projects. • Demand Management Incentive Scheme rule change (2015) • Distribution Network Planning and Expansion Framework rule change (2012) – see above • **Regulatory Investment Test for Transmission** (2009) was introduced to identify the transmission investment option which maximises the net economic benefits and, where

	applicable, meets the relevant jurisdictional Rule based reliability standards. Changes were made in 2009 to optimise the decision making process as well as improve the consistency and transparency across transmission investment assessment.
6.3 What are the benefits of cost reflective prices, and could the benefits be achieved by other means?	• Distribution Network Pricing Arrangements rule change (2014) – see above • Expanding competition in metering and related services rule change (2015) – see above • Power of Choice Review (2012) – see above
6.4 How can we ensure that competitive retail markets are working?	• Retail Energy Competition Review (commenced 2017) – see above • Retail Competition Review (2016, 2015, 2014) – see above
6.5.1 What outcomes of competition should we monitor?	• Retail Energy Competition Review (commenced 2017) – see above • Retail Competition Review (2016, 2015, 2014) – see above
Chapter 7: Energy market governance is critical	
7.1 Is there a need for greater whole-of-system advice and planning in Australia's energy markets?	• See section 1 of this submission • **AEMC submission to the Review of Governance Arrangements** (2015) suggested that the existing governance arrangements have delivered successful market and regulatory outcomes which have been in the long term interests of customers, but offered some observations on areas for potential improvement to further promote successful consumer outcomes from the continuing energy market reform agenda. • AEMC Strategic Priorities for Energy Market Development (2015, 2013, 2011)
7.1.1 If so, what are the most appropriate governance arrangement to support whole-of-system advice and planning?	• See section 1 and Box 1 of this submission • AEMC submission to the Review of Governance Arrangements (2015)- see above
7.1.2 Do the roles of ministers and energy market institutions need further	• See section 1 of this submission

clarification?	• AEMC submission to the Review of Governance Arrangements (2015) – see above
7.2 What lessons can be drawn from governance and regulation of other markets that would help inform the review?	• See Attachment B of this submission
7.3 How should the governance of the NEM be structured to ensure transparency, accountability and effective management across the electricity supply chain?	• See section 1 of this submission • AEMC submission to the Review of Governance Arrangements (2015) - see above
7.4 Are there sufficient outcome statistics for regulators and policy makers to assess the performance of the system?	• Reliability Panel, Annual Market Performance Review (2015, 2014) – see above
7.5 What governance measures are required to support the integration of energy and emissions reduction policies?	• See section 2 of this submission • Integration of energy and emissions reduction policy (2016) – see above • AEMC submission to the Emissions Reduction Fund Safeguard Mechanism consultation (2015) – see above • AEMC submission to the Review of the Renewable Energy Target consultation (2014)
7.5.1 Should the AEMA be amended?	• AEMC submission to the Review of Governance Arrangements (2015)
7.5.2 Should the NEO be amended?	• See section 1 of this submission • AEMC submission to the Review of Governance Arrangements (2015) • **Applying the Energy Objectives – A Guide for Stakeholders** (2016) provides an overview of how the AEMC applies the energy objectives (that is, the National Electricity Objective, National Gas Objective or National Energy Retail Objective) to a rule change or review and includes some context as to what the energy market objectives are, the elements that make up the objectives and the principles the AEMC applies to a rule change or review.

7.6 How can decision-making be appropriately expedited to keep up with the pace of change?	• See section 1 of this submission • AEMC submission to the Review of Governance Arrangements (2015) – see above

Attachment B

REGULATORY POLICY INSTITUTE

Energy and environmental policy:
the GB experience

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* Views expressed in this and other Regulatory Policy Institute reports and papers are those of the authors and should not be attributed to any organisations with which the authors are associated. The Institute is a charitable organisation dedicated to the promotion of the study of regulation for the public benefit and does not itself take positions on the relevant policy issues.

Executive Summary

The GB energy sector has experienced an extraordinary era of institutional change and structural reform over the last 30 years, starting with an initial failed attempt at liberalization in the early 1980s, followed by the privatization of first British Gas in 1986 and then most of the electricity supply industry in 1990. Crucially, at privatization, independent regulators were given 'market development' mandates in addition to the price control responsibilities of traditional utility regulators. The subsequent liberalization process brought a number of early successes, including: increased investment efficiency, improved operational performance of plant, reduced operational expenditures more generally, high levels of supply security, and, after an initial lag, lower energy prices for household, commercial and industrial consumers.

As early as 1990, however, academic writers had identified the significance for energy policy of emerging environmental issues, particularly in relation to climate change mitigation, and to the challenges likely to be involved in coordinating these two areas of public policy in ways that contribute effectively to the attainment of broad, government policy objectives. The challenges duly arrived, although with a longer lag than was then anticipated, and the story of the GB policy responses to them is, for the most part, a narrative of failure.

The lagged response of explicit environmental policy measures in the face of growing international concerns about climate change afforded an undisturbed period of around ten years in the 1990s for the evolution of energy policy and regulation centred on market development. The length of the lag is itself probably partly attributable to the early successes of energy market liberalization. As a side effect of competition in the wholesale electricity market, GHG emissions from electricity generation fell substantially during the 1990s as new CCGT plant, with sequentially improving thermal efficiencies, rapidly displaced older coal-fired plant and as the operational performance of existing plant, particularly nuclear power stations, improved.

When major schemes explicitly directed at carbon reduction did arrive – the first being the Renewables Obligation Certificates (ROCs) scheme in 2002, developed by the Department of Trade and Industry (DTI) – they embodied a different policy approach and strategy, based on the specification of target levels of renewables penetration in the plant mix for electricity generation. This ran counter to the principles underlying energy policy of the time, one of which was technological neutrality, although in practice it had few adverse consequences for energy policy performance. At that time, renewables penetration was at a low base and the rate of expansion contemplated was not particularly rapid: the carbon reductions of the 1990s meant that relatively little more needed to be done to meet the UK's commitment to carbon reduction under the Kyoto protocol.

For a time, the EU's Emissions Trading Scheme (EU ETS) – a cap-and-trade system introduced in 2005 – offered the prospect of a carbon reduction strategy that would be highly consistent with energy policy strategy. Similar to the situation in the first stages of energy market liberalization, the new carbon market was experimental and a prolonged period of market development was in prospect, yielding iterative adjustments that would see incremental improvements in effectiveness over the years.

In the event, in 2007 EU leaders chose to take a different road, based on agreement not only on the aggregate level of carbon reduction to be achieved by EU Member States over a defined period, but also on the specification of the *means* of achieving the desired reduction. Since choice of means/instruments is a function that is left to market participants under liberalized trading arrangements – and indeed it is a major source of benefit from such arrangements – the new strategy was directly at odds with existing energy policy in the GB, and indeed also with energy policy more generally in the EU. It was a strategy that would later entail market destruction, rather than market development.

The new road/strategy was characterized by three targets: a 20% reduction in GHG emissions, 20% of energy consumption to be supplied by renewables and a 20% reduction in primary energy use (relative to existing forecasts), all to be achieved by 2020. It rapidly diverged from the market development path, not least because of the stringency of the renewables and energy efficiency targets (the *means* by which carbon reductions were to be achieved) that were set – which may have owed something to the problems caused by a prior decision in Germany to phase out that country's nuclear plant.

More specifically, it led quickly to the emergence of a central planning approach to climate change policy, based in GB not only on legally binding commitments to overall 'carbon budgets' stretching fifteen years out into the future (and to commitments beyond that, which, subject to adjustment, would be made legally binding in due course), but also, more critically, to disaggregation of overall budgets into targets for particular sectors and particular technologies. To support this disaggregation a plethora of individual interventions have, explicitly or implicitly, led to the determination of different subsidy/support rates for different electricity generation facilities. The variations in rates are large and correspond to widely different valuations of the effects of GHG emissions. In a nutshell, they are not proportioned to any realistic measures of harms done by GHG emissions.

Since EU ETS continued to operate, the planning approach was also inconsistent with the cap-and-trade arrangements as well as with energy policy. That is, climate change policy became internally incoherent, as well as incoherent with energy policy. The principal problem was that, once GB's EU ETS GHG allocation was set, GB's contribution to aggregate EU GHG emissions was also effectively determined. Although GB policymakers have shown a predilection to be a leader in carbon reduction by seeking to overachieve the carbon reduction target implied by the EU ETS allocation, all such leadership did was to give rise to approximately 100% carbon leakage: aggressive carbon reduction in GB leaves businesses with GHG certificates that can be sold and used in other Member States to sustain *higher* emissions in those countries. The result is that is no significant contribution to global GHG emissions reduction is made, but the policies *have* made substantial contributions to increasing energy costs and prices in GB.

A major implication of these developments for the conduct of energy policy was that Ofgem became enfeebled: all major decisions concerning market design, market development and rule-making were taken over by Central Government in the name of better serving 'the plan', i.e. fulfilling quantitative targets. A new Department for Energy and Climate Change (DECC) was created in 2008 to put energy and environmental policy under one organizational roof, but organizational integration was accompanied by policy dis-integration, not least because climate change policy itself was schizophrenic: the target-based approach adopted by the EU in 2007 was incompatible with the principles of the EU's cap-and-trade scheme introduced in 2005.

The same tendency toward incoherence was also induced at the Ofgem level. The remit of the regulator had already been widened to some extent by previous adjustments to the original legislation, but post-2007 there was a marked acceleration in this process. Thus, not only were Ofgem's powers and influence reduced, a strong sense of purpose and focus in the organization was lost as a result of it being asked to pursue a range of conflicting and vaguely specified objectives, which increasingly included environmental and social policy goals and reduced the weighting to be given to promotion of competition.

DECC pursued policies that were driving up energy costs, but was resistant to the retail energy price effects that were necessarily consequential on cost increases in competitive markets. Hence it took an increasingly dim view of competition and pressed consistently for aggressive intervention in retail markets, a pathway that might yet end (possibly soon) in the restoration of retail price controls.

Even if Ofgem had been able to overcome its internal organizational problems, created by the new approach, it was in no position to address the root causes of policy incoherence, which lay in Central Government. If an analogy can be drawn between a proclivity for central control/planning and alcoholism, it might be said that independent regulation can help create barriers between the drinker and the bottle, but what it can't do is drink on behalf of the alcoholic and itself remain unaffected.

The development was ironic in that, around the same time, on 13 November 2007 the House of Lords Select Committee on Regulators produced a Report on Economic Regulators that opened (at paragraph 1.1) with the conclusion, consistent with the voluminous expert reasoning and evidence that it had heard and sifted, that *"Independent regulators' statutory remits should be comprised of limited, clearly set out duties and … statutes should give a clear steer to the regulators on how those duties should be prioritised. Government should be careful not to offload political policy issues onto unelected regulators."* With exemplary clarity, wise and experienced Members of the upper chamber of Parliament recommended continuation and further development of an institutional structure that had worked well, but the Government chose, in effect, simply to dispense with that accumulated know-how.

To support DECC, a new body called the Climate Change Committee (CCC), populated with enthusiastic central planners, was also established in 2008. The CCC's formal status is that of an independent advisory body (advising DECC, other parts of Government and

Parliament), but it has played an influential role in keeping Government minds focused on carbon budgets. The mindset it promoted was that carbon budgets simply had to be met, almost irrespective of the immediate costs of doing so. The justification offered was that, if targets were not met, costs would be higher in the future, but there was no recognition that this proposition rested on particular, long-term forecasts about prices, costs and technological developments that were necessarily speculative and uncertain and, at a minimum, merited detailed, critical assessment, particularly given that the costs of at least some low-carbon technologies were falling quite rapidly over time.

In assessing the new policy approach, investors quickly recognized that revenues for individual projects would be heavily influenced by 'the plan' and by political decisions that would flow from later comparisons of performance relative to the plan, whose carbon budgets were very demanding and therefore held out every prospect that they could be missed. That is, investors appreciated that policy uncertainty at the micro-economic level at which they operated had been substantially increased.

Recognizing the problem, in 2010 DECC concluded that the existing wholesale electricity market arrangements, developed over a period of twenty years, would be incapable of meeting the carbon budgets it had adopted and set about re-designing the market itself, in a programme it referred to as Electricity Market Reform (EMR). The result of that exercise is a set of arrangements in which virtually all generation capacity must acquire contracts that are settled via centralized procurement arrangements. In effect DECC itself acts as a monopsonistic procurer of wholesale electricity, in ways that enable it to control the *quantities* of power to be produced by different types of generation plant at different times in the future. The main contractual instruments now used are (a) Contracts for Differences, with strike prices that vary according to type of technology and with a typical contract duration of fifteen years, and (b) Capacity Payments for capacity availability, with contracts of one, three or fifteen years' duration.

A consequence of the new market design was accurately summarized in 2015 by the then Secretary of State at DECC, Amber Rudd, when she said: *"We now have an electricity system where no form of power generation, not even gas-fired power stations, can be built without government intervention."* Since that was exactly the position pre-privatization, the implication is that GB has come full circle. The work of Ofgem and of earlier Governments has been undone and there is no reason to think that a policy approach that worked poorly in the 1960s,1970s and 1980s will work significantly better now.

The developments in climate change policy since 2007 have led to rapidly escalating costs of electricity supply. In a major investigation of energy markets that ran from June 2014 to June 2016, the Competition and Markets Authority (CMA) noted that the effect of Government policies on household energy prices would be close to a 60% hike in prices by 2020.

There has also been a hiatus in new-build CCGT capacity, because the capacity markets have not worked as intended in promoting this technology as a partial replacement for declining coal and nuclear plant output. This has given rise to concerns about security of supply, although these worries may rest on over-pessimistic conjectures: the more significant impact is likely to be a further increase in energy costs and prices, over and above that indicated by the CMA, since a more certain effect of capacity payments is that they will render *any* given level of security of supply more costly to achieve.

As expected, the environmental policies have had only a modest effect on GB's estimated carbon footprint, i.e. on the contribution of GB consumption to global GHG emissions, more than half of which is accounted for by carbon 'embedded' in imports, and the published estimates of the footprint do not themselves take account of carbon leakage effects associated with EU ETS when the leakage is to producers in other Member States whose output is destined for non-GB consumption.

The privileging of identified, known technologies by means of differential levels of financial support, which has induced, depressing effects on the EU ETS carbon price, has served to foreclose potential innovative activity that does not 'fit the plan', for example because it is of a more speculative, 'blue skies' nature. Given the high importance of reducing the costs of de-carbonization in seeking to achieve climate change objectives in a democratic society – if it is cheap, the public appetite for it can be expected to be greater – this may possibly turn out to be the most damaging aspect of what policy incoherence has done.

Increasing costs and prices have, since 2010, led to re-adjustments in climate change policy, starting with Treasury attempts to exert greater control over the escalating, "off balance sheet" payment commitments being accumulated by DECC (some of which extend as far out as 2037), followed later by cuts in support rates for small-scale renewable generators.

On her first day in office in July 2016, Prime Minister May closed DECC and transferred its responsibilities to a newly named Department for Business, Energy and Industrial Strategy (BEIS), with the words climate change notably absent from the nameplate. In presenting ideas on industrial strategy in January 2017, BEIS identified two future priorities for energy and climate change policies: *"the affordability of energy for households and businesses, and securing the industrial opportunities for the UK economy of energy innovation"*. Noting that ten years had passed since the Climate Change Act, BEIS also said that the overall framework of policy *"requires updating"*

What these thoughts will entail going forward is anyone's guess. Since 2010 successive Secretaries of State have expressed a yearning to return, someday, to a market development policy strategy (in relation to both energy and carbon reduction), even as they were implementing schemes that moved the policy stance away from such a pathway. No concrete strategies have yet been identified to cross the rough terrain that now lies in the way of such a return and the Government is preoccupied with Brexit strategies (and can be expected to continue to be so for a period of years). Probably the safest conclusion is simply that the current policy difficulties add to the already elevated levels of policy uncertainty created by EMR, particularly given the now marginal influence of Ofgem, the intended guardian of regulatory certainty and the lead institution for market development until 2007.

Energy and environmental policy: the GB experience

1. Introduction

This Report provides an account of the development of GB energy and environmental policies over recent decades, with a focus on the extent to which they have worked together to bring about best-feasible trade-offs between major policy objectives such as reduction in greenhouse gas (GHG) emissions and promotion of the long-term interests of energy consumers. Attaining or approximating such ‘frontier’ trade-offs requires an overall policy strategy that ensures that pursuit of any one objective does not give rise to *unnecessary* limitations on the capacity to achieve other objectives. For current purposes, the extent to which this is achieved can be referred to as the degree of ‘policy integration’.

It can be noted at the outset that ‘policy integration’ differs from what can be called ‘organizational integration’, which amounts to putting different strands of public policy development ‘under one institutional roof’. Indeed, as will be explained, GB energy and climate change measures suffered from poor and deteriorating policy integration even as decision making was increasingly consolidated in an organizational sense.

Most of the content comprises a historical narrative of policy development, which was increasingly driven by climate change policy from around the turn of the millennium, but attention is drawn along the way to alternative options that could have been adopted and to the more immediate effects and implications of policy decisions at the times that were made. Not all environmental measures are covered: numerous measures other than those identified have been introduced, but these are excluded because their implications for the conduct of energy sector policy and regulation were more limited. A range of programmes that were or are of intermediate significance for the main issues are, however, summarised in an Annex.

Whilst a single narrative approach is adequate for considering the ways policy measures were developed and introduced, it would become unduly convoluted if accompanying changes in institutional arrangements were examined in detail along the same time-line. Institutional/ governance changes are therefore considered separately and more fully in Section 6. The Report concludes with a short assessment of the major effects of GB policies considered in their entirety, to give a sense of just how significant the low degree of policy integration has been for the achievement of both energy policy and environmental policy objectives.

2. Pre-2000 developments in GB energy and environmental policies

Energy liberalization and privatization

Liberalization of the energy sector in GB began with the Oil and Gas (Enterprise) Act 1982 and the Energy Act 1983 which respectively removed statutory entry barriers into the bulk supply of gas and of electricity to large industrial customers. In retrospect, neither piece of legislation appears to have had significant economic impacts, pointing to the first of the major lessons about liberalization to be learned: the development of new ‘rule-books’ for markets and for access to networks is a necessary condition for the success of liberalization.

Privatization in the sector came later, starting with British Gas in 1986, followed by most of the electricity sector in 1990 (England and Wales) and 1991 (Scotland). State ownership was retained for nuclear power plant. Privatization was not a source of major change by and of itself, but it brought accompanying, more critically important reforms, most notably: establishment of new independent regulators (Ofgas and Offer); greater exposure to competition law (public enterprises had enjoyed protection in this area); repeal of a prohibition on burning gas in power stations; and, in electricity, immediate wholesale market competition in consequence of a division of generation assets among three, separate companies.

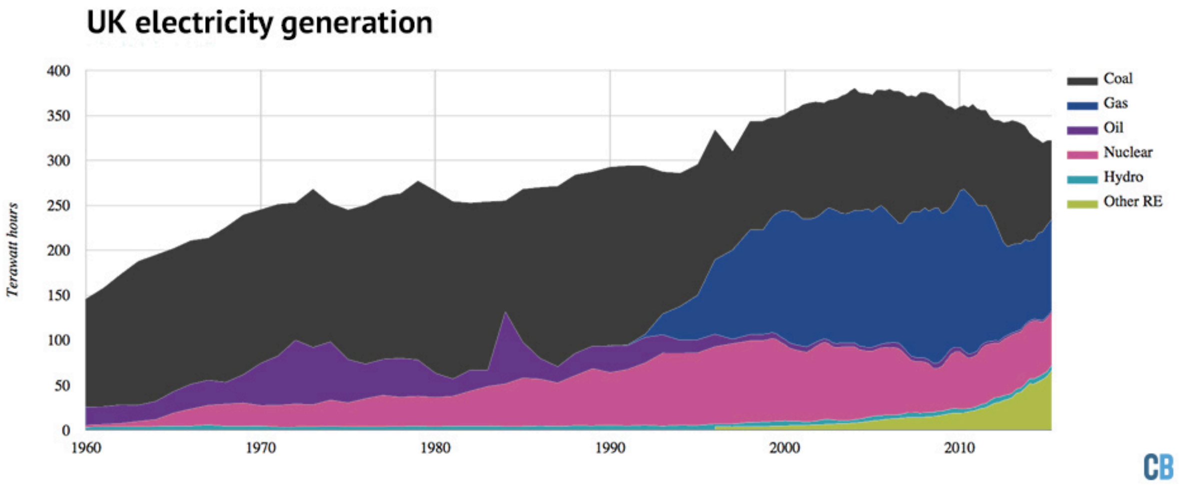
The last three of these reforms – exposure to competition policy, ability to build gas-fired power stations, and de-concentration in electricity generation – had the more immediate effects, but over time it turned out to be the establishment of independent regulators that had the greatest impact. These new bodies provided the engine for the cumulative process of developing and supervising network and market 'rule-books' in ways that served to deepen and extend the liberalization process over a sustained period.

Some of the effects of the reforms have been well documented, most notably the beneficial effects on the operating expenditures of energy network companies, at least once the first, politically-determined price control periods had come to an end and price reviews were firmly in the hands of Ofgas and Offer. Less well documented are the impacts on investment efficiency. Prior to electricity privatization, on a like-for-like basis £/MW capacity costs in GB were substantially higher than in comparable jurisdictions. Investment programmes and decisions had been heavily influenced by protectionist, political pressures from the (high-cost) GB coal industry and the country's heavy engineering and construction sectors. Following privatization, the performance gap closed rapidly and was quickly gone.

Environmental issues were not to the fore in the policymaking of the 1980s, but the reforms nevertheless had major environmental impacts. The most significant of these was associated with the relatively speedy displacement of coal- and oil-fired electricity generating plant by combined cycle gas turbines (CCGTs, see Chart 1): GHG emissions fell substantially (see Chart 2). There were also significant impacts on carbon emissions attributable to an improvement in the operating performance of nuclear generating sets, particularly in the early years of the decade (see the path of nuclear output in Chart 1). Thus, additional nuclear output, as well as CCGT output, displaced coal and oil.

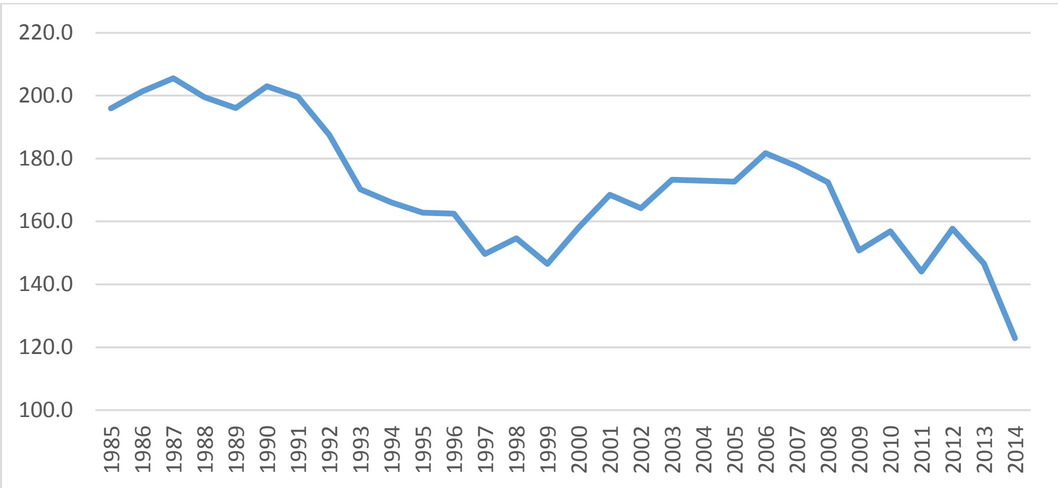
There was one measure accompanying privatization that might, just possibly, be partly classified as environmental in intent, and which merits some examination since it can be regarded as the 'first of type' in what later was to become a whole sequence of schemes. This was the Non-Fossil Fuel Obligation (NFFO), introduced in the Electricity Act 1989, which required public electricity suppliers (PESs) – which at the time were integrated distribution and marketing/supply companies – to contract for a designated fraction of their requirements from non-fossil fuel sources. The original intent was to provide support for the ailing state-owned nuclear sector, but by the time the relevant Parliamentary Orders had come into effect (in 1990) renewables had been added to nuclear power as potential recipients of financial aid. This led to the first, small-scale experimentation in competitive tendering for the procurement of contracts by renewables generators.

Chart 1. The fuel mix in electricity generation.



Source: Carbon Brief

Chart 2. GHG emissions, electricity generation, MtCO2e



Funding to support the required procurement volumes at prices above market levels was by means of a Fossil Fuel Levy, originally referred to as the ‘Nuclear Levy’, on PESs’ supplies. This added around 11% to customers’ electricity bills. Procurement of contracts was handled centrally by a newly established organization, the Non-Fossil Purchasing Agency (NFPA), which was set up by the PESs themselves and to which revenues from the Non-Fossil Fuel Levy were transferred for procurement purchases. Support for nuclear power required clearance under the EU's state aid rules and agreement was secured on the basis that the subsidies would be put in place for a period of eight years only. During this period the great bulk of the Levy was channelled to nuclear generation.

Although the NFFO arrangements had limited bearing on the ability of Offer to go about its delegated tasks, they contained another seed of later developments in environmental policy: the introduction of a collective/monopsonistic procurement process. Although a single procurement agency can invite competitive tenders to fulfil its requirements, as was done, it is still a monopsonist: the relevant market is therefore not competitive. Moreover, by and of its nature, the NFFO deviated from the policy principle of technological neutrality.

At the outset of privatization, therefore, what can be observed is a policy 'fix' by means of which non-competitive and discriminatory elements were introduced into the wholesale electricity market. The 'fix' was initially transitional and time limited (until 1998), but the approach that it embodied became more expansive and more enduring over later years.

Policy priorities in the 1990s

As was noted at the time of their implementation, the electricity sector reforms had not been developed with environmental issues in mind, but they offered scope for learning from experience for future environmental policy as well as for the further development of energy policy.[1] Climate change issues moved slowly up the list of policy priorities in the 1990s. By 1998, for example, the Royal Commission for Environmental Pollution was sponsoring work on questions concerning the institutional structures that might be developed to promote policy effectiveness across energy and environmental policy/regulation. However, actual climate change policy development, and *a fortiori* its implementation, remained limited.

On the energy side developments included: extensive rule-making exercises to establish network and connection codes; the ending of monopoly franchises across all retail energy market segments (industrial, commercial and household); price deregulation of gas storage; the implementation of new gas trading arrangements, including the establishment of a round-the-clock, screen-based exchange for trading gas; and substantial de-concentration in wholesale markets for both electricity and gas. The end of the decade saw the amalgamation of Offer and Ofgas to form the combined gas and electricity regulator Ofgem.

In contrast, a timeline of major developments in UK climate change policy by Bowen and Rydge[2] shows no entries at all between 1989 (the NFFO) and 2000 (the Government's publication of its *Climate Change Programme*). Post 2000, however, Bowen and Rydge's timeline is much more densely populated with entries.

The one policy development that these authors might have cited was an increase in Value Added Tax (VAT) in April 1994, to 8%, on supplies of fuel and power to households. Prior to this date such supplies had been zero rated. A further increase to 17.5% – which was the standard rate of VAT at the time – was planned for April 1995, but in the event the

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1 John Vickers and George Yarrow, "The British Electricity Experiment", *Economic Policy*, 1991.

2 Alex Bowen and James Rydge, "Climate Change policy in the United Kingdom", Grantham Research Institute on Climate Change and the Environment, August 2011.

Government was unable to obtain parliamentary approval. The household fuel and power rate stayed at 8% until September 1997, when it was reduced to 5% (the standard rate of VAT still being 17.5% in that year).

Explaining the proposed VAT increases in parliament in 1993, Prime Minister Major said: *"There were two reasons: we had to raise resources and also we have a commitment to get rid of carbon dioxide."* How much weight is to be placed on the second rationale is an open question, particularly in the light of the later reduction in the rate to 5% by a Government that was generally more inclined toward aggressive carbon reduction. Considerations of income distribution, affordability and the general state of central government finances appear to have been much more important determinants of VAT decisions than environmental policy.

The simplest explanation for the quietism of GB climate change policy in the 1990s is that the energy policy reforms themselves had a marked, downward impact on greenhouse gas (GHG) emissions (see Chart 2). In the 1990's, therefore, GB was well ahead of the game in terms of carbon reduction, chiefly thanks to the effects of its liberalization policies in the energy sector. The 2010 targets that would later be announced in the *Carbon Change Programme* in 2000 were already well on their way to being achieved <u>and</u> consumers were simultaneously enjoying the benefits of lower prices.

3. 2000-2007: A decisive period for climate change policy

The opening years of the new millennium continued to see considerable development in energy sector regulation. Highlights included: rapid and full price deregulation of the supply electricity to households; the introduction of new electricity trading arrangements (NETA); the separation of electricity and gas distribution from supply; and the integration of the Scottish electricity trading arrangements with those in England and Wales.

The most far reaching of these developments was NETA, which among other things abolished the wholesale electricity pooling arrangements created at privatization and replaced them with arrangements that relied upon bilateral contracting, backed up by a balancing market for dispatch purposes in which National Grid was a counterparty to all transactions, whether buys or sells. Perhaps of most significance for later developments, the 'capacity payments' aspects of the previous arrangements (payments for making capacity available to the system) were abolished, as was the Pool's governance structure which had been dominated by industry interests and had proved resistant to reforms. The England & Wales (and later the amalgamated GB) wholesale electricity market therefore became, like in Australia, an energy-only market and the last, substantial, 'administered pricing' influence on the market (which occurred via capacity payments) was removed. None of these developments in the early years of the century were materially affected by climate change policy measures, but they were the last of their kind in that respect.

Environmental policy had meanwhile entered an expansionary phase, heralded by publication of the Government's *Climate Change Programme*. Since the features of the phase were critical for future policy performance, they are worth explaining in a little detail.

The Climate Change Programme (2000)

The *Climate Change Programme* document was particularly notable in two respects:

- It set out for the first time a specific, aspirational target of reducing carbon emissions by 20% by 2010, starting from a 1990 base.
- The target was more stringent than the 12.5% reduction by 2012 required by the Kyoto Protocol. There is a first indication here that the UK Government wished to be a Stakhanovite in GHG emissions reduction, i.e. to go well beyond its internationally agreed contribution.

Termination of the NFFO

Co-incident with the implementation of NETA (early 2001) and the separation of distribution and supply businesses (which saw the disappearance from legislation of the concept of 'public electricity suppliers'), the NFFO arrangements were closed to new renewables capacity. The NFPA ceased to be an agent for companies, but instead became the 'buyer' under the legacy renewables contracts. It then resold the electricity into the wholesale market.

The Climate Change Levy (CCL)

At the same time (April 2001) a new Climate Change Levy on energy delivered to non-household end-users was introduced, although supplies to the transport sector were exempt. The stated aim was to provide incentives for increased energy efficiency and thereby to reduce carbon emissions. It remains in place today.

The Levy applied to nuclear power as well as fossil-fuel generation, but not to electricity supplied from renewables and approved co-generation schemes. The renewables exemption was abolished relatively recently, on 1 August 2015: hence output from renewables is now simultaneously taxed (via the CCL) and subsidised. Energy-intensive users were given substantial discounts on the Levy of up to 90%, if they entered into Climate Change Agreements entailing commitments to energy efficiency or carbon reduction targets. The relevant body that administers the Climate Change Agreements is the Environment Agency.

The CCL marked a significant step toward greater reliance on administrative discretion in the enforcement of regulatory rules and in the levying of taxation, and has consequently been much excoriated by analysts in the UK. There was obvious arbitrariness in the differential treatment of nuclear and renewable sources of power, which lacked any reasoned basis in terms of the aims of encouraging energy efficiency or carbon reduction. The focus on taxing intermediate products in a supply chain whilst exempting household supplies ran against the principles of the VAT system, which economists will recognize are themselves aligned with the Diamond-Mirrlees theorem of efficient commodity taxation.[3] It tends to create avoidable distortions in resource allocation.

[3] P. Diamond and J. Mirrlees, "Optimal taxation and public production", *American Economic Review*, 1971.

To offset some of the most egregious distortions, further regulatory fixes such as the discounts to energy-intensive businesses were developed as add-odds, introducing another layer of arbitrariness. Thus, as was immediately obvious to those developing the CCL, establishing taxes that would lead to the closure of energy intensive production facilities in GB, coupled with output replacement from facilities located overseas that were equally or more carbon-intensive, i.e. to 'carbon leakage', was not conducive to global carbon abatement.

Renewables Obligation Certificates (ROCs)

Renewables Obligation Certificates, made possible by provisions in the Utilities Act 2000, were introduced in 2002 and quickly became the flagship climate change policy in GB. ROCs were, in effect, a much larger-scale implementation of the renewables arrangements of the NFFO. The ROCs scheme was designed by the Department of Trade and Industry (DTI) and was (and still is) administered by a specialised sub-unit of Ofgem, subsequently branded as 'E-Serve'. The main features of the arrangements were as follows.

The Government determined an annual target for the percentage of an energy supplier's sales volume to be sourced from a designated set of generating technologies (approved 'renewables'). An accredited (by Ofgem) renewable generator could then create a ROC for each MWh that it produced and it passed the Certificate on to an electricity supplier to whom it sold output. The supplier was in turn required to present these certificates to Ofgem following the close of the relevant accounting year. If the number of ROCs so presented fell short of the level implied by the supplier's renewables target, the supplier was required to pay a 'buyout price' per MWh of shortage. The initial buyout price (for 2002/3) was set at £30 per MWh, but it was linked to the retail prices index. (It currently stands at £44.77 per MWh for the year 2016/7.)

If that had been the end of the story, the incentive effects would have been simple: suppliers would have been willing to pay up to £30 per MWh above the market price for electricity on contracts with renewable generators, providing a substantial incentive for the development of renewables capacity and output. The public finances would have benefited from any buyout payments. However, the DTI went one step further. Rather than passing buyout revenues into the Treasury's coffers, it opted to 'recycle' the monies, net of administrative costs, to the suppliers themselves, in direct proportion to the ROCs that individual suppliers presented to Ofgem. The buyout-fund payment per ROC presented was calculated as: total buyout-revenues less administrative costs, divided by the total number of ROCs presented.

For a supplier holding fewer ROCs than required to satisfy its target level, this arrangement implied that the value of an incremental ROC would be higher than the £30 per ROC buyout by an amount equal to the per-ROC buyout-fund entitlement. In theory suppliers could therefore expected to be willing to purchase incremental renewable energy at a per MWh price of up to: market price + buyout price + per ROC buyout-fund entitlement.

The arrangements allowed for trading in ROCs, and a supplier was therefore rewarded for 'overachievement' of the target: it could sell its surplus ROCs to other suppliers who were short of ROCs. Trade in ROCs therefore leads to a market price for ROCs, common to all suppliers. Renewable generators should be able to achieve a price for their output that approximates the market price of that output plus the market price of ROCs. The market price of ROCs is an increasing function of the difference between the aggregate, Government-determined, target level of renewables output and the actual level of that output. The effect is therefore to produce greater financial support for renewables the greater the gap between the market-wide target and the market-wide achievement (assuming the former is the higher of the two). Since there is necessarily some uncertainty *ex ante* about realized outputs and targets, both at the aggregate level (which affects the size of the buyout fund to be recycled) and at the individual supplier level (which affects the supplier's individual volume exposures to risk), market trading in ROCs also provides a mechanism for suppliers to hedge risks.

There is a clear logic in these arrangements and they (and their subsequent developments) have had a significant, stimulating effect on the proportion of electricity generated from renewables. However, they also suffer from major defects, the most important of which is linked to interactions with other strands of climate change policy, particularly the EU's cap-and-trade scheme. The EU scheme will be discussed below, but other defects can be noted at this stage:

- There are non-trivial administrative costs and challenges, among which are the accreditation of individual facilities for the purpose of creating ROCs – which are, for the reasons given above, valuable financial assets – and the verification of the validity of the ROCs presented to Ofgem after the close of an accounting period (fraud risks are not negligible). These costs have grown substantially as renewables capacity and output have grown and they have led to a substantial expansion in Ofgem staff levels.
- The administrative tasks involved sit uneasily alongside Ofgem's core activities – which are centred on rule-making, enforcement and adjudication, and on network price/revenue determinations – and there has been a consistent concern that their expansion could give rise to changes in organizational culture that would be detrimental to energy policy more widely. Ofgem has responded by, in effect, establishing a form of business separation within its own organization and has pressed for these administrative tasks (and others like them that came later) to be divested in their entirety. No UK Government has yet agreed to this request.
- Arbitrariness is introduced when dividing lines are drawn and different economic activities are allocated to distinct categories or boxes. The first question is simply: what is to be counted as a renewable source of electricity? This matters, because of the financial rewards that placement in the renewables box brings: renewables generators are entitled to create and sell a valuable financial asset (a Renewable Obligation *Certificate*). To illustrate, the renewables classification given to biomass has been particularly contentious, since it has led to the conversion of large-scale, coal generation plant to enable it to burn hard wood pellets. It is obvious that a MWh of electricity produced by burning wood has a different carbon footprint from that of, say, a wind turbine or hydro plant. Yet, in the first version of the ROCs scheme, these

technologies were placed in the same box and received the same financial support per MWh. The support is therefore not proportioned to environmental impacts.

- The ROCs scheme effectively offered long-term guarantees to renewables generators, which are similar in nature to a long-term contract. However, the terms and conditions were not determined by a competitive discovery process. Rather these things were determined by one, long-term forecast that led to the administered imposition of one (buyout) price, across the entire market, which, save for an annual RPI adjustment, was fixed for a period measured in decades.
- The prescriptive process by which 'renewables' are designated typically involves the privileging of some technologies at the expense of others, which is how things were prior to privatization, when investment efficiency performance was low.

The economic and policy salience of these flaws can be expected to increase the greater the proportion of renewables in the electricity generation mix. At first this was small, but it grew steadily over the following years (see Chart 1).

The Energy Efficiency Commitment (EEC)

The year 2002 also saw the introduction of the Energy Efficiency Commitment which required electricity and gas suppliers to assist household customers in taking energy-efficiency measures in their homes, for example loft and wall insulation. Each supplier was given a target level of reduction in energy consumption, set in proportion to the volume of its supplies. In principle, suppliers could trade the reductions they had achieved via what, in effect, was a form of 'white certificate' system[4], although, unlike in relation to ROCs, very little trading of certificates did in fact take place. The first programme ran for a period of three years, followed by a second phase from 2005 and 2008, at which point the arrangements were transformed into the Carbon Emissions Reduction Target (CERT) scheme (see Annex). The EEC scheme was an extension of earlier, similar arrangements that had been in place in electricity, but not gas, from 1994, but it marked a significant step-jump in the scope and intensity of this type of programme, increasing the incurred costs by something of the order of 200% (from about £1.2 per customer on average to around £3.6 in 2002).

The DTI was again the sponsoring government department, but the arrangements affected Ofgem by virtue of its role in their administration, which required supervision of supplier compliance. This is another, potentially challenging task. It is easy enough for a supplier to claim that loft or wall insulation it has helped install and/or fund could be expected to reduce consumption by, say, X%, but it is another matter to verify that this is or will be the reality, even allowing for acceptable levels of approximation. Among other things it requires assessment of a counterfactual: what would consumption have been, but for the actions taken?

[4] See http://iet.jrc.ec.europa.eu/energyefficiency/white-certificates

The European Union Emissions Trading Scheme

The EU Emissions Trading Scheme, launched in 2005, is described on the Union's europa website[5] as follows:

"The EU emissions trading system (EU ETS) is a cornerstone of the EU's policy to combat climate change and its key tool for reducing greenhouse gas emissions cost-effectively. It is the world's first major carbon market and remains the biggest one.

The EU ETS works on the 'cap and trade' principle. A cap is set on the total amount of certain greenhouse gases that can be emitted by installations covered by the system. The cap is reduced over time so that total emissions fall.

Within the cap, companies receive or buy emission allowances which they can trade with one another as needed. They can also buy limited amounts of international credits from emission-saving projects around the world. The limit on the total number of allowances available ensures that they have a value.

After each year a company must surrender enough allowances to cover all its emissions, otherwise heavy fines are imposed. If a company reduces its emissions, it can keep the spare allowances to cover its future needs or else sell them to another company that is short of allowances. Trading brings flexibility that ensures emissions are cut where it costs least to do so. A robust carbon price also promotes investment in clean, low-carbon technologies."

What has occurred in relation to EU ETS since 2005 can best be described as a process of market development, not unlike that associated with energy sector liberalization: market rules have been steadily and iteratively developed to address identified defects and limitations, and to meet new challenges as they have arisen over time.

This congruence in market development tasks (between energy and environmental policies) greatly simplifies the task of ensuring policy integration or effective co-ordination between these two pillars of public policy, in both design (including institutional design) and implementation. Those entrusted with the delegated market development tasks in each pillar can be said to be 'facing the same way' and much of their conduct is automatically co-ordinated via the simple expedient of a carbon price, i.e. by a price system performing its classic function.

If GHG emissions reduction is the policy aim across a set of economic activities, then the EU ETS approach is what in economics might be called a 'near-sufficient' instrument to achieve the aim, subject only to the condition that the caps are effectively enforced: other measures are of limited or zero significance, Most of the current difficulties, including lack of integration/coherence in the conduct of GB energy and environmental policies, stem from a failure to give due weight to this simple point.

[5] http://ec.europa.eu/clima/policies/ets_en

It suffices to compare the EU 'cornerstone' with the GB 'flagship' (ROCs) to see the major issue that has arisen. In effect, the existence of EU ETS implies that the incremental cost of carbon reduction achieved by provision of special support for renewables becomes infinite. A finite cost is incurred when the renewables contribution to carbon reduction displaces an alternative, cheaper means of carbon reduction, which is what occurs if the renewables contribution increases beyond that implied by a cost-minimizing mix of methods. However, given EU ETS, the actual reduction in EU carbon emissions is zero. If the UK undershoots its carbon allocation as a result of targeted support for renewables, emissions certificates will be sold and used elsewhere, either by other GB facilities covered by the EU ETS or by producers, potentially including fossil-fuel generators, elsewhere in the EU: there is 100% 'carbon leakage'. The incremental cost of a carbon reduction activity is just the extra cost incurred divided by the reduction in emissions achieved, and in this case the denominator is zero.

From a longer-term perspective, the situation is arguably worse than this. By raising the cost of achieving the target, there is almost inevitably some weakening in the appetite of the public for carbon reduction, which must be paid for by one means or another, whether via higher energy prices or higher taxation. The 'demand for carbon reduction' may be made manifest through political mechanisms, but it can nevertheless be expected, like most demands, to be negatively related to price/cost. If (politically mediated) supply responds to a lower demand for carbon reduction (due to higher costs), for example by setting less stringent future caps on emissions than it would if carbon abatement were cheaper, the rate of emissions reduction over time can be expected to be slower. The denominator in the definition of incremental cost turns negative and the cost concept itself becomes inapplicable. This has been described as Buzz Lightyear economics: *"To infinity and beyond"*.[6]

The obvious GB policy response to the introduction of the EU ETS would have been to close the ROCs scheme to new capacity. Government departments do not easily abandon their own children, however, and the DTI kept on feeding its own brainchild.

The EU's 20-20-20 targets

Having developed and launched the EU ETS, it did not take long for EU leaders to establish a second major branch of climate change policy: in 2007 they committed to binding legislation (enacted in 2009) that *inter alia* would impose the following obligations on Member States:

- A reduction of EU GHG emissions by at least 20% by 2020, relative to the 1990 level.
- 20% of EU energy consumption to come from renewable sources by 2020.
- A 20% reduction in primary energy use (compared with projected levels) by improving energy efficiency.

These objectives were to be achieved via a linear trajectory with binding annual targets, although some deviation from along the way was allowed.

[6] George Yarrow, *Alternatives to wooden headedness: (much) less costly ways of regulating carbon emissions*, Beesley Lecture, Institute of Directors, London, 21 November 2013.

Thus, whereas the EU ETS was focused on limiting GHG emissions, the 20-20-20 targets began also to specify the means of doing so, as is apparent from the second and third of them. The German Government was the main driver of the process, having earlier taken a political decision to phase out its reliance on nuclear power, and it held the Chair of the European Council in 2007. The run-down of nuclear power raised the question how the falling, low-carbon output could be replaced. It would have been possible to rely on the EU ETS, if necessary purchasing emissions certificates on the market to cover new-build of fossil fuel capacity (and Germany did, in fact, undertake an extensive programme of investment in new coal plant). This would not, though, have fitted with the political narrative of an *Energiewende* (transformation of the energy sector).

A cynic might interpret German enthusiasm for EU action as something that was influenced by concerns about its own, more general competitive position in European markets. A 'Green' policy of simultaneously reducing GHG emissions and phasing out nuclear power foreshadowed a significant rise in German energy prices, and hence in costs to the important manufacturing sector of the economy. If, however, costs in other Member States were also increased, shifts in relative energy costs across Europe would be more muted, and the combined effects of higher energy prices across the continent would be mitigated by a weakening of the euro, thus protecting the competitive position vis-à-vis the rest of the world. It is not necessary to be a cynic to recognize that, from this point of view, the renewables and energy efficiency targets were convenient for Germany. GB signed up to the proposals, which would re-introduce a narrative 'rationale' for its own continuation of the ROCs arrangements (a rationale that had been lacking since the introduction of the EU ETS), and had less reason to be fearful of the trade consequences than other Member States, since it was not a member of the Eurozone.

The targets were for the whole EU and the UK negotiated a less stringent target of a 15% for the renewables share of total energy consumption by 2020. Even so, given that the UK renewables share stood at only around 1.5% in 2007, this lower target still posed a formidable challenge: it seemed to point directly toward need for a massive expansion in wind capacity.

It was in agreeing to the second and third targets that the UK Government decisively veered away from the 'market development' path it had adopted and followed for over 20 years in the energy sector and to which it continued to pay lip service in environmental policy. Participants in competitive market processes will seek out the least-cost ways of doing things, both in the short-term and (by discovery and innovation) in the longer-term, and such processes offer no guarantees as to the future market shares of particular production methods. In a nutshell, in 2007 the Government came to a fork in the road, with one direction signed 'carbon market development' and the other signed 'central planning'. It followed the latter.

Had the Government taken the market development road, there would then have been only modest impacts on the ability of Ofgem to continue its own process of market development, which had been underway for nearly two decades. There would have been another major market with which energy regulation would need to interact, the carbon market, but Ofgem was well familiar with such issues. Financial trading in the wholesale energy markets meant that it had for some years been developing its understanding of the financial aspects of wholesale energy markets and Ofgem had signed a Concordat with the independent Financial Services Authority to ensure co-ordination of their respective enforcement activities. A carbon market might add a little more volatility to spot energy markets, but price volatility was something very familiar, there being few markets more volatile than a deregulated wholesale electricity market. Moreover had the Government established an independent Climate Change Authority or Commission with (whole economy) rule-making and development duties for GHG emissions markets, the wider governance structure would have built upon an institutional design that had an established record of success.

Adoption of the 20-20-20 targets[7] was, therefore, the most decisive moment for the interactions between energy and environmental policies over the last 30 years. As the two roads diverged, the differences in their implications and outcomes became so large that major disruption of energy policy became unavoidable. Prospects for policy integration were more or less extinguished.

'Banding' of ROCs (consultation commenced 2006, implemented April 2009)

Even before the EU 20-20-20 targets were agreed, the Government was becoming increasingly concerned about the balance in the rates at which new onshore and offshore wind projects were coming forward, and more generally about the cost differentials between different types of renewables. Offshore wind generation was substantially more costly per MWh than onshore wind generation, but there were planning processes and constraints that worked against the expansion of onshore wind farms, at least on a scale and at a speed indicated by the renewables targets to which the UK had committed itself in 2007. To speed up the rate of penetration of renewables, therefore, it was considered desirable to increase the support for offshore wind developments.

That could have been done by simply increasing the single, buyout price for all renewable technologies or by raising the target level of ROC redemption, but such courses of action would likely have had two, unwanted effects: (a) new onshore wind farms would command high economic rents, (b) there would be relatively rapid, accompanying increases in retail prices. Given that the bottlenecks to onshore wind developments lay in the scarcity of suitable sites, it could be expected that the associated economic rents would flow through to the owners of such sites, implying substantial transfers of income from energy consumers to a sub-set of landowners. Moreover, suitable sites were more readily available in remoter regions of GB, suggesting that considerable extra transmission capacity might be required, which would not only add to costs, but would also be contentious in its own right, not least from environmental campaigners focused on protecting the British countryside. Particularly when viewed through a political lens, these prospects looked unattractive.

The solution proposed, and eventually implemented in April 2009, was to place different technologies – and for this purpose onshore and offshore wind were counted as distinct technologies – into different categories and to set different ROC per MWh ratios for the

[7] More precisely, the second and third of the three targets.

different categories or ‘bands’. Prior to April 2009 the common conversion rate was 1 ROC per MWh of renewable energy supplied, with ‘banding’ the current (2016/7) conversion rates are:

> Onshore Wind: 0.9	> Energy from Waste with CHP: 1
> Offshore Wind: 1.9	> Standard gasification: 1.9
> Hydro-electric: 0.7	> Standard pyrolysis: 1.9
> Wave: 2	> Advanced gasification: 1.9
> Tidal: 1.9	> Advanced pyrolysis: 1.9
> Solar Photovoltaic (building mounted): 1.5	> Anaerobic Digestion: 1.9
> Solar Photovoltaic (ground mounted): 1.3	> Co-firing of Biomass (low-range) : 0.5
> Geothermal: 1.9	> Co-firing of Biomass (mid-range): 0.6
> Geopressure: 1	> Co-firing of Biomass (high range): 0.9
> Landfill Gas (Closed landfill gas): 0.2	> Co-firing of Biomass with CHP (low-range): 1
> Landfill Gas (heat recovery): 0.1	> Co-firing of Biomass with CHP (mid-range): 1.1
> Electricity generated from Sewage Gas: 0.5	> Co-firing of Biomass with CHP (high-range): 1.4
> Dedicated Biomass: 1.5	> Co-firing of Energy Crops (low range): 1
> Dedicated Biomass with CHP: 1.9	> Co-firing of Energy Crops with CHP (low-range): 1.5
> Tidal/ Wave (up to 30 MW): 5	> Dedicated Energy Crops: 1.9
> Microgeneration (under 50KW): 1.9	

Source: Taylor Wessing https://united-kingdom.taylorwessing.com/FutureEnergy/Leg_UK.html#banding

As is immediately obvious from the table, banding marked a step-increase in the degree of micro-management of producer prices in the energy sector by the UK Government (the relevant rates are set by the responsible government department, not by Ofgem). Thus, if ROCs are trading at £50 per MWh, the entitlement gifted to an on onshore wind generator would be £45 per MWh, to an offshore generator £95 per MWh, to a closed landfill gas generator £10 per MWh, to a (small scale) tidal/wave generator £250 per MWh, and so on. Before April 2009, all renewables generators were equal with one another, albeit they were collectively more equal than other generators. From April 2009 onwards, they were not equal with one another.

The micro-management entailed by banding goes further than this, however. The Secretary of State is required to review the bands at scheduled review points, which occur every four years. The first such review made a number of changes for the period 2013-17, which included:

- Reductions starting in 2015/6 in the number of ROCs/MWh for offshore wind; geothermal; microgeneration; tidal barrage and lagoon; gasification; pyrolysis; anaerobic digestion; dedicated energy crops.
- ROCs were removed from generating stations using open landfill gas sites.

- The ROC/MWh rate for wave and tidal streams was increased to 5, but only up to a 30MW cap on declared net capacity, and if the capacity is installed and operational between 1 April 2012 and 1 April 2017.

It is to be stressed that these are only highlights: the list of the detailed prescriptions and conditions is a long one

4. 2008 - 2010: From Climate Change Act to Electricity Market Reform

The Climate Change Act 2008

The Climate Change Act 2008 provided the legislative underpinning for the transition to the 20-20-20 policy strategy in GB, but, like a good Stakhanovite, the Government wanted to go further than the EU's plan. In its first drafting the intention was to commit the UK to a 60% reduction (from 1990 levels) in GHG emissions by 2050, but that target was tightened to 80% in the legislation itself. To chart a course to this distant target, lying in an unknowable future, the Act provided for the setting of a sequence of 'carbon budgets' specifying the levels of allowable carbon emissions at each stage, with each budget covering a five-year period, i.e. the legislation provided for a sequence of five-year plans. The second budget period ends in April 2017, and the third to fifth budgets, covering the period 2017-2032, have already been determined and set down in legislation. Later budgets will be set by the Government, at appropriate times.

The word 'budget' is significant in this context. It is borrowed from fiscal policy and accords with a cognitive frame that sees carbon reduction as an organizational ('hierarchical') task, rather than as an outcome of commercial activity in which economic agents interact 'horizontally' via exchange transactions. As is often the case, use of language speaks volumes. The economic term for systems of economic resource allocation that view society as a whole as an organization is 'central planning'.

The other major feature of the Act of relevance to the interactions between energy and environmental policies was the establishment of the Climate Change Committee (CCC), an independent, statutory body jointly sponsored by the new Department of Energy and Climate Change (DECC), and the Devolved Administrations in Northern Ireland, Scotland and Wales. DECC was established in 2008 by Prime Minister Brown and abolished in July 2016 by Prime Minister May. Its energy sector responsibilities were acquired from the Business Department, then called the Department for Business, Enterprise and Regulatory Reform (BERR, previously the DTI), and returned to the Business Department, now called the Department of Business, Energy and Industrial Strategy (BEIS), on its abolition.

The Climate Change Committee (CCC)

The CCC's purpose is to advise the UK Government and the Devolved Administrations on emissions targets and to report to Parliament on progress made in reducing GHG emissions and preparing for climate change. It is therefore not an independent regulator in the sense of, say, Ofgem, Ofcom or the Financial Conduct Authority, but rather an advisory body to the executive and legislative branches of government. Thus, under the heading of 'strategic priorities' on its website, the CCC currently says that in fulfilling its role its focus is to:

- *Provide independent advice to Government on setting and meeting carbon budgets and preparing for climate change.*
- *Monitor progress in reducing emissions and achieving carbon budgets.*
- *Conduct independent analysis into climate change science, economics and policy.*
- *Engage with a wide range of organisations and individuals to share evidence and analysis.*

The CCC set out its recommended approach to climate change in its December 2008 Report *Building a Low Carbon Economy: the UK's Contribution to Tackling Climate Change*. It described its role as *"to recommend a path of emissions which is appropriate as a UK contribution to global climate change mitigation, and to identify whether that path is feasible at manageable economic cost, given the range of different technologies and policy levers which could be deployed"*. This statement reveals important assumptions that the CCC made about its approach. First, it saw its role as encompassing the making of value judgements, e.g. about the "appropriate" UK contribution to carbon reduction. In doing this it said it would take account of latest global evidence on climate change and assess how much the UK should be contributing given the Government's stated desire that the UK should play a 'leadership role'.

Second, it would take a view on the extent to which the economic cost was "manageable". It concluded that the costs of meeting a new higher target (80% carbon reduction by 2050) were *"affordable and should be accepted given the consequences and higher costs of not acting"*. This reference to an assumed counterfactual – a failure to act would lead to higher costs later in time – was a consistent theme in Government rhetoric of the day, but it begged a number of questions, including those focused on the likely *relative* costs of carbon reduction now, in twenty years' time, in forty years' time, and so on. The important point here is that these relative costs can be expected to *depend* on the target chosen: they are not an exogenous factor to be taken into account for the purposes of setting a target. For example, a more stringent shorter-term carbon budget implies allocating resources now (e.g. to building high-cost, offshore windmills) that might otherwise be allocated to research and development that could reduce future de-carbonisation costs. Indeed, academics whose work focuses on 'complexity' have argued that thinking in terms of targets is fundamentally misguided in the first place, because it directs attention and effort away from the thing that really matters, advancing knowledge that will make carbon reduction much cheaper than it is now.[8]

The *assumed* linkage between UK action and global action was also not assessed or tested in any detail. The CCC did not claim that UK action would *directly* mitigate global climate change to any great extent, but the implication *was* that UK action and leadership *would*

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[8] See, for example, Steve Rayner Gwyn Prins, "The Wrong Trousers: Radically Rethinking Climate Policy", Institute for Science, Innovation and Society, Oxford, 2007, http://eureka.sbs.ox.ac.uk/66/

stimulate incremental global action that would make a substantial contribution to achieving the global objective. A similar claim has accompanied the priority given to offshore wind farms in the Government's support for renewables. The political rhetoric has been that GB has been a global leader in this area, by some distance. Critical economists have been prone to reply that that is because no other country has been silly enough to put substantial resources into such an inefficient method of carbon reduction, and also to point out that experience tends to suggest that others will follow successful policy innovations, but not failed policy innovations.

The Low Carbon Transition Plan (2009)

In 2009 DECC published its *Low Carbon Transition Plan*, which set out the Government's national strategy for climate and energy, but which did not suggest that consideration of radical domestic electricity market reform was on the immediate agenda. The focus was on removing barriers to the deployment of renewables and new nuclear plant in electricity generation, as well as progressing carbon capture and storage technology. Indeed, DECC stated that, *"the best way of incentivising the most cost effective mix of low carbon technologies is to put a limit or 'cap' on emissions"* and that the EU ETS was the central plank in UK decarbonisation strategy.

These sentiments were not entirely inconsistent with established energy policy, although the implied, decomposition of a cost-minimisation approach into separate 'low carbon' and 'other' technologies was. Removing barriers to entry was a core principle of energy sector liberalization. Support for carbon capture and storage technology via subsidies for *demonstration* projects was chiefly an aspect of a more general technology policy and, as such, had few implications for liberalized energy markets. The development of EU ETS was congruent with a policy strategy that had underpinned energy regulation for twenty years.

The sentiments were, however, more fundamentally inconsistent with the 'plan' itself. Only a little over three months *before* the *Transition Plan* was published, DECC had introduced banding of ROCs. EU ETS establishes a single, market-determined price for carbon across the EU, whereas banding establishes different carbon prices not only for different technologies, but also for carbon prices at different locations (onshore vs offshore wind) and differently constructed installations (building-mounted vs ground-mounted PV panels).

The general phenomenon observed here was identified many decades ago by George Orwell:

"Medically, I believe, this manner of thinking is called schizophrenia: at any rate, it is the power of holding simultaneously two beliefs which cancel out. Closely allied to it is the power of ignoring facts which are obvious and unalterable, and which will have to be faced sooner or later. It is especially in our political thinking that these vices flourish." [9]

Confronting realities

[9] *In Front of your nose*, in *Collected Essays, Journalism and Letters, 1946-50.*

The most significant, enduring tension was between an emissions cap determined at EU level and the UK's unilaterally determined emissions reduction targets (the carbon budgets). The EU cap was not set on a trajectory designed to be compatible with a UK plan for hitting its domestic targets, which were based on a desire to be a leader in emissions reduction (which implied going beyond existing, multilaterally agreed positions). Indeed, the nature of the EU scheme anticipated that more emissions reduction would take place in the Member States with the lowest-cost abatement opportunities. This was a chief purpose of a multilateral scheme. If leadership is measured by the proportionate reduction in emissions that is achieved in a period, a well-functioning EU ETS implied that 'leadership' would more likely lie in the eastern, not the western, parts of Europe.

The tension was not unique to the UK: the 20-20-20 targets triggered a range of policy responses to promote renewables across the EU, none of which were aligned. They did, however, all have the common factor of tending to stimulate renewables output to levels above those that could be expected in the absence of the targets and thereby served to depress EU ETS prices. Moreover, the latter were under severe downward pressure at the time because of the post-2008 recession in Europe: significantly lower economic activity led to reduced demand for emissions certificates and, against a fixed supply, prices fell sharply.

Notwithstanding that the carbon market responded exactly as might be expected, the low carbon price was interpreted by many as a sign that the carbon market had 'failed' and that it was not providing sufficient incentives for investment in low carbon technologies. Whereas the root causes of the depressed carbon prices lay in other policy failures, the general reputation of the EU ETS approach declined: the messenger was blamed for the message.

There were also difficulties surrounding regulatory credibility. Circumstances were very different from those in 2002, when the ROC buyout and revenue recycling arrangements were first introduced. There was a much more uncertainty in the air, arising not only from the policy schizophrenia in climate change policy itself (e.g. EU ETS vs quantitative sub-targets), but also much more generally from the financial crash. From the perspective of investors, offshore wind was, like nuclear power, characterised by very high upfront capital investment costs and low or zero marginal costs once in operation. This naturally focused investor attention on the confidence that could be had in the recovery of the capital costs over a long time period. The risk profile increasingly looked somewhat akin to an infrastructure investment in an activity where there was a monopsonistic buyer, since the revenue stream would be so heavily dependent on the buyout price. Prospects for a merchant approach to investment in electricity generation therefore appeared unattractive.

The conventional wisdom in DECC was increasingly that the wholesale electricity market was now no longer fit for purpose in terms of providing the necessary platform for low-carbon investment. This in turn reinforced the view that, left to its own devices, markets would at best deliver only new gas-fired plant in substantial volumes, at least in the medium term. The latter view was probably partly correct, but quick, further displacement of coal by CCGTs could have brought substantial reductions in GHG emissions. What it would not have done, however, is contribute to the renewables ‘plan’ to which the UK had committed itself in 2007.

Orwell’s facts were therefore proving difficult: the incompatibility between central planning and market-based resource allocation was increasing exposed and something had to give. In the event, it was the market.

The energy regulation perspective

Ofgem’s contribution to the policy discourse of the time was muted and limited, but an early expression of its views, in January 2007 in a response to the Government’s consultation on proposals for ROC banding, may be worth noting. The regulator was critical of the ROC scheme as a whole, on the ground that excessive costs were being passed through to energy consumers. A criticism of detail was that renewable generators were afforded rights to create and sell ROCs upon accreditation, ahead of any actual generation of power. Since there were multiple occurrences of facilities achieving accreditation (a formal administrative process), but not in the event being developed, for example because of local planning objections, costs to energy suppliers, and hence to consumers, had been inflated.

More fundamentally, Ofgem was concerned about the incompatibility of the arrangements with the EU ETS scheme, and expressed its opposition to banding on this basis. One issue was the point already mentioned: the incompatibility of a single market price for carbon with a complex array of administratively determined prices. The other was a ‘paying-twice’ point. In their different ways, the buyout price and the EU ETS price can be viewed as attempts to put a value on the marginal social cost of GHG emissions and, in competitive markets, the EU ETS price was already incorporated into market prices of energy. It was inappropriate, therefore, to treat the valuations as additive when they were, in reality, two measures of the same thing. The additivity implied that retail prices would likely be excessive.

Instead, Ofgem proposed that, if there was to be support for renewables (and this it didn’t challenge, since that was a matter for Government and Parliament, not for an independent regulatory agency, to determine), the better alternative was to resort to contracts for differences (CfDs), which were the method of linking long-term contract prices (like the ROC buyout price) to spot prices (like the EU ETS price) that had evolved in the marketplace. The advice was ignored at the time, although CfDs subsequently came to be the preferred approach in DECC’s new market design.

It would be wrong, however, to infer from this support for CfDs that there was Ofgem endorsement of the subsequent policy developments. At the end of 2006, when its response to the banding consultation was being written, there were no 20-20-20 targets and the EU ETS was the governing framework for EU climate change policy. The renewables share of the market was still at very modest levels, and much of that share was accounted for by long-existing hydro facilities (and larger scale hydro facilities in operation before April 2002, when the ROCs scheme was introduced, were not eligible for the scheme). Any government sponsored CfDs, i.e. contractual arrangements where the strike price would be set via an administrative (rather than market) process, could be expected to have only limited impacts on the operation of the energy markets. When CfDs did come to be introduced, the position was rather different: the context was one in which the scale of the effects of the contractual interventions could be expected to be at least an order of magnitude higher.

Ofgem did make a further intervention in climate change matters in 2010, but by then the regulatory body had itself performed a U-turn of its own. This intervention arose from an exercise named *Project Discovery*, which was focused on security of supply issues. The long established view of the regulator had been that, if it took care of markets, markets would take care of security of supply issues, a position well supported by the historical evidence. *Project Discovery* signalled to the world that the Ofgem leadership of the day no longer believed that this was the case.

The project was subject to criticism both within Ofgem and within government, for the same reason: the regulator was trespassing into territory that was beyond its statutory remit. Whilst it was appropriate to point to the adverse implications of current climate change policy for security of supply, it was no business of Ofgem to advertise possible 'solutions', some of which implied radical changes that would, in effect, amount to undoing a large slice of its own previous work. In consequence, Ofgem's influence in policymaking circles was further eroded: it became an even more peripheral voice and its reputation was further dented. *De facto* energy policy, as well as climate change policy, had become incoherent.

While Ofgem's suggestions differed in tone to the programme of the CCC, the CCC equally believed radical reform was inevitable. It took the view that the market was biased towards investment in conventional fossil fuel generation and that this put it at odds with the 'needs of society', in relation to which the only really relevant policy questions were: *in which low carbon technologies should GB invest and, given the carbon budgets, at what levels?*[10] This was an astonishing position to take, since it implied that even if all low-carbon generation was currently very expensive (including, most crucially, relative to *future* low-carbon generation), society simply still had to 'buy' large volumes of it <u>now</u>. The CCC's critique also carried the implication that it took a very low view of the value of market discovery processes: if those processes appeared not to be capable of meeting the planned, aggressive carbon budgets, they should be replaced, because they no longer served the 'plan'.

Feed in Tariffs (FiTs)

GB was relatively slow to adopt feed in tariffs compared with Germany, where promotion of solar PV installations was given significantly higher priority, but these became available for small-scale, low-carbon electricity generating projects by households, businesses and communities on 1 April 2010. Payments were available whether or not the electricity generated was fed into the grid, but payment rates for grid flows were higher. Payment periods varied but typically ran for between 10 and 25 years and (inflation-adjusted) rates

[10] Climate Change Committee, *Meeting Carbon Budgets – the need for a step change*, October 2009, p.18.

differed not only according to the technologies adopted, but also according to other characteristics that were deemed by DECC to be relevant in some way or other.

Because of the diversity and differentiation among the various generation sources covered by the scheme, the FiTs arrangements were and remain exceedingly complex, implying significant administrative burdens. To prevent escalation of levels of payments, the arrangements are kept under constant review by the Government, leading for example to major adjustments in 2015/6 that saw tariffs paid for solar PV generation substantially reduced for new projects, in response to falling PV costs. In consequence, the FiTs programme involves central Government in price determination at levels of detail, scope and intensity that lie far beyond anything normally be undertaken by a sectoral energy regulator.

As with a variety of other schemes such as the Energy Company Obligation (see Annex), the obligation to pay for the electricity generated under the FiTs arrangements falls on energy suppliers/retailers. It therefore adds to a supplier's own input costs, which are then recovered from its whole customer base. The effect is to put upward pressure on retail energy prices.

The obligation to offer FiTs to customers only applies to suppliers with more than 250,000 customers, a principle that applies also to a range of other schemes that require suppliers to incur additional costs. This gives such small suppliers a relative-cost advantage in competing for retail customers and the magnitude of the advantage is an increasing function of the cumulative cost burden imposed by the schemes. Competitive incentives are thereby affected, which in turn has had a clear effect on market structure: the market share accounted for by small suppliers has increased significantly.

On the face of things, this de-concentration of retail supply may look like an increase in retail competition that should be welcomed, but the position is more complicated than that. A small supplier expanding its business is faced with a major hurdle as its customer base approaches 250,000: there is a barrier to expansion in the form of a major, substantial, step-increase in policy-imposed costs at that point. The incentive structure encourages the development of small suppliers, but simultaneously puts obstacles in the way of their growth past a certain point. If the standard, *prima facie* interpretation of the link between market concentration and competition were right, it is to be expected that falling market concentration would be accompanied by downward pressure on the retail margins of the six, large electricity suppliers in GB. As the Competition and Markets Authority (CMA) found in its major investigation of the energy markets, however, the opposite has occurred: retail margins of large supplied have increased significantly, to the detriment of end consumers of energy.[11]

Electricity market reform

[11] Competition and Markets Authority, *Energy Market Investigation*, 24 June 2016.

Spurred on by the sense of uncertainty hanging over the market, DECC's thinking, with input from the Treasury, developed rapidly during 2010, culminating in its *Electricity Market Reform* publication in December of that year, by which time a new Coalition Government had come into being. This paper laid out four, major policies that together effectively came to define a new set of trading arrangements in the energy sector. The four policies were:

- A unilaterally determined GB carbon price floor, with a planned forward trajectory, to act as a top-up to the prevailing EU ETS price when the latter is below the floor (effectively a time-varying tax on fossil fuels used to generate electricity).
- Long-term contracts for low carbon generation taking the form of contracts for differences (CfDs) around the GB (spot) wholesale energy price.
- Capacity payments to generators to ensure sufficient flexible plant is available to maintain security of supply.
- An emissions performance standard, designed to rule out new-build coal plant, unless accompanied by carbon capture and storage technology.

Each of these component policies is discussed in the next section, but, before proceeding, it is appropriate to note that the 2008-10 period, like the period that followed, saw several less far-reaching initiatives. It is a feature of the top-down nature of GB climate change policy measures that it has tended to give rise to an increasing number of detailed schemes directed at different, specific aspects of the energy value chain. Some of the more significant of these are explained in the Annex, though only briefly. Each considered individually does not raise major issues for the workability of liberalized energy markets or for the conduct of regulatory policy in the energy sector (with the possible exception of smart meter roll-out). Cumulatively, however, and when taken in conjunction small-supplier exemptions, they do have material effects on competition in retail markets. They also tend to create additional administrative burdens, substantial elements of which are allocated to Ofgem, giving rise to general concerns about impacts on Ofgem's ability to perform its core functions in an effective way.

5. 2011 to the present day: Consolidation of central planning and the emergence of doubt

The nuclear dimension

The political momentum for the EMR policy package came not just from the climate change agenda in its general form, but also from a more specific desire to enable negotiated contracts for new nuclear capacity, the leading project in line being a 3.2GW plant at Hinkley point in the South West of England. The argument for nuclear power was that, if the ageing nuclear generation fleet was not replaced with a sequence of new nuclear plants, the UK would find itself in the position faced earlier by Germany, i.e. declining capacity in an existing source of low-carbon output inconveniently coupled with a policy objective of quickly increasing the contribution of low-carbon generation. In the absence of new nuclear capacity the 20-20-20 targets simply looked impossible to achieve.

In opting to pursue the nuclear option it was clear that another substantial deviation from the market development path would likely be entailed. Market prices of carbon were nowhere near the levels that might stimulate a commercial interest in this type (large scale nuclear) of investment and, while it cannot be ruled out that such price levels will come to be seen in the future, the capital market's judgment on new nuclear capacity was unambiguously 'not yet'.

Although it was not publicly stated, the reality was that DECC thinking on electricity market redesign was largely driven by what would work for nuclear power. However, there was a major problem for DECC in the form of EU state aid and competition laws, which it expected might block the development of explicitly bespoke arrangements for new nuclear projects. This was a highly significant factor: DECC inferred that it meant that, to proceed with a nuclear programme, the wholesale market arrangements would need to be redesigned in their entirety, to obscure some of the most obvious and visible bespoke aspects of the Hinkley project and thereby facilitate a compromise in Brussels on the state aid constraints. Moreover, to reduce the estimates of the level of public financial support required for the Hinkley project to proceed, the narrative accompanying EMR would necessarily have to rest on a view of the future that saw ever rising fossil fuel prices. The line was: costs and prices will go up substantially, but they will go up substantially anyway, because global fossil prices will follow a strong, upward path over the coming years. This was, quite manifestly, a conjectural, long-run price forecast, and not something that could safely be relied upon.

Feed in Tariffs with Contracts for Differences (FiT CfDs)

Faced with this market redesign issue, Contracts for Differences, a variant of the FiTs approach, had considerable appeal. Since new nuclear costs were unrelated to fossil fuel prices, it was argued that it made no sense to pay EDF (the favoured contractor for Hinkley Point) to bear the fuel-price risk. The reasoning was that a relatively low cost of capital could be negotiated with EDF if it was granted a low risk, infrastructure-type contract. Implicit in this thinking was the assumption that there would be no competitive tendering for the project: it would be a bilateral negotiation. To the extent that the assumption was rationalised, the argument was that, for this type of project, the sunk costs of preparing competitive tenders would be too high to attract much interest.

Given the logic for the use of CfDs for nuclear investment, CfDs were an obvious choice of model for all low-carbon generation. As indicated earlier, they had been suggested by Ofgem as an alternative to ROCs in January 2007 (and earlier than that in informal DECC/Ofgem discussions). The government was not convinced by the suggestion then, but now the CfD approach would make the nuclear arrangements 'look the same' as renewables arrangements, financial support for which no interpretation of EU state aid law or competition law had dared to question, at least in general principle.

As previously discussed, the Ofgem suggestion had been made in a pre-20-20-20 world, and reflected a judgment that, <u>if</u> there was to be public support for renewables over and above the competitive advantage afforded by the existence of a market price for carbon, it would be better done via CfDs than via ROCs. As for the longer term, the view from the regulator's office was that, if the EU ETS certificate allocations were tightened, a combination of increasing carbon prices and falling renewables costs (from learning by doing and innovation) could, over time, be expected to reduce the level of support required.

By 2011, however, the CfD proposals contemplated a much wider roll-out of these contractual arrangements, across a large and growing share of total output. Whilst this was a new market design, it is relevant to note that, had DECC persisted with the ROC arrangements as its flagship scheme, those too would have led to wholesale markets dominated by administrative/political decision making. The die was cast in 2007, when EU leaders took the fork in the road signed 'central planning'.

The far-reaching changes of the time naturally gave rise to policy and regulatory uncertainty, not least because Ofgem, a body expected to be the guardian of regulatory certainty, was by now largely missing from the policy playing field. Nearly all parties to the discussions, including DECC, agreed that policy uncertainty was causing difficulties for new investment. The CfD proposals themselves were not unattractive to the major energy companies and to developers: they at least held out the prospect of being able to secure contracts at fixed strike prices for low-carbon investments which could underpin revenues over long periods. Moreover, those prices would be determined by public agencies that do not have reputations as world-beaters in the procurement stakes, so there were obvious possibilities of developers being able to secure some good deals.

The new arrangements would clearly not be helpful for investment in fossil-fuel plant, which *de facto* meant CCGTs. Those with interests in CCGT investments might have been expected to be staunch defenders of a market-based approach, but that was an option no longer realistically available: the immediate choice was between CfDs and ROCs, not between CfDs and a market-based approach. Opposition to CfDs was therefore limited.

There were nevertheless many analysts who, taking a longer-term view, recognized that CfDs would fundamentally change the wholesale market, *inter alia* by insulating generators and suppliers from the risks of wholesale price movements. This, it was argued, would remove the incentives for them to hedge forward, tend to reduce market liquidity, and potentially reduce the forward market to a residual role. However, with Ofgem largely absent from the debate and the CCC and DECC focused on project delivery, this kind of longer-term view posed little real challenge to DECC's proposed way forward.

DECC itself became increasingly bold and hubristic as it developed the EMR programme. Central to its justification for the costs that would be entailed by the proposals was the claim that *"every step the UK takes towards building a low-carbon economy reduces our dependency on fossil fuels, and on volatile global energy prices"* ensuring that, *"our economy does not become hostage to far-flung events and to the volatility of market* *forces."*[12] DECC's EMR impact assessment asserted that, while energy prices for customers would be higher in the future, they would be lower than they would be in the absence of the reforms. The proposals were therefore audaciously presented as favourable to electricity consumers.

As indicated, the relevant counterfactual assumed high and every rising global oil and gas prices, an assumption that quickly looked deeply questionable as oil prices crashed and the development of shale gas in the US transformed the global gas market. However, it suited DECC to overplay concerns about foreign, volatile sources of energy given its commitment to fixed-price, contracts. Questions such as whether it might actually be *more* sensible to seek diversity of supply sources across international markets were sidestepped.

The eventual policy outcome was that CfDs will replace the Renewables Obligation as the preferred support mechanism for renewables on 1 April 2017. CfDs have been available since 2014, but in the intervening period qualified generators have been able to choose between CfDs and the ROCs scheme. However, the ROCs option will be closed to new capacity on 31 March 2017. For previously accredited renewables generators the banded ROC arrangements will continue to operate for up to a twenty-year period, i.e. until 31 March 2037, but generators accredited before 25 June 2008 will see their entitlement to issue ROCs withdrawn on 31 March 2027 whereas later accreditations will receive ROC support for 20 years from the date of commissioning of their facilities, or until 31 March 2037, whichever is earlier. CfDs are available not only for renewables generation, but also for nuclear and for fossil-fuel plant that has carbon capture and storage capabilities.

The CfD counterparty for an eligible generator is The Low Carbon Contracts Company (LCCC), a government owned enterprise. The contracts will typically run for 15 years, although it can be expected that there will be the usual exceptions. The Secretary of State has powers to adjust the terms of any contract that is settled between a generator and the Low Carbon Contracts Company whenever he/she believes that the technology justifies such intervention (which conjecturally may turn out to be the case for major nuclear and tidal projects, or where carbon and capture storage cost issues are in the frame).

The LCCC procures CfDs via staged auctions in which generators bid for contracts. There is therefore competition among generators for contracts, but the timings and requirements specified in these sequential auctions are determined by Government and these things continue, for the moment at least, to be driven by the carbon budgets. The LCCC is, therefore, a *de facto* state-owned monopsonist, so the contract market cannot be described as a competitive market (just as a market in which a state-owned monopoly operated could not be said to be competitive).

CfD payments from the LCCC to generators are financed by a means of a Supply Obligation, a compulsory levy on electricity suppliers which is collected by the LCCC. Each levy period

[12] DECC press release, 18 May 2012.

is based on a calendar quarter with the underlying amounts owed by suppliers (in aggregate) over the quarter equal to the CfD payments owed to generators in respect of that quarter. However, suppliers are required to make pre-payments against the underlying obligation.

There are two exemptions to the Supplier Obligation:

- Suppliers can be exempted on up to 85% of the electricity sold to eligible electricity-intensive industrial facilities (following the approach taken in the implementation of the Climate Change Levy).
- The Green Import Exemption (GIE) exempts renewable electricity imported from other EU member states and supplied to consumers in GB, if it was generated from plant which commissioned after 1 April 2015.

Carbon price support

While CfDs were still under consideration, the Treasury was already moving ahead with the first leg of the EMR package, carbon price support. The ‘rationale’ for this measure was that the EU ETS price was too low to drive low-carbon investment and the arrangements were based on setting a forward annual trajectory for an increasing UK carbon price. If the EU ETS price fell short of the support price, the difference would be charged as a tax. In effect, this was a ‘one-way’, Government-imposed contract for difference written on the EU ETS carbon price (the Treasury would not make payments to generators in the other direction, i.e. if the EU ETS price was in excess of the carbon support price level). The floor was determined to increase from £16/tCO2 in 2013 to £30/tCO2 in 2020, then rising to £70/tCO2 in 2030. The Treasury estimated that this would deliver £30-40 billion of new generation investment up to 2030, *“equivalent to 7.5 to 9.3 GW of new capacity”*.

It can reasonably be expected that the carbon support price will provide an incremental stimulus for investment in new and existing low carbon generation, largely at the expense of coal plant, although the estimated effects can only be viewed as highly speculative. Its major attraction for the Treasury, however, was almost certainly that it provided an incremental source of public revenue at a time when the UK fiscal position was perilous. Any potential energy and environmental policy benefits were far less clear cut, for three main reasons:

- Once CfDs had been chosen as the low-carbon investment-contract model, carbon price support ceased to be materially relevant for those generators. Moreover, the Government already had direct control over the pace of new investment via first ROCs then (later) by the LCCC’s ability to determine requirements for new capacity in its sequential CfD auctions.
- While the Treasury claimed that the rising trajectory provided investors with certainty about future carbon prices, in reality the rate of support was always going to be subject to review in the Treasury’s own, annual budget cycle. Indeed, the promise of a £70 rate was soon abandoned, mainly because no-one believed such a high rate would ever be introduced.

- Perhaps most fundamentally, it is yet another example of a failure to see the implications of participation in the EU ETS. For any given allocation of EU ETS certificates to the UK, any incremental measure that reduces carbon emissions in the GB simply tends to increase carbon emissions elsewhere in the EU, one-for-one.

Capacity payments

The increasing tension between the target-driven carbon reduction strategy of the Climate Change Act and a policy strategy based on market development had inevitably created policy uncertainty that made investors wary, and the introduction of CfDs was a way of offsetting that risk for renewables developers by offering contracts that guaranteed revenues over a long period. However, the scale of CfD programme and its implications for other forms of generating capacity such as coal and gas, which still accounted for most of electricity output, raised doubts about both the economic viability of existing plant and about the prospects of *any* new form of fossil-fuel generation coming to market unless it too received some form of state support. The intermittency issues associated with wind power were repeatedly raised in this context, particularly in relation to new-build CCGTs which in the past had relied on a life cycle of revenues characterised, in the important (less discounted) early years, by a period of base-load operation. Henceforth, it appeared that any such period could be heavily truncated. These considerations also gave rise to concerns about potentially increasing risks to security of supply.

DECC was open in admitting that the spectre of government intervention was part of the problem, noting that there are "*investor concerns that the government/regulator would not let parties earn scarcity rents*" in periods when capacity was short relative to demand.[13] There is a basic, underlying problem of trust here. Generators and investors did not trust the Government because of its past policy record, which itself was more than sufficient to demonstrate that, in relation to climate change matters, Government (and *a fortiori* Her Majesty's Opposition) did not trust the market and, when a particular challenge arose, seemed unduly ready to declare quickly that "the market is broken". Thus, the Government's own, acquired reputation in climate change matters seemed to lead inexorably to the conclusion that there would be a "missing money" problem for low load factor generators, dependent on revenues from occasional spikes in spot prices.

DECC's view therefore became that, while energy revenues from the market could continue to play a significant part in remunerating gas and coal-fired generation, the opportunity of fossil-fuel generators to achieve a more stable, availability-based revenue stream would help to sustain thermal plant that was running at lower load factors than had been previously been typical for such plant. It is important to note at this point that the pressures on load factors were not only due to increasing renewables penetration: falling demand for electricity caused by recession and by very substantial upward pricing pressure at the retail level (attributable initially to higher world energy prices) also played major roles. It was in this context that the

[13] DECC, *Capacity market – impact assessment*, 27 November 2012, page 1.

scope of Government intervention was extended further, to encompass contractual support for gas and coal capacity via the introduction of capacity payments. Henceforth, all forms of generation capacity would receive state aid in one form or another, including coal, and the Government would, *de facto*, take responsibility for ensuring longer-term security of supply.

In reaching this conclusion, little thought appears to have been given by DECC to alternative ways of addressing the trust/credibility problems. A creative and innovative rule-maker might, for example, have suggested that DECC could write contracts to indemnify fossil-fuel generators against its own, possible, future transgressions, e.g. *"If we impose a price cap, we will pay you £X million"*, but this kind of thinking was a thing of the past.

Design of the capacity market

The capacity market operates on the basis that the Government, advised by a new EMR Delivery Body (see further below), determines the amount of capacity that it deems is required to meet future, forecast demand (at a specified standard of reliability[14]). Generators[15] then compete to be paid to provide capacity availability for a specified time period. Availability is defined as the ability to respond to a system stress event by ramping up production within four hours. The main capacity auction for availability in a specified delivery year takes place four years ahead of that delivery year, with a top-up auction one-year ahead. This allows new-build projects to compete with existing plant, since developers can typically bring new capacity on to the system within four years. Hence, although the first auction took place in 2014, this was for delivery of capacity in 2018/19, and no capacity payments were to be paid until that later time.

Capacity markets or mechanisms are a feature to be found in many electricity markets and the PJM market in the U.S. was a reference model for the GB design. However, well-conducted market design should take account of market arrangements on a holistic basis, and cherry picking parts of other systems tends to lead to loss of policy coherence/integration. It is difficult to conclude other that the GB trading arrangements, considered in their entirety, have gradually become a mixed bag of sub-markets and interventions, with a single buyer for all low-carbon generation and capacity payments grafted on to balancing, settlement and forward energy market arrangements put in place by Ofgem in 2001.

DECC's impact assessments attempted to capture some of the interactions between the energy and capacity arrangements. For instance, it was argued that while there is a gross cost to customers of operating the capacity market,[16] the net cost would be lower since generators would require less energy revenue from the wholesale market to make a profit. This gross/net cost distinction is conceptually sound, but the better way to think about it is to note

[14] Unpicking the volume implications of the reliability standard is difficult for investors, given the array of assumptions (e.g.s. derating factors, outage assumptions) that the Delivery Body must make to determine a procurement volume in the face of uncertainty about future demand and plant performance.
[15] With the exception of generators covered by CfDs and ROCs, who were regarded as having contracts that already contained sufficient incentives for them to make capacity available.
[16] Equivalent to the volume of capacity procured in each year, multiplied by a capacity price (in £/kW) determined as the price paid to secure to the last unit of required capacity.

that, if extra capacity is available on the system as a result of capacity payments, it can be expected that spot prices will be lower in consequence. However, under the EMR market design based around CfDs, one consequence of lower spot prices is higher CfD payments (or lower CfD receipts), and those higher payments are ultimately financed by energy consumers.

The focus on securing commitments to new-build thermal capacity (in practice CCGTs) is a distinctive design feature of the GB capacity market. Most capacity mechanisms make payments to generators for short-term availability and do not seek to underpin long-term availability through contract (for example, that was how the pre-NETA pooling arrangements worked in England and Wales). However, given a Government policy of seeking to accelerate the closure of coal plant (to meet carbon budgets) and the prospect of existing nuclear stations reaching the end of their working lives, DECC perceived that there would be a potential supply gap of extended duration.

To meet the new-build objective, the auction design includes an option to seek fifteen-year contracts. This outcome was the result of intensive industry lobbying in which independent power producers told DECC that they needed that length of contract to attract the necessary finance. Facilities undergoing "refurbishment" are able to bid for contracts of three years in duration since, like for new plant, the extended years of available capacity are dependent on at least some level of investment expenditure, which needs to be recovered. Existing capacity not undergoing refurbishment bids for one-year contracts.

The auction design is of an open-outcry, descending-price (Dutch) type in which, over successive rounds, the auctioneer reduces the price that will be paid until the auction clears at the point at which sufficient initial offers have been withdrawn for the volume requirement to be minimally satisfied. An immediate difficulty with these arrangements arises from the facts that (a) there are twin objectives in play, short term system flexibility *and* long-term resource adequacy, and (b) no distinction is made between different contract lengths in the clearing process. The rules contain provision for the adoption of price duration curves to adjust the price of longer term contracts relative to one-year contracts (for example, if the Government is concerned about "locking in" the cost of too much new capacity when it might prefer to fill the volume requirement with more one-year contract volume). This layers complexity upon complexity and, so far as we know, no technical solution has yet been found that makes the adjustment in an acceptably fair and reasonable way: extra complexity has created extra arbitrariness.

Ironically, Ofgem has been given rule-making authority in the capacity market, as well as powers of adjudication in the event of disputes, which may signal a perception of lack of technical skills in DECC for such tasks, or of lack of market trust in the partnership between Government and the EMR Delivery Body (part of a privately-owned company, National Grid). The irony flows from Ofgem's earlier, extensive and detailed work on the electricity Pool's capacity mechanism which led the regulator to conclude that it was adverse to consumers' interests and that, via the NETA programme, it should be abolished.

Experience to date with the capacity market

One criticism of U.S. capacity markets is that the design is constantly subject to rule changes as policy-makers fine-tune the arrangements in attempts to deliver the outcomes they want. GB experience to date, although highly limited, is consistent with this view. As an example of what can happen, notwithstanding the intention of Government to encourage new-build CCGTs, in 2016 the developers for the largest, winning bid in the 2014 auction (for a 1.9 GW CCGT) announced that they could not meet the terms and conditions of the fifteen-year contract.[17] The capacity market rules contain a per MW exit penalty, but the developers wrote off their losses at that point. This has led the Government to explore ways of changing the rules to increase the costs of exit, although raising barriers to exit tends simultaneously to raise barriers to entry, and it is therefore a far from cost-free 'fix'.

The impacts of the termination of the contract in this case went wider than the private costs to the developer. Other new-build gas capacity might now be under construction had the developers not taken a relatively speculative position to secure a contract. At best, the arrival of new CCGT capacity on to the system has been delayed by two years.

In the 2016 auction the Government awarded 52.4 GW of capacity agreements at a clearing price of £22.50/kW/year, against an aggregate initial level of bids of 69.7 GW. The awards included 2.6 GW (about 5% of the 52.4 GW) of prospective new build on 15 year contracts. Significant volumes of small scale capacity accounted for most of this capacity, including new-build batteries, with only 631 MW made up by larger-scale CCGTs. This has led some analysts to conclude that the capacity market is still not serving to help achieve the stated policy aims of (a) encouraging closure of coal-fired power stations and (b) bringing forward the "right" amounts of new CCGT capacity to replace coal capacity.

In another policy reversal in 2016, DECC decided to hold an additional 'Early Auction', conducted in January 2017, for almost immediate 2017/18 delivery. This has brought the start date for capacity payments forward a year, from 2018/19, which has drawn commentary to the effect that it amounts to a panic reaction not only to a failure to attract bids for new-build gas, but also to the immediate prospect of significant plant closures. In December 2015, 5.1 GW of older plant failed to gain contracts in the four-year ahead auction, which immediately gave rise to uncertainties about the future status of that (still operative) tranche of plant, particularly given that public financial support has come to be seen as fundamental to plant economics.

Even plant that *does* have a capacity contract cannot be guaranteed to be commercially available. This was demonstrated in 2016 when SSE announced it was closing 1.5 GW of capacity at Fiddlers Ferry coal-fired station, despite having a capacity agreement for the plant to remain open in 2018/19. It was estimated that SSE will incur costs of £33m in capacity market penalties and £27m in capacity-agreement contract value in consequence of the

[17] Trafford CCGT, to be built by independent developer Carlton Power, announced in December 2016 that it could not meet the terms of its agreement, although it had been known some months before that the project was facing difficulties.

closure decision, but the company obviously judged this to be a price worth paying to mitigate further losses in the face of a major deterioration in the power station's economic outlook.[18]

As one commentator put it, the aim of the market was "*to provide a reliable stream of income to support the flexible thermal capacity required to back up intermittent renewable output. But so far the capacity market has had the opposite effect. Low capacity prices have contributed to the closure of existing thermal plants. At the same time the capacity market has incentivised very little by way of new capacity. So the UK's system reserve margin, rather than stabilising, continues to fall.*"[19]

The Emissions Performance Standard (EPS)

The aim of the EPS is to prevent new coal-fired stations being built unless they are equipped with sufficient carbon capture and storage capabilities to meet the designated performance standard. The Energy Act 2013 establishes a statutory limit, set at 450g/kWh until 2045, on the amount of annual CO_2 emissions allowed from new fossil-fuel generating stations. There are exemptions from the requirements for generating facilities that form part of the UK's Carbon Capture and Storage (CCS) Commercialisation Programme or benefit from European Union or Contract for Difference funding for commercial scale CCS.

The emissions standard has been set at a level that is expected not to constrain investment in the new CCGT capacity and fixing the level until 2045 was motivated by a desire to provide longer-term certainty to CCGT investors. The measure is intended to be a complement to, and a backstop for, the FiT CfD arrangements and carbon price support.

The Levy Control Framework

The various environmental measures introduced or proposed by DECC have given rise to escalating costs that have been funded in the first instance by energy suppliers and ultimately by energy consumers, rather than from departmental (financial) budgets. The resulting upward pressures on energy prices naturally attracted political attention and, as the scale of the effects increased, the Treasury eventually came to the conclusion that such "off balance sheet" funding of environmental measures should be set within some sort of framework of financial control.

In 2011, therefore, DECC and HM Treasury 'agreed' to establish a Levy Control Framework (LCF) to monitor, guide and control the costs of defined 'levy-funded schemes', developed and run by DECC. It operates by establishing 'soft caps' on expenditures (i.e. *financial* budgets) arising from a defined set of support schemes or types of support scheme, for a period of ten years from 2011/12 to 2020/21. The (financial) budget caps are necessarily 'soft' because there can be no close control of, say, CfD payments to renewable generators in

[18] Daily Telegraph *UK energy crisis deepens as SSE plans early plant closure*, 3 February 2016.
[19] Timera Energy *The UK's dual capacity markets* 4 January 2016.

a particular year: the level of payments will, among other things, depend upon wholesale electricity prices in that year.

The category of levy funded schemes does not include all support schemes that are funded by energy consumers. Notable exceptions include Capacity Payments, the Energy Company Obligation and the Warm Home Discount (a supplier discount to low-income senior citizens). Arguably these three examples are measures that are not directly consequential on environmental policy, although it can also be argued that they are indirectly entailed by it in the sense that they are 'follow on' interventions caused or partly caused by environmental policies (e.g. capacity payments exist to address security of supply problems created by ROCs and CfDs, and would almost certainly not exist in the absence of the latter schemes). The LCF also does not encompass other chains of cost causality such as re-configuration of energy transmission and distribution networks in response to changes in the pattern of energy flows consequential on the principal support schemes (FiTs, ROCs and CfDs). The control that is established by the LCF can therefore reasonably be described as 'partial and loose'.

At the outset, the annual cap under the LCF was set to rise from around £1.8 billion in 2011-12 to £7.6 billion in 2020-21 (in 2011-12 prices), but in July 2015 the Office of Budget Responsibility estimated that, given the commitments DECC had made and based on the take-up of the schemes and on differences in commodity price out-turns compared with earlier forecasts, total spending was on track to hit £9.1 billion in 2020/21.

Among other things, the LCF was intended to provide energy companies with greater information as to anticipated, future levels of Government support, to assist with companies' forward planning, but it has not proved helpful in this regard. The process by which levels of the caps were established, and the principles that might guide Government conduct in response to deviations in expenditure outcomes from the projected, capped levels, are not transparent. More fundamentally, the LCF gives no sense as to how its caps might be reconciled with the carbon budgets to which the Government has committed itself, in legislation, through to 2032. To meet both an expenditure target and a quantity target implies that a pricing target must also be hit, but that is not possible with arrangements that contemplate competitive tendering for CfDs (a process in which price is determined by a contest, not by fiat). If anything, the LCF has therefore added to policy uncertainty: it is very difficult to anticipate the future policies of a government that has set out to achieve impossible things when there is a forced encounter with realities (as there already has been).

In a review of the Framework published in October 2016, the National Audit Office concluded that:

"… the operation of the Framework has not been fully effective in some key areas. Spending and outcomes have not been linked in deliberations by the joint Treasury and departmental levy control board and reporting on Framework schemes has not supported effective public and parliamentary scrutiny of the overall costs and outcomes from levy-funded spending.

As consumer-funded spending on energy policies increases and new schemes are introduced, the Department needs to assure Parliament and the public that it has robust arrangements to *monitor, control and report on consumer-funded spending, and the outcomes it is intended to secure."*

6. The evolution of governance arrangements

From privatization to 2007

The starting point for the evolution of the governance arrangements of direct relevance to this Report is the establishment of Ofgas in 1986, which accompanied the privatization of British Gas. At the time, there were substantive questions as to whether a new, independent regulator with delegated duties and powers was required at all. One strand of thinking in Mrs Thatcher's Administration held that the tasks at hand could be performed by the Office of Fair Trading, the non-departmental government body that was concerned with competition and consumer protection across the economy.

That thinking did not win the day, however, and Ofgas was created as a utility regulator in the US mould, albeit with two 'tweaks' that proved to be of considerable, later significance. First, the initial, working philosophy was that price caps should be set on an indexed basis for a prescribed period, with reviews at the end of the period. In terms of the traditional US utility regulation model, this effectively implied a prescribed 'regulatory lag'.

Second, and more significant for longer term institutional developments, an amendment to the Gas Bill 1986, which emanated from the backbenches of Parliament, was accepted, requiring the regulator, in making decisions, to seek to facilitate competition wherever feasible. It appeared to be a small matter at the time and played little role in regulatory decisions for the first five years of the new framework, but it proved to be a seed for the subsequent liberalization process. Facilitating competition drew Ofgas into performing a new function, market development. In recent terminology used in the business strategy literature, market development came to be seen as the 'coherent action' element of the kernel of a policy strategy of liberalization.[20]

A market is simply a set of rules that governs the buying and selling of particular products or services, usually with the object of seeking to reduce the costs of exchange transactions, i.e. of trading. Parts of the rule-set of a market have major implications for competition, for example in a network sector such as gas or electricity rules concerning terms and conditions of access to pipelines are of great importance. A duty framed in terms of competition, therefore naturally faces a sectoral regulator with issues to do with market rules: it is no longer just a matter of making a price or revenue determination. Regulatory price determination is an exercise that *substitutes* for a flawed market exchange process[21], but the new duty, however understated in the first legislation, points to a different exercise, developing rules that *complement* and support or improve market exchange processes, *inter alia* in relation to the ways in which they determine prices. Since the initial rule-sets were minimal – British Gas was a vertically integrated monopoly with power to do more or less

[20] Richard Rumelt, *Good Strategy, Bad Strategy: the Difference and why it Matters*, Profile Books, 2011.
[21] Price determination is monopolistic in both contexts: the role of a monopolistic business is taken on by a regulator with similar or, more usually, greater market power. The substitution is made to change the criteria that are used to guide the ways in which the economic power is exercised.

what it wanted – a large, potential agenda was therefore opened up. Market rules, including rules for access to networks, had to be developed from a near zero base.

When the electricity regulation body, Offer, was established in 1990, Government policy had come to place a greater weight on the competition objective, which was more prominent in the privatization legislation. Indeed, Offer was given target dates for staged market opening that would enable retail competition to be sequentially extended from large industrial end-users (1990) to other commercial and business customers (1994) and to households (1988). Ofgas, meanwhile, had to struggle against the statutory limitations of its initial remit (set before the shift in policy priorities) to achieve similar outcomes although, in the event, it achieved the first household market-opening stage faster than Offer: by late 1996 households in the South West of England could choose their gas supplier. The two energy regulators were merged at the end of the decade, creating Ofgem. The formal legislation mandating amalgamation was the Utilities Act 2000, but *de facto* the integration was started a little earlier by the device of appointing the same person, Sir Callum McCarthy, as Director General of both Gas and Electricity Supply.

There has been only one subsequent adjustment of note. There was a new Competition Act in 2002 which aligned UK competition law with that of the EU and which afforded supervisory and enforcement responsibilities (in so far as they pertained to onshore gas and electricity matters) to Ofgem, as well as to the Office of Fair Trading, via arrangements referred to as ‘concurrency’. In effect either body could take enforcement action under both UK and EU law, with the exception that cartel behaviour was reserved for the OFT. The policy of the Government was to let the relevant bodies sort things out between themselves, just as Ofgem and the FSA were left to co-ordinate their activities when cross-cutting issues about wholesale energy trading arose. There was considerable debate about the merits of concurrency when it was first introduced, but that has faded over time and the arrangements appear to have worked satisfactorily.

Perhaps the key point in these developments was the underlying policy recognition of three distinct regulatory functions in the energy sector:

- The traditional regulatory function of price determination for enduringly monopolistic activities (substituting an ‘administered’ price for a ‘market price’ when competition is absent).
- Market development: sector-specific rule-making, supervision and enforcement focused on promoting market exchange processes as the preferred means of determining final outcomes.
- Enforcement of general competition law.

Prior to 2002, the first two functions were allocated to the sectoral regulator(s). Post 2002, Ofgem has had responsibilities and powers across all three functions.

In general, the sponsoring government department for the energy sector, then the Department of Trade and Industry (DTI), took a back seat in relation to the performance of these functions. Ofgem had extensive rule-making powers (typically through amendments to generator and supplier licences) and, later, Competition Act powers to intervene in the market should it believe that competition laws were being violated. Other important aspects of market development were managed through a range of sectoral codes, largely on a self-regulatory or self-governance basis, with Ofgem playing promotional and adjudicative roles.

There were exceptions when contemplated reforms required significant legislative change, the major examples being the NETA reforms and the integration of the electricity system in England and Wales with the Scottish system, and these were typically managed on a joint Ofgem/DTI basis. Since aims and objectives were shared, the processes worked about as well as any major reform exercises can reasonably be expected to work. For example, while there was some delay in the launch of NETA (from 2000 to 2001), the successful completion of a process involving extensive re-adjustments of contracts and a major overhaul of IT systems compares very favourably with comparable, large-scale Government exercises in other sectors, where major failures have been a recurrent feature of GB experience (the later roll-out of smart-metering arrangements falls into this latter category, see Annex).

Turning to environmental policy, the major institutional development of the period was the establishment of the Environment Agency (EA), created by the Environment Act 1995, which came into existence on 1 April 1996. It is a ‘conglomerate’, non-departmental government body that deals with a wide range of administrative functions in areas such as conservation, fisheries, flood defences, pollution prevention and control, land quality, planning, radioactive substances, waste, water quality and water resources. When formed, it took over the roles and responsibilities of the National Rivers Authority, Her Majesty’s Inspectorate of Pollution, and the waste regulations of local government authorities in England and Wales.

The EA was therefore not focused on the three functions characteristic of Ofgem and other sectoral regulators, i.e. price/revenue control, market development, and competition law enforcement. When the ROCs arrangements came to be introduced, it was the DTI and its Secretary of State who led on policy and rule-making, not the EA, just as had been the case in relation to the earlier NFFO. Moreover, when it came to the administration of the ROCs arrangements, the DTI turned to Ofgem, not to the EA with whose administrative culture it was arguably a better fit, but which had a different sponsoring department, the Department of the Environment, Food and Rural Affairs (Defra).

Similarly, when climate change concerns started to take root at the most senior level of government, Tony Blair, the Labour Prime Minister, stressed the need for global action on climate change in a 2003 DTI White Paper, *Our Energy Challenge: Creating a Low Carbon Economy*, not in a Defra White Paper.

As discussed, the ROCs development changed the nature of part of Ofgem’s activities in ways that were unwanted by the regulator, and Ofgem responded by ring-fencing these more-EA-like, administrative tasks. The most significant point is that the developments effectively introduced climate change policies, rule-making and administration into parts of wider governance arrangements (DTI, Ofgem) that had previously not been involved with environmental policies. The structure of governance in respect of environmental policy thereby became more diffuse.

The EA did come to acquire administrative responsibilities for climate change policies when the EU ETS was established, although here again the policy and rule-making functions lie elsewhere, in this case at EU level. The upshot of this was that, post-2005, one of the two flagship climate change policies was administered by the sectoral regulator Ofgem and one by the EA.

2007 onwards

The establishment of the EU ETS provided an obvious opportunity for the government to follow a policy strategy based on market development, informed by the successful institutional arrangements that had evolved in energy policy. The EU carbon market was itself at a primitive stage of development and there was much further work to do. Additionally, EU ETS applied only to major emitters of GHGs and a considerable fraction of emissions was accounted for by economic activities that were not covered by the scheme. The government could therefore have set about extending the scope of carbon trading and pricing more generally, complementing rather than duplicating or (worse) substituting for the EU ETS arrangements. The obvious institutional innovation would have been the establishment of a Climate Change Authority or Commission, with rule making and enforcement duties and powers in respect of GHG emissions markets across the wider economy. Policy integration at the sharp-end of things would then have been achieved via (a) the carbon price and (b) regulatory agencies talking with one another (as Ofgem and the FSA did in relation to energy trading and as Ofgem and the OFT did in relation to the enforcement of competition law).

This, however, was a road not travelled and it exists today only as counterfactual history. The 20-20-20 commitments drew cognitive attention to targets, i.e. to quantities not prices, and the policy that evolved was based on ever finer breakdowns of 'carbon budgets'. Thus, as recounted above, at the fork in the road encountered in 2007, GB policy took the fork signed 'central planning', not the fork signed 'market development'.

The institutional adjustments that occurred were first focused on developing a stronger priority for climate change issues in government Departments, raising familiar questions as to how co-ordinated policies could be developed across a governance structure in which different Departments: notoriously pointed in different directions; tended to give high weight to their own particular agendas; and, in a long British Civil Service tradition, tended to be populated with staff who were relatively transient. This was followed later in 2008 by the creation of a new Department of Energy and Climate Change (DECC) and the Climate Change Committee (CCC), which, though formally advisory in nature, proved to be highly influential on policy matters.

DECC took over the energy policy responsibilities that had previously fallen to the DTI – which itself had been subject to organizational adjustments and associated changes in name, first becoming the Department for Business, Enterprise and Regulatory Reform (BERR) then later the Department for Business, Innovation and Skills (BIS) – and bundled them with fast expanding climate change responsibilities. At this point, it can be said that energy and environmental policymaking became ‘organizationally integrated’ (within DECC), just as policy coherence (policy integration) was most decisively lost.

This is a familiar conjunction in the history of economic policy and only the specifics of its pathology tend to differ across the contexts in which it appears. In this case, it is straightforward to see one of these more specific features. Whilst electricity and gas (on which Ofgem was focused) are major contributors to GHG emissions, they are far from the only significant contributors, and the organizational linkage between Energy and Climate Change tended to give DECC a particular tilt toward focusing on these (electricity and gas) sub-sectors: they lay within its own remit and, unlike other sectors and sub-sectors of the economy, no longer had a distinct, sponsoring department of their own which might have had interests in some of the broader trade-offs of relevance for the carbon budgeting processes.

The lack of both ‘vertical’ (independent agencies) and ‘horizontal’ (engagement with other Government departments) checks and balances on the development of climate change policy was conducive to the development of unfettered ‘politicians logic’ on the climate change side of things, i.e. quick commitment to *perceived* ‘solutions’ rather than to algorithmic discovery of better solutions. The decision-making structure was hierarchical or top-down and mimicked the control process that a Treasury or Finance Ministry uses to control the resources available to spending departments in government, although the budgets were carbon, not financial, budgets and the control that was sought was not over the conduct of a small number of departments, but over a much, much larger domain of economic activity. Together DECC and the CCC acted like a Treasury that specified not only how much a Department could spend, but also precisely how the money was to be spent (specifically, how a higher-level carbon budget was to be broken down into lower-level carbon budgets).

DECC did at least recognize the limits of its own capabilities when it came to the implementation of EMR and it turned to National Grid (NG) for help. An EMR Delivery Body was set up as a distinct entity within NG. Its role was/is to produce annual electricity capacity reports for government, to advise on capacity requirements, and to administer and implement key elements of the capacity market and the CfD regime.

This was a significant change in the governance framework, with the EMR Delivery Body acting both as the Government’s expert adviser for some capacity procurement decisions <u>and</u> with the parent company, National Grid, acting as a for-profit principal for other capacity purchase decisions, i.e. for short-term system balancing purposes. It gave renewed prominence to questions about conflicts of interest which had been in the air since the NETA reforms, when Ofgem had opted for what it called a ‘strong system operator’ model as part of the new market design. The model afforded considerable discretion for NG to act in response to immediate short-term imbalances in the name of security of supply, but put tight and narrow bounds on the domain of that discretion so as to prevent the exercise of undue monopolistic influence on market processes and outcomes. The concerns were focused on the possibility that any expansion of NG’s discretionary domain would see the emergence of undue influence on – and, in the limit, ‘capture’ of – the market. Market participants at the time of NETA were particularly sensitive to this risk and made their views known.

The capacity market brought this issue back into the foreground and DECC sought to resolve the problem by means of physical separation and ring-fencing of the EMR Delivery Body from NG system operations. How well this works remains to be seen, but the source of the risks is easy to see. *De facto*, a government department is in close partnership with another body in relation to activities that are highly important in influencing market outcomes. That other body is part of a private company that has interests which are affected those by market outcomes. Neither the separation arrangements nor conduct more generally are monitored or supervised by an independent third-party (such as a regulator or a competition authority). Whilst we must await the outcome of the experiment, it is safe to conclude at this early stage that the institutional design necessarily leads the parties into temptation.

Evolution of the role of Ofgem

To fully understand the effects of the climate change policy developments on the governance of the electricity and gas markets it is necessary to consider how Ofgem was affected by them. The extent to which the governance arrangements in the energy sector, and particularly the relationships between DECC and Ofgem, provided a basis for effective regulation of the market is a matter that the Competition and Markets Authority considered at some length in its major 2016 report on the energy sector, and the CMA made a number of recommendations to improve both market governance and outcomes for consumers.

From around 2006 onwards, retail prices had come under strong upward pressures, initially in consequence of sharply rising world commodity prices, but also over time from what have been labelled suppliers' "non-commodity costs". This is a euphemism for the costs resulting from the various government schemes that are charged to suppliers and which suppliers then recover from their customers. In large part because of these upward pricing pressures, DECC began to take a much more active interest in Ofgem's oversight of retail prices than had its predecessor government department. This ultimately led to changes being made to Ofgem's duties in the 2010 Energy Act.

Ofgem and its predecessors had for some time been subject to sequential changes in duties and responsibilities which had invariably been in an expansionary direction. Its growing list of objectives was, therefore, slowly eroding the 'golden rule' of independent regulation, that delegated objectives should, so far as is possible be kept simple, specific and hierarchically organized, so that the regulator is not asked to engage in trade-off judgements that properly lie in the domain of Government and Parliament.

The significance of this issue was highlighted in a Report on Economic Regulators published by the House of Lords Select Committee on Regulators on 13 November 2007. The Committee's findings on the performance of independent regulators, based on the considerable body of expert reasoning and evidence that it had heard and read, were generally favourable (with the exception of Ofwat, the water services regulator, which was chided for not being sufficiently pro-active in market development) and the Committee recommended further development of the know-how embedded in the existing institutional arrangements. The Report nevertheless opened – at paragraph 1.1 under the heading *Regulators' statutory* *remits* in Chapter 1 *(Summary of Conclusions and Recommendations)* – with a lead conclusion that: *"Independent regulators' statutory remits should be comprised of limited, clearly set out duties and … statutes should give a clear steer to the regulators on how those duties should be prioritised. Government should be careful not to offload political policy issues onto unelected regulators."*

DECC chose, however, to ignore the advice of Parliament's upper chamber and the 2010 adjustments to Ofgem's statutory remit were qualitatively different from the background erosion that had previously occurred. While they preserved Ofgem's principal objective of protecting the interests of existing and future customers (now buttressed by multiple subsidiary duties, which legal advice tended to suggest were not actually subsidiary and could, at the regulator's discretion, be given greater priority) the regulator's promotion of competition duty (which had played a critical role in the liberalization process) was downrated. This move was supported by public pronouncements from the Secretary of State at DECC (Edward Miliband) that competition was not sufficient to protect customers and by declarations that DECC would take backstop powers to intervene in the market if Ofgem was not, in DECC's view, sufficiently aggressive in resisting price increases.

Here, therefore, we have a prime example of the tendency of intervention to expand almost inexorably, creating layer upon layer of distortions. DECC's various interventions served to increase retail energy prices. DECC then responded by putting pressure on Ofgem to bear down on the price increases the Department was causing, threatening to intervene itself if Ofgem failed to act in this way. The end of this pathway, which may soon be reached in GB, is retail price control and the ending of retail energy competition in any normal form.

The CMA later (in 2016) observed gently that these developments could create a perception that Ofgem was not independent and that they had the effect of creating ambiguity for Ofgem about how best to protect customer interests. The CMA also concluded, more strongly, that it created a lack of clarity in Ofgem's duties and risked undermining Ofgem's effectiveness in protecting customers through competition. Elsewhere in its Report the CMA makes it abundantly clear that the principle source of increasing retail energy prices, other than hikes in world energy prices, was, in fact, DECC itself.

The other change in the 2010 legislation was to introduce the specific requirement that consideration of energy consumers' interests should include consumers' interests in carbon reduction. The principal objective of Ofgem became *"to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or transmission systems. The interests of such consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases …"* This created a plethora of problems for the regulator, which can be glimpsed by considering some of the questions that it now has to ask itself: Could it be concluded that the adjustment to its primary objective required no substantive change in its decision making, because carbon reduction was a general interest, not specific to the consumption of electricity and gas, and because, in the energy sector, the relevant valuations were in any case already built into costs that it can take as given, such as suppliers' "non-commodity costs"? Or should it assess consumers' interests on the basis of EU ETS carbon prices? Or maybe it should derive valuations from CCC carbon budgets (by assuming that the CCC has special insight into consumer valuations)? Or alternatively should it proceed on the basis of the implied carbon valuations of the various payment rates set out in the ROCs or FiTs arrangements? Or should it set all these valuations aside on the ground that, self-evidently given their radical differences, most of them must be seriously misleading guides to the interests of energy consumers in carbon reduction and seek to do its own market research to arrive at its own, independent assessment?

Before privatization, one of the principal critiques of state-owned enterprises was that, by giving the managers of public corporations ambiguous, 'public interest' objectives, the internal governance and management of those organizations was itself undermined. The issue was pithily expressed by Sir Peter Parker, then Chairman of British Rail, in a speech at Oxford University in the late 1970s in which he said that it (the Chair of British Rail) was the first job that he had taken in his lifetime where he had no idea of the criteria by which his and his colleagues' performance would or should be judged. GB regulatory policy has now been returned to somewhere in the vicinity of that state of affairs.

In relation to energy prices, the CMA's 2016 Report noted that "institutional pressure" from DECC is likely to have had a direct impact on Ofgem, in addition to the indirect impacts of the Energy Act 2010 reforms. This, in the CMA's view, had the effect of creating confusion about Ofgem's role, which in turn deflected and further marginalised Ofgem. The wider importance of this marginalisation was that Ofgem should naturally have been the guardian of competition and value for money, providing a counterbalance to the CCC/DECC axis. It did not perform this role over this period. The CMA concluded that the relationship between DECC and Ofgem was sub-optimal, regarding both policy design, where Ofgem's role was unclear, and in policy implementation, and that there was insufficient coordination between DECC, Ofgem and industry.

The reason that Ofgem's role in rule-making and enforcement became unclear is that DECC effectively took over both policy (down to a fine degree of granularity) *and* implementation, taking charge not just of revisions to the legislative framework, but also of the detail of electricity procurement, which, among other things, entailed DECC designing and writing contracts with generators. The position was in stark contrast to that during the design and development of the New Electricity Trading Arrangements (NETA), introduced a decade earlier, when Ofgem had been the senior partner in programme design working alongside both the government department of the time (DTI) and market participants, taking a leading (but not an exclusive) role in the necessary rule-making, but staying well clear of telling generators and suppliers precisely how they should trade electricity.

Where things stand today

There was, however, a further twist to the tale, which should come as no surprise to anyone familiar with the business of government or the historical record of central planning or the literature of Ancient Greece, although as usual the timing of the twist contained an element of surprise and was linked to the occurrence of unrelated events. On taking office on 13 July

2016 in the wake of the Brexit referendum and in a new round of organizational musical chairs, the incoming Prime Minister, Theresa May, immediately abolished DECC and shifted its responsibilities for energy policy and climate change policy back to an institutional descendant of the Department of Trade and Industry, named the Department for Business, Energy, and Industrial Strategy (BEIS). From an organizational perspective at least, Hubris met its usual fate at the hands of Nemesis.

The Levy Control Framework and downward revision of small-scale FiT rates had already signalled a shift in political priorities towards concern about the affordability of energy supplies and in presenting some rather general ideas (in January 2017) about a new industrial strategy BEIS noted that with the capacity market having helped to make progress on security of supply and with climate change policy *"settled"*, *"two important areas of energy policy require a higher priority"* in the years ahead. These were *"the affordability of energy for households and businesses, and securing the industrial opportunities for the UK economy of energy innovation"*. Noting also that ten years had passed since the Climate Change Act, BEIS added that the overall framework of policy *"requires updating"*, without offering any specific information as to what this might entail or how a requirement for updating fits with a notion that policy is "settled". Bold statements about global leadership in carbon reduction are now noticeably absent, however: the political rhetoric following the Brexit referendum has shifted to global leadership in free-trade. The Anglo-Saxon passion for leadership remains, but the object of its desire has apparently shifted, for the moment at least.

Notwithstanding that the words 'climate change' have been dropped from the Departmental nameplate and that BEIS has emphasised "affordability" and "innovation", what the recent developments portend for the future is highly uncertain. There could be an attempted, major shift in policy direction towards market development in both energy and climate change policies or it could be that there will be an emergent industrial strategy based around a 'planned' transition to a low-carbon economy, underpinned in the energy sector by an enhanced emphasis on nuclear power. The UK Government is preoccupied with the Brexit process and that will likely to continue to be the dominant political priority for some time ahead. Whilst DECC is now an ex-Department, its former inhabitants live on, the CCC has not been closed down, and the carbon budgeting approach has not been abandoned. There is much still to be settled.

7. Assessment: The broad effects of lack of policy integration

Given the number of energy and climate change initiatives over the past thirty years, a full and detailed assessment of their individual effects is an impossible exercise. As should be apparent from the narrative, each step along the way creates new issues to be dealt with: regulation begets regulation in ways that can quickly be become incoherent. One measure creates unwanted side-effects, which give rise to further measures to address/fix them, which in turn have unwanted side-effects – not infrequently characterised by some unravelling of intended, wanted effects of the first measure – and the process is repeated.

There are, however, a number of high level observations that can be made about the consequences of the policy history, not least because of the findings and conclusions of the Competition and Markets Authority that emerged over the course of a nearly two-year long Energy Market Investigation and that are set out in a Report extending to over 1,400 pages, published on 24 June 2016.

Investment

As indicated, prior to privatization investment in electricity generation was centrally planned, subject to very heavy political influence and seriously inefficient in economic terms: for example, on a like-for-like basis, capacity costs for new-build plant were very substantially higher in GB than in comparator jurisdictions. Privatization and the establishment of a competitive wholesale market very quickly closed that gap.

Twenty-five years later, in November 2015 the Secretary of State at DECC in the new Conservative Administration, Amber Rudd, said, *"We now have an electricity system where no form of power generation, not even gas-fired power stations, can be built without government intervention."* That was a statement of fact, not of politically fashionable 'alternative facts'. In relation to investment decisions, therefore, policy developments over the past 10 years have returned the GB energy sector to a situation similar to that pertaining in the 1980s and earlier decades, when state-owned monopolies dominated the economic landscape. Efficiency in investment and average capital efficiency (cost per MW) have deteriorated, the most obvious illustrations being the large-scale development of expensive offshore wind capacity and the current commitment to the massively expensive Hinkley Point nuclear project, both in the face of much lower cost, more quickly available, alternative methods of carbon reduction.

Hinkley may yet be cancelled and, even if it goes ahead, there is a substantial risk that it will either never become operational or will suffer severe operational problems (it is the second-of-type of a French design, the first of which, at Flamanville, is not yet operational, is substantially behind schedule, not least due to an ongoing investigation of potential construction flaws, and is now subject to political and economic uncertainties associated with Brexit). Meanwhile, other investment in generating capacity, particularly CCGTs, is held back by the possibility that a large tranche of new base-load capacity will come on to the system (if Hinkley does, eventually, 'go to plan'). As recounted earlier, notwithstanding the introduction of a new capacity market the Government has been largely unsuccessful in stimulating the new-build CCGT capacity that it perceives to be required to ensure security of supply.

Mrs Rudd was also clear that she would like to move away from the current position, by allowing investment decisions to be 'market determined'. That, however, is an aspiration, not a fact, and, having taken the central planning fork in the road in 2007, the cross-country route back to the market development road is not easy to map out: the terrain looks rough.

In fact, Mrs Rudd's sentiment was shared by all DECC Ministers from 2010 onwards. They consistently expressed a desire for, and a longer-term intention to achieve, a return to the path of market-determined outcomes, including in relation to investment, even as they were developing and implementing measures (e.g.s. EMR, nuclear policy) that were taking public policy, market structures, and governance structures further and further down a divergent path. Whilst this may appear idiosyncratic at first sight, it is not: it is what tends to happen more generally when a coherent. long-term policy strategy ('policy integration') is absent. It is a particular example of Orwell's political schizophrenia.

Foreclosure of innovation

The history of mankind in the face of major concerns about resource adequacy – and, from an economics perspective, that is the nub of the climate change challenge – is a history of invention (of methods and of institutions). There is a long string of examples, the most enduring being the transformations in agriculture in response to pressures of population on land resources, including transformations in land ownership rights and markets as well as innovations in production methods (i.e. successive 'agricultural revolutions'). In public policy, a prominent recent example on a narrower front is radio spectrum. Perceived scarcity of spectrum led to market development (spectrum pricing, spectrum trading) and today the physically limited resource provides a capacity to accommodate a quite massively increased demand at 'affordable' prices.

Given the lessons of history, it has been a major defect of the GB approach to climate change that it has foreclosing effects on innovation. By depressing the EU ETS carbon price and privileging existing known methods of carbon reduction relative to future possible methods, it has suppressed incentives to develop alternatives to the administratively chosen, favoured/privileged technologies. At the micro-economic level, this has led to a consistent stream of complaints from developers of alternative methods of achieving carbon reduction, to the effect that their activities have been disadvantaged by not being included in the extensive financial support mechanisms that have been provided to others.

More generally, the costs incurred by the GB approach have pre-empted resources and institutional effort that might have better have been spent on supporting research and development across a wider range of future technologies. This is not simply a matter of putting more public resources into basic research, important though that is. The land and spectrum scarcity precedents were characterised by property rights reforms at an early stage of market development. There is scope for IPR reform that could help to increase the effectiveness of discovery processes directed at carbon reduction, for example by partly replacing the existing predilection for providing financial support on an *ex ante* basis – where the central planner has a large hand in determining financial allocations – with a greater emphasis on strengthening *ex post* incentive systems, where rewards are paid later on the basis of proven success (a characteristic of the incentive structure of existing property rights systems based on patents and copyright). Prize systems are an alternative way of doing this, suggesting that they are worthy of exploration as part of a carbon-market development process that is still in its very early stages.

Finally, there is perhaps the most fundamental, foreclosing effect of all monopolistic decision processes, cognitive foreclosure. These processes have a tendency toward tunnel vision and an aversion to entrepreneurial and other forms of disruptive or heretical thinking. Orwell is again the leading authority here: in *1984* the phenomenon is pinpointed in Emmanuel Goldstein's *The Theory and Practice of Oligarchical Collectivism*:

"[It] *means the faculty of stopping short, as though by instinct, at the threshold of any dangerous thought. it includes the power of not grasping analogies, of failing to perceive logical errors, of misunderstanding the simplest arguments if they are inimical to Ingsoc, and of being bored or repelled by any train of thought which is capable of leading in a heretical direction.* [It]*, in short, means protective stupidity."*

The existence of this tendency explains again why the 2007 decisions were so significant. If a high-level objective of mitigating climate change can be taken as a given, what happened was the development of a policy strategy that took carbon budgets as its operational sub-objectives, with the Government promising to underwrite the costs of achieving those sub-objectives, whatever they were (a promise that could not credibly be sustained in a democracy). Once the course was set, defensive stupidity has been a barrier to its abandonment.

The alternative strategy, much more congruent with established, successful energy policy, would have been to adopt the proximate objective of developing carbon markets. Under market arrangements, consumers would, other things equal, be attracted toward lower-carbon consumption patterns and producers/suppliers would be incentivised, via competition, to seek out lower-carbon methods of supply. Well-functioning markets are not foreclosed to entrepreneurs, innovators, heretics and the like: they are open to all ideas and can simultaneously test out multiple possibilities (a form of parallel, rather than sequential, information processing). Where it emerges, defensive stupidity has difficulty in becoming entrenched – it can be bypassed by alternative information processing tracks – and is quickly eroded.

The key difference between the two strategies is that the market development path recognizes that the key to achieving sustained carbon reduction in a democratic society is to make it as cheap as possible, and that is what GB environmental policy has conspicuously failed to do.

Energy prices

The costs of loss of policy integration are most clearly signalled by their effects on energy prices. Arguably the most telling of the very many numbers in the CMA Report appears at paragraph 18.61, under the sub-heading *Impact of policy decisions on prices and bills*, where it is said that:

"Government policies – particularly those designed to reduce harmful greenhouse gas emissions – are having an increased impact on energy prices and bills (on the basis of currently announced plans, the cost of such policies will amount to 37% of the retail price of electricity paid by households in 2020)."

The great bulk of this estimated effect is attributable to the climate change policies, and it can be noted that a 37% share of the price in 2020 implies prices that are 59% higher than they would be in the absence of the costs imposed by such policies, other things being equal. The CMA, an organization generally known for a tendency toward understatement, referred to the projected price/cost increase as "dramatic".

Of course, other things would not have been equal: there is a counterfactual to consider. It is not something that the CMA itself explored in any depth, but the main characteristic of the counterfactual the Authority had in mind is made plain in the Report at paragraph 18.68:

"We consider that an efficient approach to tackling climate change is likely to be based on a single carbon price across the economy, at a level consistent with the damage caused by greenhouse gas emissions. This should result in the least cost approach to reducing emissions, minimising costs for customers in aggregate."

In GB right now there exists a myriad of carbon prices/valuations: the costs to energy customers (of achieving a given level of carbon reduction) are consequentially very far from being minimized, even on the basis of the current state of technological knowledge, before taking account of the implications of a chaotic pricing structure for incentives for cost-reducing innovation.

The effects are visible in international comparisons of electricity prices, since it is the electricity price that has been most affected by the climate change policies. These show a deteriorating trend for GB, although it will likely have been temporarily interrupted by the post-referendum depreciation in sterling. Thus, for example, whereas UK industrial prices fell to below the EU[22] median level in the post-NETA period (the end-stage of liberalization), in commenting on the last pre-referendum data BEIS reported that: *"average UK industrial electricity prices including taxes for medium consumers for the period January to June 2016 were the third highest in the EU 15 and were 35% above the estimated EU median of 7.3 pence per kWh. The UK price for medium consumers excluding taxes was the highest in the EU 15 and was 81% above the estimated median price of 5.2 pence per KWh."*

BEIS also reported that UK industrial electricity prices were more than double those in the US in 2015.

What the levels of a single carbon price might have been in the relevant counterfactual, and what the effects might have been on household and industrial energy prices, must remain open questions, but two further points can be noted. First, all the EU 15 countries participate in the ETS, and hence a closer approximation of GB to the EU median price might be an expected characteristic of the counterfactual. Second sale of emissions certificates for schemes like the EU ETS is a source of public revenue and the level of revenue is higher the higher is the carbon price. This revenue – which is a pure economic rent and hence a highly efficient source of public finance – can be used, if a government so chooses, to offset the income distribution effects of, say, any household energy price hike caused by an increase in the carbon price, *including by methods linked to payments for energy*. A single, high carbon price does not necessarily have to have a large effect on the *average* energy prices faced by households: in technical jargon, retail energy pricing can be non-linear and there are a number of different ways in which such pricing structures could be supported by public policy, without interference in the determination of average prices.

Security of supply

[22] The EU then comprised fifteen Member States, now referred to as the EU 15.

There has been increasing media coverage over recent years about threats to security of supply, often introduced by the question "will the lights stay on?" Whilst it is certainly the case that reserve margins in the electricity system have fallen to very low levels by recent standards, and whilst there is a strong case for concluding that Government policy measures have, at least in the first instance, increased risks to security of supply, the chains of causality are more subtle than is often recognized.

A simplistic argument might claim that there is a direct causal link between promoting renewables via CfDs and a fall in flexible thermal capacity on the system to levels where it becomes insufficient to provide the required responsiveness when, for example, demand is high and the winds are not blowing. Since it is inevitable that less fossil-fuel plant will be available on the system if the renewables (or nuclear) share is increased, the key question is simply: has the level of such capacity fallen <u>too far</u>?

The answer depends in part on the size of the system, and the GB electricity system is a large one. Considerable volumes of thermal capacity can potentially be traded, even at high levels of renewables penetration. Tight system conditions can be expected to lead to high spot prices, but hedge trading can provide a means of mitigating volatility for end consumers. Moreover, the short-term balancing arrangements that Ofgem put in place at the time of the NETA reforms are robust by international standards.

Thus, when projected reserve margins are very low, National Grid has considerable discretion to take such short-term actions as it deems necessary for system balancing purposes, for example by increasing 'supplementary balancing reserve' and contracting for very-short-notice demand-reduction options. These options have been used in recent winters. In 2010/11 the spare/reserve capacity margin stood at around 14%, but by 2013/14 it had fallen to around 6% and by 2015/16 and 2016/17 to less than 2%. However, NG contingency measures taken in 2014/15, 20015/16 and 2016/7 have held response capacity steady at around 6% since 2013/4.

The major security of supply issues are therefore not directly to do with CfDs and the promotion of renewables as such, policies whose major negative consequences occur principally via consumer price effects, but rather with two other factors. The first of these is policy uncertainty. GB policy is still on the road signed 'central planning', but politicians are increasingly signalling their discomfort as to where it has led, without simultaneously providing any coherent account of what they will do next. In such circumstances, prospective developers of new CCGT plant can see other technologies receiving relief from the uncertainty via long-term contracts and have naturally been reluctant to put money on the table, for fear of being mugged.

Second, the EMR response to the policy uncertainty conundrum, the capacity market/mechanism, could potentially increase, rather than reduce, security of supply risks. The capacity market was the aspect of EMR that took Government away from simply planning for carbon reduction and into the realm of planning for security of supply, i.e. into a technically challenging area of energy policy.

The difficulty is that, in taking responsibility for ensuring security of supply, DECC has taken responsibilities *away* from market participants. If Government contracts for capacity to cover periods of system stress, suppliers have less incentive to contract for themselves. Liquidity in traded markets then suffers and generators, as well as suppliers, tend to fall back on reliance Government actions, particularly since Government itself claims to be 'responsible'. At bottom, this is a type of moral hazard problem, not entirely unlike the sort of problem that triggered the financial crash in 2008.

As in prudential banking supervision, the moral hazard issues can potentially be addressed by placing extra obligations on suppliers, i.e. by a further layer of regulation, but that has not been the approach followed and the currently existing mechanisms depend on a single, monopolistic decision maker. This reliance is the root cause of an unwanted risk. There is lack of cognitive diversity in decision making and one mistake can, because market-wide outcomes depend so heavily on one decision maker, have far reaching consequences. Put generally, the system becomes less 'robust' and more 'fragile'.

In energy, the institutional fragility of a process dependent on a single-decision maker was illustrated by the collapse of the Northern Ireland Government in early 2017 following one mistake in determining an administrative price/payment rate for the Renewable Heat Incentive (RHI) scheme (the scheme is summarised in the Annex). In this case, security of energy supply was not threatened, but civil peace could be said to have been put at increased risk. In relation to the management of peak capacity available on the electricity system, it would be the risks of power failure that would be affected by the single mistake.

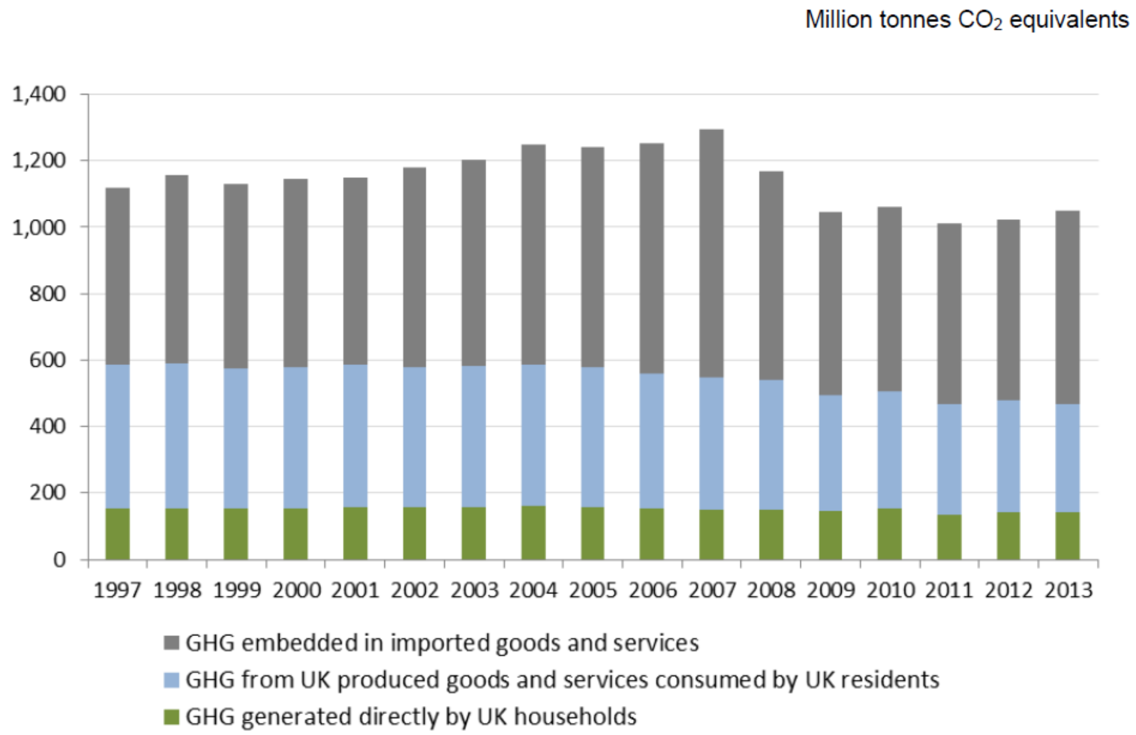
The likely response to this situation will be that BEIS will take a very conservative view of the volume of capacity for which it should contract in the capacity market. The evolving outcomes in respect of security of supply are, however, a matter of conjecture: it will depend upon a balance between political fearfulness (of the consequences of supply failures) and an increased risk of 'mistakes'. The only safe conclusion is that the trade-off between energy prices and security of supply has deteriorated in consequence of the policy decisions made. That is, whatever level of security of supply is established, whether turns out to be higher or lower, it will entail higher energy prices for consumer prices than could otherwise have been achieved.

Institutional effects

The lack of integration between energy and environmental policies has had damaging effects on the institutional capacity required for effective performance in both areas of public policy. On the climate change side of things, there is no independent, rule-making authority that can take the lead role in carbon-market development in the way that Ofgem did in the various stages of energy sector liberalization. One aspect of the harm arising from such an institutional void can be seen by looking not at GB emissions of GHGs, but at GB's carbon footprint, i.e. emissions corrected for trade effects, which can be taken as a measure of the contribution of GB's *consumption* of goods and services to global GHG emissions:

As can be seen from Chart 3, there has been a significant fall in the estimated footprint between 1997 and 2013 [23], although in percentage terms this has been a much smaller fall than the fall in GB emissions. The biggest contribution to the reduction in the footprint was between 2007-9, which it can be inferred is largely attributable to the recession of that period, when UK GDP and UK imports fell sharply. The major contribution to the shrinkage of the footprint in this short period is clearly attributable to GHGs ascribed to (embedded in) imports. Over a longer period, however, the GHGs embedded in imports have increased, by about 10% between 1997-2013.

Chart 3. The UK's carbon footprint, 1997-2013



Source: Defra statistics.

More generally, the Chart shows the high salience of the trade effects, which accounted for about 55% of the GB footprint in 2013. These effects have nevertheless been something of a backwater in GB climate change policy, whereas the existence of an independent environmental regulator with a mandate that gave prominence to market development (both domestically and internationally) and an objective that at least made reference to GB's carbon footprint would, with high likelihood, have given them higher priority.[24] This

[23] These are the earliest and latest dates in the series currently published by Defra, there being typically a lag between the estimation of UK emissions and the subsequent finalisation of adjustments for trade effects.
[24] One policy and rule-making area that has been underexplored is border adjustment for carbon content, where there exist both unliteral and multilateral options. Interestingly, there is a coherent argument that unilateral action is, in this case, likely to be a strategic complement to multilateral action, i.e. there are incentives to follow

(institutional/governance) point is perhaps the most of the important of the lessons that environmental policy failed to learn from the 'British Electricity Experiment'.

In relation to energy policy, the same institutional void in environmental policy has served to undermine the effectiveness of Ofgem, which is now hamstrung across a range of its potential activities. Rather than having another institution with which it can interact horizontally and discuss and co-ordinate on market development or enforcement issues where there are shared interests, Ofgem finds itself at the bottom of a 'vertical' structure, at the end of multiple chains each starting somewhere different in the kaleidoscopic jumble of central government. Metaphorically, the master chef has been demoted to delivery boy/girl status.

Climate change policy performance

Chart 3 illustrates one of the major flaws in GB policy, but an advocate for what has been done might point back to Chart 2. If the provisional estimate for 2015 emissions is added to the Chart it would show a further sharp fall, indicating that emissions from electricity generation have fallen by about 50% over the twenty-five year period starting in 1990. While substantial costs have been incurred, it might be claimed that policies have at least been highly successful in meeting carbon reduction targets.

An opposing advocate might reply with two points:

- Around 50% of the total carbon reduction over the period was achieved in the 1990s and it is attributable to the earlier energy policy of liberalization, not to the later climate change policies.
- Demand for electricity is a function, *inter alia*, of income and price, both of which were subject to major shocks later in the 25-year period. First there was the severe recession, triggered in 2008. Second, real energy prices rose quickly and substantially from around 2006 onwards (the CMA noted a 75% increase in real terms for household prices of electricity between 2004 and 2014). Adjusting for these effects, the carbon reduction attributable to climate change policies in the later years is much more modest in scale.

There is, however, no need to sit in judgment on these points of advocacy: since 2005 GB's contribution to global GHG emissions has been, to a good first approximation, determined by its EU ETS allocation of certificates. An extra unit of emissions reduction in the UK tends therefore to be matched, one-for-one, with an extra unit of emissions elsewhere in the EU, i.e. carbon leakage is around 100%. Given EU ETS, the contribution of other energy sector policies to global carbon abatement is approximately zero.

Indeed, the effects of the policies pursued on carbon reduction can easily be perverse. If a MWh of fossil-fuel generated electricity is displaced by a technology that is classified as renewable, but is not entirely carbon free, GHG emissions at an EU level will typically rise. That is because the fossil-fuel MWh is likely come from a large facility covered by EU ETS

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a lead given by others, at least partially. This contrasts with policy strategies based on carbon reduction targets, where strategic substitutability appears to be the tendency, i.e. one country unilaterally tightening a carbon target tends to increase the incentives for another country to relax its carbon target.

and its carbon reduction will be offset by increased emissions elsewhere. On the other hand, the renewable output may be from a small facility and not covered by EU ETS, in which case its emissions will be incremental to EU emissions as a whole.

More fundamentally, if the costs of carbon reduction are unnecessarily high, the public demand for it will tend to be lower. Relative to a feasible alternative that achieves the same effects, a policy that causes costs to be higher should, therefore, properly be assessed as harmful to climate change policy objectives themselves.

An alternative interpretation of the costs incurred in consequence of GB climate change measures in the energy sector that seek to go beyond the EU ETS allocation is that they are not costs of carbon reduction at all, but are rather costs of attempted ‘leadership’ in over-achieving multilaterally agreed carbon reduction targets, i.e. the costs of being a Stakhanovite. These are very different things. Leadership is not without value, but its value depends rather heavily on the direction that the leader is taking, and also on the likelihood of others following. There is no merit in seeking to lead people to a worse place, particularly if the likely costs are high, but that is what, unintentionally, GB climate change policy has sought to do, by failing to resist the seductive (but usually harmful in the longer term) temptations of central planning.

Energy policy in contrast was set on a different course pre-2007, one on which GB was, unintentionally, indeed a world leader that attracted followers. Market development is itself a difficult path and to follow an it invariably brings stumbles and mishaps, but it has the great merit of leading to better places. The nature of these places cannot easily be foretold – like the devil, central planners have the better tunes on this point – precisely because market development is focused on *discovery* of things unknown, which definitionally cannot be packaged and presented as promised outcomes. The unknowns include not only new technologies, but also future adaptations of rule-books to make them fit for purpose in changing contexts. The discovery process has now been largely halted in GB, which, on a standard economic argument, should serve to make it all the more valuable in other jurisdictions.

Annex

Summary of some other initiatives associated with climate change policy

The Carbon Emission Reduction Target (CERT, 2008)

The CERT was the follow-on to the Energy Efficiency Commitment, addressing the same issues, and ran until the end of 2012 when it was superseded by the Energy Company Obligation. The change in name – from energy efficiency to carbon reduction – reflects the fact that the arrangements came to be seen as an element of a wider plan, built around carbon reduction, rather than as a stand-alone energy policy measure aimed at helping consumers, particularly those on low incomes, better manage their energy usage and reduce their bills.

The Renewable Transport Fuel Obligation (RTFO, 2008)

The RTFO requires suppliers of fossil road fuels to ensure that a specified percentage of their supplies by volume are accounted for by biofuels, with the option of a buyout of their obligations at a price that was initially set at 30p per litre (a substantial penalty when compared, say, with the market price, net of taxes, of petrol/diesel).

Community Energy Saving Programme (CESP, 2009)

The CESP is a supplementary programme to the CERT, but is focused on deprived areas in GB and on promoting whole-house and whole-area energy efficiency improvements.

Carbon Reduction Commitment Energy Efficiency Scheme (CRC EES, 2010)

The CRC EES is addressed at larger businesses and public bodies not covered either by EU ETS or by other energy efficiency schemes or agreements. Collectively these bodies are estimated to account for around 10% of UK GHG emissions. It entails reporting requirements and a carbon levy on emissions. The levy is an administered price/tax of/on carbon, set at a little over £15 per tonne of CO_2 in the reporting year 2014/5 for example. The scheme is administered by the Environment Agency and its equivalents in Northern Ireland, Scotland and Wales. In 2016 the Government announced that the CRC EES will cease to operate following the 2018/9 compliance year.

The Renewable Heat Incentive (2011)

The Renewable Heat Incentive is a subsidy system to promote the generation of heat from renewable energy sources. It has two variants, one for non-domestic facilities (businesses, public sector bodies and charitable organizations) and one for households. Payments are made quarterly, based on the amount of heat generated from defined renewable sources, at rates that are administratively determined and vary according the technology involved. For example, remuneration rates (per kwh) for ground source heat pumps and solar panel thermal systems are substantially higher than for air source heat pumps and biomass. Payment periods run for twenty years for non-domestic beneficiaries and seven years for households. The scheme is administered by Ofgem and funded directly by Central Government.

The scheme is most notable for the fact that, in early 2017, its operation brought down the Government of Northern Ireland. The cause was an excessive support rate coupled with inadequate cost control. The rate set meant that is was profitable to heat previously unheated buildings of all types (barns, empty warehouses, etc.) and subsidy payments spiralled. Up to £500m of public money is estimated to have been potentially misused, which, if it were mapped to UK level at a similar per-capita value, would amount to up to £16 billion.

The Green Investment Bank (2012)

The Green Investment Bank was set up by the government in October 2012, capitalised with public funds. To date it is has provided around £11bn in finance for green infrastructure projects, of which around £2.7bn is public money.

The Green Deal (2012)

The Green Deal was a Coalition Government initiative that achieved high political prominence at the time of its launch. It offered loans for energy saving measures in houses, defined by a list of 45 different types of eligible improvements. Loans are repaid via energy bills, making energy suppliers financial agents for the Government. The loans are linked to the property and transfer from one occupant or owner to the next (an unusual arrangement in English Law). Loans require an initial assessment, estimated to cost around £150. In the event, there was very little public appetite for the loans and in 2015, following a change of Government, the Secretary of State announced that the scheme would be scrapped.

The Energy Company Obligation (ECO)

The Energy Company Obligation is the current implementation of arrangements that require energy suppliers to make commitments to securing energy efficiency improvements by their customers. It differs largely in the details of implementation and its immediate predecessor was CERT. Energy suppliers bear the costs, which they then recover from their customer base as a whole. Small suppliers are exempt.

Smart-meter roll out

Work on smart-meter roll-out began about a decade ago, at Ofgem, as an aspect of market development with a focus on benefits to customers: smart meters could give customers more direct information about, and more control over, their energy usage; metering information could be more accurate and troublesome billing errors reduced; and meter reading costs could be substantially reduced, with customers benefiting as competing suppliers passed on the cost savings. Initial work suggested that these benefits might, in the conditions of the time, exceed costs for around 30%-40% of households.

The developments in climate change policy circa 2007 rapidly led DECC to take control of the programme and the policy priority switched from consumer benefit to carbon reduction.

What followed was a familiar story. Rather than mapping out a policy strategy based on sequential ‘discovery and adjustment’, DECC opted for an ambitious, national plan based on establishment of a common information infrastructure from the outset. This immediately gave rise to delays, and implied that not much roll-out would occur until a wide range of relevant issues had been settled. The prospect of new arrangements being introduced, at an uncertain date and with uncertain requirements, discouraged unilateral developments by suppliers, although some went ahead with smart meter programmes anyway.

Whereas the EU’s Third Energy Package (2009) set out a ‘soft’ target of 80% conversion to smart meters by 2020 (it is qualified by the words *“wherever it is cost-effective to do so”*), in December 2009 DECC, ever wanting to be ‘leader’, announced that the UK target would be 100% of all homes by 2020. There was to be no cost-trade-off and little sign of any recognition of what every network regulator knows, that the final, incremental 20% of coverage could be expected to prove much more costly than the average.

The programme design is based on a supplier-led rollout with a central communications body, called the Data and Communications Company (DCC), responsible for linking smart meters in homes and small businesses with the systems of energy suppliers, network operators and energy service companies. DCC develops and delivers the data and communications (infrastructure) service through external providers. The programme has been continuously subject to delays and, well behind the initial schedule, the DCC system only went live for the first time in November 2016. The 2020 target date for 100% usage has not been changed. In 2016, the Institute of Directors said of the programme that: *“The Department for Energy has committed to perhaps the most complicated and least flexible approach, telling energy suppliers to install new electricity and gas meters in all domestic properties by the end of the decade. The problem is that they have started the project before the technology has been properly tested and finalised. There are concerns about the security of the smart meters rolled out so far (so called SMETS1 meters), while the next generation of meters (SMETS2) are not ready to be installed in significant numbers.”*

In January 2017 DECC reported that 4.9 million smart meters had been installed by late 2016, against a 2020 target of about 53 million.

Carbon Capture and Storage (CCS)

The Government has sought to promote CCS development for about a decade (the first tender process for a demonstration project having been in 2007) with the aim that the facility (for coal-fired capacity at a scale of around 300-400 MW) be operational by 2014. The tender was cancelled in 2011, following a disagreement about terms and conditions between DECC and the lead consortium.

A second tender process was launched in 2012, with the prospect of around £1 billion of public funding becoming available, and two projects were selected to receive support for an initial engineering and design stage. This second tender process was cancelled in November 2015, following a public spending review by the new Conservative Government.