# This Sustainable Isle

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IN THE EARLY 1980S, THE TONE FOR THE UNITED KINGDOM'S ENERGY POLICY was set with a much quoted speech by the Secretary of State for Energy Nigel Lawson. Speaking in Cambridge, England, in 1982 and in advance of the privatization of many of the United Kingdom's national industries, the secretary declared, "It does not help us very much to try to guess the unguessable, namely what U.K. energy consumption will be in 20, let alone 50, years' time—and then aim to produce this amount judiciously divided up between the primary fuel sources." He added, "Energy is a traded good . . . the job of government is to remove distortions in the marketplace." With the Electricity Act of 1989, this market-based vision was realized and the framework for privatization and regulation of the U.K. electricity industry was introduced. From this point on, successive administrations have been committed to the doctrine that markets (and not policy makers) will deliver a secure and affordable power system. As such, energy policy throughout this period has shied away from "picking winners" in the industry; it has maintained a constant focus on the development of market-based instruments to implement policy aims and on light-touch regulation to achieve efficient operation and evolution of the system.

## Can Regulated Markets Deliver on the United Kingdom's Green Power Challenges?

Moving into the 21st century, the United Kingdom's political agenda is increasingly characterized by a concern for the impact of carbon emissions on the global climate. In the energy policy agenda this new driver was reflected in 2008 with the reformation of a government department with an explicit remit for energy, the Department for Energy and Climate Change (DECC). With this new driver has come a questioning of the incumbent market-based approach to operation and development of the power system. In his inaugural speech as secretary of state for energy

*Digital Object Identifier 10.1109/MPE.2009.933419*


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and climate change, Ed Miliband revealed this new thinking by closing with the statement that “markets will work to best effect in the public interest if there is a strategic role for government alongside them.”

This article looks at the successes of the past regime. It examines the United Kingdom’s focusing of energy policy on regulated markets, how this has adapted to challenges since privatization, and how it is now responding to the challenges of achieving a low-carbon sustainable energy system. We set out the key challenges for the power sector in the United Kingdom that are driving fundamental changes in system operation, and we discuss whether the current market approach is continuing to facilitate competition in generation and supply and support efficient solutions for future smart grid concepts and technologies. Using the United Kingdom as a case study, we chart the historical progress and recent developments in the regulatory and market arrangements in response to these new challenges and pose the following question: can an energy policy centered on regulated markets deliver a low-carbon future?

## Energy Markets: From Privatization to the Present Day

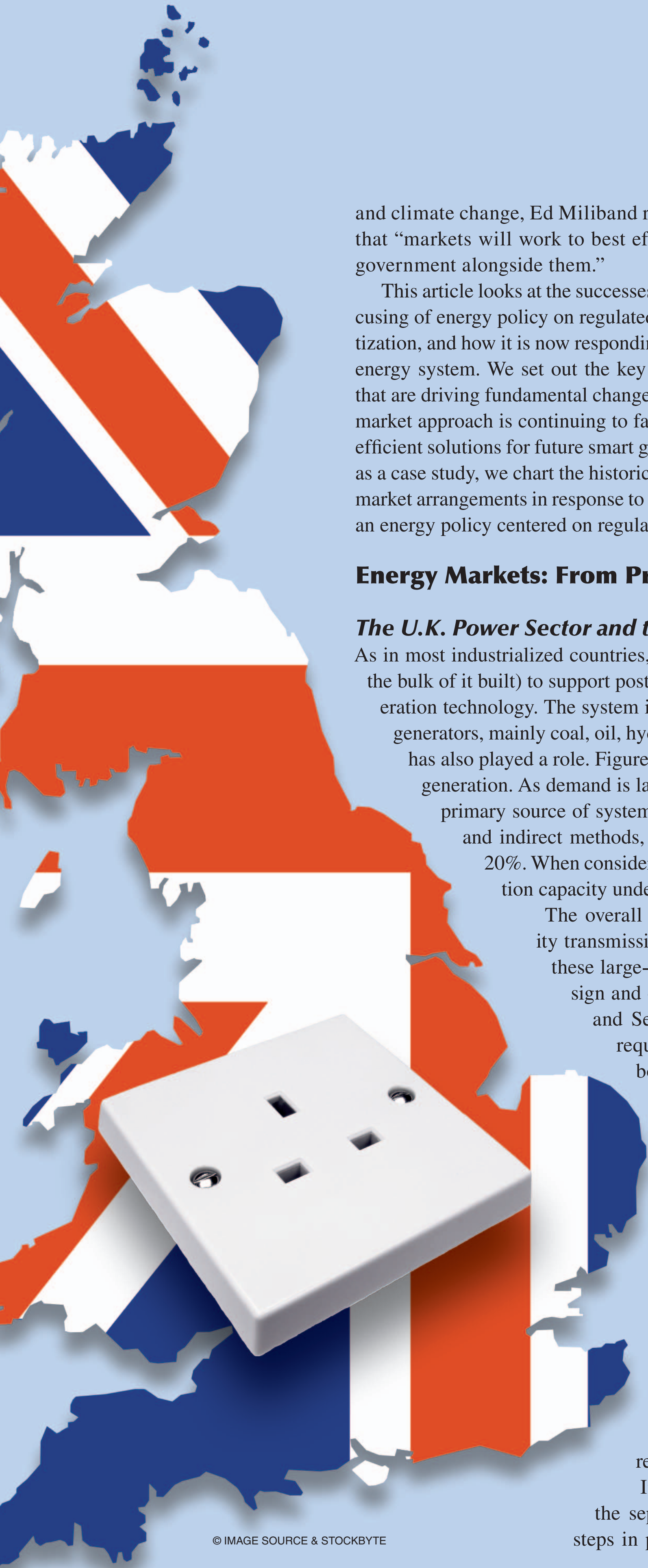
### *The U.K. Power Sector and the Approach to Privatization*

As in most industrialized countries, the United Kingdom’s power system was designed (and the bulk of it built) to support post-World War II economic growth and development in generation technology. The system is characterized by relatively small numbers of very large generators, mainly coal, oil, hydro, and nuclear; since privatization, gas-based generation has also played a role. Figure 1 illustrates the basic system, dominated by conventional generation. As demand is largely passive and uncontrollable, generation provides the primary source of system control. Up to the present day, and under various direct and indirect methods, the system has maintained a capacity margin of around 20%. When considering average demand across the year, utilization of generation capacity under this peak-demand-led regime is about 50%.

The overall philosophy for the design and structure of the electricity transmission (and distribution) networks was developed to support these large-scale generation technologies. Transmission network design and operation follows the Great Britain (GB) Supply Quality and Security Standards (SQSS), which specify the minimum requirements for transmission capacity, taking into account both network security and economics. The transmission network is designed to be able to continue to function following the outage of two circuits (planned or forced). So under normal operation (during the peak load conditions), circuits in the interconnected transmission network are generally loaded below 40% of their nominal (thermal or stability) capacity limits.

The primary demand center for the United Kingdom is in the southeast (around London), where there is also a dearth of power generation. A majority of major generation resources are located in the Midlands and the northern areas of England and Scotland, due to the proximity of fossil fuel resources (primarily coal and North Sea gas). This gives the United Kingdom an overall north-to-south power flow and puts some pressure on the network resources that connect Scotland and England.

In 1990, the creation of the U.K. power pool market and the separation of generation from transmission were the first steps in privatization. In phases from 1990 onwards, supply was



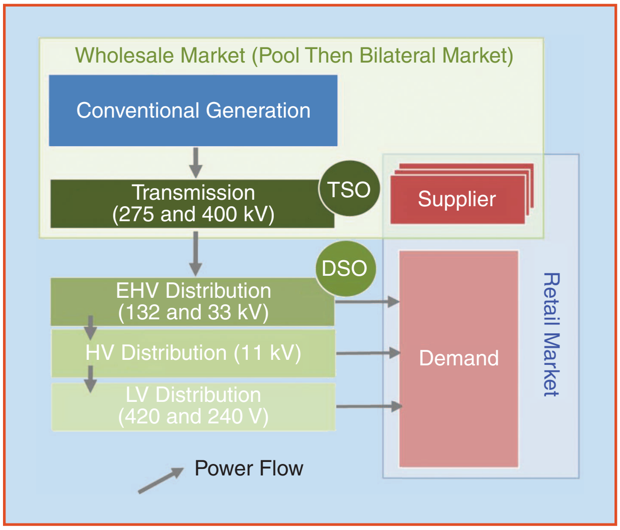



**figure 1.** Schematic of the U.K. power system with generic wholesale and retail supply markets.

also opened up to full competition, and distribution was separated out from transmission (though they remained as regulated regional monopolies). For the first decade, the system was operated by the transmission system operator (TSO) via a centrally dispatched pool market. In 2000, with the advent of full retail competition for all electricity customers, the New Electricity Trading Arrangements (NETA) were also introduced. This was a bilateral trading market featuring a power exchange within which generators and suppliers could interact and a separate "balancing mechanism" for the TSO to directly contract system-balancing services with generation (and demand).

This U.K. market approach is characterized by a separation of energy from network access. The price of power is set in the power exchange, and power is traded without regard for location as all generators that pay transmission network use of system (TNUoS) charges are deemed to have financially firm access to the market. The locational element of the energy costs is determined in the balancing mechanism, a single-buyer marketplace. Here, the system operator (SO) takes bids (amounts generators are willing to pay to reduce output) and offers (amounts generators wish to be paid to increase output) to redispatch generation and balance the system to account for network constraints and losses. The SO can also take bids and offers from the demand side, which will pay to increase (bid) or be paid to decrease (offer) their load requirements. These costs are socialized among all market participants along with additional ancillary services, e.g., frequency and reserve (which are contracted on an annual basis in a competitive bidding process). Until recently, the cost of short-term network constraints have formed a minor part of the overall value of the energy market, so this lack of locational specificity in short-term charges did not have a material impact on the efficiency of the system.

The appropriate signals to drive adequate investment in new generation capacity and optimal investment in network reinforcement should also be derived from the bilateral market without significant intervention from the regulator. Apart from those with standing reserve contracts, there are no built-in capacity payments for peaking generators operating at low load factors; all costs must be recouped by means of the power exchange and balancing mechanism. Similarly for networks, the approach of "user-driven investment" means that short-term signals on the cost of constraints are used to indicate appropriate network reinforcements.

## *Regulation of Network Monopolies*

Retail Prices Index less efficiency savings (RPI – X) price cap regulation of the network was introduced after privatization to provide incentives for efficiency in the new monopolies as well as to stimulate innovation and create the right conditions for competition to develop. This is an incentive-based regulatory framework that sets revenue allowances in advance for a period of five years (with some adjustments during this period for specified variables).

For distribution network operators (DNOs), operating expenditure (opex) is regulated on the basis of comparative analysis between the regional network monopolies, and efficiency gains in expenditure are shared with the consumer after the period of the price control. Capital expenditure (capex) is determined after scrutiny of the DNO load and non-load-related expenditure forecasts; this includes an additional incentive devised to mitigate the information asymmetry between the regulator and the DNOs and expose efficient capex spending during the price control period. In addition to this, DNO activity is also incentivized against a number of output measures. For the third price control, an interruptions incentive scheme (IIS) was introduced to reward or penalize performance in terms of minimizing the number of customer interruptions (CI) and reducing customer minutes lost (CML).

Similar incentive schemes are in place to minimize losses. In the most recent price control—and following a groundswell of policy-level output relating to the promotion of low-carbon energy—two new incentives were introduced: the Innovation Funding Incentive (a rolling capex mechanism to promote investment in network R&D and active network management) and the Registered Power Zone (to provide encouragement for deployment and connection of distributed generation).

For the TSO, opex costs were initially managed through the pool market. As of the second price control they became part of the regulated costs, and with the advent of the bilateral market in 2001, system-balancing costs became part of a separate SO incentive scheme. With the lack of comparative analysis available for the TSO, both opex and capex expenditure are reviewed through a combination of analysis by the regulator and external consultants. As for the DNOs, all opex savings are shared with the consumers at the end

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of a price control period. Capex expenditure in transmission is on the basis of "user driven" investments; uncertainty in investment decisions, however, is increased by the U.K. planning system and the U.K. energy policy approach of not directly recommending investment in new generation. To mitigate this uncertainty, the regulator introduced a flexibility mechanism to allow the transmission owner to earn additional capex as users connect. In addition to the SO incentive to minimize system operating costs (balancing, reserves, losses, and so on) and similar to the distribution system operator (DSO) incentives, the TSO also has its own targets for performance (minimizing outages and disruption against agreed targets) and for the Innovation Funding Incentive. There are also incentives to perform under the European Emissions Trading Scheme (EU ETS) and to promote the reduction of $SF_6$ use in high-voltage switchgear. Also of note is that in the last price control the RPI – X value was set at RPI + 2, recognizing a step change in the connection of new (particularly renewable) generation and a need for investment in new transmission.

### Responding to Changing Drivers

From 2000 on, an increasing policy interest in the climate change agenda began to influence the regulatory regime and the operation of the energy market. Change began with the publication of a 2000 report from the Royal Commission of Environmental Pollution (the RCEP is an independent standing body established in 1970 to advise the Queen, the U.K. government, Parliament, and the public on environmental issues) that made a recommendation for the United Kingdom to achieve a 60% reduction in its $CO_2$ emissions by 2050. This was the precursor to attention for low-carbon activity from the Performance and Innovation Unit (PIU) in 2002, which undertook a review of energy policy and brought into focus the links between energy policy and sustainable development (the PIU was part of the Cabinet Office, directly advising the prime minister and undertaking analysis of key areas to improve the government's capacity to address long-term and/or cross-cutting strategic issues and promote innovation in policy development). The PIU declared the current market framework was satisfactory for meeting these goals and recommended that the United Kingdom adopt a 20% renewables target by 2020. The energy white paper that followed in 2003 recognized that this target should be set; notably, however, nuclear power was not considered to be a major means of achieving this goal. The focus instead was on renewables and distributed generation. In response, the Embedded Generation Working Group (EGWG) was set up by the regulator to address the various barriers to uptake of distributed generation (DG).

Throughout the 1990s, Europe and to lesser extent the United Kingdom saw the deployment of significant amounts of DG (of various technologies) in response to the climate change challenge and the need to enhance fuel diversity. However, conventional large-scale power plants remained the primary source of control of the electricity system, assuring the integrity and security of its operation. The emphasis for DG was on accelerating deployment and facilitating connection to the network rather than on integration into overall system operation and development. Following these policy statements in early 2000, it became clear that this approach to DG (consistent with historic passive distribution network operation) presented two key problems: 1) it led to inefficient and costly investment in distribution infrastructure, and 2) it failed to recognize the value that DG may have in displacing network and generation assets and contributing to reductions in network operation costs and improvements in system security performance.

Through the EGWG, the United Kingdom took the lead in the early development of an appropriate technical, commercial, and regulatory framework for promoting a low-carbon, distributed future. Network planning standards were revised, and DNOs can now incorporate the contribution that distributed generation can provide to substitute network capacity (reinforcements) in areas for which demand growth could be offset by distributed generation. Typically, DNOs have used network-based solutions to deliver the required level of security. Now, in an era of increasing levels of distributed generation and with a suitably updated planning standard recognizing a wide range of distributed generation technologies, significant opportunities for generators to provide security contributions to network planners are emerging.

### Successes of the RPI – X Regime and the Regulated Markets

Since 1990, the present approach to market regulation has delivered a consistent year-on-year efficiency savings along with improvements in quality of supply and performance. Against a changing demand background, around 30 GW of new generation (primarily gas) has come onto the system, and 24 GW has left (coal and nuclear). In addition, security of supply has been maintained, with the capacity margin remaining around 20%. In transmission, the regulated network has seen investment of £0.4 billion per year in the years up to 2005; in its latest regulatory package, to run to 2012, this has increased to £1.5 billion per year. This compares to just £0.25 billion per year in the run-up to privatization (1984–1989). The figures for the distribution networks tell the same story, with £3.8 billion invested before privatization (1986–1990), £15.5 billion invested in the first price control period after privatization (1990–2004), and £7.4 billion authorized up to 2009. Against this investment record, operational performance levels have also improved year-on-year. The years up to 2005 saw 11% fewer outages, with the duration of interruptions falling by 30%. Operating costs have also been driven down since 1990, with charges dropping by 50% and 41% for distribution and transmission, respectively. Competition in the generation and supply sectors has achieved similar successes in driving down the costs of wholesale electricity, with prices falling by 30% in real terms in the first ten years of privatization.

The RPI – X regime has been responsive to external drivers for improvements in quality of service and developed new, appropriate incentive mechanisms to facilitate continuous improvement and drive down costs. The separation of energy costs and networks has been a good proxy for the system operation, as the locational element has not made a significant impact on prices. And the approach of peak-demand-driven design has been an appropriate method for the continuing evolution of both the network and the generation mix.

Overall, this approach has been successful in maintaining and incrementally improving the status quo, promoting like-for-like asset replacement, and supporting existing system operation, investment, and design philosophies. In the early part of the present decade, the regime also proved responsive to the early challenges presented by the low-carbon policy agenda, setting the United Kingdom at the forefront of innovative regulation for active distribution networks.

## 21st-Century Challenges for the Regulated Energy Market

Looking forward to the next decade and beyond, new challenges of unprecedented proportions are facing the system. Along with security and affordability, government energy policy must now rest on a third pillar, that of low carbon, and policy makers are adamant that there can be "no trade-offs" between the three drivers. The recent ratification of two stringent targets for the adoption of renewables and the reduction of $CO_2$ has further strengthened the low-carbon agenda in policy making. Under the European Renewable Energy Strategy, the United Kingdom is now legally committed to ensuring that by 2020, 40% of all its electricity demand is supplied from renewable sources. Further stretching this commitment, the U.K. government has also enacted into law the recommendations of the Committee on Climate Change (CCC), whose December 2008 report concluded that the United Kingdom should take on a legally binding commitment for an 80% reduction in $CO_2$ levels by 2050 (the CCC is an independent body established under the Climate Change Act 2008 to advise the U.K. government on setting carbon budgets and to report to Parliament on the progress made in reducing greenhouse gas emissions). Overarching policy responses to these two targets are emerging in the form of a U.K. renewable energy strategy and a direct response to the CCC recommendations from 2008 (both expected in the summer of 2009).

On top of these targets is the fact that much of the United Kingdom's energy infrastructure, conceived in the middle of the last century, is coming to the end of its useful life. The United Kingdom is now in a position where it must begin reinvesting and rebuilding the energy system on a large scale. The choice now is whether to replace like for like and maintain the status quo or take the opportunity now to set the foundation for a low-carbon system of the future. Either way, the regulatory and policy framework will play a key role in determining the outcome of this investment.

Figure 2 illustrates the major factors driving the fundamental changes in the system up to 2020

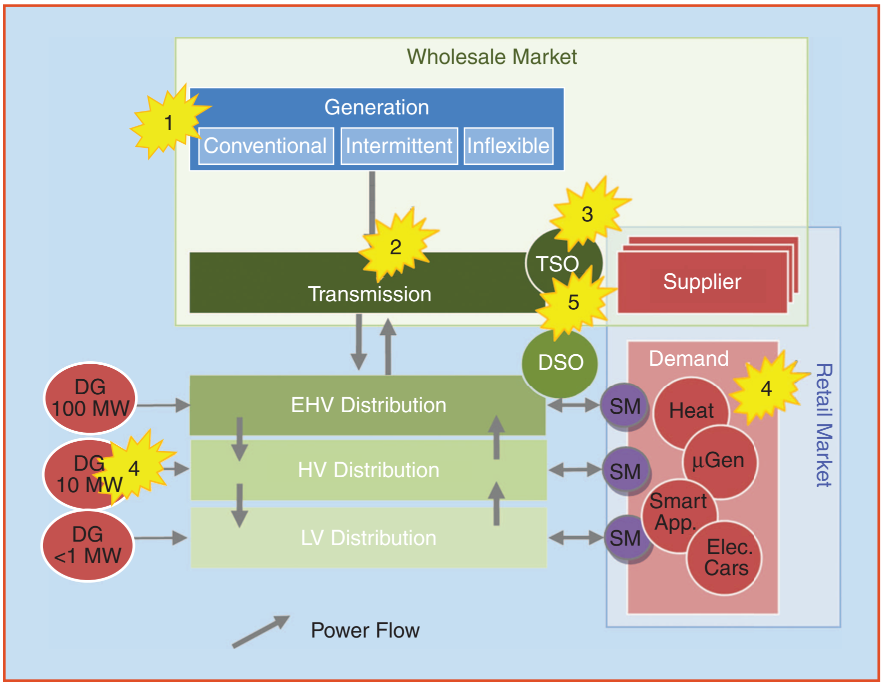


**figure 2.** Schematic of the U.K. power system shaped by low carbon energy policy.

and on to 2050. Achieving these targets requires a massive penetration of low-carbon generation into the system. The CCC report suggests that near-total decarbonization of the power sector should be reached by 2030. For the United Kingdom, this is likely to mean massive penetration of intermittent onshore and offshore wind resources and a resurgence of investment in inflexible nuclear generation, along with a requirement for all fossil fuel plants to be fitted with carbon capture and storage (CCS) technology (1). In the short term there are challenges getting renewables onto the network at a fast enough rate, as renewable resources are located in the north of the country where the network infrastructure is stretched (2). In the long term, high penetrations of intermittent and inflexible generation resources will present a challenge for system balancing and even for the philosophy of "predict and provide," peak-demand-led system development (3).

Moving down to the distribution level, new players are likely to be entering the system. Increased levels of low-carbon DG and a huge range of demand-side entities supported by smart metering will be increasing the scale of participation in the system by orders of magnitude and decreasing the average size of a participant from megawatts to kilowatts (4). The addition of demand previously supplied by fossil fuel, such as transport and heat, may add further capacity challenges to the system but will also present new opportunities for system control and demand participation. This presents an additional challenge for the now named DSO as the pressure for active system management increases. This is the case for transmission and distribution alike, as SOs must now try to optimize system operation with a new range of nontraditional resources (5).

All these changes are set against a background of uncertainty for system development because, while some of the changes described above may emerge, there are still multiple discreet pathways that the low-carbon system evolution can follow. Devising a regulatory regime and a market framework that supports the investment decisions that will achieve the overarching targets without locking the United Kingdom into a suboptimal future is the next challenge.

## U.K. Regulatory and Policy Response

The following section explores some of the current policy and regulatory responses to this challenge. Here we set out how and why the attention of U.K. energy policy is focused on transmission access for renewables, examine the recent regulatory and industry initiative to review the security standards for design of the distribution and transmission networks, and discuss the upcoming overarching review of the RPI – X regulatory regime.

We highlight how each of these elements is contributing to the creation of a low-carbon system and whether the steps to evolve a market framework are progressing towards an efficient solution.

### *Transmission Access Review*

The 2007 energy white paper (following on from the earlier 2003 white paper and a subsequent energy review in 2006) demanded that the regulator in partnership with the government undertake a review of transmission access. The review, which is still in progress, was prompted by the large "queue" of onshore wind generators waiting to be connected to the transmission network in Scotland. Wind generation is expected to make by far the most significant contribution to the 2020 renewable energy targets, so network access was a clear target for action.

Wind generation is significantly different from the conventional technologies for which the current arrangements were devised. The ability of wind generation to contribute to securing peak demand is very limited, and it would not be efficient to build a transmission network that is capable of accommodating the maximum simultaneous output of all plants, both conventional and wind. For example, assuming a peak demand of 60 GW in 2020 and penetration of wind of 30 GW, the total amount of generation on the Great Britain (GB) system will approach about 100 GW (as wind is not a very "reliable" form of generation). Clearly, it would not be efficient to build a transmission network that can accommodate a simultaneous output of 100 GW of generation if there is only 60 GW of demand. However, if the efficient transmission network cannot accommodate the simultaneous outputs of all generators, there will be a need to share capacity between wind and conventional plants (on windy days the wind generation in Scotland should occupy the transmission network, while on nonwindy days conventional plants should take over). However, present network access arrangements are unable to facilitate the allocation of scarce transmission resources in the short term.

The major output from the review to date has concluded that any new access regime should facilitate an efficient level of sharing of network capacity between wind and conventional generators (i.e., an efficient level of constraints) and in doing so, drive an efficient level of network investment. However, the decisions that would inform this efficient level of investment are to be made on a decentralized basis by the network's users, expressing their choices in a market for access. These choices will be based on prices emerging from both the nonfirm and firm access markets, so efficient pricing in these markets is the key to the success of this regime.

### *Review of Transmission and Distribution Planning and Operation Standards*

Most distribution and transmission planning and operation practices are still centered on the traditional deterministic N-1/N-2–type network security criteria developed in the 1950s. Recently, however, there have been significant debates associated with updates and reviews of network operation and planning standards and practices in a number of countries. This has been driven by a variety of factors, including:

- ✔ the need to incorporate nonconventional generation, such as wind power
- ✔ the need to demonstrate that investment in monopoly functions is efficient and delivers the best value for consumers, i.e., provides the right balance between the costs paid by users and the benefits that users derive, including reliability improvements
- ✔ the need to ensure that network planning and operational standards do not impose unnecessary barriers to entry and do not prevent a timely connection of new generating plants and demand
- ✔ the concern that the present network standards impose a barrier for innovation in network operation and prevent implementation of technically effective and economically efficient solutions that enhance the utilization of the existing assets (i.e., the present standard is based on prescribed levels of asset redundancy and is clearly a barrier for the application of smart grid technologies).

In this context, the regulator initiated a review of the security and quality of supply standards governing operation of the GB transmission network. Under discussion is a proposal to evolve the current operation and design philosophy from promoting solutions based solely on network assets to one that is open to all solutions (both network and nonnetwork) and thus deliver a smarter, secure, and cost-effective outcome. This is particularly relevant when one considers that there is no close alignment between transmission project costs and expected economic benefits. Clearly, the present deterministic approach to network planning may prevent efficient nonnetwork solutions (in the form of generation or flexible demand) from being considered and applied as an alternative to traditional network-based reinforcements.

This is consistent with the core objective of the smart grid concept, an integrated electricity and information and communication system infrastructure that is intended to enhance the utilization of existing and future primary electricity assets.

The United Kingdom has recently changed distribution network planning standards to incorporate the contribution that DG can provide to substitute network capacity (reinforcements) in areas where demand growth could be offset by DG. This has been a significant step towards efficient integration of DG in the future electricity system, given that DNOs typically use network-based solutions to deliver the required level of security. In an era of significantly increased levels of DG, with a suitably updated planning standard recognizing a wide range of DG technologies, there will be significant opportunities for generators to provide security contributions to network planners. However, although the new standards provide an opportunity for DNOs to consider the contribution of DG, there is still the need to develop appropriate arrangements that would reflect the commercial value of the contribution made by DG.

### Overarching Review of the Regulatory Approach

After 20 years of the RPI – X regime, the regulating authority is in the process of reviewing the present approach to network regulation, and it is expected that this will reflect a shift from a focus on achieving efficiency to facilitating efficient delivery of the low-carbon economy. This is the key regulatory challenge for the development of future smart grid concepts and technologies.

Delivering a sustainable energy sector will require innovation, potentially involving changes in the business culture and operational practices of network companies. They will need to test and deploy new network technologies, ensure existing network assets are used effectively, and ensure future capital investment in networks is efficient. However, there has been little technical innovation over the last 20 years that has challenged the way network companies plan, invest, and operate their networks. In this context, the introduction of the Innovation Funding Initiative (IFI) and Registered Power Zones (RPZ) by the regulator has been important, given the challenges of network asset renewal and penetration of new forms of DG. One of the key challenges for the future will be to ensure that new network technologies can be effectively deployed in order to ensure that existing and future network assets are used efficiently and that capital investment is also efficient.

One of the key issues that will need to be resolved within the review concerns the separation of networks from energy, as is currently the case. It has already been recognized that the impact of the electricity transmission networks on the operation of the wholesale energy market is growing with increased levels of penetration of intermittent renewables. Furthermore, it is expected that other technologies—particularly demand-side and DG—may further link networks and energy. The benefits from the utilization of enabling technologies such as demand-side or DG participation often accrue to different participants, however. For example, action from demand-side technologies or DG that is part of a generator's portfolio can be used to balance output and provide energy arbitrage opportunities that could bring benefits to the portfolio owner or to intermittent generators using this resource. This activity can contribute to more efficient use of existing network capacity, reducing (or delaying) the need for reinforcements and possibly contributing to other network activities such as securing supply for local demand or relieving substation congestion.

Hence, the benefits of such technologies can be associated with the operation of a number of individual businesses (e.g., generating companies, TSOs and DNOs, suppliers, and so on) that may all be willing to reward specific aspects of this activity. In the absence of the traditional vertically integrated utility that would be in a position to optimize the overall system value of such enabling technologies, there may be multiple recipients of services provided by demand-side or DG technologies. Clearly, no individual recipient of the services (e.g., generating companies or DNOs) is interested in maximizing the overall system benefits achieved by trading off the benefits between individual segments of the industry. In this context, the current regulatory arrangements may present a significant barrier to the introduction of these technologies. The fundamental review of network regulation is expected to address this question.

Furthermore, the present regulatory approach, although capable of supporting an incremental network development, may be less appropriate for a strategic development of a future smart grid. This is also an important area that will be included in the review.

### *Energy and Networks Can No Longer Be Separated*

The examples above are a sample of the United Kingdom's response to the low-carbon agenda, but to evolve the market approach in order to meet low-carbon targets there are some key points to be recognized. Energy and networks can no longer be separated, as location and time become integral factors driving costs and therefore investment decisions in the new system. To reflect this and facilitate integration of all new players entering the system, network pricing needs to be efficient and fully cost-reflective. Network design and security criteria must be updated to reflect the different requirements of the future power system. Market design must also reflect the new mode of operation of the system, rewarding positive actions and sending the correct signals for investment.

## Market for a Smart Low-Carbon Power System

Although the basic U.K. electricity market design has not yet been questioned, a number of concerns are emerging associated with the ability of the present structure to support delivery of a low-carbon system. For example, in the context of the U.K. government's strategy, a significant contribution from variable and difficult-to-predict wind generation when combined with potentially less flexible nuclear plants (in which there is significant interest in the United Kingdom), may challenge the ability of the system to absorb low-carbon energy, particularly during high-wind and low-demand conditions. Questions have been raised regarding the ability of the present market to deliver the required flexibility. What is more, if the ambitious renewable target (40% of electrical energy) is to be met, a large amount of fossil generation would need to be maintained on the system to provide peak security. Capacity margins would increase from the present 20% to more than 60%. Average generation load factor would thus fall to below 30%. There would be more than 25 GW of conventional generation operating below 10% load factor, which raises a question of the delivery of required investment in such plants under the present market design, which rewards energy production but not (explicitly) capacity. More generally, there are concerns as to whether the market developed to facilitate competition between generation technologies on the basis of marginal fuel costs can facilitate the implementation of a significantly different system with very intensive capital investment of generation technologies operating at low marginal costs.

In terms of climate change ambitions beyond 2020, the decarbonization of electricity and energy systems within the present operating paradigm would require a very significant capital investment in primary generation and network assets while simultaneously degrading the utilization of these assets. This could result in very inefficient future investment programs. In the longer term, shifting significant amounts of energy demand from other sectors into electricity, primarily heat and transport, could further reduce capacity utilization levels if the paradigm of system operation is unchanged, as peak demand could grow much more quickly than total energy consumption. On the other hand, part of the increase in energy demand could be accompanied by radical changes in system control philosophy, with the demand side taking a much more significant role in the generation-demand balancing task and in network management, particularly given the inherent energy storage capacity in the heat and transport sectors.

A distributed energy marketplace (presented in Figure 3) would address the many challenges of the lack of end-user

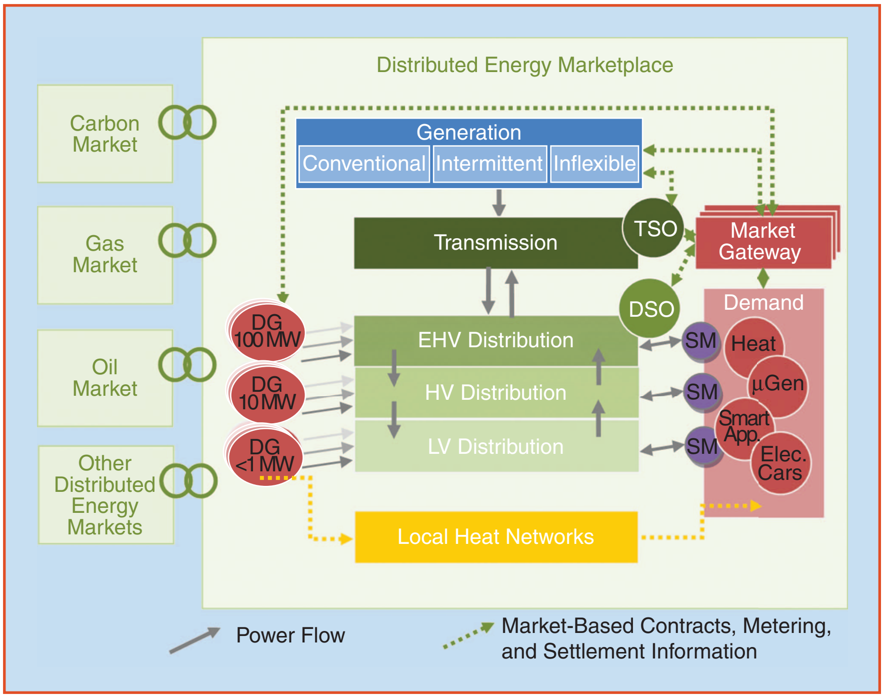


**figure 3.** Distributed energy marketplace.

participation in real-time system operation. The need for a new marketplace to expose all end users to real-time prices and manage the information flows they generate is clear: without a marketplace there is nowhere for participants to interact, and without real-time price information there is no indication to end users of the actual value of their responses. The distributed energy marketplace puts users at the center of the development and evolution of the power system and provides SOs with access to the most cost-effective solutions for system management.

The distributed energy marketplace brings together all energy system end users (both generation and demand) from all levels of the power system to interact with each other and the SOs in a competitive market-based environment, buying and selling energy and ancillary services. Crucially, the marketplace is linking all market participants in a single real-time marketplace that removes the disconnection caused by the separation of wholesale and retail energy markets and disconnections between energy and networks. It identifies the value of end-user response according to time and location (unlocking the potential for demand response) and allows the SO to access all resources suitable for system management activities.

The distributed energy marketplace would integrate all end-user technologies into a competitive market framework. This includes distributed generation and all technological innovations that are currently hidden behind the demand-side meter, such as demand-side response, microgeneration, smart appliances, and electric vehicles (vehicle-to-grid technology). It provides an accessible and flexible market framework for a future smart grid in which to incorporate these and future technological innovations.

The distributed energy marketplace opens up a market gateway role in the area typically occupied by an energy supplier (between smaller end users and the market). This role becomes a central facilitator of the distributed energy marketplace enabled through smart metering technology. The market gateway is an intermediary bringing together demand end users and small generation.

Central to the success and optimal market-based decision making is the concept of market coupling, bringing together the related energy markets of gas, oil, and carbon alongside and in parallel with the distributed energy marketplace. This is important for making optimal decisions and for fulfilling the energy services vision that would allow fuel switching and optimal decision making in response to prices.

## Conclusions

In response to the new low-carbon pillar of energy policy, the United Kingdom is shifting away from the pure liberalized approach to the energy industry of the 1980s towards a hybrid model that would combine strategic direction provided by the government with markets designed to facilitate implementation of efficient solutions. Regarding the strategic role of the government, the focus at present is on the delivery of its 2020 renewable energy strategy. Various network-related fundamental reviews are under way to prepare the market, which was primarily designed to support bulk conventional generation, for a significantly new environment. In is important that these reviews are aimed at introducing market-based approaches to network operation and investment through offering access choices to network users.

In the longer term, shifting significant amounts of energy demand from other sectors into electricity, primarily heat and transport, will require changes in the system control philosophy, with the demand side taking a much more significant role in the generation-demand balancing task and network management. This will lead to further radical enhancements of the market design that will expose all end users to real-time prices and integrate all end-user technologies into a competitive market framework. Such a distributed energy marketplace, outlined in this article, will put end users at the center of the development and evolution of the power system and simultaneously provide SOs with access to the most cost-effective solutions for system management, which is the ultimate goal of the introduction of competition to the electricity sector. Such a distributed energy marketplace is essential for the development of smart grid concepts and technologies

Although the role of government in providing the overall strategy and direction is increasing, it is clear that a regulated market will play a major role in delivering an efficient 21st-century low-carbon energy system.

## For Further Reading


SEDG (2007, Feb). Transmission investment, access and pricing in systems with wind generation [Online]. Available: http://www.sedg.ac.uk/Publication/Centre%20for%20DG&SEE%20Tx%20investment-Access-Pricing_Feb%2007.pdf

SEDG (2007, July). Integration of distributed generation into the U.K. power system integration of distributed generation into the U.K. power system [Online]. Available: http://www.sedg.ac.uk/Publication/Framework%20for%20development%20of%20enduring%20UK%20transmission%20access%20arrangements.pdf


## Biographies


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