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energyspectrum

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In this issue

The week in review

Monday 16/05—Prime minister David Cameron warns that a vote to leave the EU in the upcoming referendum would see the UK give up billions of pounds in infrastructure investment. Developer NuGen warns that first power from its proposed new nuclear plant in Cumbria has been delayed until the end of 2025. The UK's newest gas field, the Laggan-Tormore field, is officially opened by energy and climate change secretary Amber Rudd.

Tuesday 17/05—The Residential Landlords Association urges the government to delay the introduction of new energy efficiency targets for the private rented sector. Trade group RenewableUK welcomes data revealing that for the first time wind generated more electricity than coal over the course of an entire month. Energy minister Andrea Leadsom warns that a vote to stay in the EU could put the energy security of the UK at risk.

Wednesday 18/05—The Queen's Speech confirms the government's plans to introduce legislation to implement the Competition and Markets Authority's proposed energy market remedies. SSE says is to focus on "significantly" reducing the rate at which it is losing customers, confirming in its yearly results that through to the end of March it had lost 370,000 customer accounts. The Scottish government confirms Scottish economy secretary Keith Brown is to take on responsibility for the country's energy brief, replacing Fergus Ewing.

Thursday 19/05—The Office of National Statistics reveals that the low-carbon and renewable energy economy generated £46.2bn in turnover during 2014. The energy and climate change select committee announces that it will hold a one-off evidence session to investigate the implications for energy and climate change policy of the EU referendum. ICIS forecasts Britain will install 15GW of gas-fired capacity in the next five years.

Friday 20/05—Cornwall Energy finds in a new report the cost of policies to support renewable electricity and ensure energy security will increase sharply over the next couple of years. Horizon Nuclear Power announces that it has appointed a new, specially-created, joint venture to help deliver the planned new nuclear power station at the company's Wylfa Newydd site.

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Opening Pandora's Box—A look inside the strange world of embedded benefits

Today sees the publication by the Association for Distributed Energy (ADE) of a research report we have written on "embedded benefits" (or the payments distribution-connected generators can earn from reducing network usage).

The immediate backdrop to the report is recent policy steers from DECC. In particular on 1 March it issued a consultation on reforms to the capacity market in which it confirmed that Ofgem had been asked to review current network charging rules and how they impact on embedded generation. It suggested they could be providing undue reward to distribution-connected generators, highlighting diesel reciprocating engines as particular and unworthy beneficiaries. Independently National Grid is also carrying out its own review focusing on the so-called triad benefit[1].

As we explain in this *Energy Perspective*, these reviews are of fundamental interest to the many generators connected at distribution voltages and could have profound implications for the viability of smaller generation schemes, both operating and planned. More generally, they raise fundamental issues about the interactions between industry charging rules and investment, directly feeding into the three key pillars of energy policy – security of supply, decarbonisation and affordability.

But in bringing forward our report, we do not recommend specific changes or reforms; indeed the issues are much too complex to take any particular element in isolation at this early stage. We argue there is an overwhelming case for a joined up review of embedded benefits across industry rules.

Golden fleece

An embedded generator connects directly to the distribution network and locates close to the demand that it services. There are a number of operational benefits but also cost efficiencies in the form of avoided charges, and these are conventionally shared between suppliers and the local producers who they contract with.

Most obviously predictable local generation reduces the need for investment at the distribution and transmission network levels. But there is also a saving from the costs of network companies in operating and maintaining the existing infrastructure. There is a further reduction in thermal losses—the lost power dissipated through heat—both at transmission and distribution levels.[2] Finally, embedded generation generally reduces the volume from balancing energy and can make it cheaper to balance the system on a half hour by half hour basis. Controllable plant such as reciprocating engines can also make it easier to deal with intermittency at the local level, allowing increased deployment of intermittent plant than would otherwise be feasible.

There is now around 20GW of generation that is connected to the distribution network, and it is having a big impact on the development of the electricity system. A large swathe of this, about 40%, is not intermittent, and a further 2GW has earned contracts under the first two capacity market auctions providing valuable reserve and flexibility in a world of shrinking capacity margins.

Perversely DECC seems to see this not as a good news story, but as a problem and an important factor to explain why large baseload CCGT stations typically connected at transmission level have not come forward. The implication is that embedded benefits are providing an unfair commercial advantage to smaller plant, and it therefore wants to levelise the playing field by reducing or even eliminating them. This is very muddled thinking.

Seven headed hydra

The value of these benefits to each generator varies considerably dependent upon location and technology. In general the closer the generator is to demand and the more predictable and controllable the production, the higher they are. But a key issue that DECC has not recognized is that generators do not receive these payments directly; rather they have to negotiate a share out of these benefits under their Power Purchase Agreements with suppliers. Most agreements focus on the triad benefit, not least as historically this has been the most important source of embedded

[1] The cost saving realised from avoiding transmission usage charges collected from demand.

[2] Transmission losses have remained steady at about 5TWh-6TWh/year, while demand has slid from 350TWh to scarcely 300TWh in the last decade. Proportionately the volume of losses has therefore increased from under 1% to pushing 2%.

value, but it is not unusual for many older or longer term agreements not to mention some benefits at all. It is also conventional for suppliers to retain a share of the values, which can be up to 20%, as well as discounting the value of the power they purchase relative to the wholesale market.

We estimate that the total level of embedded benefits—the avoided costs shared by suppliers with local producers—has almost doubled from around £300mn to £560mn over the last five years if one looks across the seven sources of value. This is due not only to a combination of increased volumes of generators connected at low voltage following the roll-out of low-carbon incentives, but also an increase in the rate of some of these benefits as demand falls on the system.

Minotaur's maze

Our research for the ADE suggests several key conclusions:

- when the current level of embedded benefits is assessed as a whole, we believe they are broadly providing a fair level of reward to generators for the various costs that they help avoid across the system as a whole and the operational benefits they can deliver over the long run;
- there are a number of issues with individual embedded benefits which mean that some are likely to over or understate the value to network companies and suppliers, and this varies by generation type and location; and
- while the "triad benefit" that arises from reduced use of the transmission system is overvalued, particularly when assessed over the short term, the credit available for reducing a distributor's costs through offsetting local demand is significantly undervalued over any timeframe.

In terms of the triad benefit, the conclusion explains why DECC, Ofgem and National Grid are all keen to push through review. But even here our analysis suggests that many of the sunk costs actually vary with demand when a long-term view is adopted, and the extent of the implied reduction is rather less than industry analysis has suggested.

As for distribution, we believe that current charging methodologies understate the benefits of the avoided costs from embedded generators. Firstly, non-intermittent generation currently receive credits for exporting on to a distributor's network, but the level of credits is lower than the equivalent charge to demand customers. This means perversely that generators can get more benefit from installing private wires to demand customers and bypassing the distribution network. Secondly, at higher voltages intermittent generation does not get a credit even though it can still contribute to reduced reinforcement cost for the distributor as part of a diverse portfolio of generation.

So our headline conclusion is that much more work is needed to understand these incentives, how they are realised contractually and their interaction, and any change should only follow a thorough, wide-ranging review. A piecemeal approach to change of individual benefits would almost certainly impact adversely on the viability of existing embedded generators but also reduce future investment at a time when margins are at historically very low levels and security of supply has become politicised.

Trojan horse

Another key conclusion we have reached based on our research but outwith the scope of the report is that immediate changes to embedded benefits through reforming transmission charging would have a number of adverse effects.

It is true that transmission costs to demand customers would reduce if triad benefits were reduced or eliminated. However, there would be immediate offsetting costs, including:

- a higher capacity market clearing price paid to all generators who are successful in the auction through the elimination of typically price taking smaller generation (though admittedly this may be what DECC wishes to achieve);
- higher wholesale prices, reflecting an increase in the marginal cost of generation as new lower cost stations do not materialize and given the potential closure of embedded generation in response to the removal of triad benefits;
- an increase in the cost of ancillary services as embedded generators staying on the system need to make up for a shortfall in their revenue through higher contract prices;

- higher levels of reinforcement and other costs on the transmission system as embedded generation is replaced by transmission-connected generation (perversely increasing the implied value of generation connecting at low voltage);
- higher levels of reinforcement and other costs at the distribution network level as the export from embedded generation is reduced increasing local power flows;
- higher volumes of losses as power is shipped in from further away;
- potentially higher balancing costs, as national imbalance volume increases; and
- crucially in terms of the bigger picture, a higher cost of capital for all generation due to the increased risk associated with industry change.

Greek Gods' at Play

In the round we believe these impacts would create a significant net detriment to consumers through higher prices but lower security especially in the near term.

As important, there could be immediate and detrimental impacts on investment. Over 2GW of investment that has occurred in the last two capacity market auction rounds, worth an estimated £500mn, could disappear, and competition in future auctions would be immediately diminished.

Cassandra's prophesy

But what seems to have been missed is that the main impact from change would be on existing embedded plant. Much of this is not intermittent but is reliable and controllable. It is making a real and important contribution to security of supply, particularly at the local level and as back-up to industry. Embedded benefits contribute between 20%-50% to a generator's revenues, and the importance of this value stream has increased with falling energy prices and the abrupt loss of LECs, which has already been very detrimental to investor sentiment. We believe several gigawatts of plant could be put at risk by isolated action against the triad benefit, with a direct impact on the capacity requirement sitting behind the capacity market.

For every gigawatt of existing plant that goes off the system, we estimate capacity market costs would increase by between £30-£60mn. Given lead times for new build, it is also likely that further interventions would be needed by the system operator to reintroduce contingency balancing services to counteract crashing security margins.

Cerberus' first meal of the day

There are likely to be other unintended consequences of piecemeal change and short-sighted interventions. There are operational inefficiencies at the local level, especially arising from high levels of unmonitored export ("spill"), which controllable and flexible generation can help meet and which should enable more efficient asset utilisation in an increasingly intermittent generation system. In a world in which we are supposed to be moving to characterised by decentralised local markets and active network management, the value of responsive embedded generation to the wider system should increase. It is an essential accompaniment to large-scale CCGT roll-out at the transmission level and an evolution to a smarter system, not a threat to realization of either.

In addition there is a real risk of killing off flexibility markets before they have developed. The GB electricity market is becoming more diverse and uncertain. Flexibility is key to managing this uncertainty. Storage and demand-side management have the potential to transform the market and enable the future uncertainty to be managed in a cost-effective manner. To this end, embedded benefits are likely to play an important part in creating the business case for investors to invest in these types of project. A reduction in embedded benefits overall in this important stage of the development of flexible products could set the industry back years.

If you would like to more about our work for the ADE, please contact Andy Pace at andy.pace@cornwallenergy.com.

Queen’s Speech clears way for CMA remedies

The Queen’s Speech was delivered on 18 May, detailing the legislative priorities of the government for the next parliamentary session.

The Speech confirmed that a *Better Markets Bill* would be introduced by the government. It is intended to “open up markets, boost competition, give consumers more power and choice and make economic regulators work better”. The government said the bill would help deliver the Conservatives’ manifesto commitment to increase competition and consumer choice in the energy market by implementing the findings of the Competition and Markets Authority’s (CMA) energy market investigation.

The bill will also speed up decisions from the CMA to “benefit both businesses and consumers”, and will seek to simplify the way that economic regulators operate to make processes more straightforward for businesses. Consumers will further benefit from more power and choice through faster switching.

The overall aim of the legislation will be to encourage consumers to switch providers and get a better deal, supporting the government’s commitment to taking steps to keep bills as low as possible. In a briefing document published alongside the speech, the government highlighted research that found that many households could save up to £390/year by switching just three service providers.

The government will also bring forward a *Wales Bill* to establish a lasting devolution settlement in Wales. This will include the surrendering of powers to Welsh ministers over consenting for all onshore wind in Wales, and up to 350MW for all other onshore and offshore energy projects. Industry stakeholders noted that this would include the planned 320MW Swansea Bay Tidal Lagoon project.

Also included in the legislative programme was a *Modern Transport Bill*, which will aim to ensure the UK is at the forefront of technology for new forms of transport—including autonomous and electric vehicles. The government highlighted figures showing that since the launch of the Plug-In Car Grant in January 2011, there have been 60,755 eligible electric cars registered; however it did not detail any new incentives for electric vehicles.

In the text of the speech, the government also detailed how it intended to play a leading role in world affairs, “using its global presence to tackle climate change”. But specific measures to this end were not detailed in the speech or in the background documents.

The speech also saw the announcement of a *Neighbourhood Planning and Infrastructure Bill*, which will contain provisions to put the National Infrastructure Commission (NIC) on a statutory footing. Interim chair of the NIC Lord Adonis said: “I strongly welcome the government’s announcement that it will make the National Infrastructure Commission statutory and independent. This is a major advance for infrastructure planning in Britain and will give the commission the power it needs to do its work.”

Stakeholder reaction to the Speech was mixed. Mike Cherry, FSB national chairman, said: “There are a number of bills announced today which could have a big impact on small businesses and their ability to grow. A key theme appears to be improving the workings of dysfunctional markets and investing in key infrastructure […] The FSB will closely monitor the *Better Markets Bill* as an opportunity to boost competitiveness and drive growth.”

Jo Causon, CEO of the Institute of Customer Service, said: “Customer satisfaction in the utilities sector remains lower than the national average so any move giving customers more choice will drive innovation, keep the industry agile and responsive and ensures suppliers are driven to provide the levels of customer service consumers expect. “With smart meters soon providing near-real time information on customers’ energy consumption, suppliers should also be empowered to compete beyond the traditional ‘price wars’ to help customers control and manage their energy use, save money with accurate billing, and be more environmentally friendly.”

There was less for the energy sector than earlier media reports had suggested, but getting the implementation of the CMA’s findings right is going to be a difficult and important process.

Cabinet Office

Campaign group warns fuel poverty progress is slowing

Changes to schemes designed to address fuel poverty across the UK have hindered progress in addressing the problem, according to new research.

Released on 9 May, the *UK Fuel Poverty Monitor 2015-2016* was prepared jointly by National Energy Action (NEA) and Energy Action Scotland (EAS).

The report noted that there had been some "major areas where progress is being made" on fuel poverty, but that across the UK an estimated 4.5mn low-income households remained unable adequately to heat and power their homes. There are over 500,000 more fuel poor households living in cold homes now than five years ago.

The lack of a co-ordinated approach across the UK and its devolved administrations to ending fuel poverty was described as "profoundly disappointing". Despite initial enthusiasm for the possibility, as outlined in the 2001 UK *Fuel Poverty Strategy,* it was now felt to be a "very distant prospect".

One area in which this reality was particularly notable was the lack of a common approach to the way that fuel poverty was measured across the UK nations. The Low Income High Cost (LIHC) indicator definition is now used in England, but prior to that the whole of the UK used the 10% measure—where a household is considered to be fuel poor if they are required to spend more than 10% of their income on fuel to maintain an adequate standard of warmth.

The NEA said that, beyond the need to make accurate assessments of the number of fuel poor households or within each nation, the divergence in how fuel poverty was defined had also led to a potentially misleading conflation of definitions by ministers and civil servants. The report cautioned that the move to the LIHC indicator could have broader consequences for the other UK nations: for example, moves to re-target GB-wide programmes such as energy bill rebates or the Energy Company Obligation (ECO) to better match the new definition in England could have the unintended consequence of shifting support away from groups in Wales and Scotland who are also in fuel poverty, albeit under a different measurement.

The report recommended that policy makers should be clearer about which definition or measurement of fuel poverty was being referred to, but said there was an ongoing need for the UK government to report on progress under the 10% measurement. An annual reporting scheme was noted as important not only to track progress at the UK-wide level but also to ensure that the wider impact of policy decisions by Whitehall were understood prior to interventions.

A timeline in the report captures the significant variations and changes made through policy interventions over the past 15 years to relevant national and UK-wide affordable warmth policies. As at 2016, while there are statutory energy efficiency targets for the private sector in England and Wales, these are pending in Scotland and are not implemented yet in Northern Ireland. Equally while there is an *Annual Fuel Poverty Progress Report* published in England, there is no such equivalent update in the other nations. There is also no UK wide fuel poverty strategy and England is the only nation with an updated strategy.

A key recommendation of the report was for the Scottish government to implement a detailed route-map with targets and milestones for eradicating fuel poverty. Norman Kerr, director of EAS, added: "For over five years EAS has called on the Scottish government to commit to a detailed route-map with targets and milestones for eradicating fuel poverty. The new Scottish government must now act on this key recommendation. The report also calls on the new government to press on with the introduction of ambitious energy efficiency regulations for private sector homes."

Concerns were also raised in the report about how the changes to the GB-wide ECO scheme would impact on England, Wales and Scotland's own statutory fuel poverty targets. This information, it concluded, must be included within the upcoming impact assessment and consultation on the future of the scheme.

There are some legitimate concerns here, and we expect a refocusing on fuel poverty issues and measures over the coming months within policy circles as DECC begins to get to grips with how it is going to replace ECO.

NEA

Green Deal Finance Company challenges scheme cost claims

The National Audit Office's estimates of the cost of the Green Deal have been challenged by the company responsible for delivering the scheme.

The public accounts select committee took evidence on *Household Energy Efficiency Measures* on 11 May. The session followed an NAO report on the issue, which suggested that every Green Deal loan, of which there were around 14,000, had cost taxpayers £17,000. But Mark Bayley, who served as CEO of the Green Deal Finance Company (GDFC), said he had "very significant" reservations about the figure as it "includes things that were not conditional on Green Deal finance".

Bayley said: "The total cost invested in the Green Deal was not all about Green Deal finance; it was primarily about the implementation of measures. For example, it is like attributing all the costs of the meat counter for the running costs of a supermarket, and then on top of that adding all the costs of building the supermarket."He then explained that, following the government's decision to cut funding, the GDFC had 14 expressions of interest from the private sector and three indicative offers. A negotiation is underway with the preferred bidder. This had surpassed the company's expectations; it had anticipated that private sector interest was unlikely to materialise for two or three years, but a transaction might be completed by the end of the month. "If it doesn't result in a transaction, nevertheless the system is sitting there, fully funded, developing a record on repayment […] we have something, as I have said perhaps too often, of real intrinsic value for the taxpayer, created out of the investment being made."

Former DECC permanent secretary Stephen Lovegrove said that, in advance of its launch, nobody had possessed a clear view on how the Green Deal would perform—it was an "innovative" and "ambitious" policy and "nobody had tried anything like it before". But he stressed that—contrary to some views expressed by the committee—it had always been intended that the Energy Company Obligation (ECO) would deliver the bulk of the savings in terms of both carbon and pounds.

Lovegrove identified two founding failures with the Green Deal. First, from the market testing that DECC undertook, it incorrectly identified the availability of finance as the determinant of whether people would be willing to pay for energy efficiency measures. While, he said, this was an important issue for consumers, it was not in fact the key concern—and this mis-apprehension had driven the design of the scheme "in a probably unhelpful way". Secondly, DECC had not pitched the scheme to households in the most engaging way. The government had needed to propagate the fact that energy efficiency measures would make the house more comfortable, rather than focusing on the finance and the increase in the value of the property.

Bayley said the scheme had further been undermined by the lack of distribution channels for the finance. The product was only sold in the home by Green Deal Providers; the GDFC had wanted to promote a liberalised framework that would see people opt for Green Deal finance in the same way that they bought financial products—online or over the phone. In-home selling appealed only to a niche part of the market.

Peter Smith, head of policy at National Energy Action, suggested that in future the whole—rather than a subset—of the supplier obligation would need to be targeted at fuel poverty. This would avoid some of the risks of low-income consumers paying for a policy from which they did not benefit. There needed to be a guarantee for the most vulnerable households; Smith said that a key failing of ECO was that those eligible for support were not guaranteed to receive any measures despite helping to cover its cost.

Energy UK chief executive Lawrence Slade said that focus on the Green Deal's interest rates could be misleading, as equally problematic was that it had been "rushed to market". Consumers simply had insufficient time to make sense of the proposition on offer given the level of complexity behind it.

The failings of the Green Deal and to a lesser extent ECO are rightly being evaluated to inform future schemes. At present however there is little consensus on why results came in well below expectations.

Parliament

Consumers to see sharp increase in cost of energy subsidies

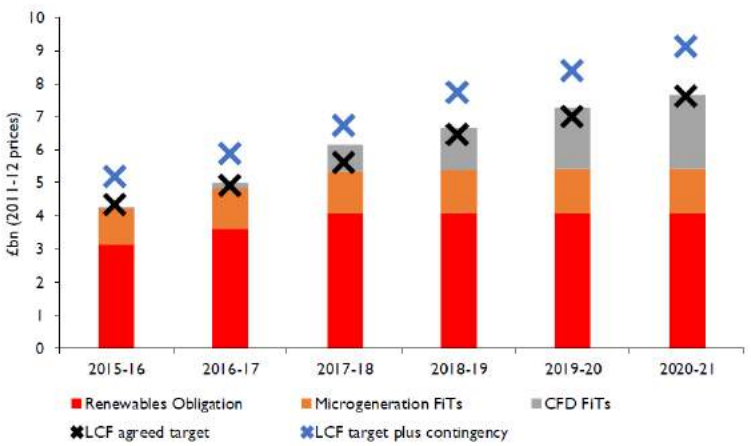
Research by Cornwall Energy has shown that the subsidies paid by consumers to support renewable electricity and ensure supply security will increase sharply over the next few years.

On 20 May the consultant published a report that analysed trends in Levy Control Framework (LCF) spending through to 2020-21, and how these costs would be recovered from consumers. It said that by 2020-21 consumers would be paying 124% more for LCF schemes than in 2015-16—with the unit cost for the policies increasing from 1.51p/kWh to 3.38p/kWh over the period.

This increase will be front-loaded; the report said that by 2017-18 a series of factors would combine to have pushed up the unit cost by 84% (to 2.78p/kWh).

The key driver of this increase would be the overlap between the closure of the Renewables Obligation (RO) to new projects and the first developments becoming operational as part of the contracts for difference (CfD) scheme.

LCF component costs and targets to 2020



Source: Cornwall Energy

Another contributor would be the government's decision to bring forward the first year of delivery under the capacity market to 2017-18.

Further, the government has recently confirmed its intention to exempt energy-intensive industries from the indirect costs of the RO and the small-scale feed-in tariff scheme. The report estimated that this would reduce the charging base for these schemes by around 7%, in turn raising costs for non-exempt consumers.

But the report also highlighted the impact made by the government's efforts over the past year to reduce spending on low-carbon subsidies. These policy moves followed analysis, published last July by the Office for Budget Responsibility, which suggested the government was set to spend £9.1bn (in 2012 prices) on the three renewables schemes covered by the LCF budget—£1.5bn over the budget for that year.

Cornwall Energy projected that by 2020-21 LCF spending would reach £7.7bn—only £100mn over budget, although the overspend could be as high as £600mn by 2017-18.

Over half of LCF costs in 2020-21 would cover the RO (at £4.1bn); however, the majority of the increase from now until the end of the decade would come from the CfD scheme. The costs of the CfD were expected to rise from £12mn in 2015-16—covering purely administrative costs—to £2.1bn in 2020-21. The main contributor to these costs would be the eight contracts awarded by DECC in 2014 to the schemes successful through its Final Investment Decision Enabling programme.

But Cornwall Energy said these costs remained difficult to forecast and a number of factors could yet shift its expectations. For example: a rebound in wholesale prices would lower the level of top-up payments required under the CfD; projects could be delayed and might not arrive on the system as scheduled; and the weather would play a major role in determining the output from power stations.

These policy costs are going to exert a significant upward pressure on bills over the next couple of years irrespective of what happens to wholesale prices, and they have historically been passed on quickly by suppliers to consumers.

Cornwall Energy

No business was scheduled in Parliament before the Queen's Speech—the next Parliamentary Update will be in next week's issue.

Smart meter savings "unlikely to change consumer behaviour"

An energy analyst has suggested that the savings available to consumers by utilising smart meters are unlikely to prompt a significant change in consumers' behaviour.

WiFore Consulting's Nick Hunn provided evidence to the energy and climate change select committee on 3 May. He said that the potential to save £26/ year—or 7p a day—through the use of smart meters, as DECC has suggested is possible by 2020, is unlikely to provide a sufficient incentive for behavioural change.

Hunn said: "Back in 2010, we started to roll out in-home displays (IHD), which were much cheaper devices. People could clip them on to a meter. Essentially, they showed the same information—how much energy you were using. You could see that in real time, so people would turn their kettles off. There are far cheaper ways of achieving savings than trying to justify a smart metering programme just on those savings." Hunn further raised concerns about the arrangements for installing IHDs. At the initial fitting of a smart meter, customers are provided with an IHD that is free; however, they are unlikely to be provided with another one if customers change suppliers. Hunn said that, "with luck", the existing IHD would work with the new meter, "but there is a lot of work to be done to make sure that happens".

"There is general acceptance that a large percentage of customers will probably stop using them after the first year", Hunn explained. "There is nothing in the plans to say that a customer will then get another IHD if they change supplier, so it is about that one-off hit. You need to try to change behaviour in the first year when the smart meters go out. At the moment, there is nothing in place to try to keep that going."

Parliament

New permanent secretary appointed at DECC

The former chief executive of the Competition and Markets Authority, Alex Chisholm, has been appointed as the new permanent secretary for DECC.

The department announced the appointment on 10 May. Chisholm has spent the last nine years heading up public agencies responsible for economic regulation and market development—he has been at the CMA, as well as Ireland's Commission for Communications Regulation. Previously he worked for 12 years in business, beginning in the strategy team at Pearson and then running a series of international businesses in the media, technology, ecommerce and retail sector.Chisholm said he looked forward to addressing the different challenges involved in ensuring the UK has secure, affordable and clean energy supplies.

Energy and climate change secretary Amber Rudd, said: "I greatly look forward to welcoming Alex as DECC's new permanent secretary. His experience across the public and private sectors, including most recently at the CMA, will be hugely valuable to our Department. This is an important time for DECC as we work to deliver the secure, affordable and clean energy our families and businesses can rely on now and in the future. Alex's leadership will be vital as we continue our drive to improve the energy market, reduce people's bills and build an energy infrastructure fit for the 21st century."

DECC

Scottish government reshuffle takes place after election

The newly appointed Scottish economy secretary Keith Brown is to take on responsibility for the country's energy brief, replacing Fergus Ewing. Brown had been the cabinet secretary for infrastructure, investment and cities since 2014. First minister Nicola Sturgeon has appointed Ewing, who had been serving as the minister for business, energy and tourism, as rural economy and connectivity secretary.

Paul Wheelhouse will serve as business, innovation and energy minister within Brown's department. The new cabinet, confirmed on 18 May, also includes a dedicated environment and climate change secretary for the first time, with Roseanna Cunningham appointed to the role. In a statement the Scottish government said that the new appointment underlines its "ambitious plans to further reduce carbon emissions".

Scottish government

Large-scale heat decarbonisation needed by 2030, say academics

Decarbonising heat at scale will need to be underway by the 2030s if the UK is to meet its carbon reduction targets, a report by Imperial College has found.

The report, launched on 5 May, suggested that preparation for the decarbonisation of the heat sector needed to begin immediately, so that carbon emissions were reduced "cost-effectively and with acceptable levels of disruption". This was especially true, it argued, in the case of space heating and hot water in domestic and commercial premises, which are responsible for between a fifth and a quarter of total carbon emissions.

The report's authors admitted that the scale of the task "can seem daunting". But they argued that the process would be made more manageable through "sufficient and timely preparation for the roll-out of an appropriate combination of approaches, and by spreading the delivery over suitable long term infrastructure programmes".

The report noted that due to the "diverse range of application environments […] no single solution suffices, so a variety of options will be needed". It recommended that "service requirements and delivery methods should be established and decided locally, rather than seeking a single national level approach".

Imperial College

Climate change policies not harming UK's competitiveness, study finds

The Committee on Climate Change's (CCC) proposed Fifth Carbon Budget would not harm the UK's competitiveness and could in fact help to deliver long-term economic growth, an academic study has found.

The report was published on 10 May by the Grantham Research Institute on Climate Change and the Environment. It found that, although the UK had one of the most ambitious plans to reduce national greenhouse gas emissions by 2030, many of its international competitors had also committed to strong cuts. The Fifth Carbon Budget, as proposed by the CCC, would commit the UK to reducing its national greenhouse gas emissions by an average of 57% between 2028-32, compared to 1990 levels.

The report's authors said that there was no evidence that businesses were less competitive globally as a result of existing policies that aim to reduce the UK's greenhouse gas emission, with only a few sectors—accounting for just 4% of GDP—at risk from significant negative impacts. They added: "Climate change policies can increase the competitiveness of the UK in the long term by encouraging greater innovation and efficiency."

The report concluded that: "The UK is well-positioned to benefit from a global transition to a more resource-efficient and renewable economy, provided flexible structural policies allow it to utilise its comparative advantages.

Grantham Research Institute on Climate Change and the Environment

Ofgem confirms RIIO-T1 mid-period review

The regulator will be reviewing certain elements of the existing transmission price controls, while progressing parallel work on holding companies to greater account for delivering outputs.

Ofgem announced its decision on 11 May to hold a mid-period review (MPR) of the price control arrangements for both electricity and gas transmission. The focuses of the review will be: National Grid Gas Transmission's (NGGT's) Avonmouth pipeline outputs, National Grid Electricity Transmission's (NGET's) Wider Works category of load-related expenditure and NGET's new enhanced system operator outputs. If Ofgem decides these outputs—collectively worth £285mn—are no longer required, then funding may be cut from the companies' price controls.

RIIO-T1 is an eight-year price control for electricity and gas transmission companies that runs from 1 April 2013 until 31 March 2021. During this period, companies are required to deliver agreed outputs for consumers, and in return they can recover their costs through transmission charges. However, when the price control is set, some outputs and funding is uncertain. The mid-period review is a way of dealing with this uncertainty. It allows for outputs to be added or removed as a result of changes in government policy or the needs of consumers and network users.

Ofgem said that, despite responses to its November consultation on a possible MPR, it will not be widening its scope to include a more fundamental review of RIIO outputs and revenues in light of network company financial performance. It reasoned that such a scope may damage confidence in the regulatory regime and increase companies' risks, which would ultimately lead to higher costs for consumers. Instead, the MPR will focus on just three issues.

The first is NGET's lower than expected volume of connections—information picked up by the regulator through annual reporting. A reduced number of transmission connections has meant a decrease in spending in NGET's Wider Works (General) category of load-related expenditure. However, NGET is planning additional investment to help manage the growing impact of embedded renewable generation on its networks. Consequently, Ofgem proposes to investigate this area as it considers that the outputs are no longer required in the volumes previously specified.

NGET's new responsibilities as system operator are second issue that the MPR will concentrate on. The Integrated Transmission Planning and Regulation (ITPR) project placed obligations on NGET to assess the need and timing of future reinforcements across GB as well as cross border interconnector capacity requirements for the annual delivery of the Network Options Assessment report. NGET estimates that the cost of this work will be around £20-30mn. Ofgem will therefore consider allowing for these additional costs to be recovered and the potential introduction of new outputs to ensure the needs of consumers and network users are met.

The third and final focus lies in gas transmission, where the MPR will look at the decreased need for a pipeline solution to ensure security of supply as part of the Avonmouth LNG storage facility's decommissioning. The price control gave NGGT £165mn to carry out this work, but the regulator now understands that the pipeline is not needed as security of supply can be guaranteed by much cheaper means. It will therefore consider the removal of this RIIO output.

In its decision document, Ofgem also set out work which it is planning to undertake outside of—but parallel to—the MPR. This work falls into three categories: ensuring output accountability; filling gaps in the RIIO framework; and improving RIIO operation. Accountability work will include clarifying what happens when outputs are not delivered or delivered late by network companies. Continued work on the Network Output Measures (NOMs) methodology for transmission and gas distribution will help to fill gaps in the RIIO framework. Clearer NOM methodologies will allow companies to better prioritise their £15bn of work on replacing or reinforcing their assets across the sectors. Finally, RIIO operations will be evaluated, looking specifically at the Environmental Discretionary Reward and the Stakeholder Engagement Incentive to make sure they are appropriately focused and reflect business-as-usual activities. Going forwards, Ofgem intends to examine these MPR issues in more detail. Proposals resulting from deliberations will be consulted on this summer and any associated licence changes will aim to take effect from 1 April 2017.

Stakeholder calls for general review of price control fundamentals have been channeled into work parallel to the review, allowing the MPR to focus on ensuring transmission charges better reflect costs.

Ofgem

Report hails success of Low Carbon Network Fund

An Ofgem-commissioned report has found that key learnings from projects completed under the Low Carbon Networks Fund (LCNF) have seen measurable uptake.

Published on 28 April, the EA Technology report said that Distribution Network Operators (DNO) were acting upon the results of LCNF projects, by incorporating flexible connections, dynamically reconfiguring networks to meet needs, and implementing demand-side response (DSR).

The LCNF provided a total of £500mn over five years to support DNO-sponsored projects, which have trialled new technologies such as voltage management and local generation.

The review's aim was to establish what learning had been derived from LCNF projects and the extent to which this learning has been incorporated into business-as-usual activities by DNOs. It was not evaluating the projects on grounds of cost-effectiveness. EA concluded that the projects had proved that innovative technologies like active network management, voltage management and DSR could deliver real benefits to customers. Meanwhile, some technologies had the potential to deliver further benefits, but were held back by external or economic barriers, such as smart meters being necessary for full DSR capabilities.

Learning from the LCNF projects was found to be contributing to DNOs' fulfilment of all six of the RIIO price control outcomes (customer satisfaction, safety, reliability, conditions for connection, environment, and social obligations). It has also helped prepare DNOs for the future challenges that technologies will pose, such as electric vehicles. In all cases, the LCNF projects worked towards increasing the flexibility of the network, which allowed for an "unprecedented" level of engagement with customers. By extension, this should give rise to greater customer satisfaction and more efficient grid connections. These, the report said, were the main beneficial outcomes from the LCNF.

DNOs also examined how grid connections for renewables developments could be sped up through greater engagement with developers, and offering flexible connections as standard. These do not involve the same level of enabling work as traditional connections and are therefore much faster and cheaper.

DSR is being incorporated by all DNOs into their approach to network management, although this covers a wide range of technologies so there is no one-size-fits-all approach. Active Network Management is already being used by all in some form or another, such a smart fuses at low voltages and automatic reconfiguring of high-voltage networks in response to outages. Together, EA said that these two technologies demonstrated the flexibility needed to cater for network needs. Additionally, because of the range of technology types available, the report identified a healthy level of competition between manufacturers and service providers.

The LCNF also saw a number of voltage management devices used for more active control, which have successfully been used to help with demand management and are under consideration for incorporation into everyday practice by several DNOs. For example, Electricity North West's Customer Load Active System Services system, involving around 485,000 customers, was shown by surveys to have had no perceptible adverse effect on power quality for customers. Energy storage has been trialled by several DNOs, but cannot yet be incorporated into everyday activity due to it being difficult to justify economically if it is only used for managing network demand.

Since the report, the regulator opened a consultation on 16 May to seek views on DNOs' applications for the Successful Delivery Reward (SDR) for their LCNF projects. Seven applications have been received, collectively eligible for up to £4.9mn in rewards, though the sums are entirely at Ofgem's discretion. The SDR rewards DNOs whose projects had been well-managed, use best practice on risk management, and been delivered to required standards, cost-effectively and in a timely manner.

Stakeholder responses are invited up to 6 June.

The LCNF projects were a major step towards incentivising innovation among distributors. This report suggests the additional costs to consumers were well worth it.

EA Technology Report   Ofgem - consultation

Distribution networks consider reforms to supply security standard

A consultation has been issued on options for reforming the P2 standard to ensure it remains fit for purpose as networks and network use evolve.

The consultation was issued on 2 May by a workgroup of the Distribution Code Review Panel (DCRP) that is currently considering options to reform Engineering Recommendation (ER) P2 *Security of Supply*. P2 is the foundation underpinning the Distribution Code and sets the standards for ensuring a secure and reliable distribution network.

The DCRP engaged a consortium of Imperial College, NERA and DNV GL to carry out a fundamental review of ER P2, which commenced in February 2015. The review is being conducted in two Phases: Phase 1 is to identify and agree a range of options for a future UK security standard and agree the most appropriate approach that should be taken into Phase 2, which is the preparation and codification of the new standard.

P2 is a "deterministic" standard that largely focuses on ensuring sufficient capacity is available to meet the peak demand in a manner and timeframe consistent with the size of network in question. It is also risk based such that larger load groups are in general seen to be deserving of a higher level of security. The consultants said the most fundamental issue regarding its future evolution is whether it continues to prescribe economically efficient investments given changes in the energy market, including emerging technologies and the changing roles of customers, demand and generation.

The consultants identified two key areas: the first concerns whether P2 balances the cost of network infrastructure with the security benefits delivered to distribution network customers now and into the future—whether the current standard is efficient and delivers value for money for all network customers. They said this required considering the difference between theoretical and actual performance of the present standard, as the consultants said in practice many 11kV and low voltage designs are considerably more secure than P2 actually requires and the account taken of security benefits from embedded generation in network planning can vary in practice.

The second area is that, given the present network design standards have predominantly resulted in network security provided through asset redundancy, whether P2 will impose a barrier to innovation in network operation and design and to the implementation of technically effective and economically efficient solutions that improve the utilisation of the existing network assets and maximise value for money to customers. High level options for reform considered included: retaining the current deterministic standard without revision; retaining it with improvement; implementing a non-deterministic planning standard: implementing a high-level standard that obliges efficient investment while retaining some deterministic elements; or abolition of the planning standard.

The consultants concluded that the P2 standard does need improvement and should not be retained unchanged, that is tends to be "conservative", dealing with worst-case scenarios. They said relaxation of the present N-1 security requirement, that enables continued supply after one fault, could improve overall economic efficiency. Work by Imperial College indicated the potential benefits of relaxing the security constraints across the HV, EHV and 132kV network at the GB level "could reach 42% to 67% of the project reinforcement spend in base of significant load growth at LV and HV level by 2030". The potential impacts on customers needed to be reviewed by all stakeholders including DECC and Ofgem and that there would be interactions with the RIIO-ED1 price control.

The consultants also concluded that improvements to the present deterministic standard within the current price control period should also include the use of all non-network technologies, including distributed generation, demand-side response, demand-side management and electricity storage where this is a suitable alternative to network redundancy. Additionally they suggest that there should be flexibility to permit network planning outside of the deterministic rules where necessary so that DNOs can conduct economic analysis where the deterministic rules are not appropriate.

Responses are requested by 12 June.

This is an important review considering fundamental trade-offs for how distribution networks are planned for the future and therefore the costs that consumers will pay.

Distribution Code

E-Serve reminds suppliers that implicit GoOs are ineligible for 2015-16

Ofgem E-Serve has told suppliers that it will not be able to evaluate any Guarantees of Origin (GoOs) backed by implicit-trading evidence that are submitted for the 2015-16 scheme year. The environmental scheme administrator made the statement on 28 April as it sought to clarify the decision it made on 1 March to accept unconstrained implicit trading evidence for GoOs from 2016-17. GoOs are used by suppliers to prove consumption of overseas electricity in the UK for the purposes of the fuel mix disclosure, and associated schemes such as contracts for difference and the feed-in tariff scheme.

Explicit trading requires suppliers to demonstrate a clear pathway for importing electricity via booked interconnector capacity. Implicit trading removes this requirement, with clearing price and cross-border capacity allocations calculated by an algorithm. This means suppliers are thus unable to provide evidence of electricity having physically crossed the interconnector. The decision to only accept implicit evidence for GoOs from 2016-17 onwards follows a consultation earlier in the year, where E-Serve said that this would avoid retrospectively changing guidance or unfairly disadvantaging some suppliers. It has since received questions about the situation for this scheme year, and assured suppliers that full guidance would be forthcoming in time for use in 2016-17.

E-Serve concluded by reminding suppliers that they are responsible for reporting only GoOs that are eligible, and that it would examine any possible distortionary effects of the changes on feed-in tariff levelisation, which may result from the trading of large volumes of implicit GoOs.

Ofgem

Ofgem consults on the effectiveness of distributors' actions to minimise thermal losses

The regulator is seeking views on how effectively Distribution Network Operators (DNOs) are managing electricity losses on their networks, and how much money they should consequently receive under the Losses Discretionary Reward (LDR).

The LDR incentivises networks to manage their electricity losses efficiently by financially rewarding DNOs who significantly shift expectations of what they are capable of doing to manage losses. Overall, the LDR can award up to £32mn across DNOs over three tranches that are spread out across the RIIO-ED1 price control. In a consultation issued on 6 May, Ofgem explained that it has now received six submissions from DNOs for Tranche 1 of the LDR, where £8mn is potentially available.

The regulator now has to assess these submissions. It explained that in the first tranche DNOs will be judged by: how much they have demonstrated an understanding of losses; effective engagement and sharing of best practice with stakeholders; processes to manage losses, and innovative approaches to losses management. Each of these four criteria has an equal weighting and DNOs must therefore produce an appropriate level of evidence for each in order to be considered for the discretionary reward.

The regulator asked if any of the processes proposed by DNOs would significantly shift expectations of what they are capable of doing to manage losses. Further, it sought views on whether DNOs had shown any changes in their engagement on losses, if their management processes are effective and efficient, and if new smart meter data will be used effectively to minimise losses.

Responses are invited until 6 June.

Ofgem

Transmission system operators invite views on network scenarios

ENTSO-E and ENTSOG issued a joint consultation on 12 May on the scenarios that should be used for the electricity and gas *Ten Year Network Development Plans* (TYNDPs) to be issued in 2018. Both organisations are required under European Regulations to produce these non-binding plans for the development of the pan-European networks every two years. They are also the first step of the European Commission's Project of Common Interest process and each candidate project must be submitted for the Plans so that the ENTSOs can apply the cost benefit analysis methodology developed for the plans.

The building of scenarios is the first stage in the process of the TYNDPs' development; they cover visions on energy demand, economic growth, prices and technology developments. Views are invited on what time horizons should be considered for the plans, which is the most important to carry out the cost benefit analysis for, and how many scenarios should be included.

Respondents are also invited to build their own suggested scenario for 2030 and 2040. A workshop will be held in Brussels on 2 June, and responses to the consultation are requested by 12 June.

ENTSO-E

Regulator publishes details of default cap and floor regime for interconnectors

In light of its decision last November to open a second cap and floor regime application window for interconnectors this year, Ofgem has now published a summary of how the default regime will work alongside an updated financial model.

The regulator created the cap and floor regime as a way to incentivise investment in interconnector capacity. It does this by setting an upper (cap) and lower (floor) limit on the amount of revenue an interconnector can collect. If the cap is exceeded then the interconnector has to pay National Grid Electricity Transmission (NGET) the excess, whereas if revenue falls below the floor then NGET tops it up to the required level.

At the same time as encouraging investment, the regime is also designed to protect consumers. When the cap is exceeded and money is paid to NGET, this additional revenue is used to lower transmission charges; a reduction that ultimately feeds through into bills. The default regime states that cap and floor values will be set over a 25-year period (rising with inflation). Cap levels can be increased or decreased by 2% depending on the availability of the interconnector. The regime will cover 50% of projects' costs and revenues, and interconnectors will be assessed every five years to compare revenue with cap and floor levels. Ofgem noted that developers can request variations to the default regime if they can demonstrate these would be in the interest of GB consumers.

The application window for the second cap and floor regime began on 31 March and will end on 31 October.

Ofgem

Ofgem confirms licence changes for Phase 3 of code governance review

The regulator issued a statutory consultation on 10 May on the licence changes to implement parts of its final proposals for Phase 3 of the review of industry code governance arrangements.

The move follows a consultation issued at the end of March on the licence modifications, opened alongside the decision on the reforms *(ES518, p13, 25/04/16)*, which impact the electricity transmission and distribution licences, and the gas transporter and gas supply licences. The licence changes will introduce an Ofgem-led Significant Code Review (SCR) process in addition to the existing process, whereby the regulator can lead an end-to-end process to develop code modifications, and also introduce the ability for Ofgem to raise SCR modifications. It believes these changes will enhance the existing process and provide additional flexibility. In addition there are licence changes to add an applicable objective related to facilitating efficiency in code administration in the Grid Code and the Distribution Code, as well as changes to facilitate open governance in the Grid Code. Changes to effect this are also being taken forward through a Grid Code modification (GC0086).

Responses to its consultation on licence drafting concluded that the licence drafting would achieve the policy proposals set out in the final proposals; the drafting would facilitate the implementation of GC0086; and, that where the licence drafting differs between licence conditions, the substantive effect is materially the same.

Any representations to this consultation are requested by 7 June.

Ofgem

Regulator consults on improving smart prepayment data collection

Ofgem has proposed two changes to the Social Obligation Requirements (SOR) for smart prepayment data in a bid to improve the information suppliers must collect on customers.

The regulator opened a consultation on 6 May, suggesting that suppliers should have to record the number of times its customer base tops up per top-up channel, with reporting to begin from 28 January 2017. It also proposed pushing back the start for suppliers' obligation to record the number of smart meter customers using prepayment and credit modes to the same date. Ofgem explained that these changes would feed into the future monitoring of the smart prepayment market.

Monitoring the use of different means of topping-up would provide additional information for Ofgem to ensure suppliers are offering customers suitable payment options. Stakeholders have brought it to the regulator's attention that some customers are actively asking for alternatives to cash for topping-up, so it is seeking additional data. Quarterly and annual reporting on prepayment and credit modes will help align new data with existing SOR information on the total number of smart meter customers. In addition, it will assist in comparing smart meter trends with those for traditional meters. Delaying the start of this process will therefore simply align it with the beginning of other proposed data items. The regulator welcomes responses until 6 June.

Ofgem

SSE reports lower profits

SSE released its preliminary results for the year to 31 March 2016 on 18 May.

The resulted showed that the company's adjusted profit before tax fell by 3.3% to £1,513.5mn. This reduction reflected a "challenging year" for the business with lower gas prices, mild weather and a new regulatory price control marking a reduction in profits in its three business divisions.

SSE's wholesale business saw operating profits reduce by 6.6% to £442.5mn, mainly due to the lower wholesale gas prices affecting its gas production business.

Total thermal generation fell from 18,931GWh in the year to March 2015 to 18,081GWh. However, this was offset by an increase in renewables generation from 8,656GWh to 9,695GWh. This meant total generation output was broadly stable at 27,587GWh in 2014-15 to 27,776GWh in 2015-16.

Operating profit in gas production fell by 94% from £36.6mn to £2.2mn, reflecting a lower average achieved price for gas produced.

SSE profits and account numbers

	2014-15	2015-16	Change (%)
Supply operating profit (£mn)	368.7	398.9	+8.19
Total energy customer accounts (British Isles, mn)	8.58	8.21	-4.31
Total adjusted operating profit (£mn)	1,881.4	1,824.4	-3.03

Source: SSE

In its networks division, SSE saw operating profit down 1.1% to £926.6m as part of its new regulatory price control. There was a 56% increase in Scottish Hydro Electro (SHE) Transmission's operating profit from £184.1mn to £287.2mn, reflecting the ongoing delivery of a major programme of capital investment including the first full year of construction of the Caithness-Moray transmission link.

SSE's electricity distribution operating profit was down by 20.7% from £467.7mn to £370.7mn primarily because of the expected reduction in base revenues under the first year of the RIIO ED1 price control. During 2015-16, SHE Transmission completed a number of upgrades and reinforcements to its transmission network in the north of Scotland, including the £210mn subsea upgrade and associated onshore infrastructure on the Kintyre-Hunterston projects.

In the last year, SSE's total capital and investment spend was £1.6bn—including the development of the Caithness-Moray electricity transmission link. The company has expanded its renewables portfolio with 67MW of new onshore wind commissioned this year and a further 548MW in construction, including the Galway Wind Park, Ireland's largest windfarm. It also purchased a 20% interest in the new Shetland Gas Plant and four Greater Laggan gas fields.

In the retail business, SSE's operating profit was down 0.4% to £455.2mn. Results were negatively impacted by the milder weather and lower customer numbers. Strong growth in business energy supply, particularly in the industrial and commercial sector, offset lower household profits resulting in an overall increase in operating profit of 8.2% in energy supply. Year-on-year SSE fell from 4.37mn domestic electricity customer accounts to 4.16mn. Gas customer accounts fell from 2.96mn to 2.79mn. Going forward, the company said it would focus on addressing this decline in customer numbers.

SSE reiterated that its objective was to earn a sustainable level of profit over the medium term. Chief executive Alistair Phillips-Davies said: "Some of the mist is beginning to clear around the legislative, political and regulatory environment and SSE will continue to invest for the future [...] Today's announcement of our plan to invest up to £6bn in the next four years will help deliver secure, low-carbon and affordable energy for the UK and Ireland's energy customers and the investment in new energy infrastructure for the decades to come."

SSE's report makes clear it is facing the same challenges as the other Big Six companies of maintaining revenues in an increasingly competitive retail landscape.

SSE

Electricity switching in April stays high

New figures from Energy UK have revealed that the number of customers switching electricity suppliers has surpassed 400,000 for the third month in a row.

The organisation's monthly update, issued on 11 May, showed that 438,166 customers switched in April—significantly higher year-on-year—but down from the previous month, when 476,528 switched. There have now been over 1.5mn switches this year. The number of transfers to small and mid-tier suppliers has remained constant, accounting for 43% of all switches in April.

The net gain by small and mid-tier suppliers was 145,737, which accounted for 33% of all switches and was also consistent with the previous month. The switches between larger suppliers accounted for 37%, whereas 10% were from small and mid-tier to large suppliers. Both of these figures were down on the previous month.

Energy UK

Offshore wind project in doubt after CfD terminated

The future of the £2bn Neart na Gaoithe windfarm project is uncertain following the cancellation of its contract for difference (CfD).

The 64-turbine project, based in Scotland's outer Forth estuary, was one of two offshore windfarms that won subsidies through the CfD process in 2015. However, the Low Carbon Contracts Company (LCCC) withdraw the subsidies after a 26 March milestone deadline to invest £200mn in the project was missed. This was the result of a delayed verdict on a Judicial Review launched by the RSPB, which is opposing the plans over a threat to the gannets at the nearby Bass Rock colony.

The *Financial Times* reported on 12 May that the developer of the 448MW project, Mainstream Renewable Power, "strongly disputes the validity of the termination notice". The developer said: "Neart na Gaoithe Offshore Wind Limited are currently in arbitration with the LCCC over the terms of its contract for the Neart na Gaoithe offshore windfarm in the outer Firth of Forth."

A spokesman for Mainstream said the project is still ready to start and the financial backer remains committed, adding that the consortium behind the windfarm "continues to work hard to ensure that this […] project will be built as planned".

No link

RWE npower encouraged by slowing customer losses

New figures from RWE npower have suggested that the company is stemming the rate at which it is losing household customer accounts.

In a statement issued on 12 May, CEO Paul Coffey said that, while no company wanted fewer customers, npower had lost only 18,000 domestic customer accounts in the first quarter of the year—the smallest quarter-on-quarter reduction it has experienced since 2013. The company has overall lost around 320,000 accounts since Q115.

Meanwhile, npower said it was also holding its ground in the business sector: SME accounts were down by 10,000 year-on-year to 190,000, while industrial and commercial accounts moved up by around 10,000 to 220,000.

RWE npower

World Bank increases oil price forecast

The World Bank revealed on 26 April week that it was to raise its forecast for crude oil prices in 2016.

The organisation increased its forecast from $37/ bbl to $41/ bbl amid improving market sentiment and a weakening dollar. The crude oil market rebounded from a low of $25/ bbl in mid-January to $40/ bbl in April following production disruptions in Iraq and Nigeria and a decline in non-OPEC production. All main commodity indexes tracked by the World Bank are expected to decline in 2016 from the year before due to persistently elevated supplies.

Senior economist John Baffes said: "We expect slightly higher prices for energy commodities over the course of the year as markets rebalance after a period of oversupply. Still, energy prices could fall further if OPEC increases production significantly".

World Bank

The value of interconnectors—Professor Michael Grubb

The UK is traditionally a trading nation, reflecting in part its island status and maritime history. One of the oddities arising however, is that same physical feature has historically impeded electricity trade, which depends on physical interconnections, to which the sea has been a major barrier. With modern transmission technologies, that has changed.

Following hesitant modest steps of interconnection up to the Millennium, a gradual growth culminated with Ofgem establishing a regulatory cap-and-floor structure to encourage private investment, and opening a "Window" for applications in 2014. This resulted in five new proposals, all ultimately approved and in various stages of development, which will by c.2020 more than double our interconnector capacity from about 4 to over 10 GW—about 20% of GB peak demand. Ofgem's central estimate is that these projects will bring over £10bn of benefits over the next 25 years.

Ofgem has now opened a second Window for Applications, with potential for new and larger interconnectors to be proposed. At the same time, there is for the first time in many years criticism from some quarters, notably a recent report from Aurora Energy, and (to a lesser degree) from Oxera, arguing that the economics of interconnectors are not as positive as most people think. This piece summarises the main issues. The economic case for interconnectors stems from five kinds of benefits.[3]

The **first** derives from structural differences in generating costs: UK wholesale electricity prices are substantially higher than on the continent, so Interconnectors give us access to cheaper electricity.

Second is the benefit of temporal diversity – different patterns over time. Electricity demand varies by the hour, as does the output of wind and solar which are growing rapidly across Europe. Coupling systems through interconnectors enables power to flow to better accommodate these variations, smoothing the net profile, maximising the value of renewables, and reducing production costs on both sides. This is a benefit that will grow in particular as the volume of variable power sources grows. The scale of benefits will also increasingly depend, however, on which system one is connected to. Connection to Denmark is more valuable than to France, for example, because its demand profile differs more and because weather fronts take hours or even days to cross the North Sea. Norway is even more valuable because its hydro capacity in effect acts as a large electricity store.

Third, interconnectors enable us to pool capacity and use it more efficiently to maintain security of supply. Peak demands in different systems do not occur at identical times, plants do not fail at the same time, and some carry more spare capacity than the GB. Even amongst our closest neighbours, over the period since 2011 when there have been frequent concerns about capacity adequacy in the GB system, the narrowest margin (of capacity above peak demand) realised *collectively* amongst GB, Ireland, France, Netherlands and Belgium was 16GW—a sizeable safety margin when viewed collectively. Pooling capacity contributes to an estimated €100bn/ yr savings from a fully integrated European system by 2030.

Fourth is the simple fact that interconnection gives us access to larger and/or cheaper renewable energy resources, the economics of which tend to depend on local physical conditions, planning obstacles, etc. As with the temporal benefits, this becomes more important as the level of renewables increases.

Finally, interconnection brings some dynamic 'balancing' capacity. Electricity systems need capability to cope with fluctuations to ensure that demand and supply always match. Traditional sources of inertia, found in large station generators and their boilers, are declining; interconnectors, coupled to another entire generating system through modern power electronics, could provide such balancing capability.

Why then have Aurora and Oxera raised question marks about the benefits? The technical reasons they give focus on the first of the five types of benefits, with particular concerns about two drivers of structural price differentials: GB generators pay network and balancing charges, which interconnectors themselves do not and GB generators pay the UK carbon floor price ("carbon price support"), whilst foreign generators pay the price of the European emissions trading system (EUETS) which is currently languishing at much lower levels.

[3] There are of course different ways of defining and grouping the benefits: Ofgem's assessment and the most comprehensive recent published analysis for the National Infrastructure Commission, which identified five types of value closely aligned to those here.

Both Aurora and Oxera estimate the cost of these charges to equate to over £10/MWh (with over £8/MWh of this being on the variable cost of generation), more than 20% of the baseload cost. Since these reflect differentials in charging, rather than underlying physical cost differences, they thus 'tilt the playing field'. These are important issues, but do not undermine the basic case for interconnection.

Network and balancing charges certainly do vary. Generators in Ireland pay transmission charges similar to GB, but on the continent most of these charges do not fall on generators, but rather on consumers. However this does not create a uniform discrepancy; in fact, most planned interconnectors connect in southern England, wh ere indigenous generating capacity is short and generators might actually benefit from the UK's charging system. A detailed recent pan -European report also concluded that differences in transmission pricing regimes did not significantly distort investment incentives.[4]

The UK carbon price floor does have a uniform impact, but the case for investment would remain clearly positive without the differential – analysis for Ofgem estimates at least 7.5GW of new projects would still be built, to the benefit of consumers, in a world without it. Moreover the EU ETS is being slowly strengthened and there are growing discussions about a similar carbon price floor at least in western Europe. The economic analyses of Aurora and Oxera assume that policy-driven differences remain for the full period of analysis; in reality, growing interconnection would increase pressures to reduce such differentials.

More importantly, any suggestion that without these charges, there would be little price difference and hence little value in interconnection is mistaken. All the major countries to which the UK is connected – or planning to connect – are ahead of the UK in renewable energy and/or nuclear capacity. These sources are capital intensive, and supported by consumer-based subsidies. The operating cost is very low. As a result, wholesale prices on the continent have been falling faster than the UK and are likely to remain substantially lower for as long as the UK lags. In effect, interconnectors enable UK consumers to benefit from renewable energy supports paid in other countries in aggregate.

Aurora go on to claim that interconnectors could reduce security of supply by displacing domestic generation and could increase CO2 emissions if foreign coal displaces domestic gas generation, claims which prove extremely dubious. So far, interconnectors have proved far more reliable than the value they are credited in the UK capacity mechanism, and if they were not built, the UK Capacity Mechanism would procure more generation in their place. The claim is thus wholly unfounded. The claim that interconnectors may increase CO2 emissions also rests on highly dubious assumptions that increase imports would come from coal generation rather than established renewables, and would not enhance the case for renewables investment elsewhere. Yet it is plain that the rapid trajectory of renewables growth is already starting to push at national system limits, and utilisation could increase with wider interconnection.

Moreover, as noted, rising renewable capacities on both sides also amplify several of the other joint benefits of interconnectors. These other benefits are not adequately accounted for—in some cases, not at all—in the Aurora or Oxera modelling. A final element in Aurora's report is criticism that the cap-and-floor regime amounts to an unfair subsidy. But whilst the floor underwrites risks, the ceiling can secure corresponding benefits for consumers; the combination lowers *project* risks and hence the cost of finance, which offers a net benefit. The economic logic is that interconnectors face a greater degree of policy-driven risk than domestic generators since the differential may be affected by energy or regulatory policy risks on both ends of the interconnector. Well-established economy theory suggests that risks are best placed with those best able to manage them – so it is entirely appropriate that governments bear the risk of policy choices that would unreasonably drive down interconnector revenues.

These consultancy critiques of interconnectors do point to some important issues, but the probable reason for taking such a negative approach to interconnectors is perhaps rather simple. Interconnectors do indeed have a downside for GB generators – they introduce new and cheaper competition to the GB generators. And that, on the whole, is good for consumers.

Michael Grubb is Professor of International Energy and Climate Change Policy at the UCL Institute for Sustainable Resources.

[4] ACER

Gas

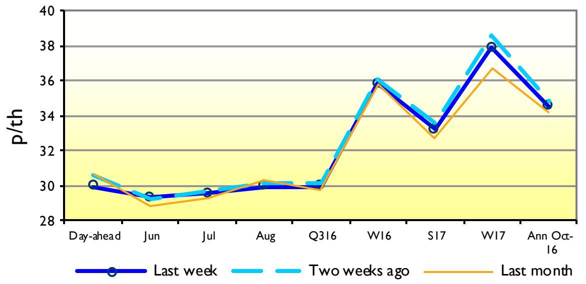
Performance of gas contracts was mixed last week.

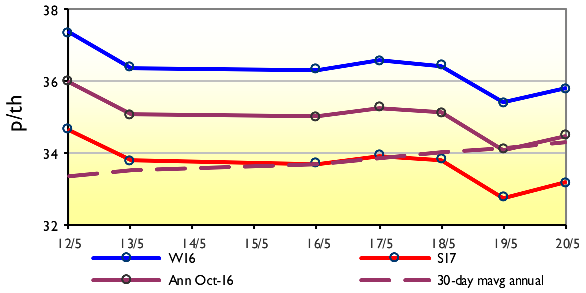
Day-ahead gas dropped 2.0% to 30.0p/th following an increase in LNG imports and a stronger pound. The contract was 2.4% lower than last month's value (30.7p/th).

In contrast month-ahead gas increased 0.3% to 29.3p/th, 1.5% above last month (28.9p/th).

Winter 16 gas fell 0.8% to 35.8p/th despite a rise in oil prices. The contract is now 0.2% above the same period last month (35.8p/th).

The annual October 16 contract was 0.3% lower at 37.3p/th. The price is now 2.0% higher than the previous month (34.2p/th), but 27.1% below last year's level (47.3p/th).





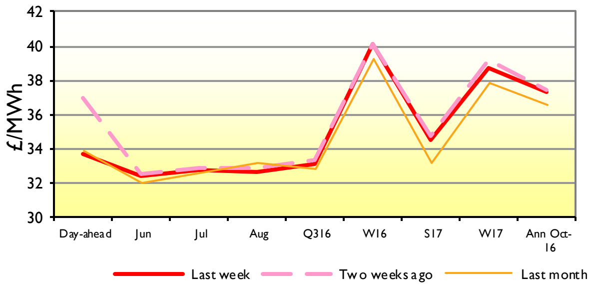
Electricity

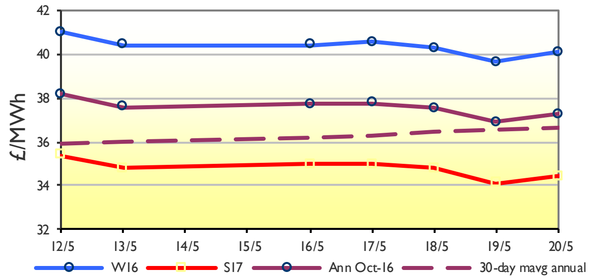
All baseload electricity contracts were lower last week.

Day-ahead power dropped 8.8% to £33.7/MWh, following its gas counterpart lower. Prices fell in spite of a rise in demand. The contract was 0.7% below last month's level of £33.9/MWh.

Winter 16 power reduced 0.1% to £40.1/MWh as supply margins remained tight. The contract was 2.4% above the same period last month (£39.2/MWh).

Annual October 16 dipped 0.3% to reach £37.3/MWh. The contract is now 2.0% above the same period last month (£36.6/MWh), but 17.0% below the same period last year (£44.9/MWh).





Oil, coal and carbon

Brent crude oil gained 5.1% last week to average $48.6/bl, following continued supply disruptions.

API 2 coal prices followed oil, and were up 3.0% last week, averaging $47.1/t.

EU ETS carbon lifted 1.2% last week to average €6.0/t.