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Tales of two islands – Lessons for EU energy policy from electricity market reforms in Britain and Ireland☆

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ABSTRACT

Britain considers the energy-only EU Target Electricity Model (TEM) wanting in delivering the trilemma of reliability, sustainability and affordability and argues that a capacity auction with long-term contracts for new entrants is the least-cost solution compared to relying on expectations of future prices to deliver adequate generation and demand side response. The Energy Union argues against feed-in tariffs (FiTs) for renewables, pressing for premium FiTs (pFiTs), just as GB has abandoned PFiTs in favour of FiTs. This paper draws on the GB experience of Electricity Market Reform before and after the 2015 change of government, to highlight promising resolutions of the energy trilemma, and the problems that have arisen between the diagnosis of the problem and the delivery of solutions. It sets out the theory and practice of delivering capacity, energy and quality of supply, gives a brief history of GB electricity from the CEGB to its current unbundled, liberalized and privatized structure. That sheds light on the trilemma problem and discusses possible solutions. The island of Ireland Single Electricity Market reforms illustrate the problem and possible answer of how best to deliver quality of service with high intermittency.

1. Introduction

Britain has taken a careful look at the energy-only market model that underpins the EU Target Electricity Model and has found it wanting in delivering the objectives of reliability, sustainability and affordability.[1] On *reliability* or security of supply, Britain argues that a capacity auction with long-term (15-year) contracts for new entrants is the least-cost solution compared to relying on expectations of future market prices to deliver adequate investment in a timely fashion. Capacity markets raise important issues for cross-border trade and this paper argues that the approach of the proposed Integrated Single Electricity Market (I-SEM) of the island of Ireland has merit in avoiding the need for pan-EU harmonization of capacity mechanisms. The I-SEM has additional lessons for reducing the missing money problem argued to justify capacity markets, by creating new flexibility services to partially address the missing market problem.

On *sustainability*, or decarbonization, the *Energy Union* (EC, 2015) argues against supporting renewables with classic Feed-in Tariffs (FiTs), pressing instead for premium FiTs (pFiTs), just as GB has abandoned PFiTs for something closer to FiTs.[2] While the EU is beginning to accept that its Emissions Trading System is inadequate for guiding low-carbon electricity investment, GB has enacted a carbon price floor intended to underwrite long-term contracts for low-carbon investment.

On *affordability*, this paper provides evidence that auctions, rather than bureaucratically set prices, dramatically lower the cost of long-term contracts for renewables and capacity.

This paper draws on the GB experience of Electricity Market Reform before and after the 2015 change of Government, to highlight promising resolutions of the energy trilemma in the electricity supply industry (ESI), and the problems that have arisen between the diagnosis of the problem and the delivery of solutions. Section 2 sets out the theory and practice of delivering capacity, energy and quality of supply to the wholesale market and final consumers, followed by a brief

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[1] The Target Electricity Model was influenced by Nordic markets, where large volumes of storage hydro, ample capacity and interconnection could make the energy-only market model appropriate.

[2] Acronyms listed at start.

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Nomenclature

CCGT	Combined cycle gas turbine
CfD	Contract for difference. This obliges the issuer (the generator) to pay the excess of the market price over the strike price per MW of contract or to receive the shortfall if the market price is below the strike price
CoNE	Cost of new entry
CP	Capacity payment
DECC	Department of energy and climate change
EMR	Electricity market reform
ESI	Electricity supply industry
FiT	Feed-in tariff: a fixed price per MWh of metered output
G	Generation
I-SEM	Integrated SEM
L	Load
LoLP	Loss of load probability
MSQ	Market scheduled quantity
MW	Megawatt
MVA	Megavolt amps, takes into account both the resistive and reactive load.
NETA	New electricity trading arrangements introduced 2001
pFiT	Premium FiT
QoS	Quality of supply
RES	Renewable electricity supply
RO	Renewable obligation
ROC	RO certificate
SEM	Single electricity market of the island of Ireland
SMP	System marginal price
SNSP	System non-synchronous penetration – e.g. wind
SO	System operator
T-4, T-1	Auctions held 4 or 1 year before delivery
TEC	Transmission entry capacity, replaced declared net capacity, DNC
TNUoS	Transmission network use of system
TSO	Transmission system operator
VoLL	Value of lost load
WACC	Weighted average cost of capital
XBID	Cross-border intraday market project enables continuous cross-zonal trading

history of the evolution of the GB ESI from a vertically integrated centrally planned state-owned company to its current unbundled, liberalized and privatized structure and the problems this presented in resolving the trilemma of reliability, sustainability and affordability. Section 4 describes the diagnosis and proposed solution to that problem, which were not peculiar to GB. Section 5 therefore studies the Single Electricity Market (SEM) of the island of Ireland, which faces higher intermittency with a lumpier and more isolated system than almost any other country. It raises the question how best to deliver reliability and quality of service with high intermittency. The British Isles (the UK *and* Ireland) therefore have important lessons for the EU *Energy Union*, drawn out in Section 6.

2. Pricing electricity: from central planning to liberalized markets

Electricity appears the archetypical homogenous commodity that underlies micro-economics – all electrons look the same – but that is deceptive. Capacity (MW) limits peak demand, energy (MWh) and power (MVA) vary over time and space, and quality of service includes stability of frequency and voltage, while the phase angle affects the ability to extract power from energy. Quality of service requires a variety of ancillary services supplied by generation or demand (reserves, reactive power, frequency response, black start capability, etc.) and in turn requires grid codes/standards on those connected (fault ride-through, ability to remain connected up to a specified rate of change of frequency, etc.). Generation plant may have fixed start-up costs, limits on the rate at which it can ramp up to full power, varying efficiencies at different plant loads, minimum stable generation output, minimum down-time between operations, etc. The transmission system has limited capacity to move power between nodes and the system has to be able to withstand the loss of at least one of the largest components (the largest single infeed - generator or interconnector - or the largest transmission link: the N-1 constraint).

Determining the least-cost dispatch to meet time and space varying demands is difficult as it is a non-convex problem with strong intertemporal dependencies. In centrally dispatched systems, the System Operator (SO) typically solves this with a Mixed Integer Program optimizing over a future period (a week for thermal systems, longer for hydro systems), to determine the optimal security-constrained dispatch (including necessary reserves and other ancillary services). The dual of this optimal quantity program is the scarcity value of electricity at each node (the nodal price or Locational Marginal Price, LMP). LMP theory, set out by Schweppe et al. (1988), has been implemented in large areas of the U.S. as the Standard Market Design. In the pioneering region of PJM,[3] nodal prices are recomputed every five minutes.

In a vertically integrated system in which transmission and generation are in a single company (the standard model for most countries until the 1980s) investment decisions in transmission and generation could be coordinated to deliver least-cost delivery of power to the grid supply points at which the regional distribution networks connect. These distribution networks were usually under different management (although often under the same state ownership) and were often charged on their specified peak power, and then a variable energy charge, with higher prices for exceeding the specified peak. The distribution network operators then translated this Bulk Supply Tariff into charges for consumers (differentiated by voltage level and whether half-hourly metered and with what maximum demand allowed or taken).

Efficient investment planning requires the right type, size, location and delivery date of generation units. Previously, these were typically large thermal stations constrained by access to fuel, cooling water, and grid connection. Transmission planning had time horizons of 60+ years, and given the constraints on securing suitable way-leaves (overcoming local opposition), had long lead times and limited choices, while locating generation assets was in principle easier. Nevertheless, tight coordination of the location and timing of generation and transmission offered the prospects of considerable saving – important when nuclear power stations need to come off-line to refuel periodically and the grid needs adequate capacity to wheel replacement power in from other sources.

State-ownership provided access to low-priced capital but limited incentives for efficient investment (operation was usually better, run by engineers and monitored by the SO), particularly as the unions had enormous threat power and extracted high rents. Privatization without liberalization risked monopoly without improved efficiency, liberalization required unbundling to prevent entry deterrence, and unbundling required markets to replace central decision making. Creating suitable markets and ensuring efficient investment and dispatch is difficult, given non-convexities in operation and synergies in investment. Competitive markets can only guarantee efficient outcomes if there are no market failures, and sufficiently dense risk and futures markets for all products supplied and demanded (capacity, energy and

[3] The Pennsylvania, New Jersey and Maryland interconnection, now much wider.

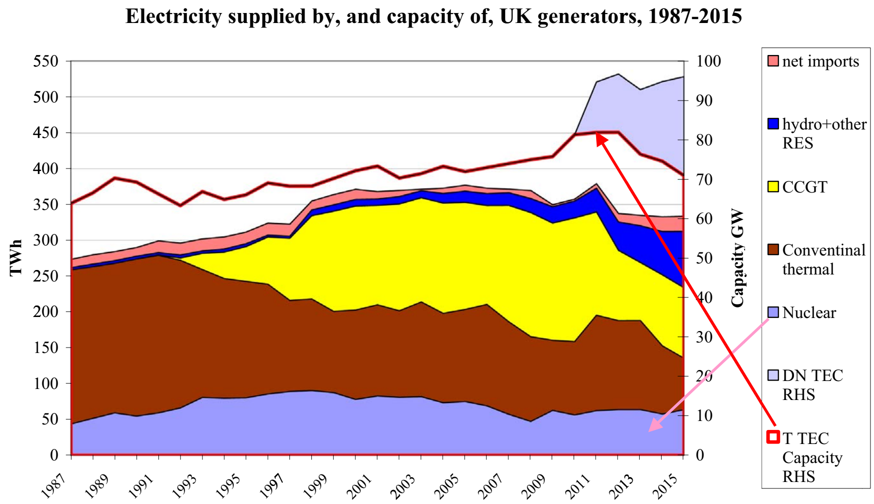

Fig. 1. Electricity supplied and declared net capacity connected to the grid.
Source: *Digest of UK Energy Statistics*, various years

quality of service). Some market failures can be addressed by charges and/or subsidies, at the risk of political or regulatory failures. Missing futures and risk markets may not be needed in a stable environment with confidence in a non-interventionist energy policy, absent which they can be replaced by long-term contracts. Natural monopolies (the wires of grid and distribution networks) need incentive regulation, which can improve on the poor governance of state ownership, but setting efficient and cost-recovering tariffs is a non-trivial undertaking. The next section illustrates this for Britain.

3. Brief history of the GB electricity sector

Fig. 1 shows generation output by fuel and total capacity since shortly before privatization and restructuring in 1990. Around 90% of conventional thermal generation was from coal, and the share of oil fell from 7% to 1% in 2002. Transmission Entry Capacity (TEC) is the contracted plant export limit. An increasing share (mostly renewables) connects to distribution networks, but data for that is only recently available. At privatization the UK ESI was supplied by coal and nuclear power with some imports. Shortly after, coal rapidly declined as nuclear power improved its performance, followed by the "dash for gas" (of Combined Cycle Gas Turbines), all new entry despite the considerable capacity margin (indicated by the gap between capacity and output). From 2000, consumption plateaued and then fell with deindustrialization and increased demand efficiency, while renewables displaced gas and increasingly coal, whose shares depended on the very volatile clean (gas) and dark green (coal) spark spreads (the margin between the wholesale price and the sum of fuel and CO_2 cost).

3.1. Privatization and electricity pricing in the pool

The state-owned companies in England and Wales were replaced by two fossil and one nuclear (initially state-owned) generation companies, with an unbundled grid. In Scotland the two vertically integrated companies were sold bundled with transmission, while in Northern Island three generation companies were sold with long-term power purchase agreements. National Grid and the Regional Electricity Companies were regulated and large customers were free to buy directly from the wholesale market, the mandatory gross Electricity Pool, which was centrally dispatched with a System Marginal Price (SMP) set by the marginal price offered by the most expensive unconstrained generator required, to which was added a capacity payment, CP.

$$CP = LoLP^*(VoLL–SMP), \tag{1}$$

where LoLP is the Loss of Load Probability and VoLL is the value of Lost Load (£2016 5000/MWh). This would give the efficient scarcity price of electricity if the System Marginal Price were the system marginal *cost*, but generators were free to offer any price, constrained by competition laws.

The sum of the SMP and CP gave the Pool Purchase Price, which, with additional ancillary service and constraint costs made up the Pool Selling Price. National Grid as Transmission System Operator (TSO) received offers from all individual generating sets the day before (complex multi-part offers with additional constraints and technical characteristics) and used a scheduling algorithm to determine a feasible dispatch. Adjustments during the day were called off the previous day's offers and charged out to consumers in the Pool Selling Price (Green and Newbery, 1992).

The two fossil generators set prices and had considerable market power (Newbery, 1995), exercised with caution under regulatory scrutiny, until the regulator intervened in 1994 to "encourage" them to divest 6 GW of coal plant to a third generator, completed in 1996. The resulting triopoly was less constrained in exercising market power, and the price-cost margin continued to widen, in the successful effort to convince outside companies to buy coal plant with apparently attractive profit margins before the dash for gas eroded this market power and lowered prices (Sweeting, 2007). The dash for gas in turn was aided by high Pool prices, low and falling gas prices, and rapidly improving and low capital cost Combined Cycle Gas Turbines (CCGTs). With energy policy under the privatizing Conservative government abrogated to market forces, political risk was considered low, encouraging substantial entry by "Independent" Power Producers. They entered on the back of long-term fixed-price contracts (and often shared ownership) with the Regional Electricity Companies, who could pass on their costs to the captive franchise domestic market. Long-term gas contracts further reduced risk.

As generator ownership fragmented towards the current Big Six,[4] they were finally allowed to buy the supply (retailing) businesses (originally integrated with distribution networks), and hence acquire a built-in hedge rather than repeatedly contracting with final customers. If wholesale prices fall but retail prices remain high, generators lose but retailers gain, and the opposite movements of profits up- and down-stream enabled hedging critical for reducing the risk previously internalized within the state-owned vertically-integrated structure. The

[4] Centrica, EDF Energy, npower, E.ON UK, Scottish Power and SSE, with domestic market shares of between 12% (Scottish Power) and 25% (Centrica, the original incumbent gas supplier).

growing price-cost gap encouraged the Government to replace the Pool with the New Electricity Trading Arrangements (NETA) in 2001, just after the price-cost margin collapsed under the weight of competition and excess capacity (Newbery, 1998, 2005).

3.2. The switch to an energy-only market

NETA was a retrogressive step, replacing central dispatch and the Pool with a self-dispatched energy-only market (abolishing capacity payments) and imposing a two-priced Balancing Mechanism so flawed it has required many hundreds of painfully negotiated modifications to approximate an efficient balancing market. The claimed logic of NETA was that self-dispatch required generators to submit a balanced offer (output matched by purchase contracts). This required them to contract output ahead of time, reducing the incentive to manipulate the spot market (under-contracting encourages sellers to increase the spot price above the marginal cost: Allaz and Vila, 1993; Newbery, 1995).

Initial support for renewable electricity supply (RES) came from the non-fossil fuel obligation auctions for feed-in tariffs (FiTs). They were successful in driving down prices, but increasingly under-delivered on investment as there was no penalty for non-delivery (Newbery, 2012). It was replaced by the Renewable Obligation (RO) Scheme, which issued one RO Certificate (ROC, essentially a premium FiT or pFiT) for each MWh produced from wind (varying fractions for other renewables). The ROC price depended on the supply of RES and demand from suppliers required to purchase an annually specified and increasing share of RES or pay a penalty price that was recycled to those selling ROCs, uplifting their value.

3.3. Transmission charging for efficient location

The electricity cost is the sum of generation *and* delivery costs to customers, which can be reduced if the *entry* of new generation is at locations that minimize total *system* (including transmission) cost. *Exit* decisions need to take place at the right time and place. Similarly, which power stations generate should take account of both generation costs and transmission losses. Transmission charging is key to delivering these objectives.

As there was (and still is) a single wholesale price across the whole of GB and as the number of ROCs per MWh delivered had no spatial variation, location decisions are guided by zonally varying Transmission Network Use of System (TNUoS) charges, set annually. Grid-connected generation pays an annual fee for entry capacity (the Generation, G, charge) and Load (L) pays for demand in the three half-hours of highest system demand (the Triad).[5] Table 1 shows that G+L is roughly constant across the country, but the components vary. In 2016/17 the G charges varied from £20.20/kW yr to −£6.09/kW yr,[6] while the sum of G+L was £49 ± £4/kW yr. Intermittent generation pays on average 72% of the G charge.

TNUoS charges would give efficient location guidance for new investment if they reflected the appropriate average of the nodal costs in each zone for the type of generation connected (baseload, mid-merit, peaking or intermittent). In fact, only the differences across space matters as it is G+L that is charged to final consumers.[7] The EU now limits the average G charge to ensure efficient cross-border trade. This still allows the full range of locational G (and complementary L) charges, but more G charges become negative. As TNUoS is a fixed charge, it fails to give efficient dispatch signals, as the underlying LMPs vary each half-hour. Equally important, TNUoS charges change annually and can only be avoided by exit, but there is no guarantee that they give efficient exit guidance (the connection point may have value to other potential entrants, but may not). This became important for the capacity auction of 2014.

3.4. Signaling efficient entry and exit

Efficient exit can be encouraged by offering a deep connection charge contract on first connection, reflecting the costs the new entrant would impose on the system over its life, recovered in a fixed number of annual payments (like a mortgage), after which the generator could sell it to a comparable in-feed. That would discourage premature exit from locations where the Generation charge is high but the value of the connection low. This is important in capacity auctions intended to encourage efficient entry *and* exit, and more consistent with creating suitable property rights for private asset owners in the liberalized market.

Setting transmission charges is complicated because efficient nodal prices only recover about one-third of the cost of an expanding transmission system (Pérez-Arriaga et al., 1995) and considerably less for a mature system with limited expansion. National Grid must recover the shortfall in its regulated revenue by an additional and large charge properly imposed on consumers. In GB, this is complicated as National Grid only meters net demand from distribution networks, so final consumer demand is invisible. Distribution networks are separately regulated under different principles. Thus distribution-connected generators pay deep connection charges (the additional investments required for a firm connection). They are compensated for the reduction in demand at the grid supply points in the same way that embedded generation (generation connected behind the meter on a customer's premises, sometimes called auto-generation), is only charged on *net* demand. This creates huge distortions to the capacity market, as discussed below,

Generation (including most renewables) that connects to the distribution network not only avoids TNUoS charges but will normally be credited with reducing load (Elexon, 2016). It receives the same locational signal (the differentiation between zones remains roughly the same) but can benefit by the sum of the G+L tariff by reducing net load on the distribution network.[8] This has risen from about £10/kW yr in 2005/6 to a predicted £66/kW yr in 2020.[9] That would be efficient if these charges represented the forward-looking marginal cost of expanding transmission for new generation (G charges) or the saving from reduced transmission investment for L. However, as just noted, only a small fraction reflects the transmission needed or avoided, massively distorting the incentive for generation to locate at distribution rather than transmission level.[10]

Efficient locational signals ideally require nodal charging as in the US Standard Market Design, right down to some minimal generation in-feed (1 MW?). Nodal pricing is not ruled out by the Target Electricity Model, but is resisted by traders preferring the liquidity of large price zones, and seems unlikely to be introduced in GB. The (considerable) shortfall in revenue would then be recovered from the *gross* (not net) consumption of consumers, ideally concentrated on hours of lowest demand elasticity (Ramsey pricing). Domestic consumers are levied such charges between 4 p.m. and 7 p.m. every day

[5] See http://www.nationalgridconnecting.com/triads-why-three-is-the-magic-number/.

[6] Negative G charges are only paid on actual export in Triad periods to relieve shortages there.

[7] This would be true if there were no link to external prices through interconnectors, but the average G charge can be set relative to that abroad, ensuring consumers bear the full transmission cost.

[8] Let the G charge on the grid in zone z be T_z, then the L charge is $K-T_z$, where K is the sum of G+L tariffs, roughly constant across zones. Distribution-connected generation is credited with $K-T_z$, or pays T_z-K, so the zonal differentiation in G charges remains the same but Distribution-connected G gains K.

[9] See https://www.ofgem.gov.uk/publications-and-updates/open-letter-charging-arrangements-embedded-generation.

[10] The German government proposes a levy on auto-generation to counter the distortions of net metering.

Table 1
TNUoS charges for an 80% generator and for load.
Source: National Grid

		2016/17	2017/18	2018/19	2019/20	2020/21
GB G	Max	£20.20	£29.64	£31.06	£31.36	£28.70
	Min	−£6.09	−£8.79	−£14.30	−£16.45	−£21.30
E & W G	Max	£7.48	£8.13	£6.05	£4.63	£2.75
	Min	−£6.09	−£8.79	−£14.30	−£16.45	−£21.30
GB G	Average	£6.01	£8.88	£7.63	£6.91	£3.51
E & W G	Average	£1.98	−£0.05	−£2.84	−£5.29	−£9.39
Average G+L						
	GB	£49.09	£47.95	£52.75	£54.94	£65.84
	E & W	£47.50	£47.44	£51.44	£53.82	£63.61
SD of G+L						
	GB	£4.07	£3.89	£5.11	£5.03	£6.63
	E & W	£2.58	£2.38	£2.63	£2.77	£2.79

G is generation charge, L is Load charge, E & W is England and Wales.

throughout the year - plausibly hours of least elastic demand.

By 2008 it became clear that the challenging target for UK RES in the *Renewables Directive* (EC, 2009) was unlikely to be delivered, while the prospect of more RES was undermining investments in conventional generation needed to replace life-expired nuclear stations and the closure of unabated coal plant (facing tough environmental regulations, a new carbon price floor, and, in 2016, a political declaration that all unabated coal should close by 2025).

4. Electricity market reform: aims and outcomes

The volatility and unpredictability of future RES revenues under the Renewables Obligation Scheme made them hard to finance except through rather unattractive contracts with the incumbent utilities, whose balance sheets were becoming stressed. RES generation is highly capital-intensive so the larger part of their cost is the cost of capital, which is considerably raised by the market risk of unpredictable revenues and the political/regulatory risk that the Renewables Obligation Scheme would be reformed or ended. Similar policy uncertainty made conventional generation unbankable, in contrast to the 1990s' dash for gas (predicated on long-term contracts whose counterparties could pass the cost to retail customers, no longer possible after the 1998 domestic retail market liberalization).

Meanwhile wide cross-party support for the *Climate Change Act 2008* (HC, 2008) provided a legal requirement to deliver greenhouse gas commitments. In response, the Committee on Climate Change set a 57% reduction by 2030 (relative to 1990) (CCC, 2015), much to be delivered from electricity. The UK originally considered renewables (mainly wind), new nuclear, and eventually Carbon Capture and Storage would deliver that, but none were commercially viable in the liberalized UK electricity market given low EU carbon prices. In response the Treasury enacted a Carbon Price Support that would bring the EU Emissions Allowance price for carbon dioxide up to an escalating price reaching £30/tonne by 2020 and £70/tonne by 2030 (HMT, 2011). This was hoped to make new nuclear commercially viable and enable a withdrawal of subsidies from mature RES such as on-shore wind and solar PV, and eventually, even off-shore wind. The credibility of the Carbon Price Support was severely undermined when it was frozen at £16/tonne in a later budget.

The proposed solution to these various problems was to replace the RO Scheme with FiTs with Contracts-for-Difference (CfDs) that essentially guaranteed the real price of RES for 15 years. Reliability (the primary political requirement within the trilemma objectives) would be delivered by annual capacity auctions (at T-4 for delivery four years ahead) for amounts specified by the Minister (advised by the Department, DECC, and quality-assured by the Panel of Technical Experts). DG COMP, justifiably suspicious of capacity payments that are covert subsidies to existing plant, granted the UK State Aids clearance, partly as auctions ensure least-cost solutions, partly as all unsubsidized plant (existing and new) receives the same payment, avoiding selective payment for new plant that depresses prices and harms existing plant. Electricity Market Reform (EMR) became law as the *Energy Act 2013* (HC, 2013).

4.1. The capacity auction

How well did EMR deliver? Reliability was to be delivered by capacity auctions. The Minister set the procurement amount in June 2014, advised by National Grid (2014) *Electricity Capacity Report* and criticized by the Panel of Technical Experts (DECC, 2014a; Newbery and Grubb, 2015). The procurement amount depends on the reliability standard (the Loss of Load Expectation, LoLE, of 3 h per year), the Value of Lost Load, VoLL, (£17/kWh), giving the predicted gross Cost of New Entry (CoNE):CoNE=VoLL*LoLE. In this case the gross CoNE=3h/yr×£17/kWh=£51/kWyr.[11] The net CoNE depends on the revenue earned when operating. If during the 3 h of expected lost load the real-time price is capped at £6/kWh (Newbery, 2015), the peaking plant could earn £18/kWyr, and if it earned no other revenue the net CoNE would be £33/kWyr.

After several different proposals, DECC set the net CoNE at £49/kWyr, locating the demand for capacity (prices below the net CoNE deliver higher capacity). At £49/kWyr, the cost of 53 GW of derated capacity is £2.6 bn/yr,[12] but the auction cleared at £19.40/kWyr, 60% lower, demonstrating that auctions better reveal costs.

The CoNE was based on a new Combined Cycle Gas Turbine (CCGT). About 2.6 GW of new entry secured capacity agreements. Surprisingly, given the low clearing price, a large (1.6 GW) new CCGT won, as did 790 MW of combustion turbines or reciprocating engines (average capacity 11 MW). By 2016 it became unlikely that the CCGT would secure financing and might forfeit the modest penalty for non-delivery (£80 million on an £800 m project).[13] The penalty had been set low to encourage new entrants, but it seems to have encouraged entrants that risk non-delivery. In response the Government increased the penalty from £5/kW to £35/kW.

The large number of diesel engines awarded capacity agreements

[11] Assuming an exponential left tail of the distribution of supply less demand (DECC, 2013a).

[12] Derating reflects availability. Subsidized capacity (RES) receives no capacity payment but its derated value is subtracted from forecast demand. Existing plant receives an annually renewable 1-year contract, new plant 15 years. Plant can choose not to bid at T-4 (4 years before delivery) but wait for the T-1 auction. Predicted T-1 plant is deducted from T-4 net demand. The auction is a last-price descending clock auction (Newbery and Grubb, 2015). Capacity procured lowers energy prices and reduces consumer cost below £2.6 bn.

[13] http://www.newpower.info/2016/07/trafford-ccgt-faces-capacity-market-contract-termination/.

attracted complaints, mainly that they were more carbon-intensive and polluting than the preferred CCGTs. Meeting peak residual demand for the few stress events[14] normally requires fast-response cheap high variable-cost plant. Small diesels respond rapidly and might seem suitable but they are costly per kW. The correct objection is they secure embedded generation benefits equal to the sum of the Transmission Generation *and* Load charge, in 2018/19 on average £52.75/kWyr. This gives a credit of £72/kWyr after adding the £19.40/kWyr auction price, biasing choices towards less efficient, more costly smaller units.

Efficient transmission and distribution pricing would make the embedded benefit only been 10–30% of the current G+L wedge shown in Table 1, perhaps £5–15/kWyr. The auction price should then reveal the correct net CoNE, perhaps closer to £33/kW yr. This distortion secures a small amount of inefficient plant connected to the distribution network relieving local constraints, and an inefficiently low auction price, reducing consumer costs (a small increase to cover the lost TNUoS revenue and a large saving through a lower auction price paid to all 53 GW secured in the auction).

The other problem revealed by falling gas prices and the high (compared to EU carbon prices) carbon price support, was that coal plant started losing money and their owners announced closures, including some with capacity agreements. As the £19.40/kWyr capacity price was below some TNUoS charges of Table 1, the question whether those TNUoS charges give correct exit signals became highly relevant, but remains unresolved.

4.2. Supporting renewables

The new Contracts-for-Difference (CfDs) for RES were initially priced by DECC bureaucrats with consultants' advice after investor consultation. For on-shore wind DECC considered the weighted average cost of capital (WACC) might fall from 8.3% under the RO Scheme to 7.9% with a CfD (DECC, 2013b) and priced CfDs accordingly. A flood of developers applied for advance contracts at these prices. The National Audit Office argued that large sums were poorly spent on these transitional contracts (NAO, 2014) as did the Panel of Technical Experts in their first report (DECC, 2014a). Under pressure from DG COMP on State Aid grounds, DECC adopted auctions for specified volumes of RES. Newbery (2016) showed the clearing prices for on-shore wind lowered the WACC by 3% real, which if auctions could deliver for the estimated generation investment of £75 billion up to 2020 (DECC, 2011) would save £2.25 billion *per year* by 2020, continuing for 15 years.

This was a very promising rediscovery of the benefits of employing auctions rather than bureaucrats, first trialled in the non-fossil fuel obligation auctions of the 1990s and then replaced by the costly and ineffective RO Scheme. Unfortunately, the final element of EMR was Treasury's requirement for a Levy Control limiting renewables support to sums rising to £7.5 bn/yr in 2020. At the time EMR was under consultation, gas and electricity prices were high, leaving the gap between CfD strike prices and the wholesale price modest. As gas prices fell, so the gap and support cost rose to breach the Levy Control. This is clearly counter-productive: as the consumer cost fell, their ability to support decarbonization rose, but investment was cut.

Germany provides some examples of good practice as well as some to avoid, such as its high cost of subsidies and absent location signals. First, during the period of liberalization, wholesale prices fell, but the Government gradually increased eco-taxes so that the retail price remained roughly constant, retaining consumer support for renewables. Although domestic renewable levies became very high, over-encouraging domestic solar PV, they were (logically) rebated for energy-intensive industries.[15]

Second, Germany provides nominal, not index-linked FiTs (more front-end loaded and more readily financed by nominal bonds) for a specified number of MWh per MW capacity, thus limiting the rents earned by those located in windy areas. This makes sense as increasing the price per MWh for the same contract length over-encourages wind farms to locate in windy areas typically far from demand centres. GB TNUoS charges fail to properly reflect this (Newbery, 2011). Suppose distant wind runs 2300 h/yr and closer wind only 2000 h/yr with an average wholesale price of £40/MWh and a FiT of £80/MWh. The extra *value* of the distant wind is £40/MW h×300 h=£12,000/yr, £12/kWyr. If the differential transmission charge is £20/kWyr, the *financial* attractiveness of distant wind (at £80/MW h×300h=£24/kWyr) is greater than local wind and it will locate inefficiently. At least GB has some locational signals, while Germany has none, over-encouraging distant wind that requires costly transmission.

GB is building extremely expensive off-shore DC links from Scotland down to England to handle excess wind and to avoid building contentious overhead lines. More to the point, the learning benefits justifying RES support derive mainly from the manufacture, siting and construction, less in their operation (which is rewarded by energy revenue). A FiT paid for a fixed number of MWh per MW capacity is effectively an efficient capital subsidy.

5. Lessons from the island of Ireland

The Single Electricity Market (SEM) of the island of Ireland involves two countries (N Ireland in the UK and the Republic), two currencies (£ and €) but a single centrally dispatched wholesale market. It provides useful lessons for integrating the EU electricity market with growing intermittent renewables. The SEM has to cope with high and increasing wind penetration while in transition from a Pool-type centrally dispatched market design to one compatible with the EU Target Electricity Model (the Integrated SEM or I-SEM). It illustrates the challenges in procuring quality of service and reliability through various flexibility services and a redesigned capacity remuneration scheme. The problems are amplified as the SEM is a small isolated system with individual generation units large compared to total demand. Its high wind penetration can cause more than 50% system non-synchronous penetration (SNSP)[16] requiring curtailment to maintain system stability.

New ancillary and flexibility services are being developed (DS3. see Section 5.3) to cope with 75% SNSP. The SEM has a bidding code of practice that requires offers at short-run marginal cost (augmented by capacity payments) while the Target Electricity Model requires bidding in the EUPHEMIA auction. Bids would need to recover full costs unless supplemented.

The SEM's ambitions for SNSP puts it at the forefront of managing intermittent RES, expected to increase in all EU markets. If wind is not to be excessively curtailed, a suite of new services need to be defined and procured. These services are set out by the market operator, SEMO,[17] and the All-Island Project.[18]

The SEM has a large reserve margin. The median peak Total Electricity Requirement is predicted to grow from 4850 MW in 2013/14 to just over 5000 MW in 2019/20. In 2013 there was 9774 MW of conventional plant, about half gas-fired (SONI, 2014). Wind capacity in October 2014 was 2646 MW and with planned (contracted) capacity, 7717 MW. The 2020

[14] A stress event is one in which market supply ahead of gate closure is inadequate, so the SO calls on extra capacity, reduces voltage and takes other measures (Newbery and Grubb, 2015).

[15] DG COMP argued these rebates were discriminatory, limited to certain industries. Good public finance argues that all revenue-raising levies should fall on final consumers, so all producers should be exempt from most eco-charges.

[16] Conventional generators have considerable inertia in the spinning turbine synchronised to grid frequency. If frequency drops, this inertia transfers additional energy, reducing the rate of change of frequency. Non-synchronous plant (wind and PV) that convert DC to AC cannot provide inertia, reducing system frequency stability.

[17] www.sem-o.com.

[18] http://www.allislandproject.org/en/homepage.aspx.

Table 2
Proposed new and existing system services.
Source: Eirgrid, 2013, Eirgrid/SONI, 2014

	New services	Now		Existing services	Now
SIR	Synchronous inertial response	65%	SRP	Steady-state reactive power	69%
FFR	Fast frequency response	54%	POR	Primary operating reserve	87%
DRR	Dynamic reactive response	82%	SOR	Secondary operating reserve	90%
RM1	Ramping margin 1 h	88%	TOR1	Tertiary operating reserve 1	91%
RM3	Ramping margin 3 h	88%	TOR2	Tertiary operating reserve 2	89%
RM8	Ramping margin 8 h	66%	RRD	Replacement reserve (De-synchronised)	83%
FPFAPR	Fast post fault active power recovery	88%	RRS	Replacement reserve (synchronised)	93%

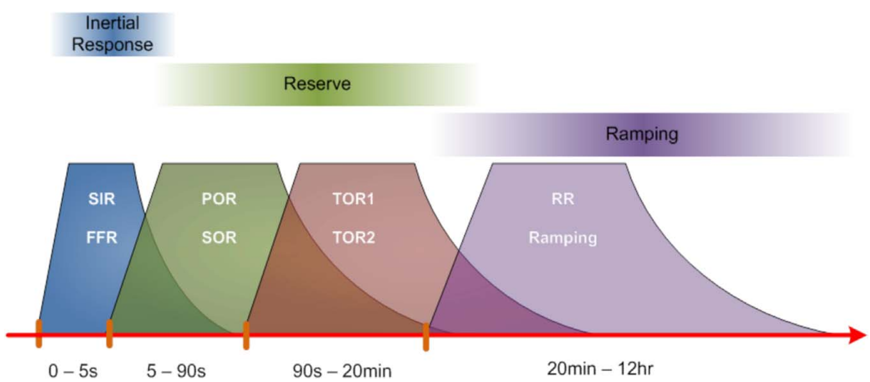

Fig. 2. The existing and proposed frequency control services.
Source: Eirgrid, 2013

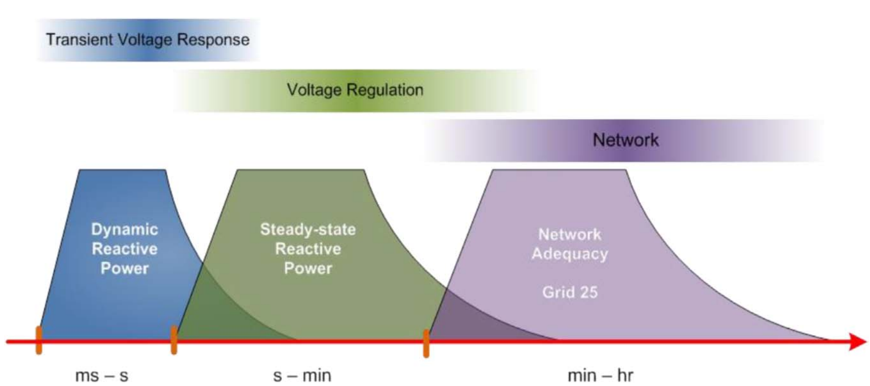

Fig. 3. Voltage control services.
Source: Eirgrid, 2013

target renewables share of 40% requires 3200–3800 MW of wind, about 240 MW installed per year. Over the past 10 years the increment has averaged nearly 400 MW/yr.

The larger conventional generator units are about 400 MW, large compared to peak demand and certainly to the minimum demand of less than 2000 MW, a swing of 3.4:1 from maximum to minimum. 950 MW can be imported, so domestic generation might only need to meet about 6000 MW in 2018, while exports can increase minimum demand to about 3000 MW, a swing of only 2:1. Interconnectors can help system balance, depending on market prices at each end,

From 2001 to 2010 the average absolute hourly change in Market Scheduled Quantity (MSQ)[19] was 213 MW (5% of MSQ). The maximum was 1165 MW, 25% of prevailing MSQ. Such large swings in residual demand compared to large unit sizes present considerable scheduling challenges, currently adequately managed in the centrally dispatched system given its centralized wind forecasts.

5.1. Price formation in the SEM

The SEM market design is similar to the former English Pool, except that generators must submit true start-up, no-load and unit variable costs. The capacity payment is an averaged scaled version of Eq. (1), based on the administratively set net CoNE. With the move to I-SEM the pool will disappear and capacity payments will be replaced by an auction for Reliability Options (Vazquez et al., 2002) discussed below.

5.2. Paying for system services

The System Operator procures System Services - "those services,

[19] MSQ is the amount of price-making plant (excluding price-taking wind) scheduled for dispatch by the software – see e.g. http://www.sem-o.com/Publications/General/SEM-13-067%20Amended%20TSC%20Helicopter%20Guide%20Version%202.pdf.

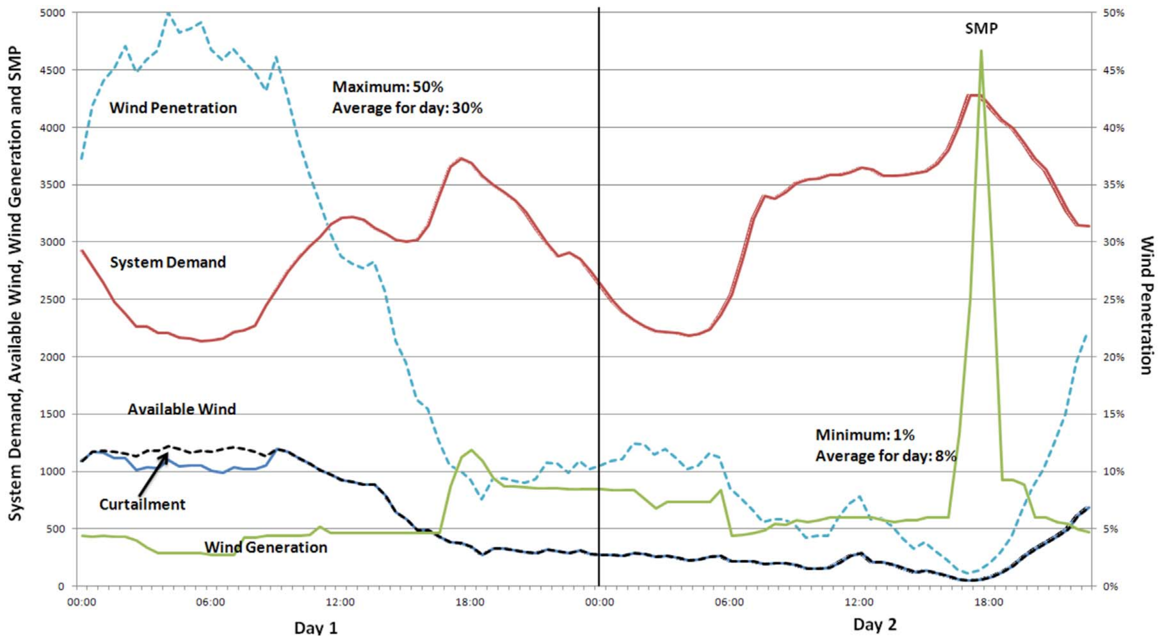

Fig. 4. System demand and wind penetration on a high vs low wind day. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)
Source: *SEM Market Overview*, July 2013

aside from energy, that are necessary for the secure operation of the power system." (Eirgrid/SONI, 2011b). Table 2 lists existing and the proposed new services considered necessary for system non-synchronous penetration. The percentages show the extent to which current plant can provide the services needed by 2020. Operating reserves (OR, Primary, Secondary and Tertiary) accounted for half the total annual cost of €61 million in 2013/14, with replacement reserves (RR) accounting for an additional 14% and reactive power for 18%.[20]

Fig. 2 shows the existing and proposed frequency control services. Voltage response products are shown in Fig. 3. Fig. 4 illustrates the challenges of high and variable levels of wind. The dotted blue line (right hand axis) shows wind varying from 50% of MSQ (the red line, left hand axis) in day 1 to 1% in day 2. The System Marginal Price, SMP (in green) peaks at 10 times its normal level as wind falls. These sharp price increases provide an incentive to invest in plant that can be called on at short notice and can ramp up rapidly to meet any shortfalls.

To assess the challenge of 40% renewables, wind from 2007 to 2010 has been scaled to this level of penetration. The maximum fall in wind over any half-hour period is 826 MW (close to the maximum half-hourly increase required in dispatchable generation, including trade over interconnectors, of 812 MW). The average absolute change in wind in any half hour is 125 MW. The average non-wind supply required over this simulated period is 3000 MW and the minimum is −1000 MW, which requires full exports in that period (and then probably some curtailment).

5.3. Delivering a secure and sustainable electricity system (DS3)

The DS3 Programme, set out in Eirgrid/SONI (2011a), proposed seven new System Services to complement the existing seven, illustrated in Figs. 2 and 3. There are various potential portfolios enabling 75% system non-synchronous penetration - either refurbishing existing plant or building new plant. There are short-run constraints on the most practical way to procure existing and new system services in the radically different market being developed for I-SEM. The hope is that most services will eventually be procured through auctions, provided there are sufficiently many providers for competitive bidding (SEMC, 2014, 2015).

5.4. Capacity procurement and remuneration

The old SEM mandated truthful variable cost bidding and hence required additional capacity payments. In the I-SEM generators will bid into EUPHEMIA and will have to recover their fixed costs in other ways. The current expectation is that there will be an auction for Reliability Options, which pay for the capacity available in stress periods in exchange for a one-sided contract-for-difference that requires the holder to pay the excess of the market price over the strike price (whether or not they are generating). The strike price is set somewhat above the variable cost of the most expensive plant (a 15% efficient diesel generator), and hedges both consumers in the I-SEM against price spikes and generators for their unpredictability. It allows prices on interconnectors to reflect the true value of electricity to I-SEM consumers while not distorting trade, and is therefore more market-friendly and efficient than the GB capacity payment, made to interconnectors regardless of the flow direction. It should allow each Member State to choose its own capacity support as any country with a Reliability Options (and suitable price setting powers) will only trade if advantageous. The I-SEM proposal therefore requires the SO to set the floor price at equation (1).

Reliability Options are voluntary, offering insurance for generators against the uncertainty of adequate periods of high prices to recover their fixed costs. Consumers will be fully covered against price spikes, causing a potential mismatch between the supply of ROs from consumers (or suppliers) and demand from generators. The shortfall will be covered by the System Operator and the costs socialized.[21]

5.5. Procuring flexible capacity

In a stable world the value of ancillary services would be predictable, enabling an estimate of the missing money required to justify

[20] http://www.eirgrid.com/operations/ancillaryservicesothersystemcharges/.

[21] http://www.sem-o.com/ISEM/General/CRM%20Settlement%20Design%20Interpretation%20Document_20160219.pdf.

investment, allowing generators to bid accordingly in the capacity auction. However, in the I-SEM, seven system services are new with no record of likely value or price. More generally, as the electricity supply industry adopts more RES, smart meters, new platform providers to define, offer and aggregate services (Weiller and Pollitt, 2013) and as the markets for demand side response and distributed energy resources develop, the potential supply costs of each service may change dramatically, making it hard to predict future prices.

One possible solution is to run a package auction in which participants submit a range of offers for different plant or refurbishment options, specifying the volume of each service offered, including firm de-rated[22] capacity for reliability, and the total annual required revenue from these services, in €/kWyr. New build would be eligible for a long-term contract, existing plant for a one-year contract, and major refurbishments for an intermediate length. The auction algorithm would search for the least-cost set of offers that meet the required demands (a complex task – see dot.econ, 2015). Once the required bundles of services have been efficiently priced, the missing money needed for capacity may be very small, given the security of long-term contracts for the system services. In practice, the complexity of such package auctions rules them out at present, leaving the SO to publish indicative prices to reduce uncertainty about the amount to bid for Reliability Options.

6. The Energy Union's approach to flexibility services

ACER (2015) stated that "We do not see a case for creating separate flexibility markets. In our view, fully implementing the *Guideline on Capacity Allocation and Congestion Management* and the *Network Code on Electricity Balancing* is necessary to reward flexibility within the market." ACER does not say that this is sufficient, and when discussing long-term contracts, appears to restrict these to contracts between generators and consumers. ACER notes they are unlikely to be sufficient to "trigger investment decisions because their prices usually reflect expectations regarding future short-term market prices and because of their own inherent limits, e.g. durations limited to a few years for standard products and complexity for tailor-made contracts."

ACER places great weight on short-term market signals to signal scarcity but it is a leap of faith that these will deliver suitable investment signals. Given the huge delays in delivering XBID (for cross-border trading intra-day),[23] removing price controls, harmonizing gate closure times, and coordinating balancing across borders, this is an optimistic and largely unfounded assertion, unsupported by any available evidence.

The case for long-term capacity contracts is the missing futures markets and to reassure investors that future policy changes will not expropriate their investments. The British philosophy is aligned with ACER (2015) in recognizing that all markets, including those for system services and transmission charges, are either spot markets or very limited duration contracts. The ideal Transmission charge is deep (i.e. reflecting the full cost impact on the system), amortized over a period via a contract. Contracts with the System Operator for various system services are normally annual but multi-annual contracts may be cheaper, particularly when introducing new services or where significant investment (e.g. in storage) could be cost-effective.

7. Lessons for Europe from the British and Irish experiences

Britain has struggled with varying success to provide adequate low-carbon capacity in a market system. The SEM is adapting to the Target Electricity Model by making quite radical changes to its procurement of capacity and flexibility services to avoid curtailing wind. Their experience suggests the following observations.

Low carbon electricity is more capital-intensive than fossil generation, relies more on future electricity and carbon prices that are harder to predict and more prone to policy and regulatory changes than in the past, and, for renewables, are more locationally anchored to areas of high resource availability, as well as requiring more responsive system operation. Policies that worked well for the traditional structure need modification for the low-carbon transition.

7.1. Renewables and location signals

The *Energy Union* document (EC, 2015) is concerned that RES is not subject to market signals - increasingly relevant for location decisions and provision of services. The document argues for pFiTs, in tension with the conclusion above that FiTs (or CfDs) dramatically reduced the cost of capital and the cost of delivering RES targets. In a full nodal pricing system (or with a large number of price zones as in Nordpool), an over-concentration of RES in one location (the sunniest or windiest place) would depress the nodal (or zonal) price in periods of high RES supply, more so if transmission export capacities were limited. If this local price were passed through (with a premium) to RES suppliers, they would find it unattractive to locate in such export-limited zones and would diversify into lower-resourced but higher-priced locations. If some RES can provide system services, they should be encouraged to offer them, perhaps through contracts, not spot prices. ACER argues that RES should bear the full extra balancing and system service costs – an argument not limited to RES. This strengthens the case for nodal pricing and allowing Member States to be early experimenters. RES subsidies should be targeted on capacity, not output, to avoid locational distortions that over-encourage output in resource-rich places and to reduce revenue risk.

7.2. Long-term contracts

Efficient risk-reducing contracts transfer the risk to who can bear it at lower cost (end-consumers, or those with complementary generation portfolios) while providing signals for efficiently managing those risks (location and balancing). This is the classic (but hard) principal-agent problem. One solution is to offer a long-term availability payment per MW (as with conventional capacity) procured in auctions, and a long-term nodal contract. These provide risk hedging with short-term price signals at the margin. Examples include Transmission Congestion Contracts or Financial Transmission Rights much used in the U.S. Standard Market Design. These specify a strike price per MW at the node, with the counter-party paying or receiving the difference with the nodal price. Balancing contracts can similarly be provided, and are already offered in GB through contracts with incumbent utilities. The TSO might be a better-placed (and regulated) counterparty, but this may run up against EU unbundling requirements that prevent transmission and generation under common management. Independent System Operators might escape that restriction (Strbac et al., 2013), but would need access to other counterparty funds, perhaps recovered as at present in GB through Balancing Service Use of System charges that could be passed through to final consumers.

7.3. Market designs to managing the transition

The lessons to draw from the theory and examples presented above is that the low-carbon transition requires considerable increases in fixed and reductions in average variable costs, making prices more volatile and less predictable. Proper scarcity pricing over time and space, and efficient remuneration of system services similarly introduce new uncertainty into revenue streams, and signal the need for different bundles of generation and demand side attributes. Risky markets benefit from long-term hedging contracts, which can (and have)

[22] In GB, National Grid publishes de-rating factors reflecting the probability of non-availability in stress periods.

[23] See https://www.epexspot.com/en/market-coupling/xbid_cross_border_intraday_market_project.

dramatically reduce(d) financing costs, as the GB renewables auction demonstrated. Transmission and distribution tariffs, which are subject to regulatory scrutiny, need considerable and urgent reform if auctions are used, as auctions deliver in perhaps one day investment decisions that have locational consequences for decades.

8. Conclusions

This paper has argued that the future electricity industry with a high share of intermittent renewables and uncertainty about carbon price and renewable support is likely to need long-term contracts for capacity and renewables to deliver reliability at least cost. These contracts will need careful design, and the paper has presented the advantages and drawbacks of various contracts introduced in GB under EMR, and the design options under consideration in the island of Ireland. The alternative is to hope that improved markets for flexibility and ancillary services could adequately reduce the scale of missing money, and that large utilities hedged via ownership of supply (retailing) companies will be willing to invest adequately despite future regulatory and political uncertainty. The British evidence is that auctions for long-term contracts appear to reduce the risk and hence cost of capital to such an extent that this author considers the case for long-term contracts decisive.

Long-term contracts lock in short-run price signals for location and technology and it is therefore critical that all these price signals, including those for access and use of the transmission and distribution systems, give efficient signals. GB has shown the dramatic consequences of a failure to do this, with several GW of the wrong kind of generation connected to the wrong networks with 15-year contracts. Because long-term contracts can be signed after a single auction, the need for regulators to respond rapidly to evidence of perverse regulated prices is clear, but the evidence that they will respond quickly and appropriately is lacking.

Given that the larger part of future electricity costs are in up-front capital, as fossil fuels reduce their share, reducing the cost of capital by hence suitably allocating risk is critical for affordability. A more radical alternative (which may be better suited to countries where investors have limited confidence in liberalized electricity markets) involves a single buyer (the TSO) auctioning long-term contracts with a capacity and energy element (and possibly separate payments for each system service). The TSO would select the least-cost dispatch on the basis of short-run (mainly energy and ancillary service) contract elements and make up the short-fall through a capacity charge on consumers. Consumers or their retailers would hedge through CfDs and/or with Reliability Options. This option was retained briefly in the First Package of EU Energy Directives but later abandoned, as giving too much power to the single buyer, prone to political and/or regulatory interference, and hence discouraging the free entry and innovative competition that liberalization envisaged.

The policy challenge is to retain free entry with the other requirements of efficient short and long-term pricing provided in both markets. This paper has argued that auctions that provide competition for market entry, suitable markets and/or contracts for the increased range of flexibility and ancillary services, and efficient and responsive pricing of regulated assets (connection, transmission and distribution) are all necessary.

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