Energy Strategy Reviews 26 (2019) 100381

Contents lists available at ScienceDirect

Energy Strategy Reviews

journal homepage: www.elsevier.com/locate/esr

Reconciling high renewable electricity ambitions with market economics and system operation: Lessons from Ireland's power system

F. Gaffney[a,b,*], J.P. Deane[a,b], B.P.Ó. Gallachóir[a,b]

[a] MaREI Centre, Environmental Research Institute, University College Cork, Cork T23 XE10, Ireland
[b] School of Engineering, University College Cork, Ireland

ARTICLE INFO

Keywords:
Target model
I-SEM
Electricity market transformation
System services
Capacity remuneration mechanism

ABSTRACT

The integration of variable generation challenges electricity systems globally. Using Ireland's electricity sector as a case study, we highlight multiple challenges in reconciling ambition for variable renewable integration with market economics and system operation. Ireland has the highest share of non-synchronous variable renewable electricity on a single synchronous power system. This case study examines the strategy being implemented to optimally balance between efficiency, flexibility and adequacy while maintaining a fully functional system that strives to adapt to evolving conditions. The transition that the Single Electricity Market underwent to comply with the EU Target Market was a major overhaul of what made the all-island market a success. Volume-based reliability options have distinct advantages over capacity payments. System services are critical for system stability and 14 separate system services are being developed. These actions, when taken together, provide an insight into the lengths to which this electricity market must go to transform from its cost-based nature to a value-based alternative that rewards flexible and reliable capacity with the ability to evolve with market conditions of the future.

1. Introduction

In many parts of the world, the electricity sector is in the midst of technological change. Generation portfolios today are different to those of the past and will continually evolve into the future. Consequently, electricity markets are also experiencing change, a change that partially stems from the sectors' failure to effectively internalise the external costs associated with electricity generation in the past, regarding emissions. While many modern-day societies have policies in place to curtail the effects of climate change through the promotion of renewable energy and the reduction of greenhouse gas emissions, this was not always the case.

In the electricity sector, these policies can often encourage zero-marginal-cost generation (generally non-dispatchable[1] and non-synchronous[2]) through support mechanisms while discouraging fossil-fuel based capacity (typically dispatchable and synchronous) with increased marginal costs through carbon taxation; displacing the latter. When the level of displacement escalates, it can create system stability challenges for the system operators in terms of inertia, frequency and voltage response requirements [1]. This can also create issues for market participants who fail to recover sufficient revenue to service debts related to fixed costs associated with dispatchable capacity; capacity which is considered important for long-term system generation adequacy [2]. In short: this situation occurs when policy measures promoting variable renewable generation push up against the limits of the system to absorb the technical characteristics of this type of electricity generation.

In this paper we use Ireland's wholesale electricity sector as a case study to demonstrate the effects of the previously mentioned displacement that results from climate mitigation policies, focusing on the planned actions/strategy to maintain a fully functional, balanced system which promotes flexibility from its market participants while remaining cost efficient and within system adequacy limits. The Irish system is an intriguing choice of case study due to its uniqueness in European terms insofar as it is an isolated system with limited storage or interconnection and yet, one of the highest levels of variable renewable generation in the region, thereby making it one of the most challenging to operate within Europe. This paper maps out the approach taken by the Irish authorities to adapt their market and overall system to the evolving conditions, attempting to remain 'fit for purpose'

* Corresponding author. Energy Policy and Modelling Group, MaREI Centre, Environmental Research Institute, University College Cork, Ireland.
E-mail address: fiac.gaffney@ucc.ie (F. Gaffney).

[1] Non-dispatchable means capacity that cannot adjust its output at will. Instead, external conditions such as wind speed or solar radiance play a defining role.

[2] A non-synchronous unit generates voltage in a waveform that is not 'in sync' with the standard used in the system.

https://doi.org/10.1016/j.esr.2019.100381
Received 11 January 2017; Received in revised form 15 June 2019; Accepted 22 July 2019
2211-467X/

in a time when many are not – a perspective shared by Refs. [3,4].

The paper is structured as follows. Section 2 outlines the transformation Ireland's electricity market underwent to align its trading platforms, ex-ante pricing structures, and other aspects to ensure compatibility with the European integrated internal market for electricity and comply with the European Union's Third Energy Package.[3] Section 3 overviews the redesign of the capacity payment mechanism to address concerns surrounding the lack of entry or exit signals, the potential for over-compensation and the absence of a competitive edge that exist in its current form. Section 4 describes how the current ancillary service arrangements will be restructured to facilitate up to 75% system penetration of variable renewable generation, creating one of the most complex system service arrangements used in the electricity sector worldwide. Section 5 concludes the case study with some final remarks.

2. Transforming an energy market

Ireland transformed its electricity market to become compatible with the greater European regional market and remain compliant with the EU Third Energy Package. After receiving derogations on implementing the EU Target Model (TM)[4] due to its unique situation of being an "*island system with central dispatch*" [7, Section 1.2], the all-island electricity market became compatible with the regional day-ahead market on 1st October 2018 [7,8]. It may also be suggested that Ireland's electricity market needed to adapt to remain 'fit for purpose' as conditions within the sector evolve, both naturally and as a consequent of policy influence.

For instance, in additional to the EU Third Energy Package which primarily focuses on the internal market for both electricity and gas, EU climate mitigation policies focused on increasing renewable energy and reducing both greenhouse gas emissions and air pollution limits, also impact the electricity sector. Policies such as the 2020 Climate and Energy Package for example, set binding targets for the EU to achieve regarding the renewable energy share of gross final consumption, reducing greenhouse gas emissions and improving energy efficiency. Once transmitted into individual Member State targets via EU Directive 2009/28/EC [9], Ireland was assigned a 16% renewable share of gross final consumption target for 2020. To reach the national target, individual sectoral targets were established for renewable electricity (40%), renewable heat (12%) and renewable transport (10%). As a result, it is estimated that 5.3 GW of wind power capacity must be installed [10], representing 33% of the anticipated total generation portfolio for the entire island to achieve the renewable targets of both jurisdictions.

2.1. The all-island electricity market

The all-island Single Electricity Market (SEM) was established in 2007 as the main trading platform for electricity on the island of Ireland. The cross-jurisdictional, dual-currency market was built on a centrally dispatched gross pool model that was the sole route to market for generators and suppliers alike.[5] The transition SEM underwent to comply with the TM was a major overhaul of what made the all-island market a success, both in terms of mitigating market power through full transparency of data and also providing a market that "*worked well for consumers in Ireland*" according to Gorecki [[11], p.677].

However, gross pool markets are often used as an intermediary step between a monopoly and a fully open bilateral market – akin to a fully open, liberalised market on training wheels according to Harris [12]. In the SEM, the 'training wheels' reference referred to the lack of risk exposure for market participants which has wider effects on the system. For example, SEM did not provide sufficient exit signals for old, inefficient capacity nor did it encourage the entry of units that added value to the system through flexibility. In other words, SEM lacked a competitive edge. This is an argument that reoccurs numerous times throughout the paper when describing different aspects of the overall market transformation.

From a high level, Ireland's electricity market did not need to change from a pool-based design to bilateral contracts based alternative to comply with the TM, instead it needed to develop the market framework in which it occupied to be more dynamic, i.e. relying less on the 'training wheels' aspect of a pool market and introduce competition for increased system efficiency. For this development to take place, several issues needed to be addressed before any alignment could be achieved. For example, system marginal prices in SEM were set (4 days) ex-post rather than ex-ante, suppliers could not submit a demand curve, and there was no continuous intra-day market or forward market liquidity of any significance. Coupled with the knowledge that SEM was centrally dispatched as opposed to self-dispatched markets in the rest of Europe (except Cyprus), the scale of the task is evident. As summarised by Gorecki; "*Aligning SEM with the Target Model appears very much to be a matter of fitting a square peg into a round hole.*" [[11], p.687].

2.1.1. Market transformation

With guidance (and the previously mentioned derogations) provided by the Agency for the Cooperation of Energy Regulators (ACER), the Regulatory Authorities (RAs)[6] laid out plans for the transition to become TM compliant. Through a number of decision papers, bilateral meetings, workshops and various working groups, the RAs put a programme in place to transition to the new electricity market for the island of Ireland, known as Integrated Single Electricity Market (I-SEM) [13]. The RAs made key decisions relating to market operations when they announced the current transmission system operator (TSO)[7] as the Nominated Electricity Market Operator, a requirement under the capacity allocation and congestion management network code,[8] and on the issue of centrally-versus self-dispatched models when it was decided there would be no change on the current stance. The decision to retain

[3] European Union 2009 *Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009, concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.*

[4] The EU Target Model for electricity emerged in 2009 from the Florence Forum process as a blueprint with top-down and bottom-up guidance on the future market design that was deemed necessary to facilitate the EU internal market for electricity [5]. Fully aligned with the three energy packages (Dir. 1996/92/EC, Dir. 2003/54/EC, Dir. 2009/72/EC), the Target Model outlines the necessary approach to complete market integration applying clear rules for implementation (network codes), market coupling initiatives (multi-regional coupling) as well as restructuring the necessary power exchanges and the necessary systems to operate the power markets (forward, day-ahead, intra-day, balancing markets) [6]. The model also involved harmonising information models, developing a central information platform, and actively adjusting the TM for better performance.

[5] There is a De Minimis threshold of 10 MW for generators. Units below this level could arrange bilateral contracts with suppliers in what was a residue from old support schemes for variable renewable energy sources.

[6] The Commission for Energy Regulation in the Republic of Ireland and the Northern Ireland Authority for Utility Regulation in Northern Ireland.

[7] EirGrid and the System Operator of Northern Ireland (SONI) are the TSOs in the Republic of Ireland and Northern Ireland jurisdictions respectively.

[8] The capacity allocation and congestion management network code has been an important network code implemented to-date. The code promotes economically-driven electricity flows on interconnectors which, as alluded to by McInerney and Bunn [14], does not always occurred. By lowering technological and institutional barriers around interconnectors, European electricity markets could be coupled in a similar way to that in the Nordic region since 1990 [15]. The code was essential when one considers the main aim of the TM is to maximise social welfare gain, i.e. maximise consumer and supplier surpluses [16]. Employing the "copper plate" effect as alluded by Barroso [17], the TM is based on the principle that electricity generated in one area can be consumed in another without constraints, causing a price equilibrium.

the centrally-dispatched model was taken as the RAs considered self-scheduling inappropriate for SEM due to the 'lumpiness'[9] of the system and therefore believed central dispatch to be a core requirement of the all-island system [13].

One of the largest differences between where SEM was and where it needed to be was the design of its trading platforms. Implementing a liquid forward market, a day-ahead market with ex-ante pricing, continuously traded intra-day market and cross-border balancing market was all new territory for the all-island market. Each different market had to become acquiescent to supplier participation, along with the centrally dispatched model to be retained under the new structure. Furthermore, importing a trading platform structure compatible with the TM was only part of the task, instilling market confidence that each platform would operate 'as per design' was equally important for market success. This was especially relevant when one considers that certain platforms (i.e. forward and intra-day) may require levels of liquidity not experienced in SEM. For instance, the forward market in SEM was not utilised to its full potential for hedging medium to long-term fuel prices as witnessed in other markets around Europe. Similarly, if one considers that all market participants (including non-dispatchable generators) must be *balance responsible* in I-SEM as outlined by the Single Electricity Market Committee [18,19], then trading in the intra-day time frame needed to occur continuously compared to SEM's twice daily intra-day auctions – a function that helps all market participants to reduce their risk exposure. Fig. 1 illustrates the market timelines in I-SEM.

The retention of the centrally dispatched model in Ireland's new electricity market also had a bearing on how market participants approach the newly designed market platform structure. For instance, notwithstanding the fact that there will be a forward market available for hedging medium-to long-term prices, this will be financial only. To physically trade electricity, the ex-ante markets (day-ahead and intra-day) and the balancing market are the exclusive routes to market in their respective timeframes, therefore generators need to be successfully dispatched to meet any financial contractual obligations agreed in the forward market. While this does not occur in other European markets due to their ability to bilaterally trade contracts between generators and suppliers, the small scale and yet complex nature of Ireland's electricity market makes the approach important for mitigating against market power exertion from legacy firms, according to the RAs[10] [13]. This introduces an additional level of risk for vertically integrated companies that may have hedged forward to reduce risk exposure around commodity prices for their thermal units for example, yet if their generation capacity does not get dispatched the company is fully exposed to market prices from their supply-side.

For market participants, transforming the pool-based energy market to become compatible with the TM provides greater financial risk exposure, especially electricity producers. Gaffney et al. [22] allude to the 'comfortable' position in which market participants in SEM have experienced to-date in such a risk adverse market design. Through an 'uplift' adder on shadow prices, 'make whole payment' and capacity payment mechanism, both short and long run costs are likely to be recovered, which provides an attractive incentive for potential new entrants investing in the sector. Under the new market structure, a capacity payment mechanism will remain in place for a select number of participants to recoup fixed costs[11] while the other 'safety nets' disappear. Therefore, I-SEM will be more onerous and complex for market participants as financial risk management comes into focus. Hedging risk exposure through forward contracting along with implementing bidding strategies will be taken to a higher level than currently being applied. In other words, for the first time since market liberalisation in 2000 the electricity sector in Ireland will operate without 'training wheels,' leaving market participants open to risk, as is the case in a fully liberalised, dynamic, open energy market [23].

With this new, heightened level of risk exposure burdening market participants, along with the anticipated increase in zero-marginal-cost generation in Ireland to reach mandatory renewable energy targets, revenues earned outside of the energy market, such as capacity payments and auxiliary revenues, become even more in focus and critical for long-term economic survival. Table 1 outlines the main changes addressed in this paper regarding the market transformation in the all-island electricity system, the focus of the case study.

3. Redesigning a capacity mechanism

Questions surrounding the inclusion of capacity payment mechanisms in the energy sector have long since been a hotly-debated topic as alluded to by Di Cosmo and Lynch [24]. From a European electricity sector context, with future generation portfolios set to contain high levels of zero-marginal-cost variable renewable energy to achieve national and supranational targets, concern surrounding the 'missing money' problem and the overall structure of modern-day electricity market design is becoming increasingly pronounced, see publications by Refs. [3,25–33].[12] Based on the merit-order approach and economic dispatch of units, the effect of high levels of zero-marginal-cost sources is shown to reduce system marginal prices. Consequently, lower prices mean less inframarginal rent is received by generators and marginal plants may fail to service debts related to fixed costs without some additional support; resulting in the 'missing money' problem and possibly leading to future concerns over generation adequacy.

The European Commission [28] recently launched an investigation into the area surrounding levels of financial support granted to electricity producers and consumers by the EU Member States to maintain sufficient generation adequacy levels. The purpose of the inquiry was to identify any unduly favourable capacity payments to providers that may have an impact on competition in the internal market and to ensure guidelines on state aid for environmental protection and energy 2014–2020 are adhered to[13] [28,29,37]. The interim report associated with the investigation stated that *"In principle, wholesale electricity markets (the 'energy-only' market) should be able to provide the price signals necessary to trigger the necessary investments provided wholesale prices*

[9] This refers to the ratio between the largest generating unit on a system and system demand. In SEM, a large unit may represent up to 20% of dispatchable generation [13].

[10] Cambridge Economics Policy Associates [21] noted that there was "*no significant market power exercised*" in Ireland. However, market power exertion has taken place elsewhere. Details of the case against E.ON AG by the European Commission for the strategic withdrawal of capacity in German electricity market, see: http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=1_39388.

[11] Capacity payments in the I-SEM will be auctioned. Discussed further in Section 3.

[12] Keay [3] suggests that European electricity markets may be broken and discusses how they must evolve to become fit for purpose again. Sen [25] outlines the need for a *'reform of electricity reform.'* Glachant and Ruester [26] believe the future EU electricity market may derail greatly from the effects of a large push to renewables, even leading to possible re-fragmentation without some coordinated policy frameworks around renewable supports and capacity mechanisms. Glachant and Ruester [26] also allude to the European Commission's ability to use its power for policing state aids to only approve capacity mechanisms if the Member State devotes funds to improving its interconnection with neighbouring states.

[13] The capacity mechanism recently implemented in Britain was the first capacity mechanism to pass EU State Aid guidelines outlined in the *Guidelines on State aid for environmental protection and energy 2014–2020 ('EEAG')* [34]. Since then France have received clearance to introduce a market-wide capacity mechanism [35] while Germany have also been granted permission for a Network Reserve in the southern part of the country to ensure security of electricity supply [36].

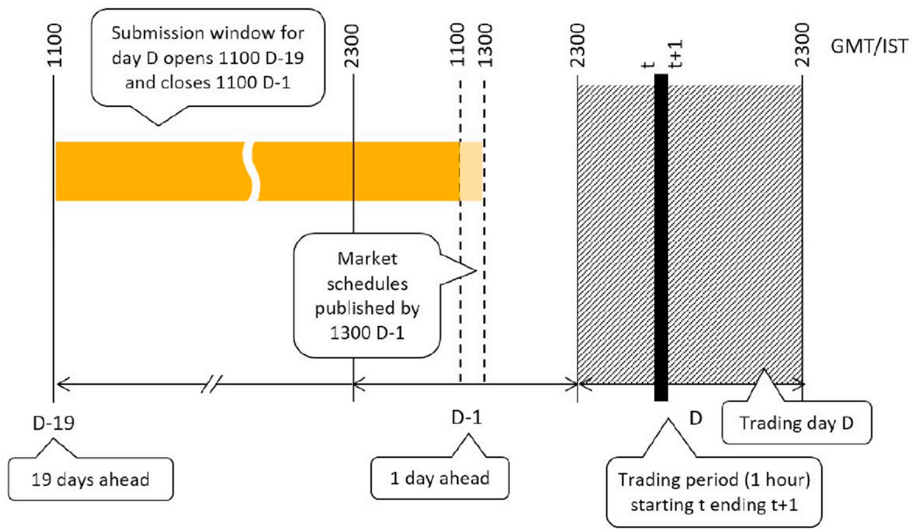

Fig. 1. I-SEM market frame timeline [20]. Trading participants submit bids and offers in the day-ahead market for a specific day between 11:00 D-19 (19 days before delivery) and 11:00 D-1 (1 day before delivery). The market is cleared with schedules are published at 13:00 D-1. Intra-day trading opens at 11:45 D-1 and closes an hour before delivery. Balancing market timeline overlaps with the intra-day and set the imbalance price for actions taken by the TSO. SEM, on the other hand was a cost-based market that included a market schedule dispatch D-1 which set the market price. This was followed by a second dispatch schedule which accounted for system constraints and system services.

Table 1
Summary of the main changes in the new market design that are addressed in this paper.

	Component	Description
Energy Market	Trading Platform Transformation	Liquidity in the forwards market and continuous intra-day trading platform is expected. Ex-ante market prices will be published before delivery of power instead of the ex-post pricing used in SEM.
	Cost Recovery	No uplift mechanism or make whole payments to ensure full cost recovery in I-SEM. Introduces risk exposure for market participants and a competitive edge into the market.
Capacity Market	Reliability Options	Auction-based financial call options, akin a one-way contract for difference, provides suppliers with a full hedge against market prices. Incentivises reliable capacity.
	Administrative Scarcity Pricing	Incentivises flexible capacity to generate when a scarcity event using high prices.
System Services	System Service Products	Increasing from seven to fourteen products. Provide greater operational control when a frequency or voltage event occurs.

allow fixed costs to be recovered.” [[28], p.9]. The report continues on to show awareness of the practicality or even the relevance of the previous statement in modern-day electricity markets where *“… [Electricity markets] are characterised by uncertainties as well as a number of market and regulatory failures which affect wholesale market price signals.”* [[28], p.9]. To combat these ‘regulatory and market failures’ along with the associated generation adequacy concerns, capacity mechanisms have increased in popularity across Europe with eleven EU Member States either using or planning to use some form of capacity payment [28,38].

However, concerns must be raised surrounding this un-unified market-by-market approach regarding capacity mechanisms which will create cross-border trade distortions where coupled markets use different approaches, e.g. an ‘energy-only’ market coupled with an ‘energy-plus-capacity’ market, or different types of capacity markets coupled. This concern is especially relevant to this case study as the GB capacity mechanism was recently suspended due to the outcome of an anti-competitiveness case taken by Tempus Energy.[14] Analysis by Gore [32] expands on this concern and quantifies, using empirical analysis, the difference between energy-only market and energy-plus-capacity markets. While the analysis finds that coupled markets work in principle, it also highlights that distributional effects are evident on interconnection flows when different capacity markets are accounted for. With the issue expected to magnify in the future as an increasing number of markets implement capacity mechanisms, a more coordinated approach throughout Europe may be necessary to help avoid negative effects on the internal market as highlighted by Gaffney [4].

3.1. Early capacity payments in Ireland

In Ireland, the first capacity payment scheme was introduced in 2001 to ensure adequate levels of generation capacity was in place to meet the growing demand for electricity resulting from large economic growth during the period. The Capacity Margin Payment Scheme, as it was known, supported open cycle gas turbine capacity in the Republic of Ireland, demand reduction schemes offered by the supply arm of the dominant firm and contracted capacity from a generation unit in Northern Ireland [39]. In 2007, this was replaced by the Capacity Payment Mechanism (CPM), which, like its predecessor, was introduced to encourage new investment in the sector, thereby stimulating competition and easing generation adequacy concerns. As the first ‘energy-plus-capacity’ market in Ireland, the CPM was a ‘Capacity Pot’ type mechanism set annually by the RAs using the Best New Entrant methodology to calculate the revenue required to recoup capital costs (net of anticipated inframarginal rent) for a hypothetical unit that represented the lowest cost per megawatt of installed capacity. Over the period 2007–2016, the pot averaged €551 million per annum[15] and broadly speaking, was distributed monthly to all generators depending on their availability for generation.

Described as a ‘market-wide price-based capacity payment mechanism’ by both the European Commission [28] and Agency for the Cooperation of Energy Regulators [31], the CPM, along with all other

[14] Tempus Energy Technology Limited, a UK-based demand response service provider, took a legal case against General Court of Justice of the EU related to the decision to afford certain market participants (generation units) contract lengths up to 15 years but not demand side response technologies as being anticompetitive, and therefore against EU State Aid guidelines. For more information on the case, see: http://curia.europa.eu/juris/document/document.jsf?text=&docid=207792&pageIndex=0&doclang=en&mode=req&dir=&occ=first&part=1&cid=1430154.

[15] Available from SEM's annual market revenues available at http://www.sem-o.com/Pages/default.aspx or the PSO levy annual reports available at: http://www.cer.ie/.

mechanisms within this category, have inherent advantages and disadvantages. Di Cosmo and Lynch [24] draw attention to a significant strength of the CPM related to the determination of the capacity pot size and its independence from any possibility of market power exertion. Since market liberalisation in 2000 mitigating against market power in a market described by Walsh et al. as "*an oligopolistic market with a competitive fringe*" [[40], p.4] has been a high priority. On the other hand, market-wide price-based capacity payment mechanisms risk over-compensating capacity providers as they rely primarily on administrative price setting and lack a competitive edge to reduce the level of remuneration received. Moreover, when a financial instrument, or specifically in the case of the CPM 'a contract for physical availability', rewards all market participants on an equal basis, it contains an innate flaw – it distorts market exit signals for old, inefficient capacity.

3.2. The capacity remuneration mechanism

Ireland's capacity payment mechanism has been redesigned and implemented alongside I-SEM to "*help deliver secure supplies for consumers in the all-island market, particularly with increasing variable generation*" according to Single Electricity Market Committee [19]. The Capacity Remuneration Mechanism (CRM), as it is known, is based on volume-based reliability options (ROs) mechanism, operating in a similar fashion to a financial call option or one-way contract for difference. The quantity of each RO is set centrally and allocated through a competitive auction. The RO length can differ depending on levels of investment made by the RO holder, ranging from 1 to 10-year contracts. Successful RO holders, who must have the physical capacity to back-up an option, will receive an annual payment. In exchange, RO holders must refund the difference between the market reference price[16] and a pre-determined strike price[17] to suppliers via the TSO if the strike price is breached, as illustrated in Fig. 2. Suppliers initially fund the ROs through a capacity charge levied as a fixed price per MWh of consumption during a pre-defined set of hours [41]. This type of mechanism allows suppliers a full hedge against market prices above the RO strike price. The principles behind reliability options are discussed in detail by Vazquez [42] and Agency for the Cooperation of Energy Regulators [31], while specific details associated with the mechanisms' introduction in Ireland can be found in Single Electricity Market Committee [41], Single Electricity Market Committee [43], Single Electricity Market Committee [44].

3.2.1. Market participant eligibility

The Single Electricity Market Committee [41] stated that all capacity providers in I-SEM, including those receiving support, are eligible to partake in the CRM once qualification requirements outlined in the Capacity Market Code [45] are adhered to. All capacity entering auctions must also apply a de-rating factor to their installed capacity that has been calculated for each specific technology type and account for the impact of plant size [46]. De-rating factors are based on historical performance data and under certain circumstances allow evidence for expected changes in future performance to be taken account of. Dispatchable capacity must enter the auctions while non-dispatchable capacity, once qualified to participate, can choose [41]. In each of the categories, de-rating factors provide reliable capacity with an advantage as higher de-ratings are associated with higher reliability, meaning a larger share of a unit's installed capacity can enter the CRM auctions.

For variable capacity where outage patterns are highly correlated, such as solar or wind power, de-rating factors are calculated based on the entire class instead of individual units. The authorities decided to include capacity receiving support to maximise competition in the CRM auctions and to remain compliant with European Commission guidelines on State Aid guidelines for environmental protection and energy which requires preference be given to capacity with lower carbon intensities in a situation where capacities are of equal technical and economic circumstances [37]. While the de-rating factors may be low for variable capacity such as wind power, in Ireland's situation with a large share of installed wind power relative to the system size, the authorities expect wind power to substantially add to the competitive auction.

3.2.2. Administrative scarcity pricing

The CRM also includes administrative scarcity pricing in the I-SEM balancing market to provide a floor price when available capacity is lower than expected demand (plus the associated reserve requirements). It is expected that introducing scarcity pricing will increase system security through strong incentives, encourage economic efficiency, provide entry and exit signals, promote demand response and finally align with the approach taken in the British market for consistent price signals when margins are tight [41]. It is also hoped that implementing this type of pricing will address an aspect of SEM that has been a concern for the RAs surrounding instances where scarcity events have occurred but were not successfully conveyed in the system marginal price; an issue also experienced in the French and Great Britain (GB) electricity markets in recent times.[18] These situations may have transpired for several reasons, for example; due to the risk adverse nature of SEM, generators might not have the awareness of such events or even the ability to adapt the output of their unit over a short timeframe. Through the overall restructuring of Ireland's electricity market, it is anticipated that market participants will play a more influential role in the future (due to new level of financial and dispatch risk exposure) and, therefore, may be better positioned to react to scarcity events. In addition, the balancing market price ceiling will increase to €10000/MWh while the day ahead market cap increases from €1000 to €3000/MWh as the RAs implement the day-ahead price cap used in the majority of TM compliance markets[19] [18,44].

The Single Electricity Market Committee [41] expect scarcity pricing to incentivise new, flexible and reliable peaking generation units entering the market using the potential for high market prices at times of system stress and therefore high revenues for those in operation, as a lure. For old unreliable thermal capacity, scarcity pricing (and the reliability option approach in general) make capacity payments a riskier revenue stream for the reasons previously alluded to and also shown in Fig. 2 where the strike price must be repaid for the volume in receipt of reliability option payment whether generating or not.

Under the new market arrangements, scarcity pricing applies when a point has been reached where available capacity is insufficient to meet demand, as illustrated in Fig. 3. The scarcity price will start from the reliability option strike price and increase using a simple piece-wise linear function until demand is met using the operating reserve capacity or a 'lost load' event occurs[20] [41].

[16] The price obtained by the RO holder in selling their power in either the day-ahead, intraday or the balancing markets [41].

[17] The Single Electricity Market Committee [41] propose that a hypothetical low-efficiency peaking unit using a floating strike price indexed to spot oil or gas prices will set the strike price.

[18] Further details available from Single Electricity Market Committee [41, p.49].

[19] The Iberian day-ahead electricity market maintained its existing price range (€0–€180.30) after entering the European internal market [47].

[20] Scarcity pricing along with other details of the CRM operational arrangements will be "*captured in and governed through, an updated Trading and Settlement Code*" which market participants must comply to according to Single Electricity Market Committee [41, p.6].

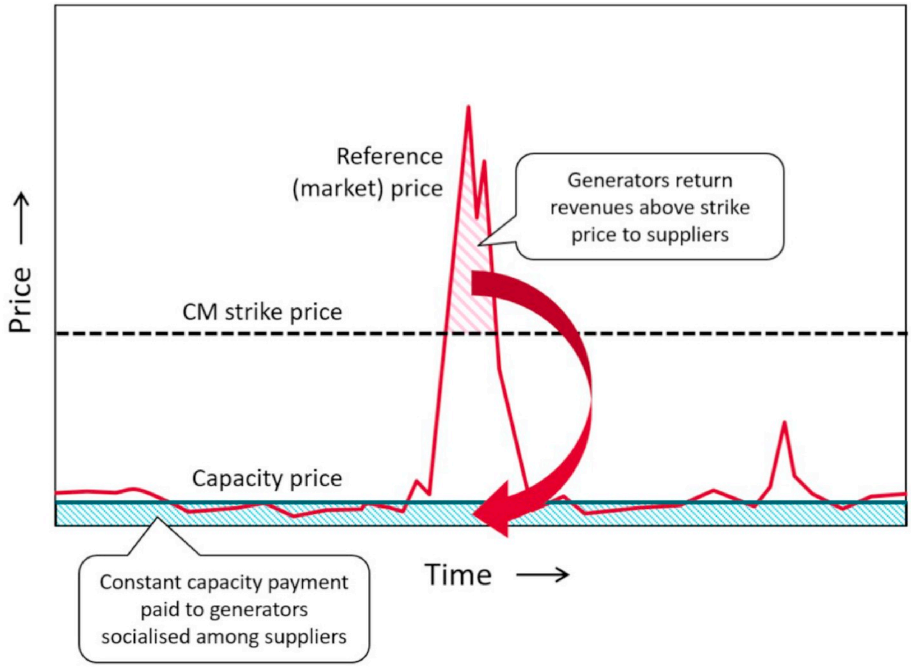

Fig. 2. Reliability option difference payments [20].

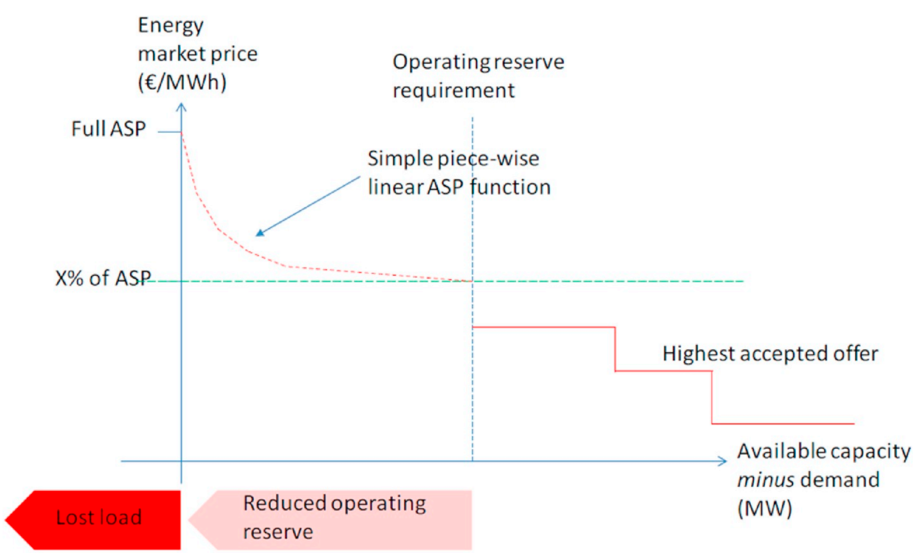

Fig. 3. Parameterised administrative scarcity price function.
Source: Capacity Remuneration Mechanism Detailed Design Decision Paper 2, SEM-16-022, Dublin [43].

3.2.3. Effects of the CRM

The CRM may benefit dispatchable generators over their variable counterparts. Under SEM arrangements, capacity payments were rewarded to all generators based on their availability to generate. Under the CRM, a generator must first bid for the RO, and if successful, must be available to generate when margins are tight otherwise face refunding the entire market reference price for the RO volume. Considering this, it is difficult to see the advantage for variable generators who receive out-of-market support payments bidding into CRM auctions when traditionally capacity payments were *not* mutually exclusive. On the other hand, if the generators in question *do* bid into the CRM and the cost to refund the difference between the market and strike prices can be passed onto the consumer, why would not they enter?[21] Therefore, all else being equal, the overall cost of renewable energy support levied onto consumers through the Public Service Obligation charge–a charge introduced to ensure security of supply and support indigenous and renewable fuel sources–may experience upward pressure directly as a result of Ireland's new capacity mechanism being implemented – a perspective shared by Di Cosmo and Lynch [24].

From a broader market perspective, changing capacity payments in Ireland to an RO style mechanism will address the previously

[21] Wind power would be a prime example of a variable energy source that may be affected by this type of capacity mechanism. It remains unclear as to whether capacity receiving out-of-market support payments can pass the cost of refunding a called RO payment can be passed onto consumers via the REFiT scheme.

mentioned concerns over 'pot' type approach regarding distorted exit and entry signals and possible over-compensation. Other benefits of pre-defined volume-based capacity auctions include the promotion of competition – providing the best value for consumers through a competitive edge, and the non-dilution of revenues when new capacity is commissioned as occurs to-date [43].

4. Restructuring system services

Managing the all-island electricity system is a challenging task for the TSO due to the nature of the system with low levels of storage and interconnection, and yet one of the highest penetration levels of variable renewable energy in Europe. Consequently, the system operator heavily depends on reserve capacity in the form of ancillary service products as a means of ensuring system stability if the delicately balanced supply and demand relationship falters. Furthermore, with future generation portfolios expected to include increased levels of variable energy sources, this enhances the technical challenges for the system operators in terms of maintaining sufficient system inertia to preserve system stability, along with the more commonly known concerns around frequency and voltage response. The scale of the challenge faced by the Irish TSO was analysed in a suite of studies called the "Facilitation of Renewables" report [48]. The findings were further refined in the "Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment" report which outlined the redesign and overall strengthening of ancillary services necessary to facilitate a significant rise in the level of variable generation capacity proposed for the island of Ireland [49]. The learnings from these studies are important for regions with ambition for high levels of variable renewable generation and are expanded on in Section 4.2 after a comparison of global systems which display similarities to that of the all-island system are discussed in Section 4.1.

4.1. Comparable system conditions

Compared to other systems worldwide, the goal of the DS3 programme regarding the facilitation of 75% instantaneous non-synchronous generation appears unprecedented on an island system with low levels of asynchronous interconnection and little energy storage. Electricity systems in New Zealand, Tasmania, and Singapore for example all have certain similarities to that of Ireland in terms of market or geographical scale. They also have either limited or no interconnection to neighbouring systems. However, none of the aforementioned have comparable levels of variable generation in their portfolios and even if this was the case, all three contain ideal technologies to accompany/facilitate variable generation with hydro-dominant portfolios in New Zealand and Tasmania and an almost exclusively gas-fired portfolio in Singapore [50]. For instance: New Zealand is completely electrically isolated, yet has a hydro-dominant generation mix that represented 55% of generation in 2015, providing vast amounts of flexible storage [51]; Tasmania has the equivalent of 16 months' worth of hydro storage capacity according to a publication by KEMA [52], making it rather unique; while Singapore generated 95% of electricity from gas in 2016 [50]. Other systems such as that of the Iberian Peninsula (Spain and Portugal) and Denmark with high levels of variable generation akin to Ireland, rely heavily on hydro in the former and interconnection in the latter to facilitate variable generation. In Spain for example, approximately 20% of generation capacity is hydro-based while Denmark has nearly six times the interconnection capacity to that of the all-island system yet is of a similar size [53].

Notwithstanding the fact of having a much greater system size, more diversified generation mix and higher levels of interconnection, some level of comparison can be drawn to the GB electricity system in terms of frequency and voltage management, along with balancing and flexibility issues recently outlined in a National Grid [54] publication. In recent years, the GB system has started witnessing the impacts associated with high levels of variable generation as balancing services are being utilised to a greater extent as capacity increases according to National Grid [54]. Consequently, reviews have been (or soon to be) carried out relating to numerous aspects of the overall approach to providing system services, such as; RoCoF requirements, frequency response, active network management, regional network voltage protection systems [54]. Other studies, such as a recent report from the SmartNet,[22] that compare ancillary services from Austria, Belgium, Denmark, Finland, Italy, Norway and Spain only further exemplify the unique conditions that the all-island system deals with on a daily basis [55]. While some of the previously mentioned systems have similarities to the all-island system, none endure the same rigor in terms of facilitating high variable generation with no synchronous interconnection capacity, low levels of asynchronous interconnection and little storage. Therefore, the learnings from this paper and particularly from the DS3 programme may be important for systems with ambition for high levels of variable renewable generation.

4.2. The DS3 programme

The "DS3 - Delivering a Secure, Sustainable Electricity System" programme was launched by the TSOs in 2011 to facilitate increased levels of variable renewables on the island of Ireland. An overview of the programme is shown in Fig. 4, identifying the three key pillars on which the programme is constructed; System Policies, System Performance, and System Tools. The figure also outlines the work streams contained in each pillar.

Strengthening the existing ancillary service products while doubling their number to fourteen is a significant feat. To facilitate this transformation, the DS3 programme included the system tools and system policies pillars as key contributors to the overall system service arrangements. System tools provide control over the programme through the various means outlined in Fig. 4 and the system policies pillar ensures the correct level of regulation is in place to support the success of DS3 through policy control. While remaining cognisant that both pillars are integral to the success of the programme, this section will concentrate on the system performance pillar and the technical aspects of the DS3 programme that may provide a financial opportunity for market participants to increase auxiliary revenue streams, thereby encouraging flexibility in the system – a characteristic which is considered essential in a system with high levels of variable generation capacity [2].

4.3. System performance

System performance relates to monitoring and managing the performance of all units connected to the all-island electricity system. Maintaining the performance level necessary to reach renewable electricity targets is important for both jurisdictions. Many changes are ongoing in this category such as Grid Code modifications,[23] developing new practices in performance monitoring and increasing the level of participation from demand side management participants. From a technical perspective, there are two critical aspects of system operation that must change for the successful adoption of the DS3 programme [56]. First, the Rate of Change of Frequency (RoCoF) standard that a thermal unit must 'ride-through' without disconnecting from the grid and second, the restructuring of system service products in the all-island electricity system.

[22] The SmartNet project is funded through the European Union's Horizon 2020 research and innovation programme. For more information see: http://smartnet-project.eu/.

[23] Grid code is a set of standards for all plant to adhere to that are connected to the system. For more details, see: http://www.eirgridgroup.com/.

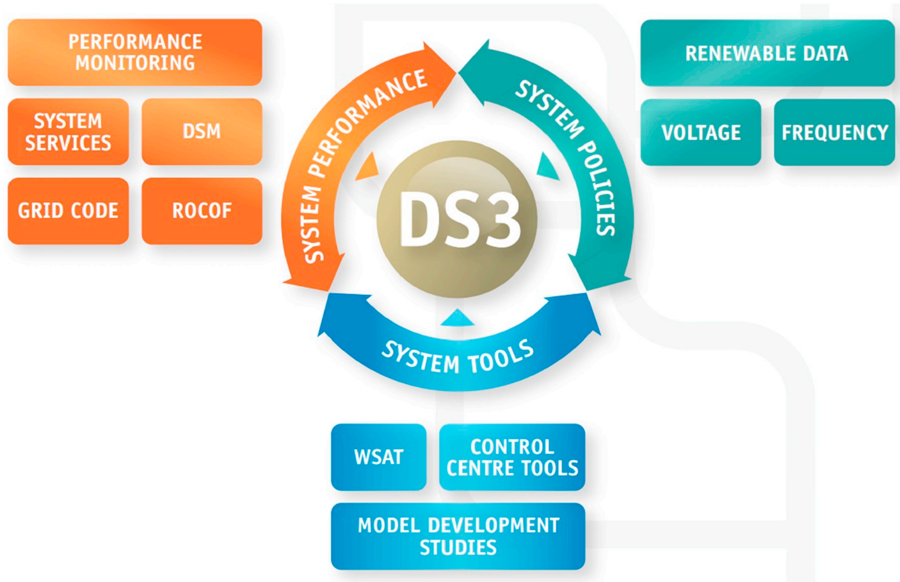

Fig. 4. DS3 programme structure.
Source: DS3 System Services Procurement Design and Emerging Thinking Decision Paper, SEM-14-108. Dublin [56].

4.3.1. Rate of change of frequency

The RoCoF standard will increase from the current 0.5 Hz per second to 1 Hz per second measured over 500 ms for all conventional plants to comply with Grid Code [57]. For synchronous generation capacity, this means their plant must stay synchronised with the system through a change of frequency of up to 1 Hz per second measured over 500 ms. Increasing the RoCoF standard is not unheard of as both Spain and Denmark, two fellow Member States with significant levels of variable renewable energy, have implemented 2 Hz/s and 2.5 Hz/s RoCoF standards respectively [58,59]. However, a significant difference between what Ireland aims to do compared to Denmark or Spain, is enforce the updated RoCoF standard on *all* existing thermal units, not just newly commissioned plants.[24]

In changing the RoCoF standard, the TSO anticipate that higher instantaneous penetration levels of variable renewable energy can be facilitated in the system [48]. The parameter used by the TSOs to measure the instantaneous penetration of variable renewable generation is called the System Non-Synchronous Penetration (SNSP) limit. SNSP limit is calculated based on the volume of non-synchronous energy source generated plus interconnector imports as a percentage of the overall demand plus interconnector exports. In Q2 2019, at the time of writing, the SNSP limit is 65% non-synchronous energy sources [61]. By introducing the updated RoCoF standard along with the other DS3 work streams, this limit is anticipated to reach 75% – reducing curtailment of renewable energy and therefore, helping to achieve binding EU Member State renewable energy targets. Fig. 5 illustrates the SNSP limits anticipated by the TSO over the period 2015–2020. The figure also shows the benefit of introducing the various new/updated standards and work streams on the system in terms facilitating non-synchronous generation.

4.3.2. System services

Maintaining a stable electricity system with as little as 580 MW[25] of asynchronous interconnection and less than 300 MW of pumped hydro energy storage is a difficult feat, especially if one considers that in 2020, the installed capacity of variable generation (i.e. wind and solar PV) is expected to be 5600 MW [10]. For comparative purposes, the peak system demand in the same year is expected to be approximately 7000 MW according to the median demand forecast for the all-island electricity system [10]. Where other systems across Europe are not as geographically isolated, interconnection with neighbouring systems is a means of increasing security of supply and thus requiring fewer system services. Similarly, EU Member States such as Spain, Germany, France, Italy, and Austria have large pumped hydro energy storage capacity which is ideal for storing energy when wholesale electricity prices are low, for providing system services and for facilitating variable generation [63]. Recognising that no new interconnection or storage capacity is expected in Ireland before 2025 when a proposed 700 MW interconnector to France may come online [64], system services remain critical for system stability.

Once the system services work stream of the DS3 programme is fully implemented in 2019, the number of system service products will increase from seven under the current arrangement to fourteen to create one of the most complex system service arrangements used in an electricity system worldwide. In October 2016, eleven of the fourteen system services became operational using regulated tariffs and volumes set by the TSOs. The three products not yet in operation are fast frequency response, dynamic reactive response, and fast post-fault active power recovery. Details of new and existing system service products are outlined in Section A of Table 2 while Fig. 6 and Fig. 7 show which of the products relate to frequency control or voltage control. The figures also allude to the 'activation order' timeline of products in the event of an incident.

Figs. 6 and 7 demonstrate how the new system services complement the existing products in order to improve system frequency and system voltage control respectively. Each figure shows that additional products have been introduced between the time an incident occurs and when

[24] This aspect of RoCoF created unrest between market participants in SEM and the authorities, i.e. the TSOs and RAs, leading to an open consultation followed by a recommendations paper on a remuneration mechanism to contribute towards costs associated with the generation studies necessary to ascertain whether a unit can meet the new RoCoF standard, for more information see: [60].

[25] The long-term view assumed by the TSOs regarding the Moyle asynchronous interconnector is that it may have an 80 MW export limit due to network constraints in GB [10].

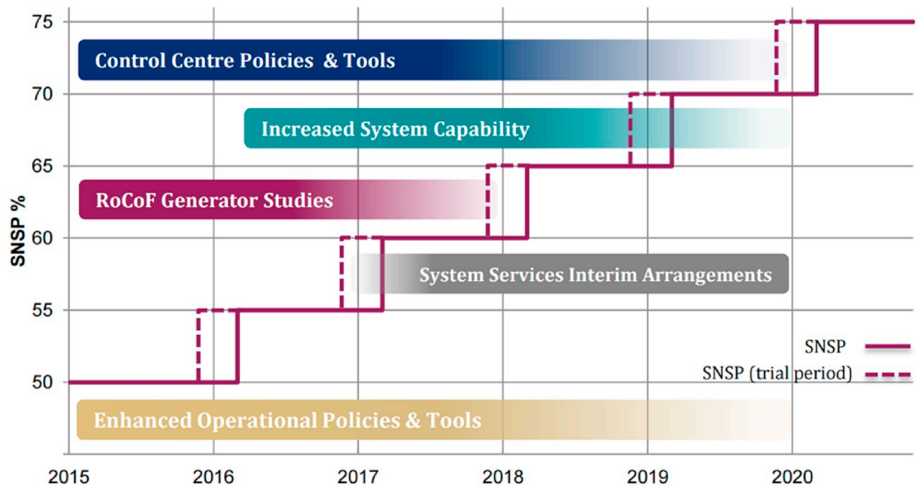

Fig. 5. Operational capability outlook.
Source: DS3 Programme Operational Capability Outlook 2016, EirGrid [62].

Table 2
Summary of DS3 system services products.
Sources: Section A: DS3 System Services Technical Definitions Decision Paper, SEM-13-098. Dublin [65]. Section B: DS3 System Services Tariffs and Scalars, Dublin [66].

Section A					Section B
Service Name	Abbreviation	Unit of Payment	New or Existing	Short Description	Tariff Rates (€)
Synchronous Inertial Response	SIR	MWs^2h	New	(Stored kinetic energy) * (SIR Factor - 15)	0.0050
Fast Frequency Response	FFR	MWh	New	MW delivered between 2 and 10 s	2.16
Primary Operating Reserve	POR	MWh	Existing	MW delivered between 5 and 15 s	3.24
Secondary Operating Reserve	SOR	MWh	Existing	MW delivered between 15 and 90 s	1.96
Tertiary Operating Reserve 1	TOR1	MWh	Existing	MW delivered between 90 s and 5 min	1.55
Tertiary Operating Reserve 2	TOR2	MWh	Existing	MW delivered between 5 min and 20 min	1.24
Replacement Reserve (De-Synchronised)	RRD	MWh	Existing	MW delivered between 20 min and 1 h	0.56
Replacement Reserve (Synchronised)	RRS	MWh	Existing	MW delivered between 20 min and 1 h	0.25
Ramping Margin 1 Hour	RM1	MWh	New	The increased MW output that can be delivered with a good degree	0.12
Ramping Margin 3 Hour	RM3	MWh	New	of certainty for the given time horizon.	0.18
Ramping Margin 8 Hour	RM8	MWh	New		0.16
Fast Post-Fault Active Power Recovery	FPFAPR	MWh	New	Active power > 90% within 250 ms of voltage > 90%	0.15
Steady-state Reactive Power	SRP	MVArh	Existing	MVAr capability * (% of capacity that capability is provided)	0.23
Dynamic Reactive Response	DRR	MWh	New	MVAr capability during large (> 30%) voltage dips	0.04

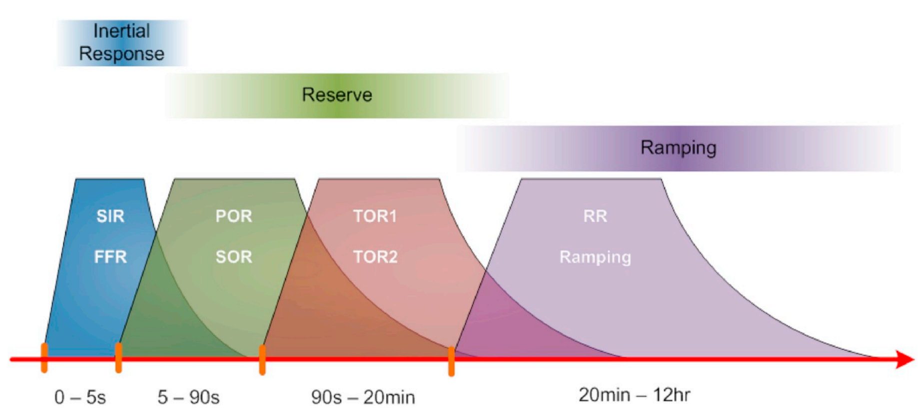

Fig. 6. Frequency control services.
Source: DS3 System Services Technical Definitions Decision Paper, SEM-13-098. Dublin [65].

the existing products activate which allows greater operational control over the system, in turn increasing the system's ability to facilitate variable generation. For example, SIR and FFR provide an inertial and fast-acting MW response from 0 to 5 s of a frequency event occurring. Similarly, dynamic reactive response is important for system stability when there are high levels of variable generation online to deliver a reactive current response for voltage dips in the period before the existing steady-state reactive power product becomes active. Fast post-fault active power recovery (FPRAPR) is the only new product not represented on either Fig. 6 or Fig. 7. The FPRAPR product provides a

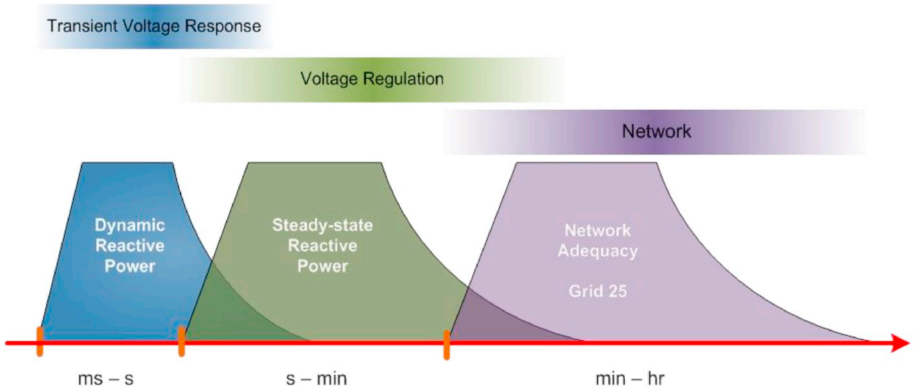

Fig. 7. Voltage control services[26].
Source: DS3 System Services Technical Definitions Decision Paper, SEM-13-098. Dublin [65].

positive contribution to system stability and security through its ability to mitigate against the impact of large frequency disturbances through fast power recovery response.[27]

Prospective providers of one or more system services outlined in Table 2 are required to complete a qualification trial process to 1) assess their technical ability to provide the product in question, 2) advise authorities on the level of competition for each product, and 3) establish the current capabilities within the system [56]. The qualification trials are carried out to assess the ability of a range of technologies to provide the various products, as described by EirGrid & SONI [67]. All technologies, including wind power, demand side, and other technologies such as battery storage, solar PV, flywheels, etc., along with conventional generation are admissible to the trials. Once qualified, prospective providers must enter successful bids for each system service at product auctions to become a provider. Contracts for each product will be awarded on an annual basis except in the case where investment is necessary to provide a service where on a case-by-case basis contracts of up to 20 years may be bestowed on the participant[28] [56]. The volume of each product described in Table 2 will be determined annually by the TSO [68].

In the event of low market participation or where the possibility for market power exertion exists, the contract price may be defined via a TSO set regulated tariff. The authorities suggest that applying regulated tariffs will not be the enduring solution in I-SEM, instead expect a competitive process to be in place in the long-term. Regulated tariffs will be calculated using a "cost-plus" approach which incorporates the previously defined Best New Entrant approach and a regulated rate of return aspect as described by EirGrid & SONI [69]. Bearing in mind the need to send the correct investment signals to market participants, the authorities will set all regulated tariffs for a period of five years once the system services are fully implemented [56]. In a move that is intended to provide greater certainty for the industry, the authorities stated that ***"[Regulated tariffs may] provide guidance on the prices that may result from the competitive process."*** [56, p.35].

Section B of Table 2 outlines the regulated tariffs for the operational DS3 system services along with the products yet to be implemented, i.e. fast frequency response, dynamic reactive response, and fast post-fault active power recovery. These tariffs allow an insight into the potential revenue to be earned by generators for providing system services. The price received by market participants for providing system service products is also subject to scalars in an attempt to increase performance of the procurement design by rewarding providers who 'turn up' in times of most need. The scalars are based on performance, scarcity, product and volume [56].

4.4. Revenues from DS3 programme related activities

While the updated RoCoF standard will be a requirement for thermal units under Grid Code, there is no direct revenue to be earned from having the ability to "ride-through" a frequency event. Indirectly, however, achieving the standard may ensure that a unit has a higher number of operational hours over a unit still to comply with the standard change for system stability reasons. System services on the other hand, do provide a direct revenue stream as shown in Section B of Table 2. Through the DS3 programme and its associated 75% SNSP target, the TSO estimated the annual benefit of reducing variable renewable energy curtailment to be in the range of €177 million by 2020 – in other words, the TSO expects the overall energy market costs to reduce by that amount [56]. When taken along with the existing expenditure cap on ancillary services (€60 million), the total is rounded to €235 million and used as the annual 'cap' for system services from 2020 onwards [56]. From a high-level view, Fig. 8 illustrates the anticipated redistribution of revenue streams estimated the RAs in the "DS3 System Services Procurement Design and Emerging Thinking" publication [56].

4.4.1. Redistribution of revenue streams

Participants in Ireland's electricity market have already witnessed a change in their revenue streams over the past number of years and this trend is expected to continue through the transition to I-SEM and beyond while policy measures influence the generation portfolio. Between 2007 and 2016 for example, the total annual energy payments in SEM decreased by 49% (€2.7 to €1.37 billion)[29] while other payments, such as capacity payments, remained relatively constant [74]. The RAs have shown awareness of the changing marketplace through their central involvement in the restructuring process to facilitate future generation portfolios in the new design for the island of Ireland. Notwithstanding

[26] Network adequacy and Grid 25 - another TSO-led programme based on improving transmission infrastructure - are included in the figure to illustrate the important part the transmission network has in neutralising a fault.

[27] For further details on the technical characteristics of FPFAPR and the other products, see Ref. [65].

[28] A potential conflict of interest was raised by market participants relating to the TSOs' ownership of a 500 MW interconnector to Great Britain that can provide system services. The SEM committee found that as the interconnector was financed by the Irish energy consumer, it should therefore be used in a means that maximises the value to the consumer. Therefore, the interconnector will not participate directly in any auctions and will be treated as a price taker for its volume. Effectively the volumes to be auctioned will be net of the provision the interconnector can provide [56].

[29] The 2016 annual energy market revenue is 32% below the nine-year average. It is recognised that fuel and emission costs have a part in this reduction; however, the effect of high levels of zero-marginal cost generation on lowering system marginal prices has been shown in numerous articles such as [70–73]. For more information on the annual market revenues, see [74].

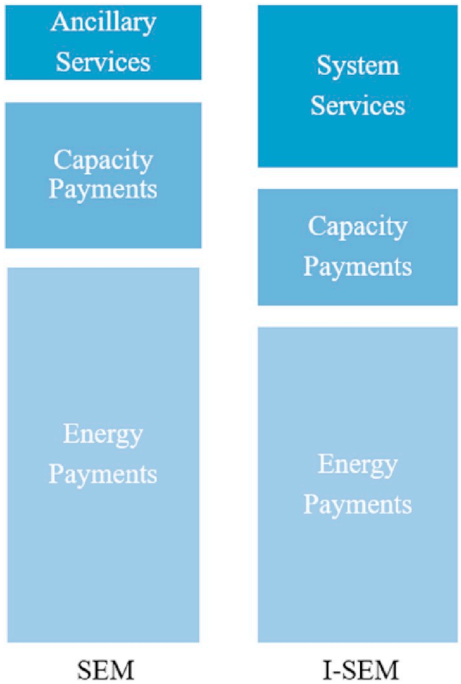

Fig. 8. Rebalance of revenue streams.
Source: own elaboration based on Single Electricity Market Committee [56].

the fact that revenue streams are naturally rebalancing as generation portfolios evolve, the transformation under I-SEM (including the capacity and system service elements) takes a significant step to what future electricity market designs may look like worldwide – optimally balancing efficiency, flexibility and system adequacy.

As demonstrated in Fig. 8, I-SEM consists of three primary revenue streams for market participants. With future energy payments expected to reduce because of large volumes of zero-marginal-cost variable renewable energy being installed to meet renewable targets, thermal generators operating purely on the energy market may not receive sufficient inframarginal rent to service debts related to fixed costs, i.e. the missing money problem. Furthermore, as outlined by Deane et al. [2], many of these generators are vital for the long-term operation of the system, in terms of meeting system adequacy requirements, providing flexible generation, inertia requirements, voltage and frequency response. To address this concern, I-SEM is more value-based than its predecessor – rewarding generators that add flexibility and reliability to the system. Through the DS3 programme for example, flexible units benefit from the increased number of system service products that can be availed of, along with scalars based on performance, scarcity, product and volume. In the CRM both reliability and flexibility are rewarded as the former is a key characteristic of any such financial option-based mechanism and the latter, an advantageous characteristic when administrative scarcity pricing is in place.

5. Conclusion

Climate mitigation policies are influencing generation portfolios. With technological change comes both, sectoral and market change. Pecuniary externalities such as support mechanisms and carbon taxes, introduced via policy measures, can distort market price formation and affect system operations. Through this case study, the other side of the coin is observed. The paper explores the strategy used by an isolated system with high levels of variable renewable generation to optimise the balance between efficiency, flexibility and system adequacy while maintaining a fully functional system that strives to adapt to the evolving conditions.

This case study highlights several concerns that are soon to be or are already, relevant to a wide range of electricity markets. Technical issues relating to frequency and voltage control, market issues around decreasing system marginal prices – leading to the 'missing money' problem, and institutional issues concerning Ireland's need to become compatible with the greater European internal electricity market, all offer an insight into both internal and external policy influences that manifested themselves in the 2018 market transformation. This paper also demonstrates the length at which Ireland will go to achieve ambitious energy-related policy decisions to curtail the effects of climate change.

Implementing the energy market changes alluded to in Section 2 instils a competitive edge that entices market participants to play a more influential/central role in the future marketplace while attempting to reduce financial risk exposure. Withdrawing the reassurance of fully cost recovery creates a situation where the "training wheels" have been removed and competition can prosper. Redesigning the capacity mechanism also fosters competition through the auctioning of reliability options. The in-coming mechanism addresses concerns surrounding distorted entry and exit signals, over-compensation, and the dilution of revenues associated with new capacity being commissioned, through a pre-defined volume-based capacity auction that promotes flexible and reliable capacity, as discussed in Section 3. Restructuring system services increases the operational ability to control frequency and voltage during an event through additional system service products, a new RoCoF standard and a range of other inputs from the DS3 programme, as described in Section 4. In short; restructuring system services aims to increase operational control of the system which equates to heightened system stability, thereby improving the system's capacity to facilitate higher levels of variable generation. The actions, when taken together, provide an insight into the lengths to which this electricity market must go, to transform from its cost-based nature to a value-based alternative that rewards flexible and reliable capacity with the ability to evolve with market conditions of the future.

Acknowledgements

The authors acknowledge the financial support provided by Bord Gáis Energy.

References

[1] A.M. Foley, B.P. Ó Gallachóir, E.J. McKeogh, D. Milborrow, P.G. Leahy, Addressing the technical and market challenges to high wind power integration in Ireland, Renew. Sustain. Energy Rev. 19 (2013) 692–703.
[2] P. Deane, F. Gracceva, A. Chiodi, M. Gargiulo, B. Ó Gallachóir, Assessing power system security. A framework and a multi model approach, Int. J. Electr. Power Energy Syst. 73 (2015) 283–297.
[3] M. Keay, Electricity Markets Are Broken - Can They Be Fixed? The Oxford Institute of Energy Studies, working paper EL, 2016 El 17.
[4] F. Gaffney, J. Deane, S. Collins, B.Ó. Gallachóir, Consumption-based approach to RES-E quantification: insights from a Pan-European case study, Energy Policy 112 (2018) 291–300.
[5] Booz & Co, D. Newbery, G. Strbac, Physical and financial capacity rights for cross-border trade, Prepared for the Directorate-General Energy, European Commission, Brussels, 2011.
[6] ENTSO-E, ENTSO-E Overview of Internal Electricity Market-Related Project Work, ENTSO-E, Brussels, 2014.
[7] Agency for the Cooperation of Energy Regulators, Framework guidelines on capacity allocation and congestion management for electricity, in *FG-2011-E-002*. 2011, ACER: Ljubljana.
[8] European Commission, Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management, European Union, European Commission, Brussels, 2015online at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222&from=EN.
[9] European Commission, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009, on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC, European Union, 2009 online at: http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009L0028.
[10] EirGrid, All-Island Generation Capacity Statement 2016-2025, (2016) Dublin.

[11] P.K. Gorecki, Ensuring compatibility of the all-island electricity system with the target model: fitting a square peg into a round hole? Energy Policy 52 (2013) 677–688.
[12] C. Harris, Electricity Markets: Pricing, Structures and Economics vol. 565, John Wiley & Sons, 2011.
[13] Single Electricity Market Committee, *SEM-12-004 Proposals for Implementation of the European Target Model for the Single Electricity Market*, SEMC, Dublin, 2012.
[14] C. McInerney, D. Bunn, Valuation anomalies for interconnector transmission rights, Energy Policy 55 (2013) 565–578.
[15] O. Olsen, Competition in the Nordic Electricity Industry, Energy Utilities and Competitiveness, Dublin, 1995.
[16] D. Newbery, G. Strbac, I. Viehoff, The benefits of integrating European electricity markets, Energy Policy 94 (2016) 253–263.
[17] L.A. Barroso, T.H. Cavalcanti, P. Giesbertz, K. Purchala, Classification of electricity market models worldwide, International Symposium CIGRE/IEEE PES, vol. 2005, IEEE, 2005.
[18] Single Electricity Market Committee, *SEM-15-065 I-SEM Energy Trading Arrangements Detailed Design: Markets Decision Paper*, SEMC, Dublin, 2015.
[19] Single Electricity Market Committee, *SEM-14-085a Integrated Single Electricity Market (I-SEM) SEM Committee Decision on High Level Design*, SEMC, Dublin, 2014.
[20] EirGrid & SONI, Industry Guide to the I-SEM, EirGrid & SONI, Dublin, 2017.
[21] Cambridge Economics Policy Associates, *Market Power and Liquidity in SEM: A Report for the CER and Utility Regulator*, CEPA, Cambridge, 2010.
[22] F. Gaffney, J. Deane, B.Ó. Gallachóir, A 100 year review of electricity policy in Ireland (1916–2015), Energy Policy 105 (2017) 67–79.
[23] ElectroRoute, I-SEM - the Reasons for Change, (2016).
[24] V. Di Cosmo, M.Á. Lynch, Competition and the Single Electricity Market: Which Lessons for Ireland? Utilities Policy, 2016.
[25] A. Sen, R. Nepal, T. Jamasb, Reforming electricity reforms? Empirical evidence from Asian Economies, The Oxford Institute of Energy Studies, 2016.
[26] J.-M. Glachant, S. Ruester, The EU internal electricity market: done forever? Util. Policy 31 (2014) 221–228.
[27] D. Buchan, Europe's unresolved energy versus climate policy dilemma, EU's Internal Energy Market: Tough Decisions and a Daunting Agenda, 2013, pp. 7–13.
[28] European Commission, Interim Report of the Sector Inquiry on Capacity Mechanisms, European Commission, Brussels, 2016.
[29] European Commission, Interim Report of the Sector Inquiry on Capacity Mechanisms - Commission Staff Working Document, European Commission, Brussels, 2016.
[30] International Energy Agency, Re-powering Markets: market design and regulation during the transition to low-carbon power systems, Electricity Market Series, IEA, Paris, 2016.
[31] Agency for the Cooperation of Energy Regulators, Capacity remuneration mechanisms and the internal market for electricity, Pursuant to Article 11 of Regulation (EC) No 713/2009, ACER, 2013.
[32] O. Gore, E. Vanadzina, S. Viljainen, Linking the energy-only market and the energy-plus-capacity market, Util. Policy 38 (2016) 52–61.
[33] M. Keay, The EU “Target Model” for Electricity Markets: Fit for Purpose, Oxford Institute for Energy Studies, 2013.
[34] European Commission, State Aid: Commission Authorises UK Capacity Market Electricity Generation Scheme, European Commission, Brussels, 2014.
[35] European Commission, State Aid: Commission Approves Revised French Market-wide Capacity Mechanism, European Commission, Brussels, 2016.
[36] European Commission, State Aid: Commission Clears German Network Reserve for Ensuring Security of Electricity Supply, European Commission, Brussels, 2016.
[37] European Commission, Guidelines on state aid for environmental protection and energy 2014-2020 (2014/C 200/01), Orkesterjournalen C 200 (1) (2014).
[38] CREG, Study on capacity remuneration mechanisms, Regulatory Commission for Electricity and Gas, CREG, Brussels, 2012.
[39] Commission for Energy Regulation, CER/05/198 Capacity Margin Payments Scheme for 2006, CER, Dublin, 2005.
[40] D. Walsh, L. Malaguzzi Valeri, V. Di Cosmo, Strategic Bidding, Wind Ownership and Regulation in a Decentralised Electricity Market, Munich Personal RePEc Archive, 2016.
[41] Single Electricity Market Committee, *SEM-15-103 I-SEM Capacity Remuneration Mechanism Detailed Design Decision Paper 1*. 2015, SEMC: Dublin.
[42] C. Vazquez, M. Rivier, I.J. Pérez-Arriaga, A market approach to long-term security of supply, Power Systems, IEEE Transactions on 17 (2) (2002) 349–357.
[43] Single Electricity Market Committee, *SEM-16-078 ESP Stocktake Report*, SEMC, Dublin, 2016.
[44] Single Electricity Market Committee, *SEM-16-022 I-SEM Capacity Remuneration Mechanism Detailed Design Decision Paper 2*, SEMC, Dublin, 2016.
[45] Single Electricity Market Committee, *SEM-17-004 I-SEM Capacity Remuneration Mechanism Capacity Market Code Consultation Paper*, SEMC, Dublin, 2017.
[46] Single Electricity Market Committee, *SEM-16-082 I-SEM Capacity Requirement and De-rating Factor Methodology Detailed Design Decision Paper*, SEMC, Dublin, 2016.
[47] A. Henriot, O. Lavoine, F. Regairaz, C. Hiroux-Marcy, J. Gilmore, J. Riesz, C. Yuen, do, D. Brasil, M. Salvador, H. Ziegler, Market Design for Large Scale Integration of Intermittent Renewable Energy Sources, CIGRE Technical Brochure, 2013.
[48] EirGrid & SONI, All Island TSO Facilitation of Renewables Studies, Tech. Rep. (2010).
[49] EirGrid & SONI, Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment, (2011).
[50] Energy Market Authority, Statistics, (2017) [cited 2017 2 May]; Available from: https://www.ema.gov.sg/Statistics.aspx.
[51] International Energy Agency, Energy policies of IEA countries - New Zealand 2017 review, Energy Policies of IEA Countries, IEA, Paris, 2017.
[52] KEMA, System Services International Review: Market Update, KEMA, London, 2011.
[53] dk Energinet, Download of Market Data, (2016) [cited 2016 November 8]; Available from: http://energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx.
[54] National Grid, *System Operability Framework*, (2016) United Kingdom.
[55] J. Merino, I. Gómez, E. Turienzo, C. Madina, Ancillary service provision by RES and DSM connected at distribution level in the future power system, SmartNet project D 1 (2016) 1.
[56] Single Electricity Market Committee, *SEM-14-108 DS3 System Services Procurement Design and Emerging Thinking*, SEMC, Dublin, 2014.
[57] Commission for Energy Regulation, CER/14/081 Rate of Change of Frequency (RoCoF) Modification to the Grid Code, CER, Dublin, 2014.
[58] dk Energinet, Technical Regulation for Thermal Power Station Units of 1.5 MW and Higher: Regulation for Grid Connection TF 3.2.3, Energinet.dk, Jutland, 2008.
[59] Australian Energy Market Operator, Wind Integration: International Experience WP2: Review of Grid Codes, (2011).
[60] EirGrid & SONI, A Proposal for Rate of Change of Frequency Remuneration Mechanism Recommendations Paper 2015, EirGrid & SONI, Dublin, 2016.
[61] EirGrid, Operational Constraints Update, EirGrid, Dublin, 2019.
[62] EirGrid, DS3 Programme Operational Capability Outlook 2016, (2016) Dublin.
[63] P. Deane, B. Ó Gallachóir, E. McKeogh, Techno-economic review of existing and new pumped hydro energy storage plant, Renew. Sustain. Energy Rev. 14 (4) (2010) 1293–1302.
[64] ENTSO-E, Ten-Year Network Development Plan 2016, ENTSO-E, Brussels, 2015.
[65] Single Electricity Market Committee, *SEM-13-098 Single Electricity Market DS3 System Services Technical Definitions Decision Paper*, CER, Dublin, 2013.
[66] Single Electricity Market Committee, *DS3 System Services Tariffs and Scalars, SEM-17-080*, SEMC, Dublin, 2017.
[67] EirGrid & SONI, DS3 System Services Qualification Trial Process Decision Paper, EirGrid & SONI, Dublin, 2016.
[68] EirGrid & SONI, Volume Calculation Methodology and Portfolio Scenarios: Decision Paper, EirGrid & SONI, Dublin, 2016.
[69] EirGrid & SONI, Consultation on Regulated Tariff Calculation Methodology, EirGrid & SONI, Dublin, 2016.
[70] M. Clancy, F. Gaffney, P. Deane, J. Curtis, B. Ó Gallachoir, Fossil fuel and CO2 emissions savings on a high renewable electricity system - a single year case study for Ireland, Energy Policy 83 (2015) 151–164.
[71] B. Cleary, A. Duffy, B. Bach, A. Vitina, A. O'Connor, M. Conlon, Estimating the electricity prices, generation costs and CO2 emissions of large scale wind energy exports from Ireland to Great Britain, Energy Policy 91 (2016) 38–48.
[72] F. Sensfuß, M. Ragwitz, M. Genoese, The merit-order effect: a detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany, Energy Policy 36 (8) (2008) 3086–3094.
[73] Sáenz de Miera, P. del Río González, I. Vizcaíno, Analysing the impact of renewable electricity support schemes on power prices: the case of wind electricity in Spain, Energy Policy 36 (9) (2008) 3345–3359.
[74] Single Electricity Market Operator. *Value of Market*, (2016) [cited 2016 15 July]; Available from: http://www.sem-o.com/pages/MDB_ValueOfMarket.aspx.