REGULATED TARIFF METHODOLOGY FOR DS3 SYSTEM SERVICES

A report to EirGrid and SONI

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EXECUTIVE SUMMARY

The generation mix in the All-Island system is changing in response to policy objectives to reduce emissions. Decarbonisation targets are expected to be achieved through continued expansion in wind generation, and this is already becoming apparent with more than 3000MW of wind installed capacity currently on the system. Moving towards 2020, the level of wind generation is set to further increase. This growth in weather-variable non-synchronous renewable generation challenges the ability to maintain low curtailment levels while managing the security of the system.

To ensure safe and secure operation of the system, whilst facilitating greater levels of intermittent non-synchronous renewable generation, EirGrid and SONI ('TSOs') will have to procure a wider range of System Services, in addition to implementing new operational policies and system tools. These initiatives make up the DS3 programme, which was established in 2011 and is designed to address this challenge with the overarching aim of delivering value to consumers.

The SEM Committee has published a decision paper (SEM 14-108) outlining the High-Level Design ('HLD') for DS3 System Services procurement. It envisages regulated tariffs to be used as an interim way of compensating System Services in 2016/17 with auctions acting as the enduring procurement and pricing tool where competition exists from 2017 onwards. However, some System Services may be assessed to be uncompetitive and regulated tariffs may persist for as long as there is insufficient competition. The technical definitions of the System Services have already been developed and a methodology for the determination of the System Services volumes to be procured is currently under consultation.

Some of the System Services are new and unique to the All-Island system. Even for System Services that can be found in other markets, there are no existing direct precedents for determining regulated tariffs as envisaged in the SEM Committee decision. In developing a methodology for determining regulated tariffs, we have had to take into consideration several characteristics of System Service provision, including:

- providers can 'jointly' offer several System Services;
  - with a single investment and/or operational choice providers may be in a position to deliver a range of System Services;
- cost of provision varies across potential providers;
  - differences are observed in both short-run and fixed costs;
- strong interactions with other markets exist ;
  - some of the costs associated with the provision of a System Service may be recovered through other markets;
  - provision of a System Service may preclude part of a provider's volumes from participation in the energy markets; and
  - provision and level of remuneration of certain System Services may result in changes in the operational behaviour of some market participants in the energy markets under I-SEM.

Our benchmark for the methodology is a set of underlying principles that regulated tariffs should:

- reflect the value of each service, and in particular place greater value where there is scarcity;
- incentivise the appropriate level of System Services that are needed by the TSOs;
- promote investment in both enhancement of existing assets and new entry when needed;
- facilitate the cost-effective delivery of wider public policy objectives such as decarbonisation;
- to the greatest extent possible, treat all technologies equitably;
- ensure consumers' interests are protected; and
- be underpinned by a simple and transparent methodology.

However, the methodology must also be consistent with the requirements of the SEM-C Decision and this may constrain our chosen approach. As such, this report attempts to answer the following key question: What are the options for a regulated tariff methodology in line with the SEM Committee decision that can satisfy the stated objectives?

In the process of developing such a regulated tariff methodology, we have found that:

- there is no single methodology that is equally applicable across all proposed System Services;
- there is some need to diverge from the SEM Committee approach, though keeping within the spirit of the decision;
- assigning costs, whether investment or operational, of a single provider between different System Services can be challenging;
- to develop cost-reflective tariffs, there is a need to make judgements on third party costs;
- without some form of targeting procurement of some System Services there is a risk of very large payments to providers that do not materially improve system security and hence increase costs to consumers; and
- there is merit in allowing adjustment of the base regulated tariffs by the TSOs to better reflect scarcity and meet budgetary constraints.

To reflect fundamental differences in the nature of the defined System Service products, there are variations in the detailed tariff methodology for particular System Services or groups of System Services. For all System Services, tariff determination is dependent on assumptions around costs of provisions and the wider market environment. These assumptions should be based on a transparent evidence base taking account of industry views. While the responsibility for managing the call for evidence may be vested in either the TSOs or the RAs, the final assumptions would require RA approval.

Although we do not propose a single methodology for determining regulated tariffs across all, there are some common aspects applicable to all products. Base tariffs are designed to be annual with any potential within-year temporal variation being introduced with the use of relevant scalars. All tariffs are to be determined in real money terms, and adjusted for inflation in subsequent years.

Taking account of the objectives of, and constraints on, the methodology our proposed approaches for the different System Services are the following:

- **Fast Post Fault Active Power Recovery ('FPFAPR') Dynamic Reactive Response ('DRR')** and **Fast Post Fault Active Power Recovery ('FPFAPR')** are services required during and following a system fault. These are inherently provided by synchronous generators, and the aim is to incentivise similar capabilities from non-synchronous generators. Regulated tariffs are set at a level that allows sufficient non-synchronous capacity to recover the incremental cost for delivering these System Services. The tariffs should at minimum be targeted in periods when there is high non-synchronous output on the system, and ideally targeted to non-synchronous generation.
- **Steady State Reactive Power ('SSRP')** is an existing product (but re-defined), aimed at remunerating reactive power provision and promoting reactive power delivery over a wider active power range. The new definition of volumes eligible for payments is intended to provide for such an 'enhanced' capability. Our proposed regulated tariff methodology relies on maintaining the base rate of procuring SSRP at the current levels. Should reactive power needs increase to a level which is insufficiently procured using this base rate, further incentives will arise from an increase in the tariff informed by the cost of a dedicated network solution.
- **Synchronous Inertial Response ('SIR')** and **Fast Frequency Response ('FFR')** are new products and complement the existing **reserve products (POR, SOR, TOR1, TOR2, RRS and RRD).** Our proposed methodology is aimed at more closely reflecting the cost of these services to the system. It acknowledges the fact that a provider can deliver more than one System Service and is based on a modelling exercise that co-optimises energy and the suite of these System Services. The relative value of the tariffs should be more aligned with the corresponding scarcity in each of these products.
- **Ramping Margin products (RM1, RM3 and RM8)** are introduced to ensure there is sufficient flexibility on the system to respond to demand and weather-variable forecast errors and plant outages. We have defined a methodology that should ensure that only incremental fixed costs relating to improving ramping capability from conventional generating units are included in tariff structures. This should benefit other providers to the extent they can offer similar ramping capability at lower cost. Cost attribution is joint as an incremental investment can enhance capabilities in more than one of the RM products. Cost distribution is then based on the relative value and scarcity of each RM product. In the future, the TSOs should have sufficient flexibility to adjust either tariffs or the requirement accordingly, as short-term energy markets and the new CRM are developed and could act as sufficient incentives for investment in flexible capability.

The proposed methodology is intended to derive a tariff for the provision of each System Service so as to ensure appropriate incentives for efficient short-term operation and longer-term entry or enhancement. The SEM Committee decision also requires the TSO to operate within an overall revenue allowance. While it may be argued that managing volume and expenditure risk is mitigated through the use of an auction-based procurement, the fact that for several System Services auctioning may not be feasible in the short-term, means there still may be a need for adjustment of the base tariffs to meet budget restrictions.

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1. INTRODUCTION

This report presents a new proposed methodology for determining base regulated tariffs for the suite of System Services to be procured under the DS3 programme. The methodology described can be used for setting the enduring tariffs for all System Services.

It has been guided by the SEM Committee decision[1] regarding the High Level Design for DS3 System Services procurement. The methodology has been informed and benefited from discussions with the TSOs, but forms our independent view of a practical approach for tariff determination within the boundaries of the proposed HLD for regulated tariffs.

The paper is structured as follows:

- Chapter 2 provides useful background regarding the issues faced by the All-Island system, the current arrangements for System Services and a brief overview of the SEM Committee HLD for DS3 System Services procurement.
- Chapter 3 describes the proposed methodology, introducing the options considered with a building block approach and detailing the proposed approach for different System Services.
- Chapter 4 summarises and assesses the regulated tariff methodology.

This paper also includes a series of Annexes referenced throughout the report:

- Annex A provides an example highlighting the difficulties in pricing System Services that can be provided jointly by a single provider.
- Annex B describes how System Services remuneration can impact bidding in the ex-ante energy markets with the new Energy Trading Arrangements (‘ETA’) under I-SEM.
- Annex C highlights the required adjustments to the regulated tariffs for some System Services as described in our main methodology assuming the SEM arrangements in place.
- Annex D aims at explaining the potential expenditure implication arising from the use of a market-wide tariff for some specific System Services.

1.1 Conventions

The term ‘TSOs’ throughout this report refers to EirGrid and SONI, unless otherwise stated.

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[1] SEM-14-108, DS3 System Services Procurement Design and Emerging Thinking, 19 December 2014

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2. BACKGROUND

Reliability of electricity supply is of vital importance to modern society and as a result is high on the energy policy agenda. Electricity market design should be aimed at developing efficient mechanisms that meet consumers' demand at minimum cost. This entails both short-term efficiency (operation of existing resources) and long-term efficiency (investment in the right type and mix of resources in the right location). The TSOs are ultimately responsible for the secure operation of the system and to achieve this they typically procure and remunerate services that are not covered under the 'traditional' electricity and capacity markets. In most markets these are called ancillary services or System Services.

The All-Island system is faced with an unprecedented challenge. Decarbonisation targets are expected to be achieved through continued expansion in wind generation and this growth in weather variable renewable generation challenges security of the system. With the exception of Cyprus, it is the smallest non-synchronous grid system in Europe and is the first to experience more than 50% instantaneous non-synchronous generation. As wind capacity continues to grow this rate is set to further increase.

The DS3 ('Delivering a Secure, Sustainable Electricity System') programme, launched by the TSOs in 2011, is aimed at ensuring secure operation of the system and facilitating these increased levels of renewable generation (particularly wind). The System Services work stream in particular is one of the most important and most complex aspects of the programme. It is should provide incentives for efficient short-term operation by the underlying capacity mix and deliver investment in both existing capacity and new entry to ensure provision of desired capabilities.

2.1 Operation of the All-Island system

Given the particularities of the All-Island system (small size, isolated network and some locational constraints), the TSOs need to take several 'out-of-merit' actions to ensure secure operation of the system. This becomes obvious when looking at the difference between the market schedule (which balances supply and demand for energy on the island of Ireland on an unconstrained basis) and the actual physical dispatch of the All-Island system. Based on SEMO data, we estimate total volume of re-dispatch to be 18% of overall demand in 2014.

These deviations reflect the limitations that are placed on dispatch by the TSOs compared to the unconstrained market schedule. There are several factors driving this different including the System Non-Synchronous Penetration ('SNSP') limit, reserve and inertial requirements, reactive power constraints and the North-South timeline. Further details on the current operational constraints are provided in EirGrid and SONI's 'Operational Constraints Update'[2] for 2015.

2.2 Current arrangements for System Services

On 1 February 2010, harmonised All-island arrangements were introduced for ancillary services and other system charges. Under these arrangements, ancillary services providers enter into bilateral agreements with SONI (in Northern Ireland) or EirGrid (in

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2 Operational Constraints Update, 21 October 2015, EirGrid & SONI

Ireland). The contracts contain ‘operating parameters’ defining the quantity of product under different conditions.

The regulated tariff for each product is set on an annual basis with EirGrid recommending a set of rates that are subsequently approved by the Regulatory Authorities (‘RAs’). The rates which were initially set on the Harmonised Ancillary Services (‘HAS’) ‘go-live’ have been maintained since with only an inflation adjustment applied from year to year. HAS payments are funded by Transmission Use of System (‘TUoS’) charges in Ireland and the System Support Services (‘SSS’) levy in Northern Ireland.

The rates for the previous two years running from 1 October 2013 to 30 September 2015 are presented in Table 1 alongside the total expenditure for each service[3] during the 2013/14 period. The SEM Committee does not allow generating units to treat ancillary service rates as an opportunity cost and these cannot be included in the bids to the ex-post market schedule[4].

Table 1 – Historical System Services rates for products common to DS3 System Services

Category	Product	2014/15 rate	2013/14 rate	2013/14 total cost (€m)
Reserve	Primary Operating Reserve	€2.34 / MWh	€2.31 / MWh	6.3
	Secondary Operating Reserve	€2.24 / MWh	€2.21 / MWh	9.6
	Tertiary Operating Reserve 1	€1.87 / MWh	€1.84 / MWh	9.7
	Tertiary Operating Reserve 2	€0.93 / MWh	€0.92 / MWh	5.7
	Replacement Reserve (Synchronised)	€0.20 / MWh	€0.20 / MWh	8.3
	Replacement Reserve (De-Synchronised)	€0.54 / MWh	€0.53 / MWh	
Reactive Power	Reactive Power Lagging	€0.13 / MVArh	€0.13 / MVArh	11.1
	Reactive Power Leading	€0.13 / MVArh	€0.13 / MVArh	
			Total	**50.6**

Source: 2013-14 and 2014-15 Harmonised Ancillary Service Statement of Payments and Charges

The introduction of a new set of market arrangements (I-SEM), changing market conditions (and in particular the increased levels of weather-variable non-synchronous generation) and the introduction of additional System Services under the DS3 programme signal the need for a revision of the existing arrangements for procurement and pricing.

3 Only products common to both the HAS and the System Services review are shown

4 SEM-11-055 Harmonised Ancillary Service Arrangements and the Bidding Code of Practice

2.3 Overview of System Services under DS3

The System Services and their technical characteristics have already been defined[5]. The new products to be introduced primarily relate to inertial, ramping and Low Voltage Ride-Through capabilities. Both new and existing products are summarised in Table 2. New services are highlighted in orange.

Table 2 – Categorisation of System Services proposed

Category	Product	Short definition
Voltage control	Steady-State Reactive Power ('SSRP')	MVAr capability*(% of capacity that capability is provided)
	Dynamic Reactive Response ('DRR')	MVAr capability during large (>30%) voltage dips
Inertial response	Synchronous Inertial Response ('SIR')	(Stored kinetic energy)* (SIR Factor – 15)
	Fast Post-Fault Active Power Recovery ('FPFAPR')	Active power >90% within 250 ms of voltage >90%
Reserve	Fast Frequency Response ('FRR')	MWh delivered between 2 and 10 seconds
	Primary Operating Reserve ('POR')	MWh delivered between 5 and 15 seconds
	Secondary Operating Reserve ('SOR')	MWh delivered between 15 to 90 seconds
	Tertiary Operating Reserve – 1 ('TOR1')	MWh delivered between 90 seconds to 5 minutes
	Tertiary Operating Reserve – 2 ('TOR2')	MWh delivered between 5 minutes to 20 minutes
	Replacement Reserve - sync'ed ('RRS')	MWh delivered between 20 minutes to 1 hour
	Replacement Reserve - desync'ed ('RRD')	MWh delivered between 20 minutes to 1 hour
Ramping	1 hour Ramping Margin ('RM1')	The increased MW output that can be delivered with a good degree of certainty for the given time horizon
	3 hour ramping margin ('RM3')	
	8 hour ramping margin ('RM8')	

Source: SEM-14-059

2.4 SEM Committee decision for System Services High Level Design

The SEM Committee has decided that where possible a competitive allocation process should be used to procure System Services (and deliver a price for each service). The level of competition is however a concern. The TSOs will carry out an initial assessment of the levels of competition for each service and make a recommendation as to which services should be procured competitively[6]. This assessment will be updated periodically.

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5 SEM-13-098, DS3 System Services Technical Definitions: Decision Paper, Dec 2013

6 DS3 System Services Competition Metrics – Consultation Paper, 21 September 2015

Where competition is deemed to be sufficient, a competitive auction will be held, whereas where competition is deemed to be insufficient regulated tariffs are to be used.

Regulated tariffs will also act as a transitional arrangement and will be set for each of the 14 services for 2016/17, pending the introduction of competitive procurement. They will be fixed for five years for all products. One year long contracts will be issued and will be maintained for products where competition is not sufficient.

This report presupposes the reader is familiar with the details of the SEM Committee's decision[7] regarding the procurement design of DS3 System Services.

7 SEM-14-108, DS3 System Services Procurement Design and Emerging Thinking, 19 December 2014

3. PROPOSED REGULATED TARIFF METHODOLOGY

Regulated tariffs are expected to be introduced for all DS3 System Services as a fixed annual tariff paid to all available volumes for the provision of System Services. The SEM Committee envisages regulated tariffs to be used as an interim way of compensating System Services in 2016/17 with auctions acting as the enduring procurement and pricing tool where competition exists. However, some System Services may be uncompetitive and regulated tariffs may persist for as long as there is insufficient competition. Therefore, the SEM Committee has directed that regulated tariffs shall be fixed for five years to provide for price visibility, with one-year contracts issued to all providers.

For the avoidance of doubt, the SEM Committee procurement design Decision Paper (SEM-14-108) does not prescribe for long-term contracts under regulated tariffs. Long-term contracts are expected to be offered only under the competitive auction process and for those System Services that will be auctioned. For System Services that are remunerated through regulated tariffs or under the interim regulated tariffs (2016/17), contracts are expected to be annual.

The timing of the introduction of auctions and which System Services would be procured through a competitive allocation will be determined through separate analysis that will explore the level of competition. In any case, the regulated tariff methodology needs to be designed to work as an enduring design or in parallel with auctions (as some System Services may still be paid through regulated tariffs, while others are priced and procured through an auction).

In this section we outline the objectives for the System Services regulated tariffs and the SEM Committee requirements. We then set out the building blocks of the tariff methodology and describe the approach for each System Service. The TSOs have previously undertaken analysis, highlighting the benefits of the DS3 System Services[8]. While this analysis provided a basis for the overall revenue cap, the SEM Committee decision requires that the tariffs are more cost-reflective.

3.1 Objectives

In principle, regulated tariffs should:

- reflect the value of each service, and in particular place greater value where there is scarcity;
- incentivise the appropriate levels of System Services that are needed by the TSOs;
- promote investment in both enhancement of existing assets and new entry when needed[9];
- facilitate the cost-effective delivery of wider public policy objectives such as decarbonisation;
- to the greatest extent possible, treat all technologies equitably;

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8 DS3: System Services Valuation, Further Analysis, Report to the SEM Committee, 2014

9 Noting that the ultimate long-term signals will come from the enduring auction design, but also recognising that for some System Services with insufficient competition the regulated tariff will need to incentivise new investment if and when required.

- ensure consumers' interests are protected; and
- be underpinned by a simple and transparent methodology.

The methodology described in this paper is guided by the above objectives.

3.2 SEM Committee decision on regulated tariff pricing principle

The SEM Committee decision allows for some freedom when developing the tariff methodology as it requires a '*BNE or similar*' methodology. The methodology to be developed is in some places referred to as a '*cost-plus*' and in others as a '*BNE*' throughout the SEM Committee decision. Our understanding is that the SEM Committee's intention is to have tariffs that are more cost-reflective rather than value-based, allowing consumers to reap some of the benefits of lower wind curtailment (economic surplus created to be shared between providers and consumers).

3.2.1 Best New Entrant ('BNE') methodology

Given the term 'BNE' is mentioned in the SEM Committee decision, it is important to understand how a notional BNE-style methodology for System Services might work. The BNE should be the least-cost new entrant that can provide the required service (or set of services). In the context of DS3 System Services, new entry also includes enhancement of existing service providers. The price delivered by a BNE methodology should therefore incentivise new entry of the least-cost provider at all times irrespective of the level of the volume requirement. In other words, the BNE price should be the long-run marginal cost of providing the service net of other revenue streams.

A familiar example of a BNE-style methodology is the current SEM Capacity Payment Mechanism ('CPM'). The capacity payment is set at a level sufficient for a new Open Cycle Gas Turbine ('OCGT') firing on distillate to recover its net costs[10]. There is no need to take into account the underlying (existing or expected) generation portfolio and the BNE price[11] is the same regardless of what the demand for capacity is.

The notional steps for determining the BNE for a particular System Service and the associated 'traditional' BNE price can be summarised as:

1. Determine the long-run cost of providing a System Service net of other net revenue streams by all potential technologies/models.
    a. Determine fixed costs (capital expenditure and annual fixed costs) of each technology/model.
    b. Identify net revenues each technology/model will capture from other sources (e.g. energy market, capacity market and other System Services.)

10 Annualised capital expenditure and annual fixed costs net of other revenues streams (expected energy market revenue and ancillary services payments)

11 The overall expenditure (pot) of the SEM CPM is fixed in advance based on the capacity requirement that would allow for the security standard to be met. This means that with more capacity on the system the 'per unit' payment drops. .

2. For each technology/model, determine the ‘supplemental payment’[12] to be recovered through the System Service for achieving a desired regulated Rate of Return (‘RoR’).

3. Identify the technology/model with the lowest ‘’supplemental payment’ and set this as the BNE for the service.

4. The ‘supplemental payment’ of the BNE is the effective Net Cost of New Entry (‘Net CONE’) and is the total annual remuneration captured by a BNE.

5. Based on the expected available volume by the BNE and its ‘supplemental payment’ a unit price can then be set.

The BNE determination could equally be expanded to identify the BNE for a set of System Services rather than a single System Service. However, pricing of each individual System Service, when a single technology/model is the BNE across a range of System Services, becomes more challenging. There is not a single set of prices that can satisfy the ‘supplemental payment’ of the BNE, rather a set of different price combinations. This is further explained in Annex A with the use of a simplified example.

A BNE approach as outlined above is not easily replicable in the context of System Services due to the nature of the provision and the range of possible providers on the demand and supply-side and from mature or innovative technologies. . Some DS3 System Services are new to the All-Island system and there is also no experience from other markets. At the same time, some of these services can be provided by innovative technologies with relatively uncertain costs, or at least more uncertain costs when compared to established technologies)[13].

One other key issue with the BNE methodology described above is the need for taking a view on income from other markets, energy and Capacity Remuneration Mechanism (‘CRM’). For the energy market this could involve a form of quantification, requiring assumption of expected operating patterns for different providers and projected electricity prices. When it comes to CRM revenue, the TSOs would need to make assumptions about the resulting capacity prices under the new CRM as those are determined through a competitive process. It may be inappropriate for the TSOs to take a view on CRM outcomes as this could result in distortions, impacting capacity providers’ bidding behaviour.

Because of these issues this ‘traditional’ approach for determining the BNE, as described above, is not necessarily the ideal solution for the tariff setting for <u>all</u> System Services, or at minimum needs to be adapted to be fit for purpose Such a ‘strict’ BNE approach is more appropriate where a specific physical investment, which delivers a particular service or group of services, can be identified and hence the BNE tariff reflects recovery of this

[12] The term ‘supplemental payment’ is the equivalent of ‘missing money’ under a CRM. For the avoidance of doubt, we do not envisage that System Services tariffs are to address the ‘missing money’ problem for generic Megawatts, rather to compensate for specific investment or operation relating to the provision of System Services.

[13] It may therefore be more appropriate in some circumstances to choose the BNE from a more ‘conventional’ set of technologies, even though some innovative providers may be assumed to be a lower cost option. The potential for over-delivery with this ‘conservative’ approach could outweigh the risks of not achieving the required investment as a result of setting a low price based on uncertain cost structures.

physical investment cost. For other System Services, where the volume and cost of available supply is dependent on dispatch decisions, this link to a physical investment does not necessarily exist (at least not for all providers).

The fundamental difference is whether the cost that the tariff represents is:

- a physical investment cost;
  - in this case a BNE approach is appropriate; or
- a system provision cost (or a combination of system provision cost and a physical investment cost);
  - in this case the 'traditional' BNE approach is not appropriate and an alternative methodology is proposed in this report to deliver the required price signal.

In the subsequent sections we detail the proposed regulated tariff approach for each System Service. Even though the notional steps described in this section are not followed in our approach for all System Services, we believe it is essential to describe the mechanics of a BNE methodology from the outset as some aspects of it are utilised in our tariff setting methodology, but also to aid the reader in capturing the difficulties and issues that may arise if this approach were to be strictly followed for all System Services.

3.3 Building blocks

We can describe the methodology for determining regulated tariffs through a set of building blocks. These building blocks and the potential choices are listed in Table 3 and further detailed in the following subsections.

Table 3 – Building blocks of the regulated tariff methodology

Building blocks	Options
Fixed cost recovery	• all capital and annual fixed costs • incremental cost for System Service(s)
Granularity	• [high (hourly/half-hourly)][14] • low (annual)
Inflation indexation	• adjusted for actual inflation • no inflation adjustment
Market-wide vs. targeted	• market-wide • targeted
Inclusion of opportunity/variable cost	• include opportunity/variable costs • no opportunity/variable costs
Cost attribution	• singular • joint
Commodity price indexation	• indexed • no indexation

3.3.1 Fixed cost recovery

Fixed cost recovery (capital investment and annual fixed costs) that may be reflected in a System Services tariff is an important consideration. Providers face a range of different revenue streams: energy revenues from various markets (forward, Day Ahead (‘DA’), Intra Day Market (‘IDM’) and Balancing Market (‘BM’)), Capacity Remuneration Mechanism (‘CRM’) revenues and DS3 System Services revenues. Fixed costs cannot be easily allocated across the different markets (how much of the capital expenditure of a plant is ‘responsible’ for providing frequency response and how much for energy?). We have identified two approaches that could be adopted:

- include all capital and annual fixed costs in the System Service; or
- assign only **incremental** fixed costs for providing the System Service.

With the first approach all identified fixed costs of a provider are assumed to be recovered through the tariff. This will undermine energy markets and the CRM, and also risks delivering double payments, not to mention the risk of System Services expenditure rising substantially, well beyond the established budget.

14 Our options for granularity of tariffs are restricted to an annual tariff in line with the SEM Committee decision. More granular pricing may be desirable in some instances, and the potential benefits are mentioned. However the potential for the introduction of such shorter term pricing is being considered separately in the Scalars design work.

With the second approach, only those fixed costs that are agreed to primarily impact the providers' capability of delivering a certain System Service are recovered through the tariff, minimising the impact on competition in other markets (energy and CRM).

3.3.2 Granularity

We consider as potential options the full range from an annual, uniform tariff, with the same price paid in all periods across a year, out to hourly granularity[15].

For some System Services, temporal variation is important for short-term operating efficiency. Provision of a System Service may be more valuable in some periods and in such cases an appropriate signal would deliver greater efficiency. This is equivalent to having more granular pricing for energy and capacity payments. Capacity payments in the SEM CPM for example are a function of 'system tightness' with higher payments over periods of capacity scarcity. However, greater granularity cannot be determined easily and accurately with analysis conducted five years in advance. Determination closer to real-time would therefore be more appropriate particularly where real-time demand for System Services is not easily forecastable a long time in advance. The use of greater granularity may come at the expense of providing investor certainty, but should improve efficiency.

For the purposes of this paper, regulated tariffs are envisaged to be annual (in line with the SEM Committee decision). Any potential within-year variation could be handled separately using scarcity scalars. Although this paper is not intended to cover the potential use of scalars, it is worth highlighting that prudent adoption of such scalars may be beneficial and can improve efficiency.

3.3.3 Inflation indexation

Regulated tariffs will be set for five years. Inflation poses a risk for providers. Regulated tariffs can either be:

- fixed in nominal terms based on an ex-ante inflation expectation; or
- calculated based on an ex-ante inflation expectation and 'corrected' for the difference between assumed and actual inflation;
  - this is equivalent to providing tariffs in real terms and then adjusting for actual[16] inflation.

The first approach relies on an ex-ante expectation with regards to the evolution of inflation and the risk is transferred to providers. With the second approach this risk is eliminated as tariffs are adjusted to reflect actual inflation variations[17]. This is similar to the current approach, whereby tariffs are adjusted for inflation.

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[15] Potentially half-hourly under SEM

[16] The term 'actual' here is used to mean closer to real-time. This may mean adjusted based on an inflation measure of the previous year.

[17] Our expectation is that the regulated rate of return is determined on a pre-tax, real money basis. Removing inflation risk can then be achieved through two equivalent ways: estimate the pre-tax, nominal regulated rate of return based on actual inflation or apply an inflation indexation factor to the regulated tariffs to reflect outturn inflation.

3.3.4 Market-wide vs. targeted payments

Regulated tariffs can be either market-wide, with all providers receiving the same tariff for all available volumes in a given trading period, or targeted to a subset of providers and/or volumes. In principle, we support the use of market-wide tariffs that recognise the value of the provision of a service by all volumes and respect technology neutrality to the greatest degree possible. However, there may be circumstances where objectives may be better achieved through targeted payments to some classes of providers. This is further explored for each System Service individually.

3.3.5 Inclusion of opportunity/variable costs

Some System Services are a 'by-product' of energy delivery. For example, a unit when generating also provides reactive power (this relates to SSRP). This means there is no additional variable cost incurred, which cannot be recovered from the energy markets, or other revenue foregone from the energy markets. In such cases, there is little rationale for including a variable or an opportunity cost element in the tariff structure. When there are additional costs incurred or profits foregone, these could be reflected in the tariffs. This is the case with reserve provision (POR, SOR, TOR1, TOR2, RR and RRD) where capacity may be 'removed' from the energy market to provide the relevant service(s). This is in line with the SEM Committee objective of providing market participants with the tools to reflect the 'desired' position in their energy (and balancing) market bids. The options under this building block are:

- inclusion of variable or opportunity costs in the tariff;
  - this may apply when there is potential for out-of-merit dispatch costs or foregone profit from the energy markets; or
- no inclusion of variable or opportunity costs.

Including opportunity costs within the tariff structure could have the following impacts:

- more pronounced change in market participants' bidding behaviour as the regulated tariffs are reflected in the ex-ante and balancing market bids;
  - for example, setting the regulated tariff for reserve products at a level such that it reflects the foregone Infra-Marginal Rent ('IMR') of the marginal provider, allows for the market participants to indirectly 'mirror' a co-optimised ex-ante market);
  - such behaviour is also typical for other (self dispatch) EU markets where providers with ancillary services contracts are scheduled so that they can honour their contracts with the TSO;
- more pronounced change in the resulting electricity market prices, when compared to an 'unconstrained' market with a mandate to exclude such opportunity costs from the bids; and
- a transfer of expenditure from the balancing (or the ex-ante energy) market to DS3 System Services.

These interactions with the energy markets are further explained in Annex B. The change in market participants' bidding would take place even if opportunity costs are not included in the regulated tariffs. This would be driven by the nature of the Energy Trading Arrangements ('ETA') under I-SEM and the SEM Committee's decision to adopt an availability payment basis that takes into account a provider's position in both the energy market and physical dispatch. However, including opportunity costs in the regulated tariffs would increase the level of the payments and make this effect more pronounced. The

direction and level of change in prices and expenditure cannot be easily quantified and may vary across periods.

It can be argued that variable costs or foregone profit from the energy markets are not required to be embedded in the System Services tariffs, as these can be recovered through bids in the Balancing Market. On the flipside, including such costs in the structure of the tariffs should allow providers to adjust their bids in the ex-ante markets accordingly and result in the market schedule being more closely aligned with the physical dispatch.

Under the SEM arrangements, providers are not able to reflect opportunity costs from System Services in their bids. If regulated tariffs are to reflect the foregone IMR then a requirement for mandating providers to include the expected regulated tariff income could be introduced. This approach has attractions, but at the same time would mean significant change for market rules that are in any case being replaced under I-SEM. We would not consider this to be a viable option given the circumstances.

Alternatively, the regulated tariffs that would include some opportunity cost should be adjusted to account for the constraint payments and the IMR captured in the ex-post pool. This 'adjustment' is further discussed in Annex C.

3.3.6 Cost attribution

A key complication is the joint provision of different System Services by a single provider. In some cases, capital investment and/or short-term operation will enable a provider to supply more than one product. One example is the provision of reserve. Typically, a provider that is positioned to supply POR can at the same time supply SOR and/or other types of reserve.

This then raises the question of how costs (whether fixed or variable) can be shared between different products for the tariff determination. It is therefore important to identify whether the cost attribution is:

- singular ('Product specific') with all costs feeding into the determination of the tariff for a single System Service; or
  - with this approach each System Service is considered in isolation to identify the least cost provider of each System Service. A drawback with this is the inability to recognise interdependencies (where such exist) between different System Services which may potentially lead to inefficiencies. This can occur if investment improves a provider's ability to provide more than one System Service and costs are allocated to each of these System Services. If the full cost is applied to each service, resulting tariffs are much higher, there is a risk of double payments and this leads to inefficiencies.
- joint ('Joint BNE') with costs shared between different products;
  - this approach involves identifying a provider (or a set of providers) which can deliver all (or a subset of) the System Services at the lowest cost taking into account joint provision. Although there is an added layer of complexity, this approach allows for cost recovery to be spread between the different System Services thereby minimising the potential for over recovery.

This building block effectively explores whether the least cost provider should be identified as the 'best' marginal provider of a specific System Service ('Product specific' methodology) or whether the link with other System Services is sufficiently strong that the 'least cost provider (or providers) across several System Services should be identified jointly('Joint BNE' methodology).

3.3.7 Commodity price indexation

The estimation of regulated tariffs may involve using assumptions with regards to future commodity prices. Where regulated tariffs contain a variable fuel cost element, indexation to commodity prices may be necessary to reflect changing market conditions.

The options under this building block are:

- inclusion of a commodity price indexation; or
  - with some form of commodity price indexation we mean that some of the System Services tariffs that depend on commodity prices, determined well in advance (for example for five years ahead), can be adjusted to reflect differences in assumed and expected commodity prices closer to real-time. This can be achieved either through some simplified indexation from the outset or a recalculation of the tariffs once commodity prices move outside a threshold window around the assumed level.
- no indexation.
  - with no indexation Systems Services tariffs are fixed and would not reflect changes in underlying market fundamentals.

A form of commodity price indexation can be argued to introduce an element of investor uncertainty as tariffs are not truly fixed and can change in response to commodity price changes. As it is difficult to estimate a relationship between commodity prices and tariffs (i.e. the relationship is not necessarily linear), it may be necessary for the TSOs to re-calculate the tariffs through complex modelling every year. Alternatively, a simplified relationship could be used, at the expense of accuracy. On the flipside, tariffs changing based on changes in commodity prices should deliver a more efficient outcome and mirror more closely a short-term procurement and pricing approach.

3.4 Philosophy of regulated tariff methodology

The overall philosophy of the regulated tariff methodology is to:

- manage the balance of the economic surplus created by making the tariffs more cost-reflective;
  - this is guided by the SEM Committee decision that suggests consumers should directly benefit from the social welfare created;
- deliver the required System Services volumes, whilst ensuring sufficient returns for providers;
  - delivering the required level of each System Service is key for meeting policy objectives and to achieve this there should be appropriate signals for providers.

We have outlined the building blocks that form the strawman for developing a methodology for each System Service. Some choices under each building block are common across all products. The overall philosophy of the regulated tariff methodology is underpinned by these common choices:

- only incremental investment costs associated with the provision of System Services to be directed to the System Services regulated tariffs;
  - this choice should minimise the risk of double payments to providers and the impact of competition in other energy markets and the CRM;
- inflation risk should be removed; and

    - although tools for managing inflation risk exist, we propose tariffs to be fixed in real terms and then adjusted to account for 'actual'[18] inflation;
- scarcity scalars could be used to introduce any potential temporal variations, with the regulated tariffs reflecting the annual average value of the System Service.
    - temporal variation of tariffs may be important, but such 'profiling' is envisaged to be dealt with separately with scalars.

These common choices are also presented in Table 4.

Table 4 – Common building block choices for all System Services

Building blocks	Options	
Fixed cost recovery	All capital and annual fixed costs	**Incremental cost for providing the service**
Granularity	**Scarcity scalar (where appropriate)**	
Inflation indexation	**Yes**	No

The following sections detail the choices under the remaining building blocks for each System Service. The outlined methodology for each System Service has been developed to fit with the SEM Committee's requirements, including cost-reflective tariffs (where possible), and the presence of a limit on the available revenue allowance.

To reflect fundamental differences in the nature of the defined System Service products, there are variations in the detailed tariff methodology for particular System Services or groups of System Services. This adds complexity to the overall approach but ensures it aligns more closely with the SEM Committee decision and wider policy objectives set out in the paper. For all System Services, tariff determination is dependent on assumptions around third party costs of provisions and the wider market environment. These assumptions should be based on a transparent evidence base taking account of industry views. While the responsibility for managing the call for evidence may be vested in either the TSOs or the RAs, the final assumptions would require RA approval.

3.5 Fast Post-Fault Active Power Recovery ('FPFAPR') and Dynamic Reactive Response ('DRR')

Both FPFAPR and DRR are services required following a system fault. FPFAPR should incentivise units to recover their active power quickly after a transmission fault. If a large number of generators do not recover their MW output following a transmission fault a significant power imbalance can occur, which could give rise to a severe frequency

[18] The term 'actual' here is used to mean closer to real-time. This may mean adjusted based on an inflation measure of the previous year

transient. Quick active power recovery following a voltage dip is a response that conventional synchronous generators can inherently provide.

DRR requires a unit to deliver a reactive current response following a voltage dip and to provide voltage support during disturbances to help maintain the integrity and stability of the system. Conventional synchronous generators are inherently capable of providing a reactive current response following a voltage dip.

With increasing levels of non-synchronous generation connecting to the system it is important for non-synchronous providers (and in particular wind generators) to also have FPFAPR and DRR capabilities for a higher System Non-Synchronous Penetration ('SNSP') limit to be achieved.

3.5.1 Tariff methodology

The BNE should be the least-cost provider that delivers the required Low Voltage Ride Through ('LVRT') capability, whilst allowing for the SNSP to be reached[19]. The relevant cost is therefore the incremental investment cost for a non-synchronous provider to be a in a position to provide this services. This is expected to be an enhanced wind generator for both FPFAPR and DRR, noting that different types of investment are needed for delivering each service.

The corresponding regulated tariff should then be set at a level that allows for a sufficient proportion of the wind fleet to have the capability of providing FPFAPR and DRR. Table 5 outlines the choices for the FPFAPR tariff under each building block.

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19 If the volume requirement for FPFAPR is defined as simply having sufficient LVRT capability at all times, regardless of reaching a specific SNSP level, the BNE would effectively be a conventional unit, setting the tariff at 0 (as there is no incremental investment required by synchronous providers to deliver the service). The same applies to DRR. Consequently, there would be no signal for non-synchronous providers (e.g. wind generators) to invest in having such capability. The requirement definition for both services should be adapted to deliver the desired outcome, allowing for the higher instantaneous levels of non-synchronous generation to be achieved. In practice, both services are 'targeted' to non-synchronous generation. Ultimately, what is needed is for wind farms to be in a position to provide what synchronous generators inherently provide in a contingency condition.

Table 5 – Building block description of FPFAPR and DRR tariffs

Building block	Options	
Market-wide vs. targeted	**Market-wide**	**Targeted**
Inclusion of opportunity/variable cost	Yes	**No**
Cost attribution	**Singular**	Joint
Commodity price indexation	Yes	**No**

A market-wide tariff would compensate the entirety of the generation fleet. For synchronous generators this would introduce a payment for a service that can be inherently provided and would not incentivise any enhanced capability for a large fraction of providers. FPFAPR provision at times of high non-synchronous generation is valuable, whether this comes from synchronous or non-synchronous providers. A market-wide payment may therefore act as an additional incentive to perform when this service is needed for conventional generators.

On the other hand, a payment solely targeted towards non-synchronous providers would promote the required incremental investment and an incentive for making the service available, whilst better managing expenditure. Such a targeted approach does not however respect the principle of technology neutrality.

In order to manage expenditure and promote efficiency, were a market-wide tariff methodology to be adopted, it would be beneficial to introduce a temporal scarcity scalar linked to the level of non-synchronous generation on the system. This scalar could then be applied to the annual tariff to deliver an hourly (or half-hourly) tariff paid to all providers of FPFAPR and DRR in each period.

As the colouring scheme in Table 5 indicates, we do not make a firm recommendation when it comes to the scope of the tariff payments and allow for two options:

- market-wide tariff with the use of a temporal scarcity scalar;
  - this recognises that the value of FPFAPR provision is common irrespective of the type of provider, but has implications for the DS3 System Services budget;
- targeted tariff for non-synchronous generators only.;
  - this attempts to manage expenditure and allows for additional budget to be directed to other System Services, but does not equitably reward all providers.

There are no opportunity costs involved with delivering FPFAPR or DRR and variable costs relating to generating are recovered through the energy markets. This then also means there is no scope for any commodity price indexation of the tariff.

Our initial assessment indicates that the ability of wind generators to provide FPFAPR relates to the control system although further assessment is required to confirm that this is the case[20]. Relevant investment does not imply a substantial impact on the ability of the wind generator to provide other System Services. As a result all the incremental costs should be solely attributed to FPFAPR. The same logic applies to DRR.

The annual FPFAPR and DRR regulated tariffs could take the form of the following formulas:

$$FPFAPR\left(\frac{€}{MWh}\right) = \frac{IIC_{FPFAPR}}{h_{FPFAPR}} \times \frac{r}{1-(\frac{1}{1+r})^{n}} \times I$$

and

$$DRR\left(\frac{€}{MVArh}\right) = \frac{IIC_{DRR}}{h_{DRR}} \times \frac{r}{1-(\frac{1}{1+r})^{n}} \times I$$

where:

$IIC_{FPFAPR} = incremental\ investment\ cost\ for\ providing\ FPFAPR\ expressed\ in\ €/MW$

$IIC_{DRR} = incremental\ investment\ cost\ for\ providing\ DRR, expressed\ in\ €/MVAr$

$h_{FPFAPR} = average\ full\ wind\ output\ operating\ hours\ expressed\ in\ hours$

h_{DRR}
$= average\ \ annual\ number\ of\ hours\ when\ a\ wind\ generator\ is\ \ 'on', expresedin\ hours$

$r = pre - tax, real\ regulated\ rate\ of\ return$

$n = economic\ lifetime, expressed\ in\ years$

$I = inflation\ index$

3.5.2 Additional requirements

For estimating regulated tariffs based on the methodology described above, an independent engineering cost review may be needed to determine the incremental cost for FPFAPR and DRR provision. Average operating hours for wind turbines on the All-Island system will also be determined, and we expect this to be estimated by the RAs or approved by the RAs based on recommendation from the TSOs. The level of the regulated Rate of Return (‘RoR’), assumed economic lifetime and projected inflation (if needed) will also be outlined when tariffs are determined.

20 Further assessment regarding the control system upgrade costs (capital expenditure for providing FPFAPR) is needed. We also recognise that the cost associated with LVRT capability may not scale linearly with the size of a wind turbine.

3.5.3 Summary of methodology

Following guidance from the SEM Committee decision we have developed a regulated tariff methodology for FPFAPR and DRR assuming an availability payment basis. For managing the expenditure, we have considered the option of targeting the payments. Annex D outlines the potential expenditure on FPFAPR and DRR if market wide tariffs for these services are implemented versus a targeted approach to specific generator types. The reason for exploring a targeted approach that diverges from market-wide payments, is to analyse the cost-efficiencies of such an approach. Another option that maintains market-wide payments, but helps manage the expenditure, would target payments to periods with high SNSP based on a function that links payments with the non-synchronous output (temporal scarcity scalar). Payments would be targeted to periods when there is a greater need for LVRT and reactive current response capability by such providers. Under both options, the expected total annual payment towards non-synchronous providers should ultimately be sufficient to incentivise the required performance.

3.6 Steady-State Reactive Power ('SSRP')

SSRP is an existing product, essential for controlling system voltage and ensuring power is transmitted efficiently throughout the system. Unlike active power, reactive power is difficult to transmit over long distances and consequently the relevant requirement can vary at different locations throughout the system. SSRP can be provided by both synchronous and non-synchronous generation.

The SSRP product has been restructured to incentivise the provision of reactive power across a wider active power range. The volume of reactive power provided that is eligible for payment, is therefore scaled by the RP Factor of the provider as follows[21]:

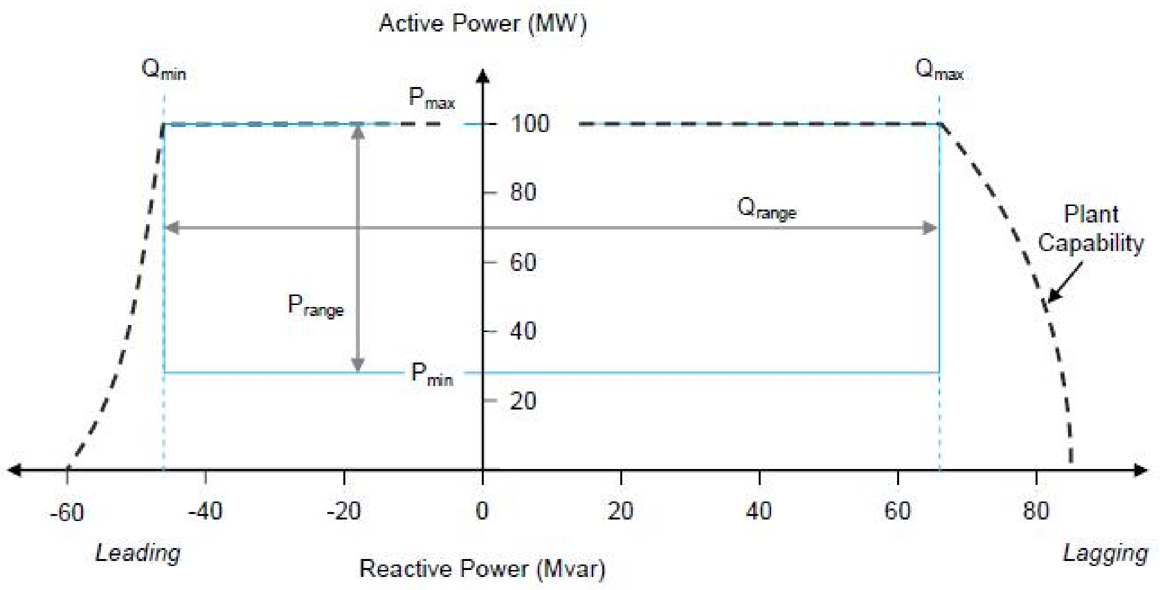
$$SSRP\ Volume = Q_{range} \times RP\ Factor, while\ able\ to\ provide\ reactive\ power$$

$$RP\ Factor = \frac{Power\ Output\ range\ (P_{range})that\ Q_{range}\ can\ be\ provided}{Registered\ Capacity}$$

and an illustration of a 'typical' reactive/active power envelope is shown in Figure 1.

[21] SEM-13-098, DS3 System Services Technical Definitions Decision Paper, Dec 2013

Figure 1 – Illustrative active/reactive power envelope[22]



3.6.1 *Tariff methodology*

From a TSO perspective, it is important to have access to reactive power from generators and other service providers at all times, and over a wide active power range. A specific investment dedicated solely to reactive power provision is best managed by the TSOs, which have better knowledge of the system and the expected electricity flows. Basing the tariff on remunerating new investment in voltage control devices from third parties may lead to inefficient investment behaviour.

Provision of reactive power over a wider active power range can be achieved through the restructuring of the SSRP payment volume, which should on its own incentivise providers to increase their RP Factor and ensure SSRP is available at even lower active power output levels. A BNE approach, on the other hand would most likely over-deliver and increase costs substantially.

Instead of a BNE-style approach, we propose to, at minimum, maintain the base rate of procuring SSRP at the current levels. In the event that even greater SSRP volumes are needed, it may be necessary to cater for further incentives. For example, the cost of a network solution to provide the increased volume (e.g a STATCOM) could be used as the counterfactual BNE to increase the tariff.

This means that even if there is no additional SSRP required in the future the base rate for reactive power will remain at similar levels as today. However, a redistribution of income from SSRP is expected in the future when compared to the current arrangements as providers with an RP factor that is higher than the system average will capture a higher

22 SEM-13-098 Figure 6, DS3 System Services Technical Definitions Decision Paper, December 2013

effective rate and conversely providers with a lower than the system average RP factor will capture a lower effective rate.

The methodology for determining the SSRP tariff is presented under our building block approach in Table 6.

Table 6 – Building block description of SSRP tariff

Building blocks	Options	
Market-wide vs. targeted	**Market-wide**	Targeted
Inclusion of opportunity/variable cost	Yes	**No**
Cost attribution	**Singular**	Joint
Commodity price indexation	Yes	**No**

Reactive power has greater value depending on location, but this locational aspect changes depending on market conditions and overall flows across the network. A market-wide tariff is more appropriate and should also incentivise the entirety of the generation fleet to attempt to increase its RP Factor.

It is not expected that there will be any material opportunity costs associated with the provision of SSRP and any variable costs relating to generation will be recovered through the energy markets[23]. Consequently, it is also not deemed appropriate to include any commodity price indexation.

We recognise that in some cases lowering a conventional unit's MSG may also result in an improvement in the RP factor and some of that incremental investment could be recovered through the SSRP tariff. However, SSRP is not the driving factor for lowering a conventional unit's MSG[24]. A singular approach towards cost attribution is more suitable.

The resulting SSRP tariff would therefore include both a term linking the tariff to the current level and an additional term to incentivise increased SSRP provision where and when required. This additional term will be linked to the cost of a dedicated network

23 Noting however that providers may be constrained on to provide reactive power. We expect that under the ETA such providers will receive energy payments through the BM for their active power output.

24 Providing inertia and frequency response (and the corresponding payments for these products) at lower output levels, as well greater ramping capability are the key driving factors for a conventional provider to reduce MSG.

solution, but the expected additional total payments should not exceed the cost faced by the TSO for resolving reactive power issues through the use of network devices[25].

SSRP payments aim at incentivising providers to maximise their reactive power capability. The TSOs can then account for providers' expected capabilities in their network planning. Should the additional relative requirement for SSRP as determined by the TSOs be zero (and assuming there is no reduction in reactive power needs in the future), the resulting tariff will simply be set at the current level.

3.6.2 Additional requirements

For estimating the increase in the SSRP regulated tariff (if needed) based on the methodology described above, an independent engineering cost review may be required to determine incremental cost for SSRP provision by a dedicated network solution. The level of the regulated RoR, assumed economic lifetime and projected inflation (if needed) will also be outlined when tariffs are determined. We believe the TSOs are best positioned to estimate the available reactive power on the system based on an underlying generation portfolio, as well as any additional needs for reactive power. With regards to the assumed cost of a network device for delivering the potential increase of the tariff, we expect the RAs to determine or approve such costs.

3.6.3 Summary of methodology

We propose for the 'base' tariff level to remain at the current rate. Regardless of the chosen method for determining the SSRP tariff we expect providers to be encouraged to increase their RP Factor, simply due to the restructuring of the SSRP payment volume. Consequently, it is expected that SSRP should be made available in the future over a greater active power range. Should additional SSRP capability be required, further incentives will arise from the 'inflation' in the tariff informed by the cost of a network solution as described above.

3.7 Synchronous Inertial Response ('SIR'), Fast Frequency Response ('FFR') and other reserve products

The new inertial and fast frequency response products, Synchronous Inertial Response ('SIR') and Fast Frequency Response ('FFR'), complement the existing reserve products (POR, SOR, TOR1, TOR2 and RR) by providing a fast response when necessary to control potential frequency drops[26].

3.7.1 Tariff methodology

The volume and cost of available supply for reserve is, for some providers, dependent on dispatch decisions and it is not necessarily linked to a specific physical investment[27]. Within this group of System Services there is a strong overlap. A single provider may be

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25 The tariff would increase by an amount, which is equal to the cost of providing the additional reactive power needed divided by the total expected available reactive power. For the avoidance of doubt, the tariff would not be set at a level that would incentivise the 'market-wide' entry of dedicated network solutions.

26 Dampening the rate of frequency drop and 'arresting' frequency.

27 Some investment may improve capability to provide a service (e.g. lowering a thermal unit's Minimum Stable Generation ('MSG') may mean provision o reserve over a greater range).

in a position to deliver more than one of these services with a single action (whether a physical investment or a short-term operation decision). We therefore diverge from the 'strict' BNE approach for this group of System Services and opt for an approach that reveals the least cost to the system of providing the service.

This type of approach is supported by similar methods used in other markets. In most centralised pool markets, market algorithms optimise energy and reserve simultaneously (co-optimisation of energy and reserve). In theory, such an approach should deliver the most efficient unit commitment at a point it time and given a deterministic set of expected conditions with regards to demand and plant availability. These algorithms produce both a market schedule as well as prices for energy and reserve.

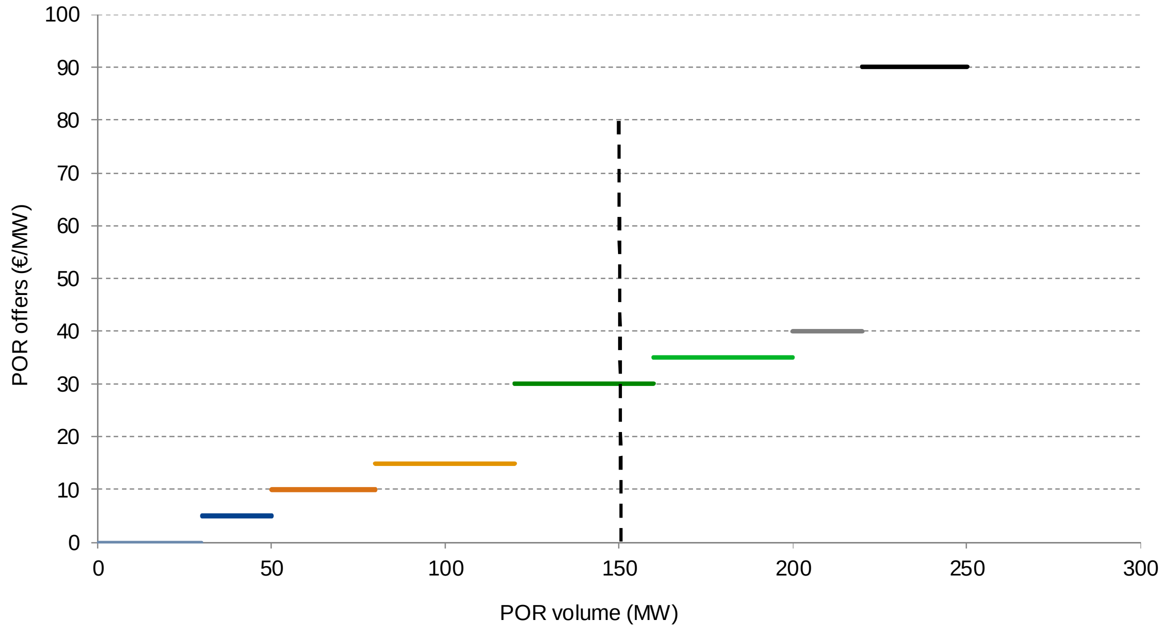
In contrast to the approach described here, procurement and pricing in those markets take place closer to real-time (typically at the Day-ahead stage) and this should deliver an outcome that is more representative of actual market conditions as information is more accurate closer to real-time[28]. Such an explicit co-optimised approach is however not compatible with the EU Target Model and the I-SEM High-Level Design and cannot be implemented as such.

Our proposed solution attempts to replicate the outcomes of such a co-optimised solution, ahead of the Day-Ahead market, and produce a set of prices that reveal the value of the different System Services based on expected set of market conditions. When delivering reserve, a provider is (potentially) giving up energy infra-marginal rent ('IMR') to withhold part of its capacity as contingency. There may be no need for incremental investment, but an opportunity cost exists. This can be best explained through a simplified example.

Figure 2 shows such an example for a single period based on POR provision. There is a 150MW demand for POR in a given period. Some providers 'close to the energy market margin' can offer headroom at a relatively low price as they face a low IMR (for example the 'blue' offer). In order to meet the POR demand a unit with a relatively high IMR has to be part-loaded, acting as the marginal provider ('green' offer) and setting a uniform clearing price for all providers. On the right hand-side we can also see a very high-priced offer from an out-of-merit provider.

28 For the avoidance of doubt, we are not proposing the introduction of a co-optimised market schedule at the Day Ahead stage. Our recommendation is to 'borrow' the co-optimised aspect in the modelling approach.

Figure 2 – Illustrative supply curve of POR offers



The above example showcases how the marginal 'cost' for POR provision is estimated in a given period, given the existing POR supply and demand and other assumed market conditions (electricity demand, commodity prices, weather profiles etc.)[29]

Table 7 presents the building block description for the reserve products, SIR and FFR. The choices for all reserve products (and FFR and SIR) are common.

Table 7 – Building block description of SIR, FFR and reserve products tariffs

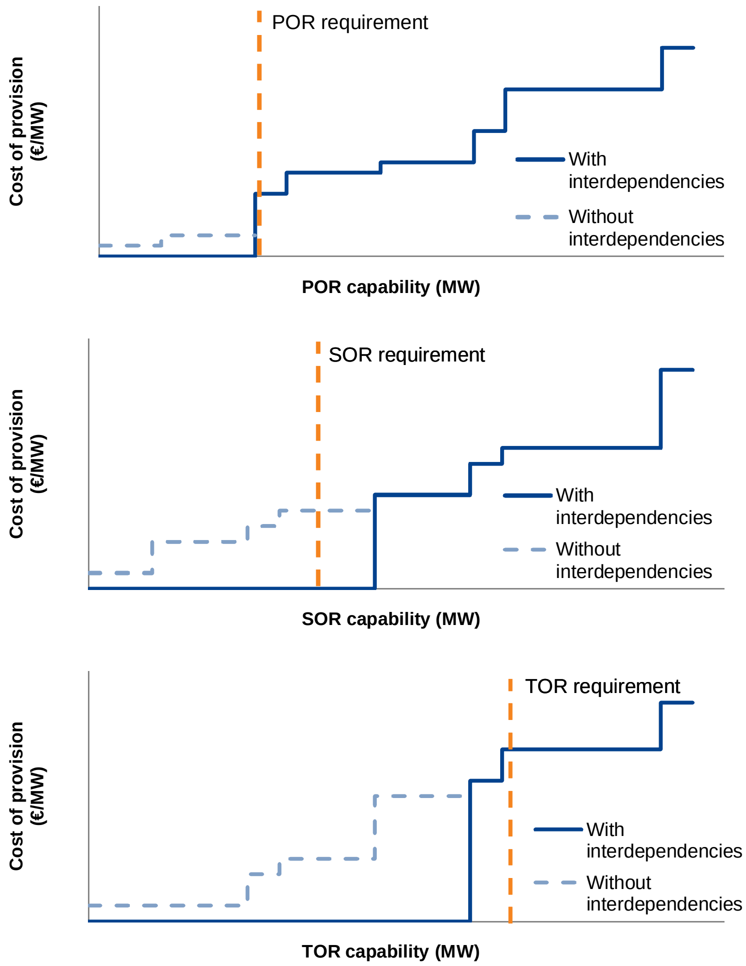
Building blocks	Options	
Market-wide vs. targeted	**Market-wide**	Targeted
Inclusion of opportunity/variable cost	**Yes**	No
Cost attribution	Singular	**Joint [SIR, FFR, POR, SOR, TOR1&2, RRS, RRD]**
Commodity price indexation	**Yes**	No

29 In practice, identifying the marginal provider is more complex due to inter-temporal constraints, but electricity market models are able to account for such constraints.

Interdependencies within this group of System Services are strong. A provider can typically supply more than one of the reserve products. One provider may be able to offer one of the services (for example POR) at the lowest cost, but there may be a 'better' global solution. Another provider may be in a position to provide a wider range of these services at an overall lower cost, even though when looking at each service individually it may not be the least cost provider. Here we can identify a strong link with the SEM Committee direction to carry out a combinatorial auction and the advantage of using a 'joint' approach over a 'Product specific' approach.

This is illustrated in Table 8 which compares the cost of procuring various reserve products (POR, SOR and TOR) at a particular moment in time with and without interdependencies being accounted for. In this example there is no additional cost for meeting the SOR requirement due to the 'free' contribution from the other reserve products (POR and TOR)[30].

Table 8 – Illustrative supply curves for reserve products



30 It should be noted that provision of a volume of one reserve product does not necessarily translate to the provision of the same volume of another reserve product.

Ultimately, the group of services can be provided by a combination of plant (existing and new) and so there is no obvious single choice. Because of this overlap in the services, a 'joint' approach is more appropriate for the suite of SIR, FFR and reserve products. This means the provider or set of providers that can offer all services at the lowest overall cost should be identified for each period.

As the regulated tariffs will be strongly influenced by the forecast of commodity prices used in the modelling a corresponding indexation would be appropriate.

As already noted, the tariff methodology for this group of System Services diverges from the strict BNE approach. It is intended to more closely reflect the value of additional provision of each product to the system by estimating the marginal cost of constraints to the system in any given period. In practice, Plexos could be adapted to model a 'constrained' All-Island system providing shadow prices for each service, including SIR, FFR and all reserve products. The shadow prices are the dual value of each reservation constraint i.e. the cost to the 'best' (i.e. marginal) provider of providing the system service in each period. As the market model will produce hourly (or half hourly) prices, these can then be averaged to deliver a final volume-weighted annual regulated tariff.

The market modelling approach can be either:

- static; or
  - the supply portfolio is pre-determined. For example, this could be one of the portfolios described in the TSOs' Volumes Calculation Methodology and Portfolio Scenarios report. The market model produces marginal prices, but there is no feedback of the prices to the assumed portfolio (i.e. the supply portfolio is not revisited);
- dynamic;
  - in the initial market model run the supply portfolio is 'fixed', but the outcomes (System Services and energy prices and operating patterns) are used to inform the 'optimal' supply portfolio. This means that generic providers with minimal capacity are included in the model and their performance is assessed ex-post. A feedback loop informs the original assumed portfolio. For example, if demand for POR is met by provider A with the original portfolio, but another provider, provider B, is deemed to be a cheaper solution, the portfolio is redefined.

There are benefits with a more dynamic determination of the supply portfolio and the System Services short-run marginal prices. However, this is a more complex solution requiring significant additional effort and could potentially be deemed less transparent.

Whether dynamic or static, it could be that the short-run marginal prices estimated by the market model are not sufficient to deliver the required volumes (i.e. the marginal provider faces 'supplemental payment'). A mark-up that would allow for the 'joint BNE' to recover its costs could be used to address this issue This means that the regulated tariff will (at minimum) be equal to the cost of the 'joint BNE', accounting for the incremental investment cost associated with providing the service.

The incremental investment cost will need to be shared appropriately between the different services to ensure cost recovery is efficient and the potential for over recovery is limited. The proportional share of this cost between the different services can be determined through the relative value of each service as determined by the Plexos market model runs. A greater proportion of investment costs should therefore be assigned to services where there is greater scarcity and value.

An additional strength of this approach is that should it be deemed necessary, the hourly (or half-hourly) price profiles can also be used to inform development of scarcity scalars reflecting the different value of each service over different times.

One important consideration is the assumed generation portfolio for the static approach. Given that some services may potentially be provided by innovative solutions and there is some uncertainty around the costs of these technologies, taking a more conservative stance may be beneficial (for example choosing an enhanced thermal generator as the 'least-cost' provider instead of a more innovative solution). This may risk overpayment and even over-procurement, but it may be best to set the tariff slightly higher given the cost uncertainties. If innovative solutions are 'cheaper' than the assumed conventional provider, they will then be in a position to lower the clearing price. However, if the regulated tariffs are set too low from the outset we risk not delivering the required performance capabilities.

3.7.1.1 SIR considerations

A desired capability of SIR providers is the provision of inertia at low MSG. This is of additional value to the system as it allows higher levels of non-synchronous generation to be supported by the inertia from a smaller volume of synchronous generation.

An incentive is embedded in the SIR volume definition:

$$SIR_{volume} = stored\ kinetic\ energy \times \left(\frac{inertia\ constant}{MSG} - 15 \right) \times unit\ status$$

A lower MSG results in relatively higher eligible volumes.

For the purposes of the setting the SIR tariff, an inertia requirement (in MWs) would be introduced in Plexos. The resulting shadow price would reflect the fundamental value of inertia to the system (in €/MWs). There would then be a factor applied to this shadow price to determine the final SIR tariff:

- an assumed average portfolio[31] SIRF of 1 could be used to translate values from €/MWs to €/MWs^2; and
- There may be scope for using a temporal scalar linked to the level of non-synchronous generation on the system to be applied to the SIR annual tariff to adjust the hourly payment. This scalar would increase SIR payments when there is a high SNSP and reduce payments during periods of low SNSP.

3.7.1.2 Adjustment of regulated tariffs under the SEM arrangements

A thorough understanding of the shadow price will reveal whether or not there is potential for double payments in the first year of the System Services (Interim Tariff arrangements before 'go-live' of I-SEM). For example, if the shadow price from the model reflects the cost of part loading to provide a product then a plant may be paid for being part loaded both through DS3 System Services payments and through constraint payments, resulting in double payments. As mentioned previously, an adjustment could be applied if necessary as outlined in Annex C. Under I-SEM this is unlikely to be as much of an issue as plants may be expected to reflect their System Services payments in their Balancing Market bids.

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[31] MSG of 50% and inertia constant of 8s

3.7.2 Additional requirements

The proposed tariff determination relies on a techno-economic analysis. A range of assumptions needs to be made. These include:

- capital expenditure and annual fixed costs for existing and new technologies based on independent engineering benchmarking;
- technical capabilities from the existing fleet and new technologies;
- for the existing fleet our starting point is that such capabilities will come from a combination of validated data and data based on the historical operation of generating units; and
- commodity (fuel and carbon) price assumptions from recognised sources (for example IEA);

We expect the above assumptions to be determined by the RAs.

3.7.3 Summary of methodology

We have described a methodology for setting the regulated tariff for the set of SIR, FFR and other reserve products that more closely reflects the cost of these services to the system. The methodology accounts for the interdependencies between different System Services, acknowledging the fact that a provider can deliver more than one System Service. It attempts to replicate market price outcomes delivered from an auction for provision of the services assuming a form of commitment by providers.

However, with regulated tariffs there is no form of commitment, and all available volumes would receive a payment. Assuming no profiling of the tariffs and given that market conditions will differ from the assumptions used or setting the tariffs, there is a risk of volumes made available in excess of the requirement. This means outturn payments for System Services may exceed expectation, but in a competitive market this should come alongside a reduction in payments in the Balancing Market.

3.8 Ramping Margin ('RM') products

Ramping Margin ('RM') products are being introduced to ensure there is sufficient flexibility on the system to respond to:

- demand forecast errors;
- weather-variable generation forecast errors; and
- (to a lesser extent) plant outages.

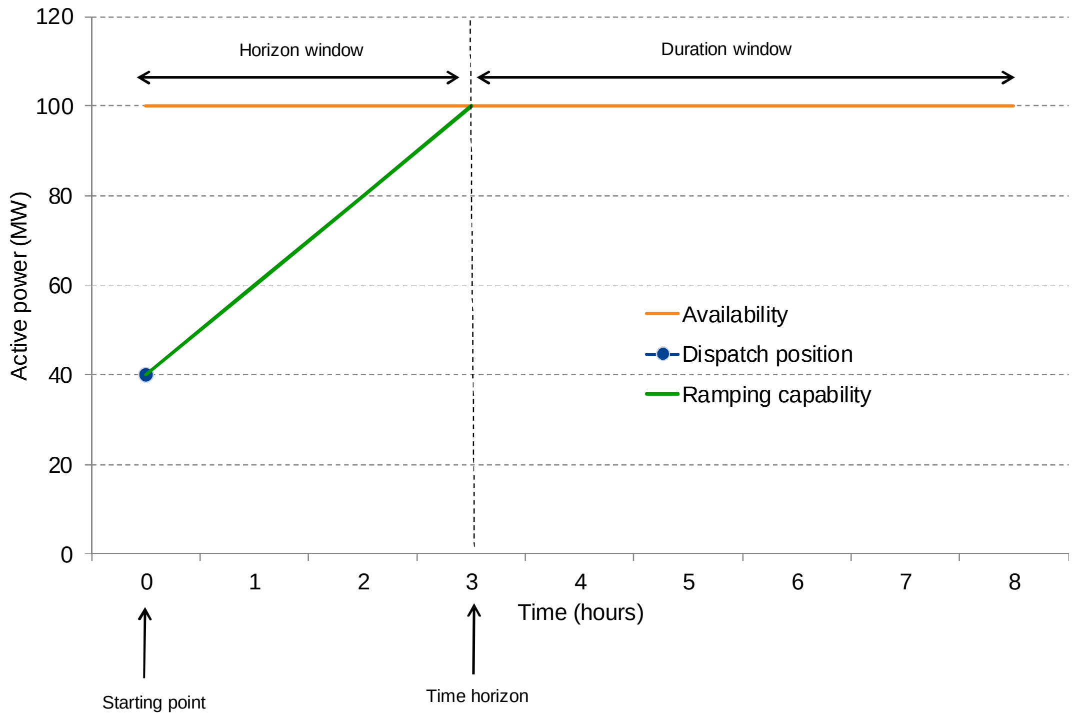
A generation portfolio that is capacity adequate is not necessarily also adequate in terms of ramping over the required timeframes. With high levels of weather variable generation it may prove difficult to manage the system efficiently and effectively without sufficient ramping capability.

Ramping Margin is defined as "*the guaranteed margin that a unit provides to the system operator at a point in time for a specific horizon and duration".* The proposed products have horizons of one, three and eight hours, and are called RM1, RM3 and RM8 respectively. Ultimately, the Ramping Margin represents *"the increased MW output that can be delivered with a good degree of certainty by the product horizon time and sustained for the product duration window".*

Figure 3 illustrates an example of ramping capability with a time horizon of three hours. The generating unit is initially positioned at 40MW can ramp up to full load (100MW) in four hours. Within three hours it reaches an output level of 85MW and can sustain that output for out to 8 hours (or even longer). This means it qualifies for a ramping margin of (85-40)=45MW under the RM3 product.

This same generating unit would also be in a position to deliver the RM1 and RM8 products. The ramping margin for RM1 would be (55-40)=15MW and the ramping margin for RM8 would be (100-40)=60MW, assuming it can then sustain that output for the required duration.

Figure 3 – RM3 product for a 100MW generator initially dispatched at 40MW



Ramping margin requirements, as already noted, are closely linked to wind output levels. They are much higher when wind output forecast is high, and, conversely, lower at low wind output levels due to the impact of higher forecast inaccuracies at high wind levels.

Unlike wind output, demand is more predictable. Over different periods throughout a trading day the expected evolution of demand is different. Overnight when looking eight hours ahead demand is expected to 'ramp up' during the so-called morning swing. The RM8 requirement will then be high. In contrast, ignoring the impact of wind on ramping margin requirements, at the evening peak and when looking eight hours ahead, no significant demand-driven ramping requirement is expected and the requirement for RM8 is low.

If the underlying generation portfolio is not considered, the tariff methodology risks delivering low prices, which will not incentivise the required investment and operation. If we were to have sufficient RM capability irrespective of an underlying generation portfolio

to meet a certain MW level of ramping margin, the expected BNE could for example be an Open Cycle Gas Turbine ('OCGT') or a Pumped Storage facility, both capable of ramping over all the defined timeframes (1 hour, 3 hours and 8 hours) without any incremental investment costs, yielding a price of 0 for all products. There should, therefore, be sufficient RM supply with an expected underlying generation portfolio.

3.8.1 Tariff methodology

The tariff should be set at a level that will ensure there is an incentive for sufficient generating capacity to have the required ramping capability. Similar considerations as outlined for reserve products apply to RM products:

- volume and cost of available supply for reserve is, for some providers, dependent on dispatch decisions and it is not necessarily linked to a specific physical investment; and
- a single provider may be in a position to deliver more than one of these products.

RM products could be treated in the same way as SIR, FFR and reserve, co-optimised alongside energy and these other products. The requirement of the RM products is more complex as it is strongly linked to wind and demand forecast errors. A more probabilistic approach would be more appropriate. Based on discussions with the TSOs, our initial view is that attempting to capture the cost to the system of having sufficient ramping capability through deterministic modelling may not yield meaningful results. This challenge could be overcome by adopting probabilistic expectations in the relevant ramping capability requirements, but this would add further complexity to an already relatively complex approach.

As RM products cover time horizons that span the intraday market under I-SEM, we expect there to be an overlap that may cause potential distortions to intraday prices as part of the flexible capability is rewarded through separate RM products.

We are therefore recommending for the RM products to reflect only relevant capital investment costs with short-run costs being recovered through the ex-ante energy markets. However, the challenge of identifying the relevant incremental investment costs still exists, as there is no meaningful way of separating those for some providers. This means we need to resort to a more pragmatic approach and use an incremental investment cost of a provider that may not necessarily be the BNE.

This could be a 'conventional' provider other than an OCGT, where enhanced ramping capabilities can be achieved through retrofitting in existing capacity or additional cost during construction for new build relating to the capability of being 'warm' even when offline. Focusing on the currently most widely spread technology in the All-Island system, the KEMA DNV report[32] sets out the required equipment for keeping a Combined Cycle Gas Turbine ('CCGT') installation 'warm'. The main items include:

- auxiliary boiler;
  - an operational cost will also be attached to this due to fuel and water use;
- flue gas valve;
- chest warming;
- DCS improvement; and

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32 http://www.eirgrid.com/media/DNV_KEMA_Report_on_Costs_of_System_Services.pdf

- insulation improvement.

If there is a gap in ramping capability in the existing portfolio, RM prices should then reflect the incremental investment costs, providing for an appropriate investment signal. Table 9 presents the description of the tariff methodology though the relevant building blocks.

Table 9 – Building block description of RM tariffs

Building blocks	Options	
Market-wide vs. targeted	**Market-wide**	Targeted
Inclusion of opportunity/variable cost	Yes	**No**
Cost attribution	Singular	**Joint [RM1, RM3, RM8]**
Commodity price indexation	Yes	**No**

A market-wide tariff would compensate all capacity that is capable and available to provide ramping. A targeted payment, on the other hand, would direct payments to only part of the qualifying capacity. Such a targeted approach would bring the RM market closer to a targeted purchase of some flexible generation by the TSOs, similar to the STOR market in GB. Given the size and nature of the Ireland and Northern Ireland power system, a market-wide payment is more appropriate and is also in line with the wider nature of the System Services philosophy.

Similar to the reserve products, there are potential variable costs and foregone profits for providers that:

- need to be turned on to be in position to provide ramping; or
- allow for some headroom when scheduled.

Market participants' behaviour in the ex-ante markets and their bidding in the Balancing Market should be also driven by their expectation of the market conditions and not solely by the RM tariffs. We believe that opportunity/variable costs should not form part of the tariff.

Many units capable of providing RM1 will also be able to provide RM3 and RM8. A joint cost attribution is therefore more appropriate and should deliver the most efficient outcome. Proportioning the costs between the three products could be linked to the relative scarcity.

Commodity price indexation is unnecessary as the tariff will not contain a variable cost element[33].

The annual RM tariff could take the following form:

$$RM_j \left(\frac{€}{MWh}\right) = \frac{IIC_j}{h} \times \frac{r}{1-(\frac{1}{1+r})^n} \times I$$

where:

$IIC_j \ = incremental\ investment\ cost\ for\ providing\ RM_j, expressed\ in\ €/MW$

$h = expected\ total\ hours\ of\ available\ ramping\ capability\ of\ marginal\ provider$

$r = pre - tax, real\ regulated\ rate\ of\ return$

$n = economic\ lifetime\ expressed\ in\ years$

$I = inflation\ index$

The cost attribution between the different products is proposed to be linked to the relativity of the supply and demand with a greater fraction of the cost allocated to the RM product with the greatest scarcity and value to the system.

3.8.2 Additional requirements

For estimating regulated tariffs based on the methodology described above, an independent engineering cost review may be needed to determine incremental cost for RM provision. The expected total hours of available RM provision by the 'marginal' provider will also be determined. These should be determined by the RAs or approved by the RAs based on a TSOs recommendation. The level of the regulated RoR, assumed economic lifetime and projected inflation (if needed) will also be outlined when tariffs are determined.

3.8.3 Interactions with CRM and intraday markets under I-SEM

All System Services will have some interactions with the ex-ante energy markets and the CRM. These interactions are even more pronounced for RM products, and in particular once I-SEM is introduced, as they relate to timescales also covered by the intraday market.

The current SEM is a relatively 'static' market and there is little incentive for market participants to invest in flexible capability. Capacity payments under the current CPM are determined based on a static definition of 'availability'. This means that as long as a unit is not under maintenance or undergoing a forced outage it will capture the capacity payment, even if it is ultimately unable to deliver energy as a result of ramping restrictions. Both market quantities and prices are determined by an ex-post algorithm with perfect hindsight over a trading day. A generating unit may in real-time have not been in a position to ramp-up sufficiently fast as wind generation was changing, but that may not be reflected in the ex-post schedule pricing.

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33 There is however some fuel and water use from the auxiliary boiler, but we expect this cost to be annuatised.

RM products would have therefore had a key role, was the SEM to persist, to provide for a signal in investing in more flexible plant capability as well as promoting operation that can support system needs. They would effectively complement the CPM by providing for an explicit remuneration for flexible capability.

However, parallel to DS3 System Services the overall market design is changing to align with other European markets. I-SEM is expected to have a more 'dynamic' nature:

- market participants will be Balance Responsible;
  - this means they will have to respect their ex-ante market positions and will be subject to imbalance prices for volumes for which they have not secured an ex-ante market price;
- imbalance prices in their turn will start reflecting the changing conditions close to real-time, revealing additional price volatility;
  - the expectation of the imbalance price will drive the formation of prices in the ex-ante markets and in particular the IDM prices will see comparable levels of volatility;
- the IDM will form an additional tool for market participants to trade closer to real-time and allow for hedging against the imbalance price
  - the IDM is expected to better reward more flexible capacity.

Complementing the ETA, a new CRM is being developed based on Reliability Options ('ROs'). The current thinking points towards a 'closer to real-time' reference price for the RO contracts. The exact terms of these contracts will be key in determining the degree of flexibility required by capacity providers. For example, if the terms of the RO contracts require for capacity providers to be in a positon to respond to a TSO instruction with 3 hours notice, capacity that signs an RO contract will be willing to undertake the risk of exposure to the peak energy rent and the potential additional penalty arrangements. Capacity providers do not necessarily have to be capable of having the equivalent ramping capability. Generating capacity that is less flexible may have to ensure they are positioned in the market to avoid such exposure over critical periods. Still, the exposure to market prices provides an additional incentive for investing in flexibility and promoting more flexible operating modes.

The presence of an IDM and a CRM that builds flexibility within its design may raise concerns about the simultaneous presence of explicit remuneration for flexible capability. The introduction of RM products will inevitably have an impact on other markets.

Balancing and IDM prices may be impacted as generating units capture part of their costs (investment, maintenance-related or variable) through RM products and there is less of a need to reflect these in their energy bids; and

Therefore, under I-SEM there may be less of a need for the RM products as long as there is an efficient and liquid IDM present. I-SEM provides for a design that should incentivise flexible capability, both in terms of short-term operation and long-term investment.

However, we recognise that there may be a risk with relying on the short term markets and the CRM to deliver such capability and it may be necessary to maintain the RM products under I-SEM. More importantly, the presence of an IDM is not a sufficient condition for not requiring explicit remuneration for ramping margin availability. The IDM should be efficient and liquid.

3.8.4 Summary of methodology

For RM products we have defined a methodology that should ensure that only incremental fixed costs relating to improving ramping capability from conventional generating units are included. Cost attribution is joint and the distribution should be based on the relative value and scarcity of each RM product. The TSOs should have the flexibility to adjust RM tariffs accordingly in the future if the short-term energy markets and the CRM can sufficiently incentivise investment in more flexible capability.

3.9 Managing Expenditure

The proposed methodology is intended to derive a tariff for the provision of each System Service so as to ensure appropriate incentives for efficient short-term operation and longer-term entry or enhancement with the overarching aim of delivering value to consumers. The SEM Committee decision will also require the TSO to operate within an overall regulatory revenue allowance framework.

At the current time, we do not have visibility of the full revenue framework for the period up to 2020 nor have a full set of regulated tariffs been calculated using the methodology. As such, there remains a risk that applying the tariffs derived through the proposed methodology may result in higher costs than anticipated. This is a consequence of several factors including:

- the increase in number of System Services being procured;
- the (by definition) absence of a rationing process[34] for System Services volumes with a tariff approach; and
- the combined effect of System Services payments on an availability payment basis, as per the SEM Committee direction, and the switch from SEM to I-SEM, which introduces uncertainty with regards to volumes paid for provision under I-SEM.

While it may be argued that this risk is mitigated through the use of an auction-based procurement, the fact that in the first year of operation (i.e, the interim tariff) there will be no auction and that for several System Services auctioning may not be feasible in the short-term, means this is a real constraint on the regulated tariff regime.

We note that there are several mechanisms, in particular the application of scalars, through which some or all of the tariffs may be adjusted that could serve as a 'feedback loop' to lower the risk of exceeding an overall budget and deliver signals of relative scarcity (or abundancy). Proposals for scalars are being developed through a linked workstream, so here we restrict ourselves to commenting on some of the high-level implications of possible options.

The options outlined here are not fully developed, but highlight that undue limits on overall expenditure could potentially affect the performance of the DS3 regime and that consideration will have to be taken of the effect of any budgetary restrictions on the certainty of tariffs, their incentive properties and the ability to deliver a higher SNSP:

- application of an ex-post adjustment to the base tariffs;
  - uniform;

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[34] For example, a regulated tariff that is set at a level to ensure the most cost-effective new entry does not necessarily guarantee delivered volumes will not exceed requirement.

    - this is an ex-post adjustment that would seek to scale tariffs in some defined proportions to ensure it is consistent with the overall regulatory revenue allowance or budget. This not only introduces uncertainty, but will also lead to some tariffs not delivering the desired signals for providers to invest in enhancement or new technology options. For example, if the base FPFAPR tariff is set at a level that incentivises wind generators to install the relevant equipment, a reduction risks not delivering the desired volumes and undermining the efforts for increasing the SNSP limit.
  - targeted;
    - the risk of inefficiency in a uniform adjustment does depend on how the proposed adjustment mechanism affects specific tariffs. If an appropriate mechanism cannot be identified, then where specific investment incentives are anticipated from a particular tariff, these could be exempted from any general de-rating with the adjustment taking a more 'targeted' form.

- application of an-ex ante adjustment to the base tariffs;
  - to mitigate uncertainty, an ex-ante adjustment, based on a comparison of expected payments against the overall allowance, could be applied by the TSO to the tariffs. By making such adjustments before announcing tariffs, the providers retain the certainty for investment decisions over the period. Potential exclusion of some System Services tariffs from the adjustment process could again take place to ensure investment incentives are not distorted.

- application of a scarcity scalar;
  - under this option, the TSOs can adjust tariffs to reflect relative scarcity. This would directly address the concern around the payment basis that it over-rewards provision when there is no requirement or benefit to the system. While this would make payments more cost-reflective of system needs, any change through application of a scalar will introduce some ex-post uncertainty to providers, especially if the scalar basis is not transparent or easy to predict.

4. SUMMARY AND ASSSSMENT OF REGULATED TARIFF METHODOLOGY

The proposed regulated tariff methodology has been guided by a set of underlying principles, whilst trying to meet the constraints imposed by the requirements of the SEM Committee decision. To reflect fundamental differences in the nature of the defined System Service products, there are variations in the methodology used for different System Services. The colouring scheme in Table 10 highlights which System Services share a common approach, but also where cost attribution is joint. Assumptions around costs of provision and the wider market environment are important to determine the tariffs and should be based on a transparent evidence base taking account of industry views. While the responsibility for managing the call for evidence may be vested in either the TSOs or the RAs, the final assumptions would require RA approval.

Table 10 – Summary of regulated tariff methodology

Category	Product	Tariff methodology
Voltage control	SSRP	• Market-wide • Maintain current tariff level increased by the total cost (plus regulated RoR) of incremental investment for meeting the relative <u>additional</u> volume requirement divided by the total expected delivered volumes • Redistribution of captured rates with high RP providers capturing higher effective rates and low RP providers capturing lower effective rates
	DRR	• Market wide or targeted to non-synchronous providers • Use of a temporal scarcity scalar is recommended • Reflect cost (plus regulated RoR) of incremental investment for meeting DRR volume requirement
Inertial response	FPFAPR	• Market-wide or targeted to non-synchronous providers • Use of a temporal scarcity scalar is recommended • Reflect cost (plus regulated RoR) of incremental investment for meeting FPFAPR volume requirement
	SIR	• Market-wide • Volume-weighted average of foregone energy IMR or cost of out-of-merit dispatch of the marginal provider in each period as determined by co-optimised market modelling • Potential mark-up (if needed) to ensure fixed cost and regulated RoR recovery for the [SIR. FFR, POR, SOR, TOR1,TOR2, RRS and RRD] subset • Account for interdependencies within the [SIR. FFR, POR, SOR, TOR1,TOR2, RRS and RRD] subset • Partial commodity price indexation to reflect changing market conditions (for the 'variable' cost element) is recommended
Reserve	FFR POR SOR TOR1 TOR2 RRS RRD	
Ramping	RM1 RM3 RM8	• Market-wide • Cost (plus regulated RoR) of incremental investment for meeting the volume requirement for each product • Account for interdependencies within the [RM1, RM3 and RM8] subset • Cost attribution based on relative scarcity is recommended

Figure 4 presents the impact assessment of this proposed methodology against a set of policy and commercial assessment criteria.

Figure 4 – Impact assessment of regulated tariff methodology

		Description of criteria	Regulated tariff methodology
Policy	Security of supply	The scheme ensures the required volumes of capacity/service are delivered The scheme ensures that EirGrid is able to access the services to manage the system securely	Tariff methodology has been developed to ensure the targeted volume of System Services is procured. However, the volume scalar has the potential to adjust tariffs downwards in the event the expenditure exceeds regulated revenue allowance and could result in under-procurement. It is unlikely this would compromise security of supply, but would require greater levels of wind curtailment and reliance on grid code minimum provision levels to ensure security of supply.
Policy	Sustainable	The scheme contributes to meeting the 2020 renewable energy targets The scheme contributes to a reduction in wind curtailment	Tariff methodology has been developed to ensure the targeted volume of System Services is procured. However, the volume scalar has the potential to adjust tariffs downwards in the event the expenditure exceeds regulated revenue allowance and could result in under-procurement. This could mean increased wind curtailment in order to manage system security (and hence lower investment in wind in the longer-term).
Policy	Efficiency	The design does not lead to over-procurement and ensures the least-cost portfolio is contracted	The supply-demand balance and hence marginal cost of provision for most System Services changes significantly across the year. The requirement for an annual tariff limits the ability to fully reflect the value of flexibility at particular periods. This can be managed through the use of temporal scalars.
Policy	Affordability	The scheme minimises the cost to consumers of delivering the services The scheme protects customers from exposure to over-payment	An appropriate revenue allowance helps to ensure that consumers do not face excessive costs of delivering the System Services. Targeting of some System Services should reduce the overall cost of procurement.
Policy	EU Compliance	The scheme is compliant with EU Network Codes with particular relevance to the guidance on provision of balancing services The scheme is robust to State Aid issues	Any potential compliance issues would not relate to the methodology per se, rather to the use of regulated tariffs. That said, there are provisions in the Electricity Balancing Network Code that allow for diverging from market-based procurement methods.
Policy	Competition	The scheme is not susceptible to market power and encourages participation of a wide range of participants	Not applicable
Commercial	Transparency and Simplicity	The scheme is transparent and equitable and enables users to understand the impact on revenues and ways of participation	The introduction of seven new System Services will inevitably add complexity to the procurement arrangements. The market modelling involved in tariff setting may be perceived to add complexity, but there will be a published methodology for the tariffs which will be consulted on.
Commercial	Financeable	The scheme provides certainty to investors in terms of size, timing and certainty of cashflows and ensures appropriate levels of return	Methodology is aimed at providing sufficient returns for new investment.
Commercial	Robust	The system is flexible to adapt to changes in market requirements (eg, new services, evolving volume commitments, new technologies, changing generation mix)	Not applicable.
Practical	I-SEM compatibility	The scheme is in line with the I-SEM philosophy The scheme has no undue distortions on other I-SEM components (ie, CRM, ETA)	System Services tariffs will have an impact on behaviour in the ex-ante energy markets. We would expect that providers would include the opportunity cost of System Services in their bids under I-SEM. However, this is not an 'undue' distortion.
Practical	Implementation	The scheme can be implemented within the proposed timescales and the enduring arrangements can be operated at reasonable cost to resources of the RAs and TSO	New products will need to be added to the System Service settlement systems. Additional data feeds will be required for existing products (e.g. market position in additional to physical dispatch). Additional analysis and modelling will be required by the TSOs.

ANNEX A – 'JOINT BNE' PROVISION

The simplest way of explaining the 'joint BNE' concept is through a simplified worked example. Assume the only System Services procured are FFR and POR. The volume requirement for each System Service is 50MW and there are three providers available, as shown in Table 11.

Table 11 – 'Joint BNE' worked example

Provider	Volume provided	'Supplemental payment '[35]	Products
Provider 1	50	€50	POR
Provider 2	50	€30	FFR
Provider 3	50/50	€70	POR, FFR

Provider 1 can only provide 50MW of POR at a total cost of €50, Provider 2 can only provide FFR at a total cost of €30, whereas Provider 3 can deliver both services with an aggregate cost of €70. In this simple example, it is straightforward that the least-cost solution is delivered by the Provider 3. Provider 3 is the 'BNE' for the [POR, FFR] set. Extending to the entire suite of System Services a portfolio consisting of one or more providers would be able to cover for the total required volumes. The complexity of the problem increases in line with the number of products and number of potential providers. However, the 'theory' behind it remains similar to this example.

Determining the price is relatively more complex than identifying the BNE. Firstly, prices for POR and FFR should ensure that the 'BNE' (Provider 3) recovers the 'supplemental payment', but not more than that. In our example, any combination of prices for POR and FFR hat sum up to €70 would satisfy this condition. At the same time, prices should not incentivise entry by 'losers'. This means that the POR price should be lower than €50, as any price greater or equal to that would be a sufficient price signal for Provider 1. Similarly, the FFR price should be less than €30. These constraints ultimately map a space of price combinations that satisfy all criteria, aiming at delivering the right type and amount of capacity.

35 'Supplemental payment' relates to the additional revenues required to meet the expected rate of return. It is equal to the annualised gap between the annualised capital expenditure and annual fixed costs and the expected net revenue from other streams (energy market, CRM etc.).

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ANNEX B – INTERACTIONS WITH ENERGY MARKETS UNDER I-SEM

The presence and the level of the regulated tariffs will have an impact on market participant bidding in the ex-ante energy and balancing markets. Regulated tariffs will be visible ahead of the short-term markets (Day-Ahead and intraday), and market participants will be in a position to bid according to their relative expectation of the energy price formation. The availability payment basis plays an important role in this. It encourages market participants to attempt to be scheduled so that they can capture the regulated tariffs, when the monetary incentive is sufficiently high. This can be explained though a simplified example.

For simplicity, in our example, we assume the following:

- the presence of a single System Service, SOR;
- no bidding restrictions (such as Short Run Marginal Cost bidding) and if such restrictions are in place then providers are allowed to treat System Services tariffs as an opportunity cost and include it in their bids; and
- the Day-Ahead market position is the final market position (i.e. there is no intraday trading).

Suppose the expectation of the Day-Ahead market price in a given period is 60€/MWh and the running cost of a provider is 50€/MWh. This equates to an IMR of 10€/MWh. If the regulated tariff for providing SOR is 15€/MWh, then the provider is incentivised to offer part of its capacity for SOR and forego the IMR in the Day-Ahead market for the corresponding capacity.

If now the provider is unsuccessful in being scheduled in the Day-Ahead market at a position that allows it to capture the SOR payment, then its bid in the balancing market should now reflect this expected payment. For example, if it is out of merit (and has not been scheduled in the Day-Ahead market) and it needs to be constrained on, its offer should be reduced by an amount reflecting the expected SOR payment. If, on the other hand, it is scheduled at full load its decremental bid should again reflect the expected SOR payment and it should be willing to 'pay back' the fuel (and carbon) cost savings as well as the captured SOR payment.

Another provider with a running cost of 20€/MWh is expecting an IMR of 40€/MWh. This provider in its turn has no incentive to part-load to provide SOR. The IMR is more attractive and the provider would most likely attempt to schedule its entire capacity for energy provision.

Ultimately, System Services tariffs may have an indirect impact on:

- providers' bidding behaviour in the ex-ante and balancing markets;
- market prices; and
- overall expenditure in the ex-ante and balancing markets.

We have to note that our approach assumes a certain degree of competition in the energy markets and within the System Services. In the presence of market power for a specific System Service or a set of System Services there is a risk of overpayment. For example, a provider, which can exercise market power, could offer its entire capacity for energy, having reasonable certainty that the TSOs would then re-dispatch part of its capacity for System Services provision, without reflecting the opportunity cost in its Balancing Market

bid. This is however an issue that can arise in any case in the Balancing Market in the presence of market power and we expect this would be dealt with through some form of market power mitigation.

ANNEX C – ADJUSTMENT OF REGULATED TARIFFS UNDER SEM

For SIR, FFR and the other reserve products we have described a methodology that reveals the value of each System Service and assumes providers can account for such potential income in their bids in the ex-ante energy and balancing markets. However, under the SEM arrangements, providers cannot reflect any such potential revenue in their bids and receive IMR based on an ex-post unconstrained market schedule when 'in merit'. When not 'in merit', but dispatched to provide a service needed by the TSOs they would receive a constraint payment, ensuring bid recovery.

There is therefore a need to adjust the estimated tariffs to account for this difference in scheduling and payments under SEM. We propose for the estimated modelled System Service price in each period to be adjusted so that, on average, each unit (MW in the case of FFR and other reserve products and MWs^2 in the case of SIR) providing the System Service receives the same overall payment. Effectively, the System Service tariff should be equal to the difference between the aggregate profits from the energy market and provision of System Services accrued by all capacity in the constrained and unconstrained 'schedule' divided by the total capacity providing the System Service.

This approach can be best explained with a simplified example. Table 12 presents the technical and economic characteristics of the two providers available in our simplified example. Let us also assume the electricity demand in a given period is 700MW and there is also 30MW POR requirement.

Table 12 – Technical and economic provider characteristics

	Capacity (MW)	MSG (MW)	Variable cost (€/MWh)	POR capability (MW)
Provider A	400	200	50	20
Provider B	400	200	60	20

For simplicity we assume that both generators have negligible start-up costs and zero no-load costs

The unconstrained schedule would 'dispatch' Provider A at full load, 400MW, and Provider B at 300MW, to meet the 700MW demand. The resulting electricity price would be €60/MWh. Provider B is marginal and not capturing any IMR, whereas Provider A is capturing €10/MWh IMR for its entire capacity. This is similar to a typical outcome produced by the SEM ex-post market schedule.

However, as there is a 30MW POR requirement, the constrained model run would produce the following result: Provider A would part-load at 390MW and Provider B would run at a higher load when compared to the un-constrained run, at 310MW. This is the outcome that would be produced by a 'constrained' model attempting to minimise overall cost of reliable electricity supply.

In this second case the resulting electricity price is again €60/MWh. The POR price, as estimated from the constrained run, is €10/MWh, reflecting the foregone energy IMR from the marginal POR provider, Provider A.

Provider A is indifferent between the two outcomes, as it just foregoes profit from the energy market for its last 10MW and receives the same payment though the DS3 System Services payment. However, at the same time it reveals the value of POR to the system and a payment that is captured also by Provider B. Table 13 shows the profit captured by each provider in the constrained and the unconstrained model 'runs'.

Table 13 – Profit captured by each provider in the two model 'runs'

Profit (€)		Provider A	Provider B
Unconstrained	Energy market	4,000	-
	DS3	-	-
Constrained	Energy market	3,900	-
	DS3	100	200

The additional surplus created for the two providers is equal to €200. This additional surplus can then be spread across all capacity providing the required service. In this case, this results in a POR payment of €6.67/MW.

This means no difference for consumers that ultimately face the same system cost. When it comes to the supply side, providers capture the same surplus in both cases when considered collectively. There is, however, a redistribution of the surplus.

ANNEX D – MARKET-WIDE TARIFFS FOR FPFAPR AND DRR

Based on the IPA 'Economic Appraisal of DS3 System Services' report[36] we can estimate the enhancement cost for wind to be able to provide FPFAPR and DRR as shown in Table 14. According to this study, these investment costs are required for wind turbines to be able to provide enhanced fault ride-through through active power and reactive response (FPFAPR and DRR). We have to stress that these cost estimates do not form or represent our or the TSOs' view of what the level of those is.

Table 14 – Enhancement cost for wind turbines by product

Product provided through enhancement	Enhancement cost (€/kW)
FPFAPR	158
DRR	72
FPFAPR and DRR	**230**

D.1 Fast Post-Fault Active Power Recovery ('FPFAPR')

Given that fault ride through capabilities from wind turbines are necessary to allow for increasing the SNSP limit, tariffs for FPFAPR and DRR should be set at a level that incentivises such investment. Based on the capital expenditure outlined in Table 14, we have estimated the annualised cost of enhancement faced by a wind turbine for providing FPFAPR. Assuming a 'typical' annual wind load factor of 30%, we then calculate the equivalent required uniform tariff, which would allow for the capital expenditure to be recovered. Finally, if tariffs are market-wide and paid to all FPFAPR providers, we can approximate the total expenditure relating to FPFAPR.

Market-wide payments for all units that provide FPFAPR would pose a significant burden on the expenditure pot. The example below illustrates what the total sub-pot for this FPFAPR alone could be if paid to all generators deemed to be 'available' (Example 1). Example 2 assumes only a fraction of the wind installed capacity wind is paid for FPFAPR capability.

Under Example 1 where all 'available' generation is remunerated (assuming all generation has FPFAPR capability) the total expenditure is estimated to be around €204.3 which represents a significant proportion of the nominal €235m regulated revenue allowance cap in 2020. However, if only wind turbines with the relevant capability were to receive FPFAPR payments, the total expenditure would be significantly lower (estimated at €44.7m).

However, we have to note that this additional burden on DS3 System Services expenditure under Example 1 may come alongside a uniform decrease in the ex-ante market prices under I-SEM. Market participants may treat this payment as an opportunity cost, captured for each MWh generated, with a corresponding reduction in their energy bids. Consequently, this may mean a reduction in expenditure for buying electricity in the

36 SEM-14-059b Economic Appraisal of DS3 System Services, IPA, 8 July 2014

ex-ante markets. Such a uniform reduction in energy prices may change cross-border trade balance and be perceived to have an impact on efficiency.

Table 15 – Estimate of total expenditure from FPFAPR

Example 1 - Paying all generation		
Estimated cost of enhancing wind to provide FPFAPR	158.0	€/kW
Annualised cost of enhancement (approx.)[37]	14.9	€/kW
Annual generation at 30% LF	2628	kWh/kW
Required tariff	0.0057	€/kWh
Total annual generation that is 'available' (approx.)	36	TWh
Cost	**204.3**	**€m**
Example 2 - Paying new wind		
Estimated cost of enhancing wind to provide FPFAPR	158.0	€/kW
Annualised cost of enhancement (approx.)	14.9	€/kW
New wind capacity by 2024 (approx.)	3	GW
Cost	**44.7**	**€m**

D.2 Dynamic Reactive Response ('DRR')

Similarly, uniform payments for DRR will result in significantly higher expenditure when compared to payments targeted solely at new build wind turbines.

In Table 16, we have estimated the annualised cost of enhancement faced by a wind turbine for providing DRR. Unlike FPFAPR, DRR can be provided at any non-zero output level by a wind turbine. For simplicity we have assumed that a wind turbine can provide DRR over 80% of the periods within a year. We then make the same comparison, as per FPFAPR: Example 1assumes all 'available' generation (including conventional units) receives a DRR payment, whereas in Example 2 it is only new wind turbines that get paid for DRR.

As previously shown for FPFAPR, the cost associated with paying all generation is significantly greater than with payments targeted only at new wind. The estimated cost of paying all generation the tariff required for wind generators to provide DRR (€69.1m) exceeds the current €60m expenditure and will represent a significant proportion of the nominal €235m regulated revenue allowance cap in 2020.

37 Assuming a 20 year economic lifetime and a 7% rate of return

Table 16 – Estimate of total expenditure from DRR

Example 1 - Paying all generation		
Estimated cost of enhancing wind to provide DRR	72.0	€/kW
Annualised cost of enhancement (approx.)	7.2	€/kW
Annual DRR volume available from wind (approx.)	7008[38]	kVArh/kW
Required tariff	0.00097	€/kVArh
Total installed capacity (approx.)	12	GW
Annual average plant utilisation (assumption[39])	0.6	
Installed capacity of utilised plant	7.2	GW
Total annual DRR volume that is 'available' (approx.)	63.1	TVArh
Cost	**61.2**	**€m**
Example 2 - Paying new wind		
Estimated cost of enhancing wind to provide DRR	72.0	€/kW
Annualised cost of enhancement (simple)	7.2	€/kW
New wind capacity by 2024 (approx.)	3	GW
Cost	**20.4**	**€m**

38 A 'typical' wind turbine has a non-zero output for 80% of the periods cross a year

39 In order to estimate the annual DRR volume that is available from all capacity an assumption is made on the annual average plant utilisation (0.8), this refers to the proportion of the year when a plant is connected to the system and capable of providing DRR regardless of output level.

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