DS3:
System Services Review
TSO Recommendations

Report to the SEM Committee

Contents

Executive Summary

The power system of Ireland and Northern Ireland is in a period of transition driven by national and European policy, particularly with respect to renewable energy. This transition will result in a fundamental change to the power system generation portfolio, the operational characteristics of the system under both steady state and transient conditions and it will significantly transform the requirement for, and composition of, essential system services.

EirGrid and SONI have put in place a multi-year, multi-stakeholder programme of work, "Delivering a Secure Sustainable System" (DS3), to address these challenges. EirGrid and SONI also have licence and statutory obligations to ensure sufficient system services are available to enable efficient, reliable and secure power system operation. The System Services Review, which forms a central component of the DS3 programme, was initiated to ensure system services would be available to meet the needs of the system in line with policy objectives. It has involved a multi-stage consultation process, culminating in this recommendations paper.

The consultation process to date has included three consultation papers. The first paper set out the proposed approach to the system services review, and sought industry input on the scope and nature of the review. In conjunction with this paper, the TSOs published an international review of system services that had been carried out by independent consultants. Prior to the System Services Review, the TSOs had established the need for system services through detailed studies and technical analysis, and in the second consultation paper proposed new products which address the emerging challenges associated with achieving the governments' renewable energy policy objectives. The third consultation paper focussed on the financial aspects of system services. A detailed summary of the responses to the third consultation has been included in this paper, with an explanation of how the respondents' views have been incorporated into the TSOs' recommendations.

The essence of the recommendations contained in this paper, following the consultation process, can be summarised as follows:

- The performance needs of the power system will radically alter in order to efficiently and effectively manage a system which can facilitate the renewable energy policy objectives. The design of system service products and the level of remuneration for these needs to be similarly changed. A range of new and modified system services products are proposed to achieve this.
- A greater level of remuneration is required to incentivise the necessary performance levels, but this should only be paid for proven capability that can be relied upon. The proposal recommends price regulation on a range of existing and new system services products. The level of this price regulation is in the first instance, a value-based assessment of the production cost difference between operating the system with and without the necessary services, and the knock-on impact on windfarm build. This value is then allocated between products based on an assessment of their relative benefits. The aggregate pot of money to make this allocation may also be informed by the incremental capital cost required to deliver the additional system services.
- Supplementing these principles are a number of specific recommendations on values, areas for further consultation and specific figures for SEM committee approval.

Summary of Recommendations

Recommendation on principles:

The TSOs recommend that:

- The system service products are designed by the TSOs to address the needs of the power system to meet all appropriate policy objectives in an efficient manner.
- The system service products are, in so far as possible, technology neutral.
- The existing ancillary services are included as system services in this process with the exception of Blackstart. Specifically these include Primary, Secondary, Tertiary and Replacement reserves and Reactive Power (with suitable modifications to the definitions of last two products).
- The following products, whose descriptions are provided in supporting material, are implemented as new system services: Synchronous Inertial Response, Fast Frequency Response, Ramping (1, 3 and 8 hour), Fast Post Fault Active Power Recovery and Dynamic Reactive Response.
- A “Value Based” approached is utilised in the determining the aggregate value of system services. This is determined with reference to the production cost savings of being able to operate the power system more efficiently with the addition of new system services as compared with the current “business as usual” level of services.
- The distribution of the total value between the end consumer and the system services providers should be informed by the incremental capital costs of the enhanced system services required to meet a transparent and published set of policy objectives.
- The determination of the annual system services pot and ensuing tariffs should be fixed for at least a five year period. This is to achieve an appropriate balance between the provision of certainty to the investor (service provider) and the long-term costs to the consumer. In particular, the longer the tariff period, the greater the risk that the consumer does not realise the benefit of future innovation.
- The allocation of the determined system services pot between the system service products should be based on a relative marginal benefit approach as outlined in Option 3 of the third system services consultation. This weighting between the products should remain fixed for at least the tariff period to provide increased confidence to investors and reduce uncertainty in the future.
- The additional monies are recovered through appropriate regulated consumer tariffs in Ireland and Northern Ireland.
- If the market does not deliver the required system services, or in the event of unexpected circumstances, the TSOs must be able to enter into longer-term contracts for services to take into account the longer-term needs of the system and the policy objectives.
- The contractual arrangements for system services are, in so far as possible, technology neutral.
- A single payment mechanism will be used (described in detail in section 4) for all services and will include a scalar to incentivise performance reliability.
- Product rates used for payments to service providers should be fixed (i.e. not time-varying).
- For services that align with a minimum requirement in the Grid Code, the TSOs are obliged to contract with all compliant providers for that minimum requirement. Contracting for quantities in excess of the minimum requirement will be at the discretion of the TSO, based on the needs of the system.

- For services which require performance in excess of the minimum Grid Code standard, the TSOs will only contract with providers that meet the enhanced standard.

Recommendation on specifics for period Oct 2015 – Oct 2020

Specifically for the period Oct 2015 – Oct 2020, the TSOs recommend that:

- The system service rates should be determined by the approach and principles outlined above. For the 2020 system analysed, the total benefit from System Services is €355 million.
- €355 million should be used to determine the system service product tariffs to be employed from 1st Oct 2015.
- The determination of how these revenues interact with Capacity Payments is a matter for the SEMC. Assuming the existing design of the Capacity Payment Mechanism, the following is recommended:
    - The system services remunerated on a Dispatch Dependent basis are:
        - Ramping Margin (1, 3, 8 hour)
        - Primary, Secondary, Tertiary and Replacement Reserves
        - Fast Frequency Response
    - The system services that are remunerated on a Capability basis are:
        - Synchronous Inertial Response
        - Dynamic Reactive Response
        - Fast Post Fault Active Power Recovery
        - Steady State Reactive Power
    - Capability based payments should employ an additional rate scalar, which adjusts the remuneration received by a provider based on their average production cost (relative to a reference price). This rewards more efficient providers with relatively higher remuneration vs. less efficient providers.
- The arrangements for blackstart should remain unchanged.
- October 2015 should be set as a firm target date for "go live" of the new System Service arrangements.

Recommendation on details requiring further consultation

The TSOs recommend that, for a number of aspects of system services, a high level decision is made at this point on the principles, with further consultation on some of the details and implementation aspects to follow. In particular, it is proposed that further consultation would take place on the following:

- The exact portfolios and methodology to be used in determining the allocation between system services as per the relative marginal benefit approach (Option 3) recommended above.
- The System Services contract framework.
- The process and implementation details for determining the performance scalars.
- The details associated with the implementation of the products and their remuneration.
- The process for determining and setting the rate scalars (including reference price).

1. Introduction

1.1 Background

The power system of Ireland and Northern Ireland is in a period of transition driven by national and European policy objectives, particularly with respect to renewable energy. This transition will result in a fundamental change to the power system generation portfolio, the operational characteristics of the system under both steady state and transient conditions and it will significantly transform the requirement for and composition of essential system services.

System Services are those services, aside from energy, that are necessary for the secure operation of the power system. These services are also referred to as Ancillary Services (AS) and System Support Services (SSS). EirGrid and SONI have licence and statutory obligations to ensure sufficient system services are available to enable efficient, reliable and secure power system operation.

To address the challenges of the policy objectives, EirGrid and SONI put in place a multi-year, multi-stakeholder programme of work, "Delivering a Secure Sustainable System" (DS3). The System Services Review, which forms a central component of the DS3 programme, was initiated with the goal of ensuring that system services would be available to meet the needs of the system in line with policy objectives. It has involved a multi-stage consultation process[1,2] including industry fora and bilateral discussions with industry participants. The objectives of the review were published and formed part of a preliminary consultation paper. This paper was followed by two further consultation papers, two rounds of bilateral meetings and an industry workshop. The consultation process is described in more detail in section 1.3 below.

As part of the System Service Review, the existing Harmonised Ancillary Service arrangements and Generator Performance Incentives (GPIs) were examined. The existing arrangements, including the introduction of GPIs and enhancement of performance monitoring, have brought about a number of benefits, including parity of treatment in both jurisdictions, improved transparency and a greater focus (from a number of generators) on performance capability and Grid Code compliance. However, the review also highlighted that there was no evidence that the service providers were making any significant investments to enhance the service provision beyond current levels.

Prior to the System Services Review, the TSOs established, through detailed studies and technical analysis, the need for system services that address the emerging challenges associated with achieving the governments' renewable energy policy objectives. The Facilitation of Renewables (FoR[3]) and subsequent studies indicated that it will only be possible to securely operate the power system by addressing the main challenges (inertia, frequency response, ramping capability and voltage control).

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[1] System Services consultation process
http://www.eirgrid.com/operations/ds3/industryengagement/

[2] System Services review project plan
http://www.eirgrid.com/media/DS3%20System%20Services.pdf

[3] http://www.eirgrid.com/renewables/facilitationofrenewables/

Several metrics were examined during the FoR studies to aggregate these issues into an all-encompassing, easily understandable metric. The most appropriate approximation was found to be the System Non-Synchronous Penetration (SNSP) level. It was found that for the current system a prudent maximum SNSP limit of 50% should be observed, but that if mitigation measures were put in place, a real time operational limit of 75% SNSP would be possible. New system services and an enhanced generation portfolio capability are an essential component of being able to move from the current maximum SNSP limit of 50% to a future limit of 75%. The studies also indicated that moving to 75% SNSP results in reduced curtailment levels and lower dispatch balancing costs. Essentially, if the system evolved with the necessary system services then the system could be operated in a manner that could efficiently and securely meet the RES-E targets.

This current paper sets out a number of recommendations from the TSOs for the SEM Committee to consider. These recommendations, which are based on the previous consultation papers and the associated industry responses, relate to the future provision of and payment for system services to facilitate the renewable policy objectives and enable the TSOs to obtain the required services. It is hoped that the SEM Committee will publish a decision on these recommendations by Q4 2013.

1.2 Principles Covering the TSOs' Approach

The TSOs consider that the design of system services needs to consider a range of elements if an effective and efficient scheme is to be developed. There is often a tension or conflict between these elements, for example the provision of investment signals vs. minimising the cost to consumers. In order to achieve an implementable solution, pragmatic tradeoffs have to be made. In this regard, it is important to set out a range of overriding principles that can help guide the design of pragmatic arrangements. The following are the core principles that the TSOs consider to be most relevant in the design of system services:

- Value to the consumer
- Transparency
- Proportionality
- Non-discrimination
- Provision of a long-term signal consistent with electricity policy objectives

1.2.1 Value to the Consumer

The level and design of system services should be able to meet the long term security requirements of the power system, including the transmission and distribution systems, consistent with the electricity policy objectives in place, and at a cost that represents value to the consumer.

1.2.2 Transparency

In the consideration of system and ancillary service payments, the TSOs are minded that there needs to be clarity on the level of reward available and on the capabilities and reliabilities expected from a service provider. This should be as transparent as possible as this fosters industry confidence in the incentive mechanisms and, if appropriately designed to meet the long term needs of the system, provides a greater focus on meeting the challenges associated with the policy objectives. Transparency can, over time, build a history of data and information that provides the background to make informed long-term investment decisions. Without this transparency, it is difficult to see how the necessary investor confidence can be developed.

1.2.3 Proportionality

The level of reward for system services should be proportionate to the scale of the limitation being overcome and not unduly in excess of this. The proportionality principle aims to ensure that a change in system services or regulatory market mechanisms is such to deliver the changes needed to meet the needs of the power system without an undue effect on the market. In this regard, the level of reward should be of a size that steers the outcomes effectively and in a timely manner.

1.2.4 Non-discrimination

In so far as possible, incentives should be designed so that any service provider who is capable of providing the services in a reliable manner is eligible to participate and be remunerated. When combined with transparency and proportionality these incentives should efficiently and effectively deliver the needed system services without unduly locking out the inclusion of innovative technologies over time.

1.2.5 Provision of a long term signal consistent with electricity policy objectives

The incentives for system services should be designed not only to meet the real time needs, but also the long term system security requirements of the power system. Indeed, incentives should be adaptable over time to allow for the evolving electricity policy to be reflected.

1.3 System Services Review Consultation Process

The aim of the System Services review is to develop the correct structures, levels and types of services in order to ensure that the power system can operate securely with higher levels of variable non-synchronous renewable generation. In cooperation with the Regulatory Authorities (RAs), the TSOs initiated a multi-stage consultation process in 2011, as part of the DS3 programme, to incorporate the views of industry on the arrangements for future System Services. Three TSO consultation papers have now been published on the System Services review:

The **first consultation** was published on 13 December 2011 (closing date: 3 February 2012). The first consultation period was extended from 4 weeks to 6 weeks after feedback from industry via the DS3 Advisory Council.

The **second consultation** was published on 8 June 2012 (closing date: 3 August 2012). The second consultation period was extended from 6 weeks to 8 weeks after feedback from the DS3 Advisory Council.

The **third consultation** was published on 18 December 2012 (closing date: 15 February 2013). The consultation period of 8 weeks was agreed following feedback from the SEM Committee. This was subsequently extended until the 20 February following the publication of some supplementary data, which had been requested by respondents at bilateral meetings.

As the outcome of the System Services review is of importance to a wide array of industry stakeholders, the TSOs have worked to ensure that the review process is as inclusive as possible. It was considered important that all developments were clearly communicated and that all stakeholders were given an opportunity to understand the process and the proposals.

Targeting

Beginning in December 2011, the TSOs have engaged in a multi-stage consultative process on the future of System Services with a diverse range of industry stakeholders.

Accessibility

In conjunction with the formal consultation stages, the TSOs held a series of bilateral meetings with respondents in order to provide an additional avenue of communication for all stakeholders. To ensure consistency and in the interests of fairness, each bilateral meeting was attended by the same members of the TSO project team. For the first round of meetings (Q1 2012) a representative from the RAs also attended each meeting.

During the second consultation period (July 2012), an industry workshop was hosted by the TSOs (in Dundalk) to present the details of the consultation paper to the industry and to provide an opportunity for the TSOs' proposals to be debated by interested stakeholders.

Transparency

The process for responding to the consultation and providing feedback to the TSOs was clearly outlined in each paper issued. As the System Services review progressed, every effort was made to communicate to stakeholders in a timely and open manner. All relevant information on the System Services review - including a System Services programme plan - is published on the TSOs' websites. The RAs have also published information on each System Services consultation paper on the All-Island Project website.

Consistency and Flexibility

Regular updates on the System Services review have also been provided through the DS3 Advisory Council and Industry Fora. After each consultation period, the TSOs presented an update to the Advisory Council (which was subsequently published). All responses were evaluated and reviewed in detail by the DS3 team and were discussed with the RAs. All information received from the associated bilateral meetings was considered in the final evaluations.

The TSOs extended the period for each consultation period after feedback from the DS3 Advisory Council and/or the RAs thus providing additional time for respondents.

1.3.1 The First Consultation

This was a "fact-finding" consultation paper and was accompanied by a questionnaire for respondents to complete. It presented the background and context, the proposed approach to the System Services review and asked for the views of the industry on the scope and nature of the review.

In parallel with this consultation process, the TSOs engaged independent consultants (KEMA) to carry out an international review of System Services. The report of their review contains a comparison of the system services (or ancillary services) arrangements in a number of markets around the world, with an emphasis on markets and/or services that are relevant to the SEM and the power system of Ireland and Northern Ireland. The resulting report was published in January 2012 (during the consultation window).

The TSOs received 27 responses. Following the consultation period, 15 bilateral meetings were held with interested stakeholders to discuss their responses and answer any queries arising. At the DS3 forum in March 2012, a summary of the outcome of the first consultation and the next steps was presented to the industry.

1.3.2 The Second Consultation

The second consultation paper identified a number of new system services proposed by the TSOs that are required in order to continue to ensure the safe and secure operation of the system as levels of instantaneous penetration of wind increase. This consultation focused primarily on the design and technical aspects of these new services, including an enhanced focus on reliability.

The second consultation was accompanied by a SEM Committee cover note which highlighted the key issues which the SEM Committee believed needed to be resolved throughout the course of the review. An Industry workshop on System Services was held in July 2012. The workshop allowed the details of the second paper (particularly the new product designs) to be presented to and debated by interested stakeholders. A total of 26 responses were received; most of the responses were from generators or generator affiliations, with the remainder from demand affiliations and academia.

EirGrid and SONI also held a DS3 Industry Forum on the 5th of November 2012 in the Alexander Hotel, Dublin, which included an additional update on the System Services review.

1.3.3 The Third Consultation

The third consultation paper examined the valuation of the required System Services, financial modelling and analysis, revenue allocation, possible approaches to service remuneration, contractual arrangements and described the TSOs' proposed final product designs. It also provided an indication of capital costs which may be incurred to provide these new services based on independent analysis carried out by DNV KEMA. The TSOs also published DNV KEMA's report which provides details on the potential costs of providing the new system services which the TSOs require. During the consultation window, 20 bilateral meetings were held with interested stakeholders to assist their understanding of the paper and to answer any queries arising. The TSOs received 26 responses to the consultation.

1.3.4 Recommendations Paper

Following a detailed review of responses to the System Services consultation papers and consideration of the issues raised at the bilateral meetings, the TSOs have developed a recommendations paper (this paper) for the SEM Committee to consider. The RAs have indicated their intention to conduct a further public consultation prior to any decision on System Services. A final SEM Committee decision on the new System Services structures, products and remuneration is expected later in 2013.

2. Responses to December 2012 Third System Services Consultation

In December 2012, the TSOs sought the views of industry on the financial arrangements for System Services in the third consultation paper of the System Services Review. The issues for consideration were split into areas as follows:

1) Value of System Services to the Electricity System
2) Financial Modelling and Analysis Approach
3) Allocation of System Services Revenue
4) Remuneration Approach
5) Contractual Arrangements and Payments

A total of 26 responses were received. Of these, 19 had generation affiliations (10 of which included wind plant), two had demand-side affiliations and the others were from consultants, interconnector owners and academia. Most of the questions posed in the paper resulted in a clear majority response (in favour or against). The views of respondents have been summarised and addressed in the narrative below. A number of respondents provided a much more specific reply, often reflecting the respondent's particular circumstances.

In keeping with previous System Service consultation papers, all responses that were not marked as confidential (21 in number) have been published by the TSOs.

2.1 Value of System Services to the Electricity System

Question posed
Do you agree that the proposed value based approach to informing the amount of funding available for System Services is necessary and appropriate to deliver the required services to achieve the renewable targets?

Respondent Views:
A majority of respondents supported the value-based approach so long as this approach was sufficient to enable service providers to recover the costs of providing the services. A small number of respondents suggested that the range of external matters described in the consultation paper (e.g. not achieving 2020 targets) that are outside the TSOs' core remit should be considered when the final decision is made. One respondent commented that payments in excess of value should not be incentivised. It was also queried why the value-based approach was not extended to existing System Services.

TSOs' View:
The TSOs welcome the general support for the value based approach. The recommendation described in section 5.1 reflects this consensus.

On reflection, the TSOs concluded that external matters outside the TSOs' core remit should not be considered in the System Service Review. The TSOs are obligated to procure System Services solely for the purposes of maintaining the security of the electricity system. Hence a consideration of production cost value is necessary and the TSOs are appropriately positioned to undertake this assessment. The allocation of rents arising from a pricing mechanism is a market design question that is more appropriately a matter for the Regulatory Authorities, while wider considerations such as RES targets are matters for policy makers.

In the recommendation to the SEMC, the TSOs are proposing to include the existing System Services (other than blackstart) in the value based approach. Blackstart is excluded as it has no impact on the day-to-day production cost and is a unique service utilised in the restoration of the power system following a partial or full system shut down.

2.2 Financial Modelling and Analysis Approach

Questions posed

Do you agree with the proposed methodology for determining the aggregate available pot for System Services?

Respondent Views:

There was broad agreement from respondents that the proposed methodology was reasonable. Some respondents requested more detail concerning the modelling and assumptions and one respondent called for a rigorous cost-benefit analysis. One of the concerns raised by several respondents was that the proposed methodology assumed that RoCoF is no longer an issue. There was concern that this was a very optimistic assumption.

TSOs' View:-

The TSOs welcome the consensus on this matter and our recommendation reflects this. The TSOs have provided significantly more detail on the modelling assumptions in conjunction with this recommendations paper. The TSOs also propose to hold a forum to provide an opportunity for detailed questions on the modelling before any final decision on the matter by the SEMC.

The TSOs have provided more details on the production cost modelling to the RAs alongside the DNV KEMA capital cost report and our estimates of the annualised costs. In addition, significant additional analysis is presented in this paper which shows where and how payments to service providers will arise from the proposed enhanced system service capabilities.

Several respondents correctly identified that in the proposed System Services solution, the TSOs have assumed that RoCoF has been solved. The TSOs note that there is an ongoing Grid Code process in both jurisdictions, which at the time of writing, was still under review by the Regulatory Authorities. It is clear that generators generally consider that detailed studies are required before their generation can be confirmed to be capable of withstanding the proposed new RoCoF standard. The TSOs have detailed their view on this in the RoCoF recommendation issued to the RAs in late December 2012.

This raises two questions that need consideration: The first is if the RAs respectively determine that generators have to meet the new standard, is there an implicit over statement of the production cost benefits for enhanced System Services? Secondly, irrespective of whether RoCoF is mandated or not, should there be a new product to incentivise for this service?

On the first question, the TSOs agree that the system non synchronous penetration (SNSP) limit of 50% is currently bound by the RoCoF issue. Resolution of this would see benefit in the level of SNSP that the TSOs could operate to – estimated at approximately 60% for the purposes of the provisional generator output reports issued to Gate 3 participants. In this context, if it was assumed that RoCoF was resolved without any need for fundamental enhancements then it could be argued that the approach for identifying the value of system services benefit might start at a higher level of SNSP (e.g. 60%).

The TSOs would caution on this consideration. The SNSP metric is an amalgamation of a range of analysis conducted in the "Facilitation of Renewables" report and was designed to best fit the available data. It is not possible to accurately predict the exact level it could rise to following a solution to the RoCoF issue without detailed modelling of the actual system and network configuration. This is exactly the approach being undertaken within the broader DS3 programme, particularly with WSAT. However, it is not clear how this can be done with any certainty until the RoCoF process has fully completed; conventional generators have estimated that this process will likely take at least two years. Secondly, if there is an increased capital cost to rectify this issue this may need to be included in the incremental capital cost analysis to inform the System Services pot. This can only increase the level of System Services pot is needed. Finally, given that one of the main objectives of the System Services review is to provide greater certainty in investing for needed performance and that it is likely that the clarity on RoCoF resolution appears to be a few years away, the TSOs recommend that the benefit of the value is based on a 50% to 75% SNSP consideration as outlined in the consultation and subsequent analysis.

On the second question, the TSOs are minded that there should not be an explicit product for RoCoF. Developing a product in this area implicitly allows for a degree of sub-standard performance. Unlike other services where a deficiency of one service provider can generally be managed by sourcing additional services from other providers, the required RoCoF standard must be met by all generators. Thus the system operation is constrained by the provider with the "worst" RoCoF capability. This materially impacts on either the security of the power system or the efficacy of the RoCoF capability of other units realising a benefit for consumers, neither of which is a desirable outcome. Only mandated standards that are universally applied and credibly enforced will suffice in this regard.

The TSOs do consider the incentivisation of inertia on the system to be of benefit, particularly when provided at low generation outputs. Although this may be difficult to achieve on the existing plant, it is a potential alternative to changing the required minimum RoCoF capability of the portfolio to a higher level. The Synchronous Inertial Response (SIR) product has been proposed to achieve this. It is noted that the relative value of the SIR in the allocation method will be materially impacted by the RAs' final decision with respect to the RoCoF standard. This is a key input required before the allocation weightings are determined.

Finally, the TSOs would argue that the use of Generator Performance Incentives (GPI) has been shown to have improved performance on existing plant in recent years. GPIs are an appropriate and proportionate mechanism for ensuring compliance to a mandated standard for service providers that already have the inherent performance capability. In that regard, if the RAs approve the proposed

RoCoF modification and deem units to be capable of meeting the standard, it might be appropriate for a GPI to be developed for RoCoF to incentivise ongoing compliance in this regard.

Questions posed

To what extent, if any, should the capital costs inform the decision regarding future System Services?

Respondent Views:

In general respondents believed that capital costs should to a degree inform the decision regarding future System Services. It was stated that capital costs are an integral part in the decision to invest and there must be sufficient revenue from System Services to deliver investment so that capital costs associated with providing the services can be recovered. It was also suggested that financing costs and ongoing maintenance costs should inform the decision. A number of respondents recommended that operational costs should also be a factor that informs the decision on the arrangements.

TSOs' View:-

The TSOs welcome the broad consensus that the incremental capital costs required to provide enhanced System Services should inform the decision regarding the System Services arrangements. The capital costs should include appropriate outage costs to facilitate an upgrade for existing plant and also include any increased maintenance costs for new and existing plant to meet the enhanced capability. In addition, it is acknowledged that there may be a degree of increased operational costs that are difficult to capitalise and estimate.

As described in the consultation paper and in section 5.1, the TSOs are proposing the adoption of a value-based approach (rather than cost-based) for System Services. It should also be noted that adopting a cost-based approach would require the pre-determination of the "correct" future portfolio, whereas in providing illustrative costs the TSOs have presented non-exhaustive examples of potential future portfolios and associated costs.

For the reasons above the TSOs believe that incremental capital costs incurred in meeting enhanced system service capability, should only inform rather than prescribe the outcome.

In addition, the TSOs have proposed a revised payment mechanism (described further in section 5.5.3 below) that seeks to address the issue of the interaction between operational costs, capital costs and the system service value.

2.3 Allocation of System Services Revenue

Questions posed

Which of the four methods outlined to allocate the funds between the System Services products would you prefer or is there another approach which should be considered?

Respondent Views:

There was broad agreement from respondents that Option 3 was the preferred method although some respondents qualified this with a requirement for revenue sufficiency. A small number of

participant favoured variations on Option 3 that took in elements of Options 2 and 4. One respondent proposed a 'sense check' of the values produced by the allocation methodology.

TSOs' View:
The TSOs welcome this consensus and have proposed that Option 3 is adopted. To provide participants with additional information, details on the revenues that would accrue to service providers based on the estimated allocations are provided later in this paper. This system service revenue has been compared against annualised capital costs obtained from the DNV KEMA report to "sense check" the outcomes and verify revenue sufficiency as suggested by respondents.

Further details of the TSOs' recommendation on Option 3 are presented in section 5.4 below. A key element of the recommendation is that, following a SEMC decision on the high level aspects of the System Services Review, further industry consultation should be undertaken to establish the precise methodology and portfolio to be used for determining the relative product values.

2.4 Remuneration Approach

Questions posed
Is the rationale for proposing dispatch-dependent payments clear?

Respondent Views:
Many respondents believed that the rationale for proposing dispatch-dependent payments was clear but did not agree with it. There were a range of preferences expressed including all capability based, blending capability and dispatch dependent, etc.

Questions posed
Is there further justification, not included in earlier consultation responses, for adopting a more capability-based approach?

Respondent Views:
There was a wide range of responses on this question. These can be broadly separated into the efficacy of dispatch against capability products for releasing funding, interaction with Capacity Payments and miscellaneous questions relating to a range of investment uncertainty issues.

The following is a broad grouping of the comments made by respondents:

Dispatch Dependent vs. Capability System Service Products
- ***Dispatch-dependent payments will lead to banks imposing a discount factor on the projected level of utilisation leading to a more challenging banking model and an increase in the cost of investments.***
- ***Dispatch-dependent payments are excessively risky and therefore have the potential to render the needed investment 'un-bankable' which creates a risk to adequate service provision.***

- *It is difficult for generators with unpredictable dispatch profiles to forecast revenues with dispatch-dependent payments.*
- *Dispatch risk is not an acceptable risk for a new entrant with a single project. The requirement to be dispatched in order to earn System Services revenues is identified as a method to target payments to those who deliver, and it also has the desired impact on the capacity pot. Only portfolio players can take a view on dispatch across all their plant. For a conventional new entrant competing in the merit order, the risk is not investible. In effect, the decision to utilise dispatch as the metric to reward System Services is discriminatory (though consequence rather than intent) towards incumbent refurbishment.*
- *One respondent proposed that a long-term market schedule dispatch (i.e. commercial and technical availability within the control of the generator) is proxied within the System Services products instead of using actual dispatch as this would remove system operator discretion from materially influencing generator revenues.*
- *Potential loss of revenue due to potential alterations in the methodology of TSOs dispatch in real time adds risk.*
- *Designing a plant to contain the features that enable it to provide enhanced System Services makes it less efficient and therefore likely to run. This means dispatch-dependent payments are a perverse incentive.*

Interaction with Capacity Payments

- *Many respondents believed that System Services revenues had to be kept separate from Capacity Payments. It was stated that the revenue streams had separate objectives; Capacity Payments incentivise generation adequacy, whereas System Services revenues incentivise generation flexibility, and that the scarcity of one should not determine the value of the other. It was stated that the required investment will not occur without decoupling System Services from the Capacity Payment Mechanism. One respondent stated that the features that enable plant to provide System Services make it less efficient so less likely to run. Another respondent stated: "The provision of system flexibility must be incentivised through System Services payments ring fenced from other revenue streams. The rationale behind this argument is further supported when consideration is given to the fact that one of the most 'flexible' unit types (OGCT) available to the TSOs is invariably the 'BNE' in the ACPS calculation - it is simply not logical to, on the one hand encourage and incentivise the provision of 'flexibility' and simultaneously deduct revenues for the very same 'flexibility'. This is not a market 'signal' which will attract investment."*

Miscellaneous Comments

- *Compliance with the European Target Model and the changes that will entail for the SEM mean that there is a lot of uncertainty for generators in the SEM. How does this interact with this Target Model and how does it fit with the recent EU Consultation on the internal market, capacity mechanisms and generation adequacy.*
- *Network issues remote from the site could greatly impact the dispatch of a generator, pushing it in and out of the merit order. A transmission issue that requires generation in one location to be constrained on might result in an otherwise dispatched System Services revenue reliant plant being turned off. Transmission line maintenance or forced outages could impact the ability of a generator to deliver the services.*

TSOs' View:-

The TSOs understand the concerns raised by respondents regarding the investability of both dispatch-dependent and capability-based system service products. The arguments are well made and are linked to the interaction with current capacity payments. This has three dimensions: length of contract/tariff setting; level or price of product; and the predictability of revenues with respect to the payment types (capability or dispatch-dependent).

2.4.1 Dispatch-Dependent vs. Capability Payments

The responses indicate that single or small portfolio project developers of conventional plant have significant concerns that dispatch-dependent payments will not provide the investment confidence necessary to allow them to access project funding. In particular, respondents maintain that dispatch-dependent products, irrespective of the value, are such that they will be heavily discounted in any consideration of funding. This is further exacerbated by the length of the contract: most of these respondents questioned the validity of only a 5 year review period. Most sought at least a 10-15 year review period and the need for it to be linked in some manner to the payback period of the funding. In their view, capability products, with the appropriate duration, provide the necessary certainty and remove the risk that any decisions by the TSOs would impact on the financial position of investors. This, they argue, would ultimately facilitate their investments.

Larger portfolio players or those with priority status were somewhat less vociferous on the need for capability rather than dispatch-dependent products. This is possibly due to the mitigated risk of dispatch-dependent products on their aggregate revenue position. The portfolio player is likely to gain and lose equally across their service providing units and has a natural hedging mechanism. This advantage, which is gained from having a larger portfolio, is a common feature of the electricity industry and is one of the drivers for the need for regulation. While this may be the case, it is not appropriate to design the System Services arrangements to discriminate in favour of individual service providers. It is also noted that having priority dispatch, which is a policy matter, reduces the exposure to being scheduled off the system.

While many of the respondents made strong arguments for capability products, longer contracts and no reduction in the capacity payments, the TSOs believe that there was little recognition of the potential increase in costs to the consumer or more importantly, how the proposed mechanism would be designed to mitigate these impacts. It is important to note, that the SEMC has previously indicated that any monies that are awarded for System Services needs to be accounted for under existing interaction mechanisms with respect to the Best New Entrant calculation. The TSOs note that the SEMC has also determined the Capacity pot out to 1st Oct 2015. In this recommendation, the TSOs have estimated the impact on Capacity Payments revenue as requested.

The TSOs recognise that with increased revenues being rewarded for service provision the efficacy of the product for stimulating the necessary investment could be materially undermined by the disproportionate use of dispatch-dependent products. However, the TSOs are also minded of the need to keep costs to the consumer at an appropriate level. To this end, the TSOs have explored a range of possible capability and dispatch dependent product configurations. This analysis is based on a range of potential combinations of dispatch and capability payments and is further explored later in this paper.

2.4.2 Interaction with Capacity Payments

The interaction of system service revenues with Capacity Payments is ultimately a matter for the SEMC. Nevertheless, the TSOs note that many respondents indicated that they believed it was necessary and appropriate to decouple system service from capacity revenue.

The high level principle design for Capacity Payments came about through industry discussions and regulatory process starting in the formative years of the Transitional Electricity Settlement System (TESS) and the Interim Market for Energy (IME). The demand growth on the all-island system in the early part of the century was exceptionally strong and there was a significant need for additional capacity. Since then, the economic and energy policy landscape has fundamentally altered. The recent All Island Generation Capacity Statement finds that once the additional North-South tie-line is completed, the combined systems of Ireland and Northern Ireland can be assessed as a single system. Combined studies confirm that the all-island generation standard is met for all years (2013 - 2022), for all scenarios. However, Northern Ireland is at risk of deficits from 2016 onwards in the event of a prolonged outage of a large generation plant or of the Moyle interconnector.

Current energy policy objectives have changed the needs of the power system. Based on the analysis contained in the reports “Facilitation of Renewables” and “Ensuring and Secure, Sustainable Power System” and the TSOs’ operational experience to date, there is now a fundamental need for increased performance across a range of metrics and attributes. Traditionally generators have received their revenues from the energy market and the capacity mechanism with a very small proportion from ancillary services. These two revenue streams incentivise efficiency and availability of capacity respectively. The changing needs of the power system mean there is now a need to consider a third dimension for remuneration – system services.

The TSOs consider that the changing needs of the power system must be reflected in a proportionate increase in System Services revenue. Any such increase should be shown to be of benefit to the consumers (compared to the status quo) and/or necessary for meeting the energy policy objectives. The TSOs believe sufficient information has been provided throughout this multi-stage consultation process and the broader DS3 programme to support a change to system services structure and level.

There is a relationship between System Services and the Capacity Payment Mechanism (CPM). It may be appropriate for a degree of reallocation of wholesale revenues, particularly between these mechanisms; this should be considered by the RAs in setting the CPM level.

In parallel to this change there is significant uncertainty due to the introduction of EU target model by 2016. Against this backdrop, the TSOs advocate a SEMC decision on System Services later this year to provide the industry with some certainty in this area. The interaction with, and level of, Capacity Payments can explicitly be made a consideration of the new market design. This approach is fully consistent with all existing SEMC and regulatory decisions to date, including the BNE paper.

2.4.3 Miscellaneous Comments

THE INTERACTION OF SYSTEM SERVICES WITH THE EUROPEAN TARGET MODEL

The European Target Model is the main regulatory vehicle for achieving market integration. It establishes common rules to facilitate efficient use of cross-border capacity and encourages the harmonisation of cross-border trading. The European Target Model is set out in both the Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (CACM FG) and the Framework Guidelines on Electricity Balancing published by ACER in July 2011 and September 2012 respectively. In these guidelines, the European Target Model is silent on major aspects of domestic electricity policy and focuses on cross-border arrangements.

The Framework Guidelines on Electricity Balancing refers to the procurement and settlement of balancing energy, including cross-border reserves which have been activated. This includes obligations with respect to cross-border balancing products. The specifications for these balancing products are set out as follows:

- safeguarding operational security;
- fostering competition, non-discrimination and transparency in balancing markets;
- facilitating wider participation of demand response and renewable sources of energy;
- increasing overall social welfare and efficiency;
- promoting cross-border balancing exchanges.

These specifications are fully aligned and consistent with the aims of the proposed new System Services arrangements.

In addition, the Ireland and Northern Ireland power system has policy objectives with respect to RES-E that are posing operational challenges that are fundamentally different from those in other member states. The need for reform in system services is therefore more pressing for the island system and is more pressing. Indeed, under statutory and licence duties EirGrid and SONI are obligated to ensure the availability of all system services (“ancillary services” and “system support services” in the TSO licences) which are necessary for the transmission system operator to operate the power system in a secure manner.

In that regard the TSOs consider, given the need for system services reform and the specific needs of the Ireland and Northern Ireland power system, that the material development of System Services is maintained outside of consideration of the European Target Model implementation while at the same time the retaining alignment with the balancing products’ specifications.

EU consultation on the Internal Market, Capacity Payments and Generation Adequacy

The recent communication on the EU internal market has highlighted the EU Commission’s concerns about the increasing trend for Member States to introduce Capacity Markets in parallel with the development of the target model which are unduly distorting efficient outcomes and undermining the efficacy of the market. There is also discussion about the need to incentivise necessary flexibility to meet and support the impacts of increasingly variable RES-E generation although there is no prescriptive mechanism provided to achieve this. Finally the communication indicates the intention of subjecting poorly designed Capacity Payments/Market mechanisms to State aid clearance. To that end there was a parallel consultation with the communication which will lead to guidelines/criteria later in the year from the EU Commission setting out what dimensions need to be reflected in a well designed Capacity Market.

The TSOs note that in the recent SEM/13/009 the SEMC clearly linked any considerations of capacity payments in the Target Model to revenues from ancillary services and energy market. Also the TSOs consider their System Services proposal to be outside of the remit of the EU consultation on generation adequacy and capacity mechanisms. However, it is acknowledged that the proposal is a form of incentivisation for necessary flexibility to meet the needs of power system with high RES-E.

In their consultation the EU Commission had indicated its desire to subject poorly designed Capacity Mechanisms to State aid approval. If the System Services arrangements were considered a form of capacity mechanism then it would meet the criteria proposed for consideration of a well designed mechanism. Specifically the mechanism is based on a real and not perceived need, is non-selective and time-limited.

Furthermore, even if the System Services was examined as a form of State aid, these design qualities would again meet the principles under which State aid can be granted. Specifically the objective of State aid control is to ensure that government interventions in the market do not distort competition and trade inside the EU. Article 107 of the Treaty on the Functioning of the European Union (TFEU) could be considered as anything that confers an advantage in any form whatsoever on a selective basis to undertakings by the State. The technology neutral approach in the System Services proposal appears to satisfy these requirements.

Furthermore EU law does allow State aid in some circumstances and acknowledges that government intervention is necessary for a well-functioning economy. Article 107 (3c) (TFEU) allows for aid that may be considered to be compatible with the internal market "to facilitate the development of certain economic activities or of certain economic areas, where such aid does not adversely affect trading conditions to an extent contrary to the common interest." System Service provision is essential to the functioning of the electricity system, without which, system security could not be guaranteed at all times and the ambitious RES-E policy objectives would not be met.

The EU Court of Justice has ruled that public service compensation does not constitute State aid when the following cumulative conditions are met:

- the recipient undertaking must have public service obligations and the obligations must be clearly defined;
- the parameters for calculating the compensation must be objective, transparent and established in advance, and
- the compensation cannot exceed what is necessary to cover all or part of the costs incurred in the discharge of the public service obligations, taking into account the relevant receipts and a reasonable profit;

In this regard, while the TSO does not consider the System Services proposal to require State aid clearance, if it were deemed to, we believe that its design is sufficient to pass the requirements for allowable State aid.

<u>Network Limitations</u>

A number of respondents expressed concern that network limitations were not modelled in the analysis.

TSOs' View:-
There are significant grid development strategies in place in Ireland and Northern Ireland. Grid25 and Network25 have been put in place to, amongst other things, deliver the network to accommodate the increasing levels of renewable generation out to 2020. The TSOs have assumed that the beneficial effect of Grid25 will have started to deliver materially by 2020. It is difficult to forecast the network precisely for any specific year, 2020 included. The inclusion or omission of a particular reinforcement could have a significant impact on constraint costs in that year. However, network constraints tend to be temporary, as the network development generally targets the mitigation or elimination of network constraints. The System Services review and the DS3 programme more generally are focussed on resolving operational issues (rather than network limitations), which give rise to curtailment. Thus network limitations were not modelled so that the production cost and curtailment benefits associated with resolving the operational issues could be identified clearly and explicitly.

It should be noted that including the transmission network would add significant complexity to the approach and if reflected in the payment arrangements would add significant uncertainty to provider revenues.

For the above reasons, the TSOs consider that reflecting network limitations in the overall design of System Services is neither desirable nor appropriate.

2.5 Contractual Arrangements and Payments

Questions posed
Are the proposed general contractual and payment arrangements clear?

Respondent Views:
In general respondents believed that the general contractual and payment arrangements were clear, however, further detail/consultation was requested particularly regarding:

- ***when contracts will become available given the lead-time necessary to deliver investment***
- ***the basis/timing of contract award***
- ***indicative product rates/tariffs, product volumes and location***
- ***how the performance and performance monitoring (due to the effect of transients) will operate in reality (particularly where events are infrequent)***
- ***how certain (new) technologies would be treated***
- ***how the aggregate pot will be reallocated during the review periods.***

In addition many respondents believed that longer contracts with fixed rates over the life of the contract are required for new plant investment. It was also stated the rate review periods are not investible and that review in a three to five year timeframe is equivalent to a three to five year contract. One respondent proposed different length contracts; short contracts for plant that require no investment to provide services, medium-term contracts for plant that require investment and long-term contracts for new build. Another respondent proposed that a 10-year new entrant category of contract is created that are a blended structure of a fixed (premised on plant dispatch based capability) and a floating structure (based on utilisation). It was stated that a fixed element will provide certainty to both new entrants and TSOs in terms of revenue and services available

respectively. The floating structure would be open to all participants and would allow those with differing risk profiles to take further dispatch risk.

TSOs' View:-

The TSOs welcome the broad support for the contractual design outlined in the paper and recommend that following the SEMC decision there is a consultation with industry on the details of a framework contract. This consultation should cover many of the areas of concern to respondents and provide clarification where possible. The TSOs consider that any such consultation would:

- expand on the details of an equivalent contract in Ireland and Northern Ireland subject to necessary legal requirements in each jurisdiction;
- outline the obligations and duties on participants around monitoring equipment on site;
- detail how monitoring will impact on the performance scalar. Consideration in this regard will be given to how the scalar is determined for a new service provider, outline rules when there is insufficient event data and outline duties and process when there is faulty monitoring equipment or communications to site; and
- outline the basis of contract award and execution.

Further details on this proposal are provided in section 4.2.

2.5.1 Length of Rate setting

The TSOs recognise that any decision on the length of time where tariffs or rates are fixed will need to factor in the direct impact on investor confidence, the costs to the consumer, and the need for fair and non-discriminatory access to service providers irrespective of the technology, while at the same time not unnecessarily locking out innovation. The TSOs believe that all service providers should be offered the same terms for System Service provision as to do otherwise could be seen as discriminatory. A full consideration of these impacts and the TSOs recommendations can be found in sections 4.4 and 4.5.

2.6 Product-Related Comments

2.6.1 Synchronous Inertial Response (SIR)

One respondent commented that the indicative pot size for SIR seems small given the importance of inertia to the system. Another respondent queried how the performance of this product would be measured. A third respondent also noted that there is no payment for response in less than 2 seconds if the device is not synchronised, even though it can provide value to the system, e.g. a flywheel or batteries connected to the system via electronics. Another respondent believed that all inertia should receive SIR remuneration since it is scarce and valuable to the power system.

TSOs' View:-

The pot size of SIR was determined by analysis based on assumed RoCoF compliance. The TSOs consider, as outlined elsewhere in this paper, that the decision from the RAs in this regard could have a material impact.

The TSOs agree with the essence of the respondent's position that if it is not possible to adequately measure the provision of a product then there should be no remuneration associated it. However, the TSOs are confident that it is possible to measure voltage, currents and associated active and reactive power production to a sufficiently accurate level which ultimately can be the basis of commercial settlement.

The respondent is correct that there is no explicit payment for response in less than 2 seconds but which is not synchronous inertia. The analysis to date has not identified a distinct need for this although the TSOs view that increased system performance in this area is likely to provide some benefit. The 2 seconds measuring point for Fast Frequency Response was chosen pragmatically to complement other product definitions and to allow a wide range of service providers participate effectively.

The respondent is implicitly correct that all inertia has value. However, the value is small when there are significant amounts of inertia such that the system has a surplus. This has traditionally been the case since power systems have historically been powered almost entirely from synchronous generators. In Ireland and Northern Ireland, the transition towards higher levels of renewable generation entails a move towards higher levels of non-synchronous generators, which do not contribute to the synchronous inertia of the system. In order to meet the policy objectives while maintaining system security, it is necessary to maintain inertia on the system while making space for the non-synchronous renewable generation. The SIR product is therefore designed to target the scarcity by reflecting this combination of inertia at relatively lower MW outputs which is intrinsically more valuable in this high RES policy environment.

2.6.2 Fast Frequency Response (FFR)

One respondent asked for clarity regarding whether energy provision is restricted to the 2-10 seconds timeframe and recovery restricted to 10-20 seconds. It was their belief that the current wording of the FFR may incentivise a response of fixed magnitude to a frequency deviation from wind turbines providing an emulated inertial response and suggest a cap be placed on the product to prevent proportional frequency deviation. The respondent also queried if the TSOs considered a reduced response beyond 10 seconds, whereby a generator could be incentivised to provide a long, sustained power response where energy recovery is not entirely captured within the 10 – 20 seconds time frame mentioned. Another respondent noted that at partial load, the time it takes for the wind turbine to recover the kinetic energy that is released to the grid through the generator as a response to a drop in frequency may be longer than the 20 seconds.

TSOs' View:-
In the TSOs' proposal, the increased energy is not restricted to the 2-10 s timeframe but payment will be based on the increased MW output that can be sustained in this timeframe. Recovery is not limited to the 10-20 s timeframe, but, as stated in the consultation paper, the extra energy provided in the 2-10 s timeframe by the increase in MW output must be greater than any loss of energy (i.e. recovery energy) in the 10-20 s timeframe due to a reduction in MW output below the initial MW output. Thus the net additional energy provided in the 2-20 s timeframe must be positive. The TSOs have not considered a reduced response beyond 10 s as the existing operating reserve products cover this timeframe.

2.6.3 Fast Post-Fault Active Power Recovery

One respondent requested clarity regarding the clearance time of 900 ms as it does not correspond to the fault ride through curve fault clearing time of 625 ms found in the Grid Code. The respondent also states that the requirement to have the generator remain connected for at least 15 minutes can be challenging for a wind turbine as the wind speed may drop below cut-in speed within the 15 minutes time period, which will lead to a disconnection of the generator.

TSOs' View:-

This product incentivises capability above the Grid Code minimum standard hence the clearance time of 900 ms. The TSOs accept the point about wind speed dropping below cut-in speed and propose that the performance monitoring implementation for this product will allow for the wind speed dropping below the cut-in speed within 15 minutes of the fault.

2.6.4 Ramping Margin

Two respondents requested confirmation that non-synchronised plant which can realise this service in the timeframe allowed are eligible for payment. A number of respondents believed that the additional flexibility provided by dual fuel and multi-mode plant should be remunerated but under current market rules it is only possible to have one set of TOD accepted per trading day which does not reflect the optimised plant ramping capability. Two respondents stated that if the TSO avails of the service, the service is no longer realisable and the payment will stop. It was felt that this creates a perverse incentive on providers not to get called.

TSOs' View:-

The TSOs can confirm that non-synchronised plant which can realise the proposed ramping margin products in the timeframes allowed are eligible for payment. The TSOs do not propose a change to the means of remunerating the product.

The TSOs remain of the view that the purpose of this product is to incentivise the availability of operating margin, which is available at short notice, that is not otherwise remunerated for providing energy. When a ramping margin provider is called on to provide energy at short notice (thus utilising the ramping capability), the provider is paid for the energy supplied. When this is the case, the TSOs believe that, as the ramping margin is depleted, it should not be remunerated for this service as well as for the energy. In this way, the TSOs have designed the margin-type services (reserve and ramping margin) to supplement and complement the balancing arrangement emanating from European Framework Guideline and Network Code development as described in section 2.4.3.

The intention for a multi-mode unit would be that a generator will be paid for whatever can be physically delivered in either mode, the mode agreed and dispatched by the TSO. Currently that agreement is implicit in the technical offer data submitted to the market. This being the case, the TSOs think it is correct that a unit which is operating in a distinct mode of operation should only be remunerated for the characteristics in that mode at that time. In addition, if the unit saw a better commercial proposition in offering an improved ramping margin capability, these technical characteristics could be submitted to the market to reflect this as its default mode of operation. The TSOs are open to further consideration of multi-mode operation during the next phase of consultation but note that any such change would require an appropriate, complementary change to the process for submission of technical and commercial offer data to the energy market.

2.7 Other Comments

Grid Code Compliance

A number of respondents commented on Grid Code compliance. One respondent believed that Grid Code compliance should be a pre-requisite for a System Services contract. Another respondent commented that provided that a service provider is Grid Code compliant with a service then the provider should be remunerated. One respondent believed that service providers should only be remunerated for services that are in excess of Grid Code compliance.

TSOs' View:-

The TSOs view that Grid Code compliance is important and have sought to further underline this with the System Services proposals. Compliance with the appropriate System Service standards is a requirement for remuneration for each distinct product. However, it would not be appropriate to have full Grid Code compliance as a pre requisite to System Services contracts. The TSOs note that where there is a Grid Code standard, the proposal states that if there is remuneration for the Grid Code standard then the TSOs are obligated to contract with compliant service providers. However, the existence of a Grid Code standard in a particular capability does not in itself mean that there is a system shortage. The TSOs support paying for services that the system needs to efficiently to meet the policy objectives which means payment for only a selected range of Grid Code requirements.

Bilateral Contracts

There was broad agreement among respondents that bilateral contracts are the most pragmatic approach to contracts.

TSOs' View:-

The TSOs welcome this consensus and will factor this consideration into the programme of work to start following the high level design decision from the SEMC due in the latter half of 2013. The TSOs are recommending a consultation on the development of the nature of this System Services Framework agreement.

Eligibility of Distribution-Connected Plant

Two respondents believed that distribution-connected plant should be eligible to provide System Services.

TSOs' View:-

The TSOs concur that distribution connected service providers should be eligible for consideration for System Services remuneration. However, as discussed in the second consultation, the TSOs will only contract with these service providers where the relevant DSO is satisfied that there are no safety or security issues on the distribution network arising from the TSO accessing these services.

Funding

A number of respondents believed that System Services revenues should be funded by the demand customer. Two respondents believed that currently ancillary services are recovered through TUoS on a 25% - 75% split between generators and consumers respectively and therefore any increase in System Services revenues for new services is overstating the net benefit to the generator since it will be funded 25% by the generator.

TSOs' View:-

The TSOs believe that any increase in the System Services revenue requirement will be funded by demand customers through the appropriate regulated tariffs. An estimate of this has been provided to the SEMC in this recommendation paper with some sensitivities, including with respect to anticipated service provider investment and overall portfolio performance levels. However the net cost to the consumer is related to how much of this increase for System Services impacts on the Capacity Payments. This interaction is a matter for the SEMC but indicative figures have been provided to the SEMC as requested.

The respondents that noted that Ancillary Services are currently recovered through TUoS or SSS tariffs are correct. However, some mistakenly consider these as a wires costs rather than non-wires costs. This view has been corrected by one respondent with a clarification. Wires costs – capital and operational expenditure to pay for the installation and maintenance of the network assets – are recovered through charges to generators and demand customers and are split 25%, 75% respectively. However, non-wires costs (including ancillary services costs) are fully recovered from demand consumers.

Weighting Payments at Times of Scarcity

One respondent believed that payments should be weighted towards the times when they are most required.

TSOs' View:-

In principle there is merit in paying higher rates when there is greater scarcity. In addition, there is also merit in considering charging those that are causing this scarcity. The combination of rewarding needed service provision and charging those "polluters" is likely to have a material impact on the efficacy of the investment signals. However, this has to be balanced against the complexity of modelling the time-varying scarcity and the impact that time-varying rates would have on the bankability required in a timely manner. Given the concerns expressed by many respondents on the impact dispatch dependent payment structures have on investibility, it is not clear how introducing the complexity required to achieve this would in the short term lead to the necessary investment required. For this reason, the TSOs are not proposing to set rates based on the real time needs of the system. This is approach is consistent with incentivising for the longer term needs of the power system.

System Security Issue in Northern Ireland after 2015

One respondent believed that the consultation has not recognised system security issues in Northern Ireland after 2015. Some respondents questioned the locational requirement of System Services and one respondent believed that payments should be locational, i.e. there is greater benefit from some services (e.g. reactive power) when they can be provided close to where they are required and therefore should be remunerated accordingly.

TSOs' View:-

In a number of bilateral meetings and responses the issue of the North-South tie-line and the increased needs for Northern Ireland were raised. This is addressed in the recent All-Island Generation Capacity Statement. In it there are some concerns over generation adequacy in Northern Ireland. Material delays on the second North-South tie-line would exacerbate this localised capacity inadequacy issue.

This potential difference in the adequacy is not reflected in the System Services consultation for two fundamental reasons:

- The issue identified in the Generation Capacity Statement is primarily a capacity adequacy rather than System Services deficit. In that sense any modifications to incentives to address this are more correctly managed in Capacity Payments.
- There has been no detailed analysis performed to indicate there is a specific system service deficit distinctly in Northern Ireland.

More generally, the analysis shows that, in the absence of improvements to the portfolio capability, there are a range of security metrics that, at a system level, have a deficit in aggregate of 25% or more in 2020 compared to 2010 (Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment, 2011). These include synchronous inertia, synchronous reactive power capability and ramping. Theoretically there is little impact of the location of the provider for inertia and ramping in maintaining security. The TSOs do acknowledge that there are more material benefits for reactive power (and dynamic reactive) with respect to location. However the significant issue is still that service provision is required. Complicating the incentives by trying to include locational aspects in product remuneration is difficult to achieve in practice. In addition, generators have argued previously that locational pricing (e.g. for transmission loss adjustment factors) tends to add volatility and uncertainty, thereby increasing risk for service providers. The examination of transmission access and its application to wind is an example of how complicated, difficult and time consuming this can be. Finally there are controls to manage over-investment which the TSO has (highlighted elsewhere in this paper) and where there is over-investment of a capability in a particular location this can be mitigated. However, the TSO s do not consider this a likely outcome in the period under review.

Declining SMP, Infra-Marginal Rent and Dilution of Capacity Payments

A number of respondents expressed concern that the proposed levels of System Services would have a number of detrimental impacts on the revenue earning capability of their plant. In particular with increased levels of wind this would reduce the SMP, lowering infra marginal rent. In addition, a reduction of the Capacity Pot due to the interaction with System Services would impact negatively on a generator's total revenue.

TSOs' View:-

The interaction with the SEM, infra marginal rent and capacity payments ultimately are matters for consideration by the SEMC and policy makers and outside of the direct remit of the TSOs. Indeed, the addition of RES will increase volatility in prices but reduce the overall energy prices over time (SEM-09-002). This is one of its stated benefits. However, this benefit needs to be balanced against costs and the impact on the efficacy of market outcomes.

The TSOs are cognisant of these issues, but other than the specific requests from the SEMC it is not within the current remit to explore these further. It is for the market to deliver long term efficiencies to the consumer. The production cost methodology though does provide the true benefit in fuel cost savings and is the appropriate mechanism for valuing system services. The issue of rent allocation in the design of a pricing mechanism is the remit of the SEMC to decide.

Volatility of Value-Based Approach

One respondent was concerned that the Value-Based Approach is volatile and introduces considerable uncertainty for the setting of future rates.

TSOs' View:-

It is true to say that there is potential for volatility in the value-based approach. However, this volatility ultimately would arise from significant changes to policy objectives; this is a risk that already exists today. For example, the energy market design and possible 2030 EU RES policy are two areas today that could have a significant impact on the inputs to the future value-based analysis. Nonetheless, all participants will have an opportunity to input into this policy and any changes will be well signalled by the appropriate authorities.

The TSOs believe that the proposed approach provides increased investor confidence for five years compared to the current approach, which is only guaranteed for a year. In addition, over time, with a stable regulatory environment, the risks of a five-year review can be minimised, particularly with well-defined principles and methodologies governing the approach to the review.

Insufficient Information

A number of respondents believed that there was insufficient information in areas discussed in the consultation paper.

TSOs' View:-

The TSOs accept that there is insufficient detail in the third consultation to definitively work out what any particular service provider's future revenue might be. However, there is sufficient information to inform respondents of the approach and methodology being proposed and to indicate the broad thrust of payments. This is the aim of the consultation paper.

Notwithstanding this, this recommendation paper to the SEMC includes additional analysis which will increase the transparency in this regard. On top of this the TSOs are proposing that further detailed modelling be conducted before final rates are set. The TSOs fully expect that between the additional information provided in the recommendation to the SEMC, the SEMC consultation following this, and the detailed modelling exercise discussed earlier, that sufficient information will be provided to enable service providers to estimate their revenue streams.

Interconnectors

One respondent queried the services that can be provided by an interconnector. There was concern by one respondent about the impact on the modelling results of the assumption that interconnector flows are determined by the ex-ante run and are fixed inputs in the constrained run. It was also stated that Moyle's NI-GB capacity was assumed to be 300 MW but that this is due to fall to 80 MW

in 2017. One respondent was concerned that there could be a conflict of interest with the East-West Interconnector (black-start services agreed without consultation).

TSOs' View:-

The TSOs are confident that both Line Commutated Convertor (LCC) and voltage source converter (VSC) HVDC interconnectors can provide a range of system services. Indeed the Moyle interconnector has been providing these for over a decade. However, there are differences between the two that mean that VSC is more able to provide reactive, dynamic reactive and fast post fault active power recovery compared to LCC technologies.

It is not exactly clear to the TSOs the exact concern that the respondent has. The TSOs consider that the fixing of interconnector flows based on the market schedule best reflects the current operational and procedural processes in place. A sensitivity to more flexible options has also been conducted. In addition the use of 300 MW export capability on the Moyle seemed to be a reasonable assumption given the timeframe for possible options for grid enhancement in Scotland.

On the issue of conflict of interest the respondent's comments are noted. The TSOs independence is fully maintained through the applicable regulatory approvals.

Demand-Side Management

One respondent believes that for Demand-Side Management to grow there cannot be any dilution of the Capacity Payment pot.

TSOs' View:-

The respondent's view raises two points. The first is the interaction of the System Services with the Capacity pot, is addressed elsewhere in this paper and ultimately is a matter for the SEMC. The second is that DSUs today are emerging in the market because of revenues they earn through Capacity Payments. However, their performance capabilities are not necessarily aligned to the needs of the long term policy objectives for RES. In particular, managing the additional variability in a high RES system requires more flexible capacity. In that regard, the TSOs consider that ramping products are more aligned to these needs and ultimately will provide a better incentive for service provision from all technologies, including DSUs.

Constrained Off

A number of respondents believed that payments for System Services should also be made when a provider is constrained off.

TSOs' View:-

The essence of this question is at the heart of the capability/dispatch dependent product design discussion addressed elsewhere in the paper. It also implicitly raises the question of where differences between market and dispatch outcomes are best managed.

The TSOs are proposing that the majority of the new System Services are remunerated on a capability basis. This removes any impact of being constrained on or off.

For the remaining (reserve-type) products, which are proposed to be remunerated on a dispatch dependent basis, there is an interaction between dispatch and System Service revenues. This is already the case for the existing ancillary service (e.g. Operating Reserve). Given the current market structure, the TSOs believe that impact of dispatch decisions on System Service revenues could largely be reflected in commercial offer data. As this is an interaction with the Bidding Code of Practice, it is a matter for the SEMC to consider.

Limitations of Portfolios used for modelling

A number of respondents believed that in employing certain portfolio assumptions, the TSOs' proposals were skewed towards certain technologies which would favour incumbent service providers. In addition in certain cases respondents expressed some concerns that the effect of the consultation approach was that the TSOs had acted contrary to their remit to be fair and impartial.

TSOs' View:-

The TSOs noted with concern that a few respondents believed that the modelling or approach was skewed towards certain technologies over others. This certainly was not the intent nor the TSOs submit, the result. The TSOs reiterate that the design and implementation of the System Services products is such as to allow any technology which provides a useful system service to be eligible for remuneration. Nevertheless the TSOs consider these respondents may have inadvertently formed this view based on the treatment of two areas in particular: the portfolio selection for the overall value calculation and in the cost of enhanced system service estimation.

In order to estimate the value of enhanced system services, it is necessary to establish a "business as usual" portfolio. The TSOs believe that the Generation Capacity Statement (GCS) provides an appropriate basis for this. The GCS, by necessity, assumes certain generation types and build rates. However, these are based on considered inputs including signed connection agreements. In addition it is the only transparent forecast of portfolio available in industry today. Any other portfolio selection by the TSO at this stage would be selective, with associated challenges arising from this. The TSOs are aware of the importance of the portfolio in determining the value. It is for this reason that the TSOs are recommending that a further industry consultation is carried out on the portfolio to be used for pot allocation and rate determination. The scope of this consultation, which we expect will involve the Regulatory Authorities, will confirm the appropriate portfolio to be used in this process.

The use of two scenarios in estimating the cost of enhanced system services may also have given the impression that these are the only technologies that are being considered for system services remuneration. For the avoidance of doubt, the TSOs utilised the Generation and Network Investment scenarios (based on the GCS 2011-20) to illustrate the potential spectrum of aggregate capital costs incurred in delivering a 75% SNSP compliant system services capability. They were not selected to be a definitive high and low cost, but merely to inform the analysis as requested by the Regulatory Authorities. As noted in the consultation paper, neither of the two scenarios used purported to be an optimal solution. Nor were these scenarios intended to be prescriptive of the future portfolio of service providers. The TSOs expect that if the proposed System Services arrangements are adopted, there will be an appropriate incentive for other new, more flexible service providers to compete with enhancements to existing plant such that the market delivers the most efficient outcome. These new providers may include technologies such as demand-side response, flexible CCGTs, high efficiency OCGTs, storage and other emerging technologies.

In summary, the TSOs have presented analysis to address questions raised by the Regulatory Authorities and participants on revenue sufficiency and cost to the consumer. To do this a number of portfolios and scenarios have been assumed. These assumptions are necessary in order to determine the value from System Services and to inform the question of how much of this value needs to be released to service providers. Once the value is established, the mechanism for remuneration is explicitly technology neutral and is open to all service providing technologies, irrespective of the portfolios used by the TSOs to determine the value.

Performance Scalar

A small number of respondents believed that the performance scalar was quite punitive and service providers should be paid whenever the service is provided

TSOs' View:-

The TSOs view the performance scalar as essential to the efficacy of the new system services. It clearly rewards reliable service provision. In that sense the TSOs would not support any diminution of the role of the performance scalar. However the TSOs are open to consider some of the more detail design requirements during an industry consultation post high level decision from the SEMC.

Product Design Detail

One respondent stated that to deliver services by 2015 work on product design detail and performance criteria must continue during the regulatory consultation process.

TSOs' View:-

The TSOs understand the respondent's position and have a number of parallel workstreams already activated. While certain elements of the next phase of the System Services Review are contingent on a SEMC decision, the TSOs will work closely with the RAs to ensure that progress continues to be made.

3. TSOs' Recommendations – System Service Products

In previous studies (Facilitation of Renewables, Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment), and in the System Services consultation papers, the TSOs have demonstrated the need for new system services to be remunerated. Based on the proposals in the second and third consultation papers and the responses received, the TSOs are proposing the introduction of a number of new products and the refinement of some of the existing products as described in this section.

3.1 Technology Neutrality

The TSOs have an obligation to be independent and non-discriminatory. The approach adopted in the TSO recommendations is to allow any technology that is capable of providing a service to be eligible for reward. In essence this allows market choice to be brought to bear on the outcomes and in that sense should deliver a long-term efficient solution. It is recognised that different technologies have different costs, operating regimes, maintenance requirements, and ultimately length of life, all of which impact on the required revenue. However, this is something that is more properly addressed in the contractual aspects of the System Services arrangements and is dealt with in section 4.1 below. Thus, from a product design perspective, the proposed system services are, in so far as possible, technology neutral.

RECOMMENDATION ON PRINCIPLE

The system service products are, in so far as possible, technology neutral and are designed to address the needs of the power system to meet all appropriate policy objectives in an efficient manner.

3.2 Proposed Products

Based on the needs of the system, and mindful of the principle of technology neutrality described above, the TSOs have developed a number of new products. These products were consulted upon in the second System Services consultation paper, presented at an industry forum, and further consulted upon in the third consultation paper.

The TSOs reaffirm the need for the new products described in the third consultation paper. The TSOs also propose a number of refinements to the existing ancillary services products. For brevity, the details on the final proposals for the product definitions and descriptions are provided in Appendix 0.

RECOMMENDATION ON PRINCIPLE

The new system service products to be introduced are:

**** Synchronous Inertial Response***

**** Fast Frequency Response***

**** Fast Post-Fault Active Power Recovery***

**** Dynamic Reactive Response***

**** Ramping Margin***

RECOMMENDATION ON PRINCIPLE

The existing ancillary services are to be retained, with refinements to the definitions of:

**** Steady-state Reactive Power***

**** Replacement Reserve***

4. TSOs' Recommendations – Contractual Aspects

4.1 Technology Neutrality

The approach adopted in the TSO recommendations is to allow any technology that is capable of providing a service to be eligible for reward. In essence this allows market choice to be brought to bear on the outcomes and in that sense should deliver a long-term efficient solution. Nevertheless, even allowing for choice and the proposed design there are some advantage to the providers who contract early as there is a deficit of system services to meet the RES policy objectives in the short term. These providers will potentially have a longer period of fixed rates. However, with a rate review at anything less than the payback period (estimated to be 10 years), this introduces price risk which may deter necessary investment which could have implications for efficiently and effectively meeting the RES policy targets. If that is the case there are three possible mitigation strategies.

- Increase the monies made available to a level where this risk is reduced. This has implication for the cost of the consumer.
- Offer auctions in needed services and in that offer the necessary contract length to guarantee payback. While this might reduce the risk in any individual investment it may well be at the expense of inefficient outcomes in the long term and will impact on the ability to introduce innovative technologies.
- Develop distinct contracts and lengths for specific technologies or service providers. This might include long term contracts, as suggested by some respondents, for all new service providers or distinct length of contracts for specific technologies. In either case it is not clear what criteria would be used to differentiate between service providers or, more importantly, who would set these. It is difficult for the TSOs to set these and satisfy its statutory duties with respect to independence from generators and suppliers. Distinct contract durations for different technologies would make the arrangements inherently less transparent. In addition, in an environment where system needs are evolving, distinct contract durations would act as a barrier to allowing competitive forces act. This type of contract also requires a degree of presupposition of the "correct answer" that ultimately undermines the structures of competitive markets. Finally, selective contracts such as these are likely to be subject to State aid clearance.

RECOMMENDATION ON PRINCIPLE

The contractual arrangements for system services are, in so far as possible, technology neutral and are designed to address the needs of the power system to meet all appropriate policy objectives in an efficient manner.

4.2 Contractual Arrangements

As described in section 2, there was broad support from the industry for the contractual design outlined in the third consultation paper. The TSOs are therefore recommending that, following the SEMC high level decision, there is a further consultation with industry on the details of the contractual arrangements. This consultation should cover many of the areas of concern to respondents and provide clarification where possible. The TSOs consider that any such consultation would:

- expand on the details of an equivalent contract in Ireland and Northern Ireland subject to the necessary legal requirements in each jurisdiction;
- outline the obligations and duties on participants around monitoring equipment on site;
- detail how monitoring will impact on the performance scalar. Consideration in this regard will be given to how the scalar is determined for a new service provider, outline rules when there is insufficient event data and outline duties and process when there is faulty monitoring equipment or communications to site; and
- outline the basis of contract award and execution.

Subject to the outcomes of the consultation, the TSOs consider that:

- remuneration for System Services should only commence after appropriate verifiable testing has been conducted on a service provider's plant. This, at the earliest, can only occur for a new plant after commissioning. However, the TSOs are open to engaging with participants following a SEMC decision to explore whether some form of "letter of intent" for potential service providers, or early contract execution subject to testing requirements is of benefit in releasing funding before this;
- the contract should bind the TSOs into an SEMC approved system service remuneration scheme with the participant for the lifetime of the plant, subject to appropriate exit clauses;
- In principle, contracted capabilities will be agreed when a unit has been physically tested to be able to satisfactorily meet the required performance standard. Where physical testing is not prudent for the system then model simulation/evidence will be used but this may impact on the initial scalar value used in settlement.
- given the frequency of disturbance events on the system it is likely that there will be sufficient data to verify service providers' performance each quarter. Nevertheless, there is a possibility that due to a confluence of circumstances, there is a service provider with insufficient data. It is for this reason that the TSOs consider a rolling 12 month average of performance is used to determine the scalar. This is likely to be long enough to always ensure sufficient event data. There are, of course, other possibilities which might include basing the scalar on the last number of distinct events irrespective of the time they occurred. Both of these methods have merits but also are subject to issues where due to the order or the frequency of events there may be periods of time that the provider is assessed above or below the median performance level. The TSOs consider this to be an entirely stochastic issue and as such over time is not a material issue provided there are stable rates for a sufficiently long period of time; and
- provided there is evidence that new technologies can provide appropriate services then the TSOs are open to contracting with them. The issue with new technologies and new services is that there may be no Grid Code based standard and as such contracting for such services will be at the discretion of the TSOs.

RECOMMENDATION ON SPECIFICS

An industry consultation covering all material aspects, outside of rate determination, of a System Services framework contract to be conducted. This consultation to include contract award and execution criteria, performance monitoring standards of service provision and declaration protocols.

4.3 Generic Payment Structure

It is proposed that payments for system services will be calculated individually for each system service on a half-hourly basis and that settlement will be carried out monthly in arrears. The generic formulation for payment will be as follows:

$$Payment = Product\ Volume \times Product\ Scalar\ \times\ Product\ Rate \times Rate\ Scalar \times Performance\ Scalar$$

Note that, for simplicity, the payment algebra presented in this paper assumes hourly payment to avoid the complexity of half-hourly scaling.

Product Volumes

Product volumes will be calculated based on a number of parameters:

- Contracted capability
- Declared availability (for MW and/or for service)
- Dispatch Instructions – for dispatch-dependent payments only

Details of how product volumes are calculated for each product are described in Appendix 0 below.

Product Scalar

In general, the product scalar will be set to 1. For some services, where there is a distinct difference between the types of product offered by different providers, a scalar will be used to vary the payments. An example of this is the reactive power product under the existing HAS arrangements, which uses an AVR scalar to distinguish between reactive power provision with AVR action and reactive power provision without AVR action.

Product Rate

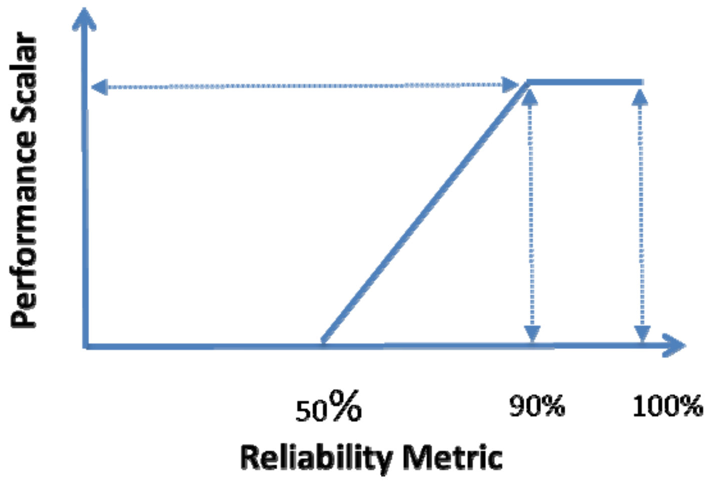
Payment rates for System Services could be fixed (time-invariant) or could vary by half-hour. Time-varying payment rates, such as those used in the CPM, have the advantage of enabling payments to be targeted towards specific periods where the need is greater or the value is higher. However, time-varying rates add significant complexity to the payment structure and are likely to be difficult for service providers to forecast. Fixed payments are simpler and more predictable, but they are less targeted. These issues are considered further in section 4.4 below.

Rate Scalar

The rate scalar is a new term that has been introduced by the TSOs based on the feedback received from respondents to the third consultation paper. The rate scalar adjusts the remuneration received by a provider based on their average production cost (relative to a reference price). This seeks to incentivise more efficient service providers by offering relatively higher remuneration compared to less efficient providers. The rate scalar, and the basis for it, is discussed in more detail in section 5.5 below).

Performance Scalar

Performance reliability is a key aspect of the proposed services. A unit that performs consistently when called to provide a service gives a greater degree of certainty to the system operators than a unit that performs sporadically. A sliding scale of reducing payment rates for performance reliability below 90% but above 50% will be utilised. There should be no payment for performance below 50% as this is inherently unreliable service provision. We are aware of a number of respondents concerns that this might be overly harsh but are still minded that this is appropriate. However the TSOs do consider that additional consultation on the exact levels of this, possibly distinct for different products merits further consultation.



A performance monitoring process will be developed and documented as part of the DS3 Programme following the SEMC decision on the principles and approach proposed for System Services. Further details are provided in section 4.6 below.

RECOMMENDATION ON PRINCIPLE

All the products should use the same generic payment structure that includes a performance scalar as follows:

$$Payment = Product\ Volume \times Product\ Scalar \times Product\ Rate \times Rate\ Scalar \times Performance\ Scalar$$

4.4 Product Rates

As explained in the second and third System Services consultations, the TSOs believe that system services should be rewarded based on scarcity. Scarcity can be a long-term or short-term issue. A regulated static tariff will, by design, provide a long-term signal but it will reward at all times, whether or not there is a real-time scarcity. Therefore, it is arguable that a fixed rate would result in an over-payment in real-time when there is no scarcity. In contrast, time-varying rates (potentially set in real-time) can reflect short-term scarcities but tend to add significant complexity to the payment structure and are likely to be difficult for service providers to forecast, at least in the short-term.

The TSOs have considered a range of options for determining dynamic, time-varying rates. However, based on the consultation responses and a consideration of the complexity and opaqueness of real time system services pricing, the TSOs consider that the best approach at this stage is for static tariffs, approved by the Regulatory Authorities.

RECOMMENDATION ON PRINCIPLE
The system service products are remunerated using fixed, regulated rates.

RECOMMENDATION ON SPECIFICS
A formal industry consultation with appropriate regulatory approval should be conducted on the fixed, regulated rates for system services.

4.5 Length of Regulated Rates

The TSOs recognise that any decision on the length of time where tariffs or rates are fixed will need to factor in the direct impact on investor confidence, the costs to the consumer, and the need for fair and non-discriminatory access to service providers irrespective of the technology, while at the same time not unnecessarily locking out innovation. The current industry structure for ancillary services payments is that tariffs are approved by the Regulatory Authorities on an annual basis, the level of revenues for them are comparatively low and, with the exception of black start, they are dispatch dependent products (except for blackstart). This combination of factors means, in the TSOs' view, that today's ancillary services are incapable of incentivising transformational levels of investment for the needed levels of performance.

While the existing ancillary services structure has been adequate for the needs of the system to date, the transformational nature of the policy targets requires a fundamentally different approach to remuneration of performance. To this end, the TSOs have proposed an approach that provides significantly increased revenues, has a fivefold increase in the length of time that rates are guaranteed for and has a mix of dispatch dependent and capability payments. The TSOs' proposed new System Services structures improves the investment case for transformational levels of investment for the needed levels of performance.

Nevertheless, the TSOs note that respondents have indicated that these improvements may not be sufficient to facilitate investments in general with respect to needed System Services. In particular, several respondents considered that the length of contract or fixed tariff should be at least and generally in excess of ten years. The TSOs recognise that longer contracts provide greater certainty and may therefore result in lower costs to consumers but are concerned that this length of fixed tariff has the potential to lock out new innovation and is a significant change in structure from the present. In addition, long term contracts would result in lower costs only where the future requirements are certain. This could have significant implications during a period of progressive transformation in the power system. Given the degree of uncertainty in the external environment, particularly to planned changes to the market design for 2016 and potentially changed RES policy targets for 2030, the TSOs do not believe, on balance, that it would be appropriate to fix rates for longer than five years.

The TSOs believe that all service providers should be offered the same terms for System Service provision as to do otherwise could be seen as discriminatory.

RECOMMENDATION ON PRINCIPLE
The determination of the services annual system services pot and associated tariffs should be fixed for a five year period.

4.6 Proposed Performance Monitoring Process

Details of a Performance Monitoring Process for System Services (e.g. Performance Level Expectation, Performance Review Period, Bad Data, Commissioning, etc) will be developed and documented as part of the DS3 Programme following the SEMC decision on the principles and approach proposed for System Services and will be included in subsequent consultation papers.

A process for handling situations where there are too few events to statistically ascertain performance levels would be developed as part of the implementation phase for new products. This process will also need to identify situations where a unit is commissioning, has been unavailable for a long period of time and/or the measuring equipment is unavailable.

It is envisaged that disturbance recorders will be required for fast acting products (Synchronous Inertial Response, Fast Frequency Response and Dynamic Reactive Response). It is further proposed that the service provider pays for the initial capital cost of these units, their installation and commissioning at agreed locations. The relevant TSO will then take ownership of the recorders after commissioning and provide the external communication links to the TSOs' offices.

Ramping and Steady State Reactive products will utilise SEM data combined with EDIL dispatch instructions as data sources.

RECOMMENDATION ON SPECIFICS

An industry consultation covering the performance monitoring process will be carried out following the high level SEM Committee decision on the System Services arrangements.

4.7 Eligibility - Link between System Service Products and the Grid Code

As indicated in the second System Services consultation paper, it is proposed that the provider must be compliant with the relevant sections of the Grid Code in order to be eligible for remuneration for a system service product. Some respondents to that paper considered that derogated plant should be excluded from payment for system services if they were unable to achieve the Grid Code standard while others sought payment for lower product volumes and quality.

To help clarify the proposed approach, the third consultation paper set out the link between the requirements of the Grid Codes and the proposed system services. This link can be considered to have two aspects: volume and quality.

Volume

Where a provider is eligible and the minimum product volume is set out in the Grid Code then the TSOs are obliged to contract (e.g. existing HAS product 5% POR) for this volume. Where a provider has the capability to provide more than the Grid Code minimum, the TSOs have discretion in contracting for this additional capability, subject to the needs of the system.

Quality

For some services, where it is necessary to incentivise performance (quality) in excess of the Grid Code standard or where no clear Grid Code quality standard exists, the TSOs will only contract with those service providers who can demonstrate delivery according to this enhanced standard. Examples of this type of product include Dynamic Reactive Response and Synchronous Inertial Response.

RECOMMENDATION ON PRINCIPLE
For services that align with a minimum requirement in the Grid Code, the TSOs are obliged to contract with all compliant providers for that minimum requirement.
Contracting for quantities in excess of the minimum requirement will be at the discretion of the TSO, based on the needs of the system.

RECOMMENDATION ON PRINCIPLE
For services which require performance in excess of the minimum Grid Code standard, the TSOs will only contract with providers that meet the enhanced standard.

5. TSOs' Recommendations – Remuneration aspects

5.1 Value of System Services to the Electricity System

Historically, under the "Harmonised Ancillary Services" (HAS) arrangements, the payments have been loosely related to the cost of this basic service provision. Many of the inherent services provided by synchronous generators in the past will not be available in the high wind generation scenario to maintain system security unless appropriately incentivised. As a consequence, there is a need to fundamentally review the valuation paradigm for system services. The third consultation paper considered and proposed an approach regarding how system services should be valued. In principle, the chosen mechanism should, at a minimum, ensure that any increased payments for system services are off-set by at least similar savings to the consumers.

The TSOs propose that regulated fixed price tariffs are used for the range of existing and new system services products. The level of price regulation should be sufficient to incentivise providers to deliver the necessary performance to efficiently and effectively manage the power system while meeting the policy objectives for renewable energy. The total remuneration for services should be determined by a <u>value-based</u> assessment of the production cost differences between operating the power system with and without the necessary services and the knock-on impact on renewable generation build.

This proposed approach captures both the direct Dispatch Balancing Costs savings associated with enhanced operational capability and the indirect effect of market cost savings due to higher levels of installed wind. It is assumed that, while curtailment levels remain low, a portion of the required renewable generation (RES-E) will build due to external supports. The remaining RES-E build will be contingent on reduced curtailment levels that occur when new system services are in place and the SNSP limit can be raised to 75%.

Factors to be considered in determining the portfolios that are utilised to calculate this value include:

- Energy market signals;
- Current portfolio and system service providers;
- Impact of Interconnector flows on adequacy, energy market outputs and physical operation;
- EU and Member state policy with respect to Carbon, RES and energy efficiency;
- Cost to the consumer; and
- Support mechanisms available.

Selected portfolios, based on the Generation Capacity Statement (GCS) 2011 – 2020 and agreed with the Regulatory Authorities, were used to determine total production costs over a range of 8760 hour simulation scenarios.

In following this approach, the TSOs recognise that there are a number of external factors that might have been considered in determining the benefit of System Services but would not be regarded as appropriate for the TSOs to include in the current value calculation. With delivery of new system services, these other considerations could include the increased energy production of windfarm plant output as their capacity factor increase with reduced dispatch down levels. This could offset potential future RES penalties enforceable on Member States for not reaching targets. There may also be an Emission Trading benefit with reduced carbon dioxide emissions.

A base case model for 2020 was developed based on the All-Island Generation Capacity Statement 2011-2020 (GCS 2011). The Plexos production cost modelling tool was then used to simulate annual market schedules and dispatch schedules for 2020 over a range of generation portfolios, fuel prices, portfolio operational capabilities and operational constraint scenarios. For the dispatch schedules, four main constraints were imposed: fixed interconnector flows based on market schedule; operating reserve to cover loss of largest infeed; maximum SNSP limit; minimum synchronous inertia level.

Two principal operational scenarios have been considered:

1) **Business As Usual (BAU):** this is a representation of current operational constraints. All of the operational constraints are included with an SNSP limit of 50%.
2) **Enhanced Operational Capability (EOC):** this represents the possible operational constraints if enhanced system services are adopted. Interconnector and Operating Reserve constraints are included with an SNSP limit of 75%. No inertia constraint is included (i.e. assuming the RoCoF issue has been resolved).

The overall benefit of moving from 3,600 MW of wind with a 50% SNSP limit to 5,200 MW wind with a 75% SNSP limit can be quantified by comparing the total production costs for the BAU 3,600 MW wind case, with the EOC 5,200 MW wind case. The higher levels of installed wind capacity, combined with enhanced operational capabilities, lead to a reduction in market production costs and, through lower curtailment levels, a reduction in constrained production costs (which determine DBC). When these two reductions are combined to give the total production cost reduction, the annual net benefit to the all-island system is €295m. With the existing €60 million to ancillary services there is a total value of €355 million for system services.

This €295m value represents the cost savings that will be seen by the end consumer if the needed system services are delivered and it therefore provides an upper bound for the net additional monies that should be paid to service providers.

The TSOs consider that it would also be appropriate to include the existing HAS products in the same product revenue allocation method determined from those considered in Section 4 of this paper for the new SS products. Changes to the existing HAS financial arrangements would then be part of the Implementation phase of System Services development and subject to appropriate consultation processes at that time.

RECOMMENDATION ON PRINCIPLE

A "Value Based" approached is adopted to determine the value of the system services pot.. This value should be determined by the production cost value of being able to operate the power system more efficiently with the recommended system services than with the current services.

<u>Recommendation on Specifics</u>
The value of system services (including existing ancillary services) in 2020 is €355m.

<u>Recommendation on Principle</u>
The existing ancillary services are included as system services in this process with the exception of Blackstart. Specifically these include Primary, Secondary, Tertiary and Replacement reserves and Reactive Power (with suitable modifications to the definitions of last two products).

5.2 Cost of enhanced System Services

The provision of enhanced system services will require additional capital expenditure and have possible impacts to the operational efficiency of the service provider. While the work outlined in the previous section has focused on the production costs benefit of obtaining these services, it is also appropriate to consider the potential costs that may be incurred in achieving this.

In order to answer this question, the TSOs, in the third system services consultation paper, took a view of the changes to the portfolio that may be required to solve the issues. Any view of future developments contains inherent assumptions and is therefore open to challenge. To mitigate some of the risks associated with this, the TSOs have approached answering this question by considering two alternatives:

- **<u>Generation investment</u>**: enhanced performance from existing and potential new plant based on the GCS 2011 portfolio; and
- **<u>Alternative investment</u>:** no alteration to existing plant and no enhanced performance from new plant, necessitating alternative investment (e.g. network devices) to deliver the needed services.

Each of the two scenarios were considered from the perspective of the additional costs that are incurred. The benchmark, against which the additional costs will be determined, is a system without any investment. For this system, higher levels of renewables cannot be accommodated and therefore the production cost benefit of €295m described cannot be achieved.

For each of the illustrative scenarios, a level of investment was assumed in enhanced/improved technology, which would be sufficient for the delivery of the needed system services in 2020. The TSOs' view on the possible ways of obtaining the services from different technologies has been informed in part by bilateral discussions on a range of issues with a variety of developers and manufacturers particularly over the last 12 months.

The two scenarios considered are indicative of the possible spectrum of scenarios for 2020 but have not been optimised. There is significant uncertainty around what investment in portfolio capability will materialise as this is dependent on both the incentives provided by system service payments and wider electricity market considerations (including the design of the energy market and capacity mechanism). In addition these scenarios are not definitive and are purely used to inform the additional capital cost required to ensure a 75% SNSP compliant system.

It should be noted that this approach was not intended in itself to explicitly or otherwise imply that these are the only service providers who are eligible for the system service remuneration nor that the mechanisms are designed to deliver investment from only those service providers and technologies in the two scenarios. The recommendation of a value-based approach is fundamentally to enable the market to deliver the most efficient providers and foster innovation. For this reason, the TSOs are recommending that any cost consideration is used to inform rather than determine the revenues available for system services.

RECOMMENDATION ON PRINCIPLE
The allocation of the pot value between system services and the consumer should be informed by the incremental capital cost of the enhanced system services required to meet a transparent and published set of policy objectives, to the extent that the value-based approach gives an investible solution.

5.3 Impact on the all-island consumer

The valuation methodology proposed has quantified the benefit of system services in terms of the total production cost savings that arise due to the curtailment-lowering effect of enhanced system services and the consequential impact on the level of wind generation. These savings (principally due to a reduced all-island fuel bill) represent the maximum overall benefit to the all-island system based on the proposed methodology and assumptions made e.g. fuel costs.

The extent to which the total production costs savings result in lower energy costs to consumers is a rent allocation question. It is determined by the market design, which includes factors such as price-setting and the treatment of priority dispatch, and is therefore ultimately a matter for the SEM Committee. Nonetheless, some of the benefit will appear through lower dispatch balancing costs, some through lower SMP, while the remainder will appear though increased infra-marginal rents.

There is an interaction between payments for system services and the capacity payment mechanism. The impact of increased payments for system services on the end consumer may be lessened due to a reduction in capacity payments.

The analysis carried out has quantified the benefit of system services in terms of total production cost only. Other costs and benefits have not been explicitly included, including fixed costs and capital repayment costs. In addition, there are external factors that could be considered in determining the overall value of System Services (e.g. RES penalties, an increase in the PSO level (REFIT) or cost to suppliers to procure sufficient ROCs, Emissions Trading benefit).

Therefore it is not possible in this analysis to determine the full impacts on the all island consumer. However, within the areas examined there is a value of up to €355 million.

RECOMMENDATION ON SPECIFICS
The TSOs recommend that the full value of €355 million identified in section 3.1 is paid out to system service providers in 2020. The net cost to consumers (and hence the consumer savings) will be determined by the interaction with the Capacity Payment Mechanism, which is a matter for the SEM Committee to determine.

Recommendation on Principle
The additional monies are recovered through appropriate regulated consumer tariffs in Ireland and Northern Ireland.

5.4 Distribution of Pot across Products

The TSOs received broad support from industry in the consultation responses for the product funding allocation methodology which calculates the relative value of the products, using a series of Plexos studies of the system in which each of the products are removed. The outcome of the studies are the relative impacts on total system production cost which can then be used to weight the allocation of the system service money between the various products.

The TSOs have no plans to change the definitions of most of the existing HAS products other than Replacement Reserve and Static Reactive Power as part of the current DS3 Review. It would, however, be sensible, given the increasing scarcity of these products, to include the HAS products in the same allocation methodology used for the new products. Changes to the existing HAS financial arrangements would then become part of the Implementation phase of System Services development and subject to appropriate consultation processes at that time.

Indicative results using this methodology were provided in the third consultation paper. However, to ensure robust analysis behind the relative weightings, the TSOs propose that a formal industry consultation with appropriate regulatory approval be conducted to consider the range of portfolios and the methodology used for the calculation of the relative product values within 9 months of a high level principle decision by the SEMC.

Recommendation on Principle
The TSOs recommend that the allocation of the determined production cost value between the system service products should be based on a relative marginal benefit approach as outlined in Option 3 of the third system services consultation.
This weighting between the products should remain fixed for at least the tariff period to provide increased confidence to investors and reduce uncertainty in the future.

Recommendation on Principle
The TSOs recommend that the existing ancillary services are included as system services in this process with the exception of Blackstart. Specifically these include Primary, Secondary, Tertiary and Replacement Reserves and reactive power (with suitable modifications to the definitions of the last two products).

Recommendation on Specifics
A formal industry consultation with appropriate regulatory approval should be conducted on the portfolios and the methodology used for the calculation of the relative product values within 9 months of a high level principle decision by the SEMC.

5.5 Remuneration Approach

5.5.1 Dispatch-Dependent Payments

Having considered the relative merits of the different payment mechanisms and the impact on the CPM, the TSOs indicated their view in the third consultation paper that Dispatch Dependent payments for most System Service products, with extended fixed rates (to aid forecasting), represent the best compromise. While generator responses to the most recent consultation preferred Capability payments as they are more certain to investors than dispatch-dependent based services, the design of some of the new system services products are less dependent on MW output, allowing greater certainty than the existing ancillary services products. In addition, there is a significantly reduced impact on the capacity payment mechanism. This approach also has the additional benefit that, since dispatch-dependent payments provide a more targeted incentive, the interests of the consumer are better protected. [1] It should also be noted that the future market integration project could impact on the current CPM and its design.

5.5.2 Capability Payments

In the second consultation paper the TSOs outlined the benefits of capability payments, which included the relative stability and predictability of revenues for service providers. This is a view that was shared by many respondents to both the second and third consultation papers. However, the capability approach suffered from having a very significant negative impact on the CPM pot, and for a given level of money, providing an incentive that is both too small and too blunt.

5.5.3 Modified Capability – the Scaled Rate Approach

In choosing between capability and dispatch-dependent payments, there are a number of issues that are in conflict:

- Dispatch Dependent payments are risky for providers, particularly where there is investment in a single provider (i.e. single project players)
- Capability has a greater impact on CPM (assuming the current link remains)
- Capability, although low risk to provider, proves a signal that is both small (widely spread) and indiscriminate, which may result in "inappropriate" or inefficient investment

Following a review of the responses to the third consultation, where many respondents opposed Dispatch Dependent payments and some respondents provided suggestions to refine the proposed remuneration mechanisms, the TSOs have sought to identify alternative options. The following proposal is a modified version of the capability payment that should:

- De-risk providers
- Incentivise efficient provision of services
- Reduce impact on CPM

It is suggested that this proposal is used for capability payments for some or all of the new products. It may be appropriate to combine this with a dispatch dependent element.

This proposal includes a rate scalar, which attempts to target providers that are more likely to be providing services. On the assumption that lower cost providers are more likely to be running than higher cost providers, the rate scalar acts as a proxy for dispatch dependence, but crucially removes the dispatch risk.

The generic payment formulation as proposed in third consultation paper is as follows:

$$Payment = Product\ Volume \times Product\ Scalar \times Product\ Rate \times Performance\ Scalar$$

The generic payment formulation is therefore proposed to include an additional scalar as follows:

$$Payment = Product\ Volume \times Product\ Scalar \times Product\ Rate \times \mathbf{Rate\ Scalar} \times Performance\ Scalar$$

Where the Rate Scalar is

$$Rate\ Scalar = \frac{Reference\_price - Provider\_unit\_price}{Reference\_price}$$

The provider_unit_price is the average MWh production cost of the provider (and has a floor value of zero). The reference price should be set to some value between the average full load production cost of the BNE peaker and the SEM price cap.

The concept of the rate scalar is well established, being used in two ways in the capacity payment calculation in the SEM (one for scaling based on SMP and one for scaling based on COD).

A generator that provides energy at zero cost (or lower) would have a rate scalar of 1, while a generator that provides energy at a price at or above the reference price would have a zero rate scalar (and thus zero payment).

If the reference price is set equal to the BNE price, this would mean that a BNE peaker would receive zero payment for that product and consequently there would be no impact of that product on the CPM.

Similarly to dispatch dependent payments, this proposal provides a more targeted incentive to those providers that offer better value services than a simple capability payment but removes the revenue risk associated with dispatch dependent payments.

It should be noted that this proposal does add complexity and the implementation aspects should be fully considered. The precise details of the calculation of the reference price and the provider prices will be the subject of a further consultation, as will the treatment of special cases such as energy limited generators and pumped storage.

It is proposed that this methodology would be used for the voltage control and stability products: Synchronous Inertial Response, Fast Post-Fault Active Power Recovery, Dynamic Reactive Response and Steady-State Reactive Power. As proposed in the third consultation paper, the existing Operating Reserve products should retain their existing payment structures (i.e. dispatch dependent). To ensure consistency, it is proposed that the new "reserve-type" product – Fast Frequency Response and Ramping Margin – should also be paid on a dispatch dependent basis.

Thus the "reserve-type" products are paid on a dispatch dependent basis (as at present), while the other products (voltage and stability related) are paid on a capability basis with the rate scalar applied.

In section 6, the appropriateness of the various remuneration approaches are illustrated by examining the impact of each on the generation portfolio.

RECOMMENDATION ON SPECIFICS
The following reserve-type products are remunerated on a dispatch dependent basis:
Fast Frequency Response
Primary Operating Reserve
Secondary Operating Reserve
Tertiary Operating Reserve 1
Tertiary Operating Reserve 2
Replacement Reserve
Ramping Margin (1, 3 and 8 hour)

RECOMMENDATION ON SPECIFICS
The following non-energy system service products are remunerated on a capability basis:
Synchronous Inertial Response
Static Reactive Power
Dynamic Reactive Response
Fast Post-Fault Active Power Recovery

RECOMMENDATION ON SPECIFICS
If the existing CPM design is maintained, the scaled rate method should be used for products paid on a capability basis.

6. Further Analysis Addressing Substantive Issues

The previous analysis, presented and disseminated through the reports and the three consultation papers, indicated that there were many technical challenges that would manifest themselves in trying to achieve both governments' objectives of high RES-E penetration in the Ireland and Northern Ireland power system by 2020. Throughout the consultation process, bilateral meetings and the responses, a number of issues were identified whose solution requires satisfying a set of conflicting objectives. It is not clear if it is possible to propose a System Services paradigm that resolves all these conflicts. Specifically, the following high level conflicts have been identified by the TSOs as:

1. The primary requirement from the SEMC, outlined in its covering notes on the second and third System Service consultations respectively, is the protection of the interests of consumers of electricity in Ireland and Northern Ireland. In addition where monies are given to System Services an estimate of their impact on the Capacity Payment Mechanism has been requested by the SEMC. Existing generator participants have requested that there is no change to the Capacity pot and any monies given will be in addition to the existing payments.
2. Generally new developers have stated that the use of dispatch dependent or "realisable" system services products introduces a level of uncertainty that they find unacceptable and request capability product designs only. However, *ceteris paribus,* the introduction of capability payments will be less targeted and will require an overall level of remuneration at least an order of magnitude greater to provide the targeted incentive required for investment. This alone is likely to lead to increased costs to the consumer contrary to the desires of the SEMC.
3. Respondents have expressed concern about the length of time that the rates are set for. Universally the respondents have concerns that anything less than 8-12 years fixed will not deliver the necessary investment environment to be able to release funding. However, the length of rate fixing is such that it is not flexible to policy changes in the interim period and potentially locks out innovation or prevents the consumer from gaining the benefit of such innovation. These downsides ultimately impact on the cost to the consumers.
4. The approach is explicitly technology neutral and adopts a single tariff approach. However, the cost structures and payback periods of technologies are inherently different and the timeframe for meeting the policy objectives is challenging. Some providers argue that special arrangements are required to enable new technologies be delivered. However, this would be at the expense of the principle of technology neutrality and price transparency.

Specifically the TSOs have addressed points 1 and 2 below. Point 3 has been addressed in section 4.5 and point 4 has been addressed in section 4.1.

6.1 Balance of Risk between Consumer, Investor and System

To examine the design of system services an examination of the balance of risk between the consumer and the service provider is necessary. This necessitates consideration of the relationship between the cost to the consumer and the confidence that investors have in system service revenues. To explore this, the TSOs have taken a view on two distinct measures. The first, as requested by the SEMC, is the level of reward which is deemed sufficient to make needed investment (Section 6.1.1). Secondly, how product design, particularly with a range of different product configurations, might impact on revenue sufficiency to cover the incremental capital cost for enhanced system service capability for various technologies (section 6.2). It is important to note that this approach was only used to explore the level of revenue sufficiency for a representative range of technologies. The answers from this informed the TSOs final recommendation as to the appropriate allocation of the system services value between consumers and service providers. It was not intended in itself to explicitly or otherwise imply that these are the only service providers who are eligible for the provision nor that the mechanisms are designed to deliver only service providers from the chosen representative range of technologies.

In addition, as requested by the SEM Committee, the TSOs have examined the potential impact that the proposed system services arrangements would have on the Capacity Payment Mechanism (section 0).

6.1.1 Necessary Return on Regulated Investments

The TSOs have been asked by the Regulatory Authorities (RAs) to provide a view on the necessary return required (comprising return of (principal repayment) and return on (WACC) capital invested over a given period) to remunerate parties for investment in the provision of the proposed new system services. In this section the TSOs present a framework for considering how an appropriate range could be arrived at.

The return on capital is normally considered in terms of the weighted average cost of capital (WACC). The WACC is a function of both economy-wide components and company-specific components. Consistent with corporate finance theory, only systematic risk is remunerated. We understand that arguments can be made as to whether the cost of capital is formed at a market level (i.e. finance raised at bond and equity markets) or at the project specific level (i.e. project finance). The project specific level would generally involve a higher cost of capital. We note, however, that regulators typically assume that finance is raised at the market level when determining a WACC.

Regulatory estimates of the economy-wide components of the WACC (e.g. risk free rate, equity risk premium) can be inferred from recent regulatory determinations. The company specific components (i.e. the Debt Premium and Asset Beta) require a more subjective view to be taken although comparison can still be made to regulatory determinations whilst acknowledging and adjusting for any differences in risk profile.

The company specific risk will be a function of:

- Surety regarding future earnings (influenced by the regulatory framework chosen, e.g. the period rates are set for, remuneration based on capability or utilisation);
- Project risk (including risks around the cost and timing of delivery of the investment); and
- Operational risk

It is assumed that as the payment streams are likely to be less certain and subject to competitive forces, that the investment made by service providers in the provision of system services is relatively higher risk than other investments such as for the provision of capacity services. Nonetheless the framework set out here, and associated returns, do assume a certain level of regulatory certainty and underpinning. However, although the payment rate per service provided may be fixed by the regulator for a period, the use of the service and hence the payments may vary depending on the system operation requirements over time.

Table 1 below provides a possible range for the WACC. A base case is formed around the BNE 2013 determination[4] and further scenarios are extrapolated from this base case. The scenarios simply increase the Debt Premium and Asset Beta in order to gauge how changes to these components affect the WACC. The table outlines WACCs for both Ireland and Northern Ireland. Given that the DS3 programme is an all-island programme the payments will need to account for this distinction in some form. It is recognised that the parameters in this table are only estimates at a point in time and will vary with both the macroeconomic cycle and investor sentiment. Nonetheless they provide a reasonable gauge as to the levels of return potentially required.

[4] Decision Paper on BNE Peaker for 2013, SEM/12/078.

Table 1: WACC range

	Base Case		Scenario A		Scenario B		Notes
	IRE	NI	IRE	NI	IREI	NI	
Cost of Equity							
Risk-free rate	4.50%	1.75%	4.50%	1.75%	4.50%	1.75%	Oxera in BGN consultation outlined 3.5% - 5.5% range. BNE 2013 decision specified figure of 4.5% for IRE (incorporates Irish Country Risk Premium) and 1.75% for NI. NIE control used 2%.
Equity risk premium	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	Oxera in BGN consultation outlined 4.5% - 5% range. BNE decision specified figure of 4.75%. NIE control used 5%.
Asset Beta	0.5	0.5	0.7	0.7	0.8	0.8	0.5 figure inferred from BNE 2013 decision – assumes no debt beta
Equity Beta	1.25	1.25	1.75	1.75	2	2	Using gearing of 60%
Debt Beta	-	-	-	-	-	-	
Post-tax CofE	10.44%	7.69%	12.81%	10.06%	14.00%	11.25%	
Pre-Tax CofE	11.93%	10.12%	14.64%	13.24%	16.00%	14.80%	
Cost of Debt							
Debt premium	2.50%	2.50%	3.50%	3.50%	4.50%	4.50%	BNE 2013 decision used figures of 2.5% (based on corporate level funding i.e. bond markets)
Pre-tax CofD	7.00%	4.25%	8.00%	5.25%	9.00%	6.25%	
Post-tax CofD	6.12%	3.23%	7.00%	3.99%	7.87%	4.75%	
WACC							
Notional Gearing	60%	60%	60%	60%	60%	60%	BNE 2013 assumed gearing of 60%
Post-Tax WACC	7.85%	5.01%	9.32%	6.42%	10.32%	7.35%	
Vanilla WACC	8.38%	5.63%	9.93%	7.18%	11.00%	8.25%	
Pre-Tax WACC Real Terms	**8.97%**	**6.60%**	**10.66%**	**8.45%**	**11.80%**	**9.67%**	
Pre-Tax WACC Nominal Terms	10.01%	8.16%	11.51%	9.61%	12.53%	10.57%	Assuming a IRE inflation rate of 2% and UK inflation rate of 3%
Tax Wedge	1.143	1.32	1.143	1.32	1.143	1.32	
Tax Rate	12.5%	24%	12.5%	24%	12.5%	24%	The BNE 2013 used a NI corporation tax rate of 24%.

Key Sources

- Decision on October 2012 to September 2017 transmission revenue for Bord Gáis Networks, CER/12/196 and Oxera Report on Cost of Capital, CER/12/058c
- Decision Paper on BNE Peaker for 2013, SEM/12/078.
- Northern Ireland Electricity Transmission and distribution price controls 2012-17, final determination, November 2012.

In relation to the return of capital (repayment of principal), it is necessary to make an assumption over what period it is reasonable for an investor to receive repayment of the principal invested. In the table in the next section we have illustrated the level of returns on the assumption that the investment is paid back over a 10 year period. Of course the investment itself may have a longer life than 10 years, depending upon the life of the service provider technology; however, even though the service provider may provide service beyond the 10th year the proposed payment structures are such that full remuneration is not necessarily guaranteed within the 10 year period. The use of 10 years as a illustrative example therefore seems reasonable as an approximation in the first instance.

6.1.2 Setting the DS3 remuneration rates

Having set out above an illustrative time period for the repayment of capital (10 years) and scenarios against various risk profiles for the return on capital (WACC), we now express the two in combination, on an annuitised basis, in the table below. This shows a range of total returns on investment (repayment of principal as well as return) to be of the order of 15%-18% in real terms, slightly lower in Northern Ireland, with a likely point estimate towards the upper end of this range. In all instances nominal returns are ultimately required; however nominalisation is achieved, *ceteris paribus*, through the annual indexation of payment rates which is also assumed.

Table 2: Annual Return required for a 10-year payback

	Base Case - WACC		Scenario A - WACC		Scenario B - WACC	
	IRE	NI	IRE	NI	IRE	NI
WACC (Real Terms)	8.97%	6.60%	10.66%	8.45%	11.80%	9.67%
Annual % Return	**15.56%**	**13.97%**	**16.74%**	**15.20%**	**17.55%**	**16.05%**

6.1.3 Annualised revenue requirements for DNV KEMA scenarios

As part of the System Services Review, the TSOs engaged DNV KEMA to estimate the capital and incremental capital costs of a range of technologies to provide enhanced services. This was used to inform the levels of monies required for these technologies and is not a prescriptive revenue sufficiency calculation. It should be remembered that the list of service provider here is illustrative and is non-exhaustive.

Based on the example above for a payback period of 10 years, the required annual revenue for the capital costs as determined by DNV KEMA are illustrated in Table 3 below.

Table 3: Annual revenue required by technology type for a 10-year payback period

Service Provider	Capacity (MW)	Capital Cost	Enhanced Cost	Normalised Enhanced Cost (€/MW)	Annual Return = 15%	Annual Return = 18%
Enhanced Wind	2	4,200,000	278,000	139,000	20,850	25,020
CCGT New	450	360,000,000	13,446,172	30,000	4,500	5,400
CCGT Existing	450	360,000,000	54,690,497	122,000	18,300	21,960
OCGT New	50	32,500,000	3,699,440	74,000	11,100	13,320
OCGT Existing	50	32,500,000	7,163,575	143,000	21,450	25,740
Thermal	650	845,000,000	53,663,920	83,000	12,450	14,940

6.2 Illustration of Remuneration Approach Options

In order to inform the TSOs' recommendations on product design, detailed analysis has been conducted for a range of scenarios. A number of hour by hour dispatch schedules for the 2020 system were simulated assuming a variety of enhanced operation capabilities (EOC). From this, the aggregate (dispatch dependent) availability for each of the different system services was determined. The total service pot used for each distinct product was taken from the example of allocation method option 3 contained in Appendix B of the third consultation paper (Total Payment field in Table 4). Rates were determined by dividing each distinct pot by the annual volume of aggregate system services from all providers. The rates determined were based on four distinct product options: Capability, Dispatch Dependent, Capability with Rate Scalar and Dispatch Dependent with Rate Scalar. The latter two options employ a rate scalar as described in section 5.5.3; the reference price used was the average full load cost of a Best New Entrant peaking generator. Note that in the case of the Rate Scalar products, the aggregate volumes of service by generator were scaled by the Rate Scalar[5] to ensure the total payments for that product equalled the pot.

[5] The Rate Scalars were calculated based on the generator cost data and fuel price forecasts used for the Plexos modelling. In the case of priority dispatch and pumped storage, zero bid prices were used.

Table 4 Rate determination based on 2020 EOC case for Capability and Dispatch product designs

Product	Unit	Total Payment (€)	Rates (€/unit)			
			Capability	Dispatch-Dependent	Capability with Rate Scalar	Dispatch-Dependent with Rate Scalar
SIR	MWs^2h	8,000,000	0.00100	0.00220	0.00144	0.00291
FFR	MWh	41,000,000	6.3633	19.8642	9.4451	22.4207
POR	MWh	39,000,000	3.8876	14.2693	5.9743	16.6604
SOR	MWh	24,000,000	1.7620	7.4385	2.4665	8.4992
TOR1	MWh	29,000,000	1.9600	8.8763	2.8030	10.0709
TOR2	MWh	27,000,000	1.4886	5.4112	2.3270	5.9079
RR	MWh	4,000,000	0.0593	0.5338	0.0990	0.6536
DRR	MWh	2,000,000	0.2601	0.3132	0.5747	0.8553
RM1	MWh	9,000,000	0.3104	0.4439	0.4452	0.8751
RM3	MWh	18,000,000	0.5607	0.8320	0.8133	1.5918
RM8	MWh	19,000,000	0.5103	0.6487	0.7540	1.1316
FPFAPR	MWh	62,000,000	0.8371	2.1000	1.2263	2.6014
SSRP	Mvarh	38,000,000	0.2823	0.5919	0.3789	0.6790
DRP	MWh	35,000,000	0.4299	0.8003	0.5986	0.9536

Based on these rates, analysis was conducted on different sets of product combinations to examine the level of revenues accruing to different service providers. Six scenarios with different product configurations were analysed:

A. All products Capability based
B. All products Dispatch Dependent
C. All products a 50:50 blend of Capability and Dispatch Dependent
D. All products Capability based with Rate Scalar
E. Reserve and Ramping Margin products Dispatch Dependent, all other products Capability based with Rate Scalar
F. Reserve products Dispatch Dependent, Ramping Margin products Dispatch Dependent with Rate Scalar, all other products Capability based with Rate Scalar

This analysis was carried out to help inform the TSOs' recommendation on total system service pot size, the allocation between consumers and service providers and the mix of product design. It is noted that the choice of product configuration had no bearing on the assumed portfolio in 2020 and therefore there was the same aggregate service provision in all scenarios. However, the choice of product configuration, the level of reward associated with each product and the duration of rate fixing all would have material impacts on the evolution of the portfolio which has not and cannot be accurately modelled. In addition, as requested by the SEMC there was an examination of the interaction of how these system service revenues would impact on the capacity payments pot assuming the existing mechanisms.

Finally to gauge how a changing portfolio impacts on service provision revenue the actual outcomes in 2012 were examined utilising the rates determined from the 2020 scenario in a subset of the product configurations. This provided an opportunity to see how service provision and revenues might change and help estimate necessary funding requirements for system service provision from the period 2015-2020 and the respective impact on the capacity payments pot.

Figure 1 below shows the annual average System Services revenue (per MW installed) aggregated by technology type for each of the six scenarios. In addition, the relative allocation of the revenue between different technologies for each product can be seen in Figure 2. Full tables with figures are provided in the Appendix I.

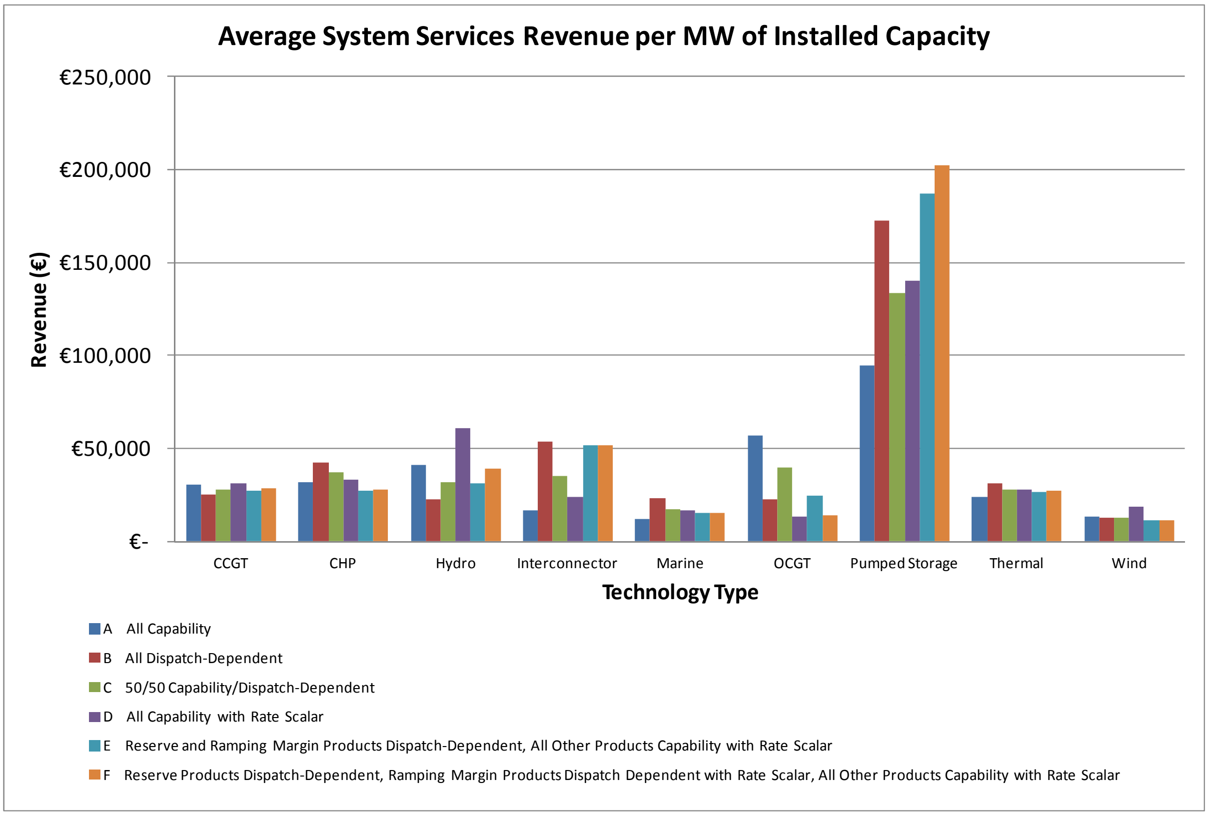


Figure 1 Normalised Average System Services Revenue by Technology Type

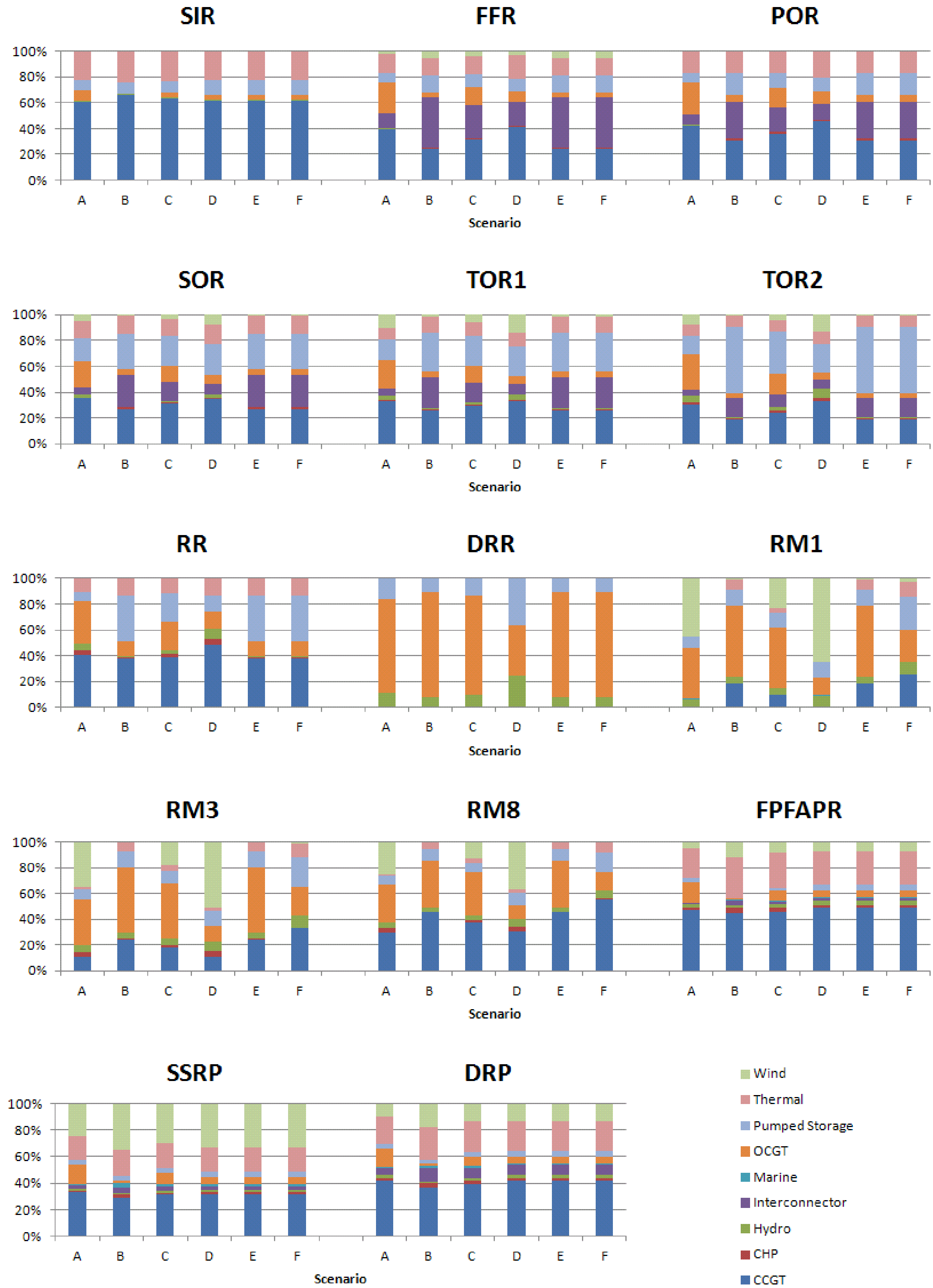


Figure 2 Relative Allocation of Product revenues by Service Provider

6.2.1 Discussion of Results

An analysis of the figures confirms some of the advantages and disadvantages with capability and dispatch dependent products. In particular for dispatch dependent products revenue earned by service providers is strongly related to the run hours (and to a lesser extent the load factor) of the unit. This is to be expected and has three significant outcomes:

- The level of service provision is related to the aggregate system demand. Effectively with service providers of similar capability the level of payable service is largely a function of how many units are on line which is correlated with demand. This manifests itself in the level of spend being similar between the 2012 and 2020 case (€313 million compared to €355 million assuming similar levels of performance). In some ways this is a perverse outcome. If the purpose of the incentive is to drive change in capability then there should be a significant difference in spend for a system service compliant system that can meet 75% SNSP to one that only meets 50% SNSP.
- The target spend for a range of service providers who are on-line more frequently is significantly higher than for capability only. This can be seen for example by the level and percentage of overall products revenue that OCGTs obtain compared to CCGTs (which have higher run hours). This has implications for the level of monies and the efficacy in the scheme to obtain the necessary investment. Essentially it appears to be a more cost effective mechanism for achieving a predetermined revenue amount for realisable service provision which is what is required from an operational perspective.
- However, the volatility of the revenues between service providers with significant run hours in the same technology category is significantly greater than that for capability only. This supports the argument that dispatch dependent products are, by themselves, more difficult to predict. This needs to be managed either by increased reward or having some form of natural mitigation mechanism or hedge. In that regard units with priority dispatch or large portfolio players have inherent advantages in managing these risks over single project developers. This advantage is not necessarily anti-competitive but needs appropriate consideration in any final decision.

When examining capability products it was found that revenues move from service providers who provide a realisable service to those that have the capability that is not realisable all the time. In particular, from the modelling, there is a significant shift from on-line generators (e.g. CHP, some CCGTs) to off-line generators (e.g. OCGTs) compared to dispatch dependent only. This is a perverse trend in the short term in that it rewards equally units that cannot provide a service in real time and those that can. However, this short term issue has to be balanced against the possible benefits this structure might have in the long term as it provides greater certainty of revenues for service providers (and hence investors).

The design of the Capacity Payments pot is based against a Best New Entrant (BNE) plant which is an OCGT. This market structure attempts to ensure that there are sufficient revenues for enough OCGTs to build without recourse necessarily to ancillary service payments. Capability based system service products provide significantly higher revenues to OCGTs than dispatch dependent products. In order to ensure this does not unduly impact consumers, by effectively over-rewarding an OCGT, the interaction between the System Services and Capacity payment streams needs further examination. This is explored in section 6.3 below.

In the 50/50 Capability/Dispatch Dependent case there is a mixture of the strengths and weaknesses of both of the mechanisms. In essence the level of revenues to any given technology type lie half-way between capability and dispatch dependent. However, there is a still significant uncertainty for providers as 50% of the revenues are dispatch dependent.

The introduction of the rate scalar seeks to combine the strengths of the capability and dispatch dependent mechanisms, while minimising the downsides. In particular, with the rate scalar there is a significant increase in the certainty of revenues. In addition, for the products to which it is applied, payments will be higher for providers that are more likely to be dispatched. This provides more targeted spend.

Combining a mix of rate scalar capability products with dispatch dependent for a selection of products appears to offer the best compromise. The reserve products today are already remunerated on a dispatch dependent basis. Retaining this approach with the new reserve type products (ramping margin and fast frequency response) while using a rate scalar capability payment for the other services allows service provision revenues to be appropriately targeted to useful providers while removing a significant amount of uncertainty. It also appears to provide a level of reward that is sufficient for a range of technologies to invest in enhanced capability.

6.3 Interaction of System Services with Capacity Payments

Many respondents expressed the concern about how and why Capacity Payments interacted with ancillary services revenue. The TSOs' position on this has been explored elsewhere in this paper and ultimately is a matter for the SEMC. Nevertheless with the current review of the internal energy market, due to be finalised and implemented by 2016, there is some uncertainty on the longevity of the whole capacity payments concept. The recent EU Consultation on the IEM and adequacy further increases this uncertainty. Also it is noted that the recent SEMC Capacity Payments review resulted in a guarantee of no changes to the Capacity Payments pot for three years which ends on the 1st Oct 2015 – the recommended date of implementation of the new system services.

A possible pragmatic consideration in this regard might be for the SEMC to make a timely decision on the design of System Services now but noting that the future interaction with Capacity payments would be a consideration in the ongoing market review. This has already been allowed for in SEM/13/009.

Nevertheless the SEMC has requested information on how changes in System Services would impact on the Capacity Payments pot if the existing arrangements were to remain. The following Table 5 contains the estimate on Capacity Payments pot if €355 million was assigned to System Services. In short all capability payments have the largest impact on the pot where as the all rate scalar Capability payments have the least. However both of these mechanisms on their own have challenges as identified earlier. Both scenario B (all dispatch dependent) and scenario E (TSO recommended option) have a moderate impact on the CPM and are in this consideration the favoured mechanims. While these two scenarios have a similar impact on the CPM, scenario E has significant advantages in terms of revenue certainty for providers and is therefore the TSOs' recommended option.

Table 5 Estimated Impact on Capacity Payments pot based on a range of System Services configurations for spend of €355m on System Services

	Scenario	Capacity Payments Reduction (€m)
A	All products Capability based	**€352**
B	All products Dispatch Dependent	**€163**
C	All products a 50/50 blend of Capability and Dispatch Dependent	**€257**
D	All products Capability based with Rate Scalar	**€0**
E	Reserve and Ramping Margin products Dispatch Dependent, all other products Capability based with Rate Scalar	**€157**
F	Reserve products Dispatch Dependent, Ramping Margin products Dispatch Dependent with Rate Scalar, all other products Capability based with Rate Scalar	**€30**

6.4 Implementation and Funding Timetable

If the decision is taken by the SEM Committee to adopt the principles and high level design recommendations made by the TSOs in this paper then it is currently estimated that approximately two years is required to complete implementation of the new arrangements following receipt of all necessary regulatory approvals.

As a consequence, 1st October 2015 appears to be the earliest likely start date for any new system services. This allows time for full consultation on the details and to allow for the design and implementation of all required IT systems. In addition this timing would also dovetail with the next pricing review for EirGrid and SONI and the CPM review. Based on this, the TSOs recommend that a target date for full implementation is set for October 2015.

There is likely to be a rise in funding requirements from the introduction of the System Services up to 2020. This rise will be linked to the investment in the necessary system services capability and the level of RES-E, particularly windfarms. An estimate of the 2015 system service spend was determined by calculating what the spend would have been in 2012 (based on outturn data and the rates in Table 4) and assuming that the average performance scalar would be 70% in 2015.

Table 6 Estimated funding requirements

Scenario	Funding requirement 2015 (70% performance scalar)	Funding requirement 2020 (95% performance scalar)
A	€191	€337
B	€270	€337
C	€230	€337
D	€185	€337
E	€259	€337
F	€259	€337

Recommendation on Specifics:
October 2015 should be set as a firm target date for "go live" of the new System Service arrangements

7. Additional Information

7.1 Risk to the consumer for under and over investment in System Services

Considered in aggregate the TSOs' recommendations amount to a form of price regulation. This is based on a range of pioneering technical analysis. These studies indicate that there is a range of security of supply metrics other than capacity that need to be considered. From these studies the needs in each distinct area can be estimated. In addition the studies have indicated the production value in total from the services as well as relative merits. Combining all these a price has been determined for each service which is based on the long term technical needs of the power system to efficiently and effectively meet the governments targets for 40% RES-E by 2020, and which is guaranteed to service providers for a period of several years, with principles around any review.

While the TSOs contend that the analysis conducted underpins an efficient and well targeted mechanism it is accepted that in all forms of price regulation there is a risk of either over or under investment. In that regard what are the risks of over and under investment arising from this proposal and are there any mitigation measures?

7.1.1 Risk of Over Investment in Service Provision

If the price of system services is higher than it should be then it may lead to over investment. Given the range of uncertainties outside of the remit of this consultation including the implementation of the EU target model, possible new 2030 RES targets, timing and delivery of actual infrastructure build, concerns about state aid considerations on capacity mechanisms as well as uncertainties in the global monetary markets, over-investment in service provision is unlikely to occur prior to 2020, irrespective of the price. Nevertheless to manage this potential limit the TSOs have recommended the rate review period to be five years to limit the exposure to high price over-incentivisation and to stimulate innovation for the benefit of consumers. In addition to this, the TSOs are recommending that contracting for service provision above and beyond Grid Code requirements is at the discretion of the TSO.

From a consideration of these factors the TSOs consider that the risk of over investment to be small and that between a 5 year rate review and the discretion of the TSOs to contract there are sufficient controls in place to mitigate it.

7.1.2 Risk of under investment in Service Provision

Given the current investment environment (outlined above), the TSOs consider that there is a greater risk of under investment in the necessary service provision particularly in a timely manner to efficiently support and facilitate meeting the governments RES-E targets by 2020. Clearly with all this uncertainty, any undervaluing of the services will contribute to this arising. The TSOs consider that the principled methodology and analysis presented in determining the prices has materially mitigated this risk as much as it is practicable to do so. However it is difficult to see if there is significant underinvestment in the necessary services how the government targets for RES-E can be met by 2020.

In addition, given the TSOs' recommended combination of product designs, the total spend on services should be strongly linked to additional investment in services. This design construct, combined with performance scalars means that any monies paid out above the levels of today's ancillary services will be more strongly linked to reliable delivery of needed services. This is a material benefit to the system above the current mechanisms used for remunerating ancillary services. Finally the risk of under investment and any increase in system service spend is mitigated by the interaction that system service payments have with the capacity mechanism. This consideration is a matter for the SEMC.

Nevertheless the TSOs consider it appropriate and consistent with our primary statutory duties to procure sufficient ancillary services to maintain the resilience and reliability of the power system that an alternative option should be available to the TSOs. In particular, if the market does not deliver the necessary services, or in the event of unexpected circumstances, the TSOs must be allowed to enter into longer-term contracts for services to take into account the needs of the system and the policy objectives. This principle is consistent with the principles set out in the SEMC decision paper on Harmonised Ancillary Services (SEM-08-013). However, the TSOs will not exercise this right without demonstrating that the proposed system services approach cannot deliver the necessary services in a timely manner to maintain system security.

RECOMMENDATION ON PRINCIPLE

If the market does not deliver the necessary services, or in the event of unexpected circumstances, the TSOs should be allowed to enter into longer-term contracts for services to take into account the needs of the system and the policy objectives.

Appendix I

Detailed results from the analysis of different payment mechanisms described in section 6 is provided here.

For each of the six scenarios examined, the annual revenues (aggregated by provider type) are shown in the following tables

Table 7 Revenues (€) by product and technology type

	SIR	FFR	POR	SOR	TOR1	TOR2	RR	DRR	RM1	RM3	RM8	FPFAPR	SSRP	DRP
Scenario A														
CCGT	4,868,506	16,065,284	16,358,427	8,459,387	9,603,090	8,055,620	812,220	0	53,441	1,919,333	5,596,387	29,270,342	12,674,650	14,726,112
CHP	0	238,002	242,345	109,841	281,962	713,810	75,827	0	0	726,709	645,684	1,110,549	372,807	553,160
Hydro	54,745	122,110	124,338	507,019	861,216	1,224,727	91,449	449,025	511,760	955,238	857,898	1,444,851	607,433	742,025
Interconnector	0	5,030,534	3,073,396	1,393,000	1,549,522	1,176,822	0	0	0	0	0	712,278	843,110	1,888,129
Marine	0	0	0	0	0	0	0	0	32,938	15,555	6,594	219,874	470,402	351,152
OCGT	644,420	9,690,732	9,867,558	4,839,433	6,527,607	7,633,659	663,068	2,898,524	3,547,981	6,300,955	5,578,868	9,666,864	5,422,055	4,807,036
Pumped Storage	650,048	2,682,952	2,731,907	4,209,956	4,683,001	3,818,135	152,099	652,451	777,622	1,402,094	1,271,962	2,099,422	1,375,956	1,102,668
Thermal	1,782,281	6,483,720	6,602,029	3,189,486	2,619,527	2,194,442	205,338	0	0	319,115	287,146	14,465,055	6,975,118	7,479,244
Wind	0	686,666	0	1,291,877	2,874,074	2,182,785	0	0	4,076,257	6,361,000	4,755,461	3,010,764	9,258,470	3,350,474
Scenario B														
CCGT	5,286,549	9,947,788	11,909,893	6,432,010	7,439,368	5,136,140	756,261	0	1,632,591	4,408,681	8,617,962	27,684,266	11,075,043	12,888,823
CHP	0	545,471	653,060	340,436	406,238	247,655	24,432	0	25,717	47,518	36,212	2,689,913	781,725	1,029,697
Hydro	42,088	12,891	15,434	40,639	62,258	57,072	11,927	323,724	444,815	868,815	668,771	1,403,837	486,729	554,069
Interconnector	0	15,703,810	11,280,741	5,880,574	7,017,227	4,277,906	0	0	0	0	0	1,786,885	1,767,888	3,514,718
Marine	0	0	0	0	0	0	0	0	648	271	124	539,308	986,482	637,364
OCGT	31,702	1,736,422	2,078,914	1,103,265	1,326,471	812,863	231,841	3,264,733	4,943,981	9,109,646	6,910,974	601,572	730,978	575,640
Pumped Storage	673,948	5,421,589	6,490,946	6,594,613	8,691,828	13,941,439	711,922	411,542	1,157,907	2,166,165	1,683,951	340,059	1,244,864	966,477
Thermal	1,965,713	5,488,466	6,571,012	3,463,799	3,713,520	2,317,767	263,617	0	684,220	1,272,186	1,044,339	19,401,090	7,560,400	8,705,262
Wind	0	2,143,563	0	144,665	343,090	209,158	0	0	110,120	126,718	37,667	7,553,071	13,365,890	6,127,950
Scenario C														
CCGT	5,077,527	13,006,536	14,134,160	7,445,699	8,521,229	6,595,880	784,241	0	843,016	3,164,007	7,107,174	28,477,304	11,874,846	13,807,467
CHP	0	391,737	447,702	225,139	344,100	480,733	50,129	0	12,859	387,113	340,948	1,900,231	577,266	791,429
Hydro	48,417	67,500	69,886	273,829	461,737	640,899	51,688	386,375	478,288	912,026	763,334	1,424,344	547,081	648,047
Interconnector	0	10,367,172	7,177,068	3,636,787	4,283,374	2,727,364	0	0	0	0	0	1,249,582	1,305,499	2,701,423
Marine	0	0	0	0	0	0	0	0	16,793	7,913	3,359	379,591	728,442	494,258
OCGT	338,061	5,713,577	5,973,236	2,971,349	3,927,039	4,223,261	447,455	3,081,629	4,245,981	7,705,300	6,244,921	5,134,218	3,076,517	2,691,338
Pumped Storage	661,998	4,052,271	4,611,426	5,402,285	6,687,414	8,879,787	432,010	531,996	967,765	1,784,130	1,477,957	1,219,740	1,310,410	1,034,572
Thermal	1,873,997	5,986,093	6,586,521	3,326,642	3,166,523	2,256,105	234,477	0	342,110	795,651	665,743	16,933,072	7,267,759	8,092,253
Wind	0	1,415,114	0	718,271	1,608,582	1,195,971	0	0	2,093,189	3,243,859	2,396,564	5,281,917	11,312,180	4,739,212

	SIR	FFR	POR	SOR	TOR1	TOR2	RR	DRR	RM1	RM3	RM8	FPFAPR	SSRP	DRP
Scenario D														
CCGT	4,947,305	16,913,388	17,830,510	8,348,130	9,641,104	8,875,998	967,463	0	53,556	1,945,066	5,745,834	30,566,137	12,121,384	14,613,844
CHP	0	256,020	269,903	111,431	292,228	808,663	91,710	0	0	763,889	691,436	1,179,055	362,586	558,172
Hydro	78,786	181,249	191,077	709,736	1,231,615	1,914,504	152,617	991,870	734,036	1,385,523	1,267,652	2,116,664	815,183	1,033,156
Interconnector	0	7,466,899	4,723,073	1,949,952	2,215,953	1,839,619	0	0	0	0	0	1,043,467	1,131,466	2,628,933
Marine	0	0	0	0	0	0	0	0	47,244	22,562	9,744	322,108	631,286	488,926
OCGT	276,010	3,476,813	3,665,342	1,594,744	1,812,290	1,504,510	271,608	1,566,907	1,203,065	2,164,815	1,959,053	3,343,801	1,763,752	1,642,800
Pumped Storage	935,508	3,982,346	4,198,287	5,893,188	6,697,103	5,968,543	253,834	1,441,223	1,115,373	2,033,665	1,879,485	3,075,591	1,846,552	1,535,297
Thermal	1,762,391	7,704,057	8,121,807	3,584,421	2,999,530	2,676,014	262,767	0	0	458,177	420,001	15,942,497	6,902,792	7,833,846
Wind	0	1,019,228	0	1,808,398	4,110,178	3,412,149	0	0	5,846,726	9,226,304	7,026,795	4,410,679	12,424,999	4,665,026
Scenario E														
CCGT	4,947,305	9,947,788	11,909,893	6,432,010	7,439,368	5,136,140	756,261	0	1,632,591	4,408,681	8,617,962	30,566,137	12,121,384	14,613,844
CHP	0	545,471	653,060	340,436	406,238	247,655	24,432	0	25,717	47,518	36,212	1,179,055	362,586	558,172
Hydro	78,786	12,891	15,434	40,639	62,258	57,072	11,927	323,724	444,815	868,815	668,771	2,116,664	815,183	1,033,156
Interconnector	0	15,703,810	11,280,741	5,880,574	7,017,227	4,277,906	0	0	0	0	0	1,043,467	1,131,466	2,628,933
Marine	0	0	0	0	0	0	0	0	648	271	124	322,108	631,286	488,926
OCGT	276,010	1,736,422	2,078,914	1,103,265	1,326,471	812,863	231,841	3,264,733	4,943,981	9,109,646	6,910,974	3,343,801	1,763,752	1,642,800
Pumped Storage	935,508	5,421,589	6,490,946	6,594,613	8,691,828	13,941,439	711,922	411,542	1,157,907	2,166,165	1,683,951	3,075,591	1,846,552	1,535,297
Thermal	1,762,391	5,488,466	6,571,012	3,463,799	3,713,520	2,317,767	263,617	0	684,220	1,272,186	1,044,339	15,942,497	6,902,792	7,833,846
Wind	0	2,143,563	0	144,665	343,090	209,158	0	0	110,120	126,718	37,667	4,410,679	12,424,999	4,665,026
Scenario F														
CCGT	4,947,305	9,947,788	11,909,893	6,432,010	7,439,368	5,136,140	756,261	0	2,270,102	5,930,083	10,556,956	30,566,137	12,121,384	14,613,844
CHP	0	545,471	653,060	340,436	406,238	247,655	24,432	0	36,741	65,883	45,783	1,179,055	362,586	558,172
Hydro	78,786	12,891	15,434	40,639	62,258	57,072	11,927	323,724	876,876	1,662,184	1,166,696	2,116,664	815,183	1,033,156
Interconnector	0	15,703,810	11,280,741	5,880,574	7,017,227	4,277,906	0	0	0	0	0	1,043,467	1,131,466	2,628,933
Marine	0	0	0	0	0	0	0	0	1,278	519	216	322,108	631,286	488,926
OCGT	276,010	1,736,422	2,078,914	1,103,265	1,326,471	812,863	231,841	3,264,733	2,220,065	3,978,519	2,761,910	3,343,801	1,763,752	1,642,800
Pumped Storage	935,508	5,421,589	6,490,946	6,594,613	8,691,828	13,941,439	711,922	411,542	2,282,612	4,144,226	2,937,715	3,075,591	1,846,552	1,535,297
Thermal	1,762,391	5,488,466	6,571,012	3,463,799	3,713,520	2,317,767	263,617	0	1,095,244	1,976,153	1,465,013	15,942,497	6,902,792	7,833,846
Wind	0	2,143,563	0	144,665	343,090	209,158	0	0	217,083	242,432	65,711	4,410,679	12,424,999	4,665,026

Table 8 Minimum, Average and Maximum Revenues (€) per MW installed capacity of plant in each technology type

	CCGT	CHP	Hydro	Interconnector	Marine	OCGT	Pumped Storage	Thermal	Enhanced Wind
Scenario A									
Minimum	24,074	31,338	23,155	14,224		48,147		15,436	
Average	30,217	31,496	40,859	16,378	11,790	57,144	94,556	24,096	13,055
Maximum	36,963	31,654	55,908	18,532		74,685		30,487	
Scenario B									
Minimum	4,458	42,313	17,514	50,680		17,294		17	
Average	25,197	42,411	22,410	53,764	23,271	22,241	172,936	31,059	12,631
Maximum	59,964	42,509	25,963	56,848		43,453		64,573	
Scenario C									
Minimum	14,266	36,826	20,335	32,452		32,720		7,726	
Average	27,707	36,954	31,634	35,071	17,531	39,692	133,746	27,578	12,843
Maximum	48,464	37,081	40,935	37,690		59,069		47,530	
Scenario D									
Minimum	25,420	33,297	35,133	21,159		0		9,797	
Average	31,038	33,449	61,047	24,057	16,364	13,432	139,918	28,139	18,577
Maximum	36,541	33,600	83,056	26,956		52,932		43,840	
Scenario E									
Minimum	17,935	27,449	26,797	50,009		17,290		9,511	
Average	27,475	27,494	30,834	51,465	15,520	24,863	187,208	26,361	11,221
Maximum	51,934	27,539	38,088	52,920		48,931		53,851	
Scenario F									
Minimum	18,548	27,691	34,031	50,009		2,510		9,508	
Average	28,465	27,736	39,308	51,465	15,530	14,186	202,128	26,929	11,297
Maximum	53,153	27,781	49,919	52,920		49,514		55,341	

Appendix II – Proposed System Services Products

As detailed in section 3.2, the TSOs have developed a number of new System Services products and have proposed refinement of the definitions of some of the existing ancillary services.

New products

- Synchronous Inertial Response (SIR)
- Fast Post-fault Active Power Recovery (FPFAPR)
- Dynamic Reactive Response (DR)
- Fast Frequency Response (FFR)
- Ramping Margin (RM)

Existing products

- Operating Reserves: POR, SOR, TOR1 &TOR2
- Replacement Reserve – minor modification proposed
- Steady-state reactive power – modification proposed

The details of these proposals are provided in this appendix.

New product: Synchronous Inertial Response

Synchronous Inertial Response (SIR) is the response in terms of active power output and synchronising torque that a unit can provide following disturbances. It is a response that is immediately available from synchronous generators, synchronous condensers and some synchronous demand loads (when synchronised) because of the nature of synchronous machines and is a key determinant of the strength and stability of the power system. It has significant implications for rate of change of frequency (RoCoF) during power imbalances and for transmission protection devices and philosophy. With increasing non-synchronous generation this response becomes scarce and there is therefore a need to incentivise it. In particular, if synchronous inertial response can be provided at low MW outputs, the system can accommodate higher levels of non-synchronous generation.

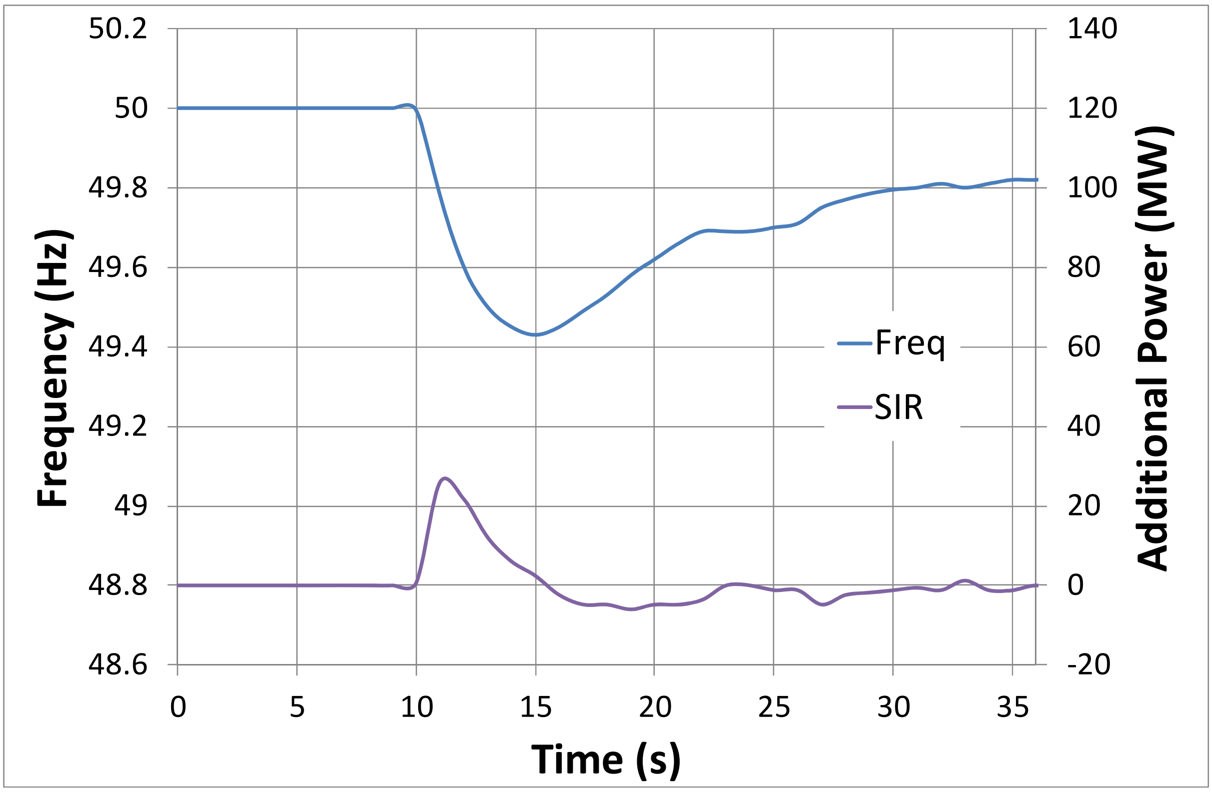


Figure 3: Illustration of typical inertial response

The proposed SIR product is defined as the kinetic energy (at nominal frequency) of a dispatchable synchronous generator, dispatchable synchronous condenser or dispatchable synchronous demand load multiplied by the SIR Factor (SIRF). The SIRF of a synchronous generator is the ratio of the kinetic energy (at nominal frequency) to the lowest sustainable MW output at which the unit can operate at while providing reactive power control. It will be based on the commissioned design capability of the plant as determined through appropriate testing procedures. The SIRF will need to exceed a threshold of 15 s for the provider to be eligible for payment and payment will be capped at a SIRF of 45 s. The SIRF for a synchronous condenser or a synchronous demand load that can provide reactive power control is 45 s. Payments for SIR will be based on the SIR Volume:

SIR Volume = Stored Kinetic Energy × (SIRF – 15) × Unit Status

Product Volume	*SIR Volume*
Product Scalar	*2 if the provider is capable of providing operating reserve at the lowest sustainable MW output at which the unit can operate at while providing reactive power control* *1 otherwise*

New product: Fast Post-fault Active Power Recovery

Units that can recover their MW output quickly following a voltage disturbance (including transmission faults) can mitigate the impact of such disturbances on the system frequency. If a large number of generators do not recover their MW output following a transmission fault, a significant power imbalance can occur, giving rise to a severe frequency transient. It is proposed to introduce a service that rewards generators that make a positive contribution to system security.

Fast Post-fault Active Power Recovery is defined as having been provided when, for any fault disturbance that is cleared within 900 ms, a plant that is exporting active power to the system recovers its active power to at least 90% of its pre-fault value within 250 ms of the voltage recovering to at least 90% of its pre-fault value. The generator must remain connected to the system for at least 15 minutes following the fault.

Product Volume	*MW Output*
Product Scalar	*1*

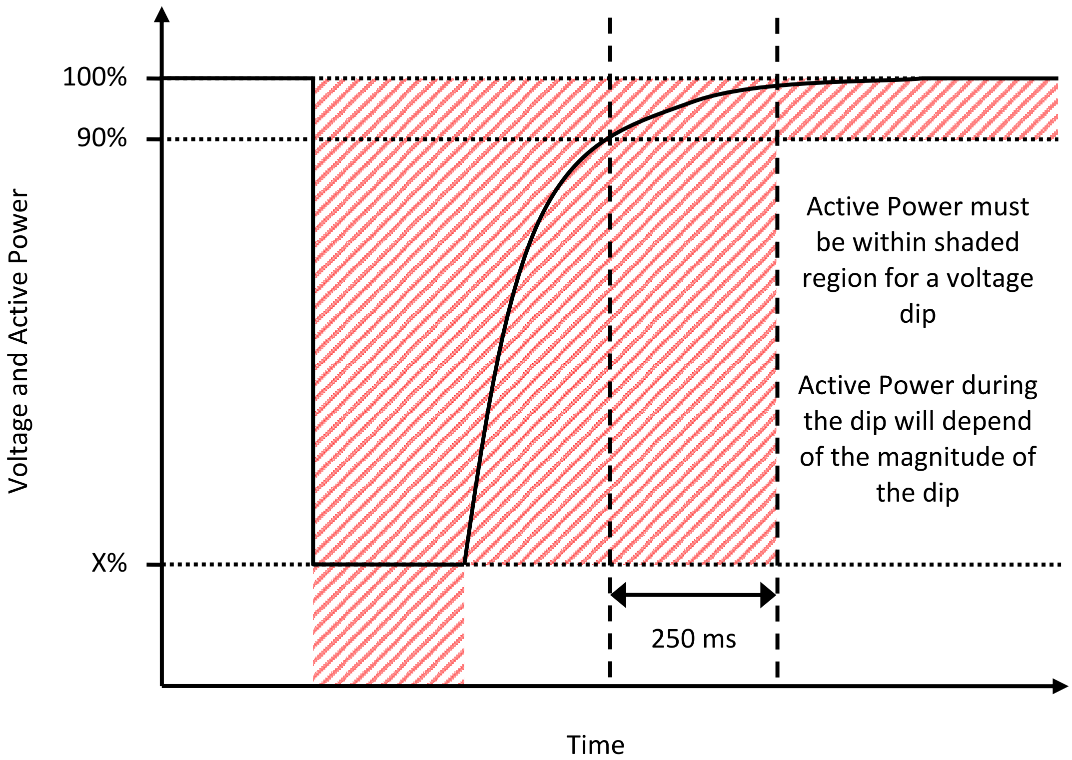


Figure 4: Fast Post-Fault Active Power Recovery Product

New product: Dynamic Reactive Response

At high levels of instantaneous penetration of non-synchronous generation there are relatively few conventional (synchronous) units left on the system and the electrical distance between these units is increased. The synchronous torque holding these units together as a single system is therefore weakened. This can be mitigated by an increase in the dynamic reactive response of wind farms during disturbances. Therefore, a new service is proposed to incentivise this type of response, which is particularly important at high levels of renewable non-synchronous generation. In line with the proposed changes to the Grid Codes, a Dynamic Reactive Response product is proposed.

The Dynamic Reactive Response product is defined as the ability of a unit when connected to deliver a Reactive Current response for voltage dips in excess of 30% that would achieve at least a Reactive Power in Mvar of 31% of the registered capacity at nominal voltage. The Reactive Current response shall be supplied with a Rise Time no greater than 40 ms and a Settling Time no greater than 300 ms.

Product Volume	*Registered Capacity when connected and capable of providing the required response*
Product Scalar	*1*

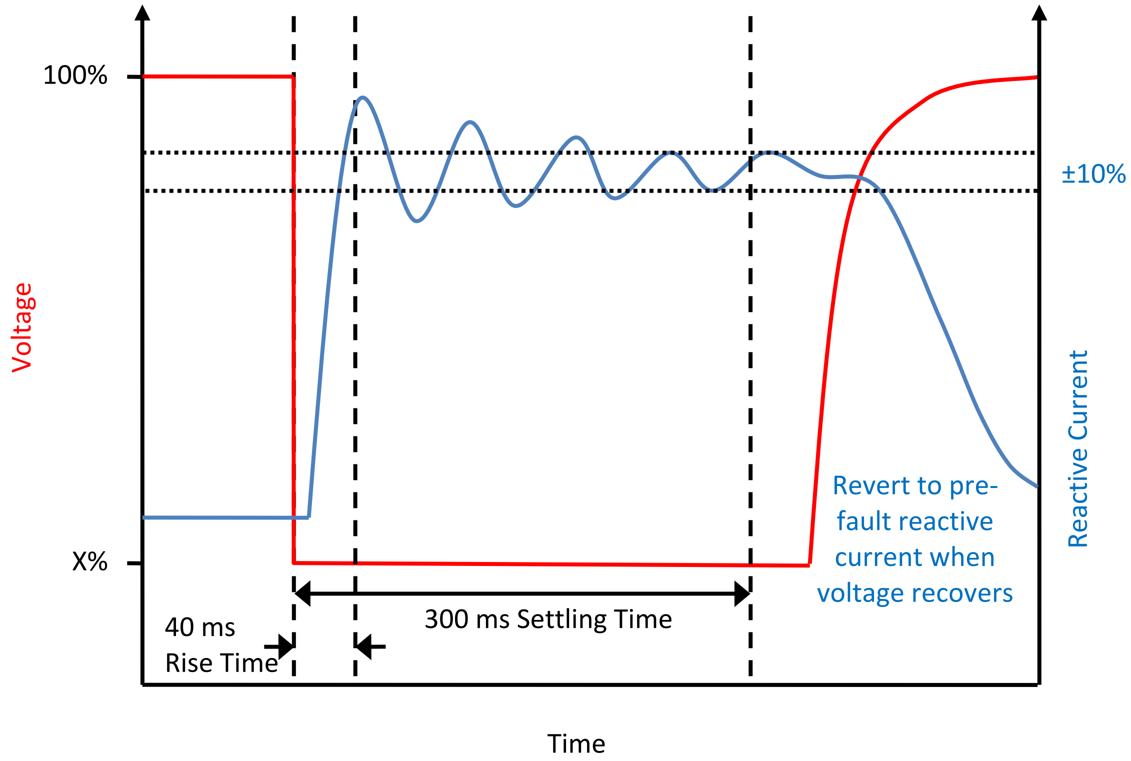


Figure 5: Dynamic Reactive Response product

The measurement of this product will require high quality phasor measurement units to be installed at the provider's site with appropriate communication and access arrangements agreed with the TSOs.

New product: Fast Frequency Response

With appropriate control systems, both synchronous and non-synchronous generators can provide fast-acting response to changes in frequency that supplements any inherent inertial response. In particular, Fast Frequency Response (FFR) as defined below (MW response faster than the existing Primary Operating Reserve times) may, in the event of a sudden power imbalance, increase the time to reach the frequency nadir and mitigate the RoCoF in the same period, thus lessening the extent of the frequency transient. This product runs in conjunction with SIR so providers who can maintain or increase their outputs in these timeframes are eligible for both services.

Fast Frequency Response is defined as the additional increase in MW output from a generator or reduction in demand following a frequency event that is available within 2 seconds of the start of the event and is sustained for at least 8 seconds. The extra energy provided in the 2 to 10 second timeframe by the increase in MW output must be greater than any loss of energy in the 10 to 20 second timeframe due to a reduction in MW output below the initial MW output (i.e. the hatched blue area must be greater than the hatched green area in Figure 3).

Product Volume	*Additional MW Output that can be provided when connected*
Product Scalar	*1*

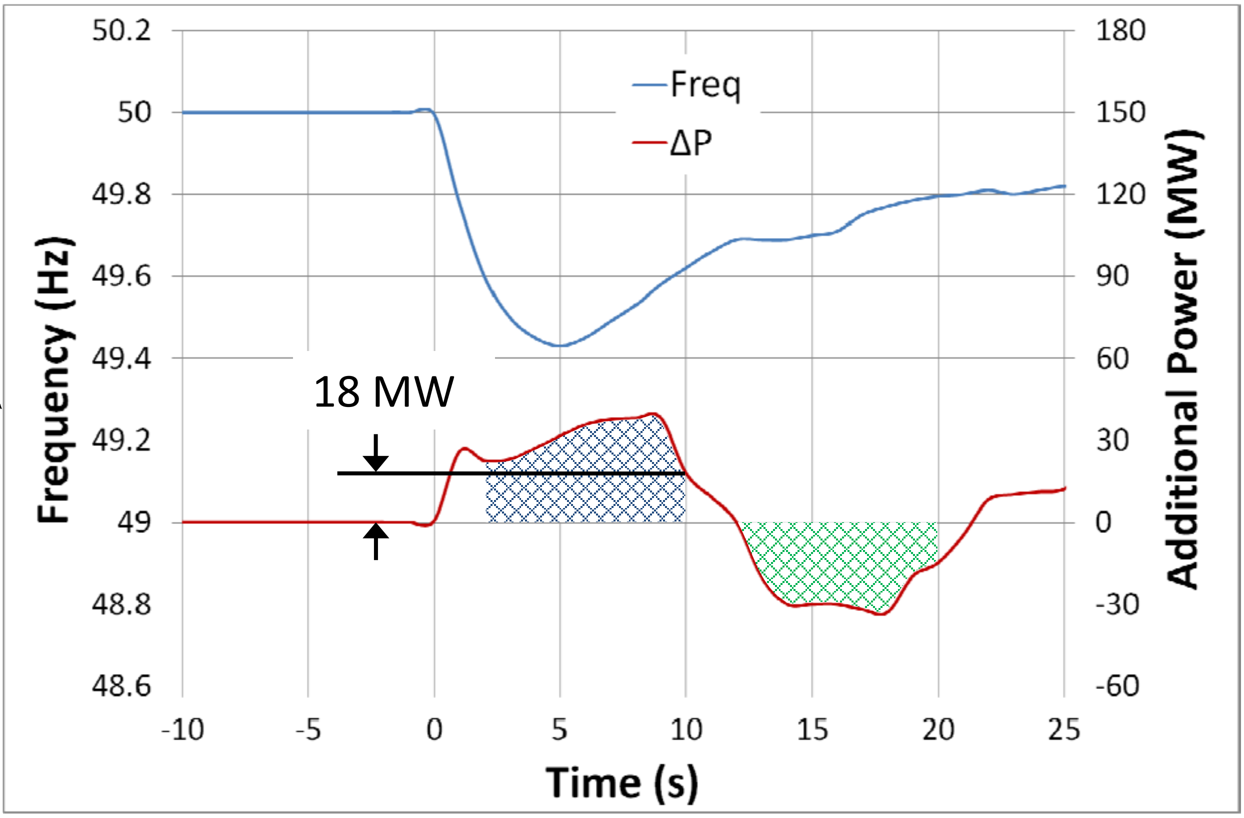


Figure 6: Fast Frequency Response Product

New product: Ramping Margin

The management of variability and uncertainty is critical to a power system with high levels of wind penetration. Detailed analysis has shown that portfolios that are capacity adequate are unlikely to be adequate in terms of ramping over all the necessary timeframes to efficiently and effectively manage the variable renewable sources and changes in interconnector flows while maintaining system security. The analysis has also indicated that a ramping-down product is not currently required.

To incentivise the portfolio to provide the necessary margins to securely operate the power system a new ramping-up product is being proposed over three distinct product time horizons.

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 TSOs are proposing horizons of one, three and eight hours with associated durations of two, five and eight hours respectively. The Ramping Margin products are called RM1, RM3 and RM8 respectively. The Ramping Margin for a unit at the starting point is the ramp-up capability of the unit in the horizon time limited by the lowest availability in ***both*** *the horizon and duration window (e.g. from 0 to 8 hours for RM3). Thus 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.*

Product Volume	*Ramping Margin*
Product Scalar	*1*

Please note the following points in relation to the Ramping Margin Product:

- The ramping-up capability of the plant will be based on Technical Offer Data submitted to the SEM and will include ramp rates, dwell times, break points, etc. as applicable.
- The measurement of this product will be based on half hour figures of MW output and availability.
- Performance metrics will be based on a consideration of performance against dispatch instructions, technical offer data and start reliability (e.g. failure to synchronise).
- The three proposed products are not mutually exclusive. Plant capable of providing all three products are eligible to receive payment for all three, similarly for two.
- Both synchronised and non-synchronised plant is eligible for payment.
- The TSOs do not currently propose to weight payments at times of scarcity.
- The TSOs acknowledge that further discussions will take place regarding plant constrained on/off in the implementation stage.

Potential providers of these services include conventional generators that are not dispatched to their maximum output, storage devices, demand side providers and wind farms that have been dispatched down. In the future with the potential for implicit continuous gate closures, interconnector participants with excess capacity for importing may also be able to provide this service.

Existing product: Operating Reserve

As per current definitions – no changes to the definitions of the POR, SOR, TOR1 and TOR2 services are proposed.

Existing product: Replacement Reserve

It is proposed that, to avoid overlap with the 1 hour ramping product described below, the timings associated with the Replacement Reserve product are redefined.

Replacement Reserve is the additional MW output (and/or reduction in demand) provided compared to the pre-incident output (or demand) which is fully available and sustainable over the period from 20 minutes to 1 hour following an Event.

Existing product: Steady-state reactive power

The need for reliable steady state reactive power control is important for the control of system voltages and for the efficient transmission of power around the system. Both synchronous and non-synchronous sources can contribute to this requirement.

The need for reactive power varies as demand varies and as the sources of generation vary. Since reactive power is difficult to transmit over long distances (unlike active power), reactive sources are required to be distributed across the system. Thus there is not necessarily a strong link between the need for active power and reactive power from the same sources. It is therefore proposed that the reactive power product is re-structured in a way that incentivises reactive capability across the widest possible active power range (P_{range}).

The Reactive Power Capability product is defined for conventional generators as the dispatchable reactive power range in Mvar (Q_{range}) that can be provided across the full range of active power output (i.e. from minimum generation to maximum generation). For wind farms the Reactive Power Capability product is defined as the dispatchable reactive power range in Mvar (Q_{range}) that can be provided across the active power range from Registered Capacity down to at least 12% Registered Capacity. Payment for Reactive Power Capability will be scaled by the RP Scalar:

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

RP Scalar = 1 for dispatchable synchronous condensers and dispatchable loads.

Product Volume	*Q_{range} × RP Scalar, while able to provide reactive power*
Product Scalar	*2 if provider is operating under the control of an AVR* *1 otherwise*

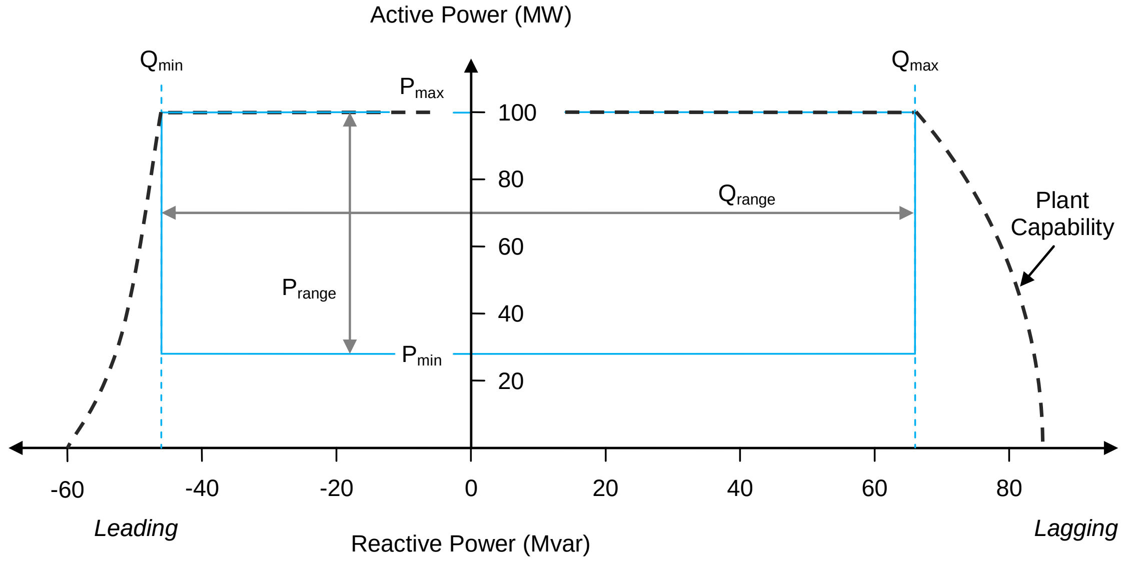


Figure 7: Illustration of Q_{range} and P_{range} for the Steady-State Reactive Power product