Final Report

Economic Appraisal of DS3 System Services

for

The Commission for Energy Regulation and The Utility Regulator

8 July 2014

IPA

Energy + Water Economics

Economic Appraisal of DS3 System Services

for

The Commission for Energy Regulation and the Utility Regulator

IPA Energy + Water Economics Limited

74 Wigmore Street

London W1U 2SQ

United Kingdom

Tel: +44 (0) 20 7659 9888

Fax: +44 (0) 20 7962 1321

Email: contact@ ipaeconomics.com

Web site: www.ipaeconomics.com

Wind Farm and Power Pylon images courtesy of freeimages.co.uk; Energy Saving Bulb image courtesy of FreeDigitalPhotos.net

TABLE OF CONTENTS

DISCLAIMER

IMPORTANT NOTICE

This report has been prepared for the exclusive use and benefit of the client and solely for the purpose it was intended. Review or use of this report by any party other than the client constitutes acceptance of the following terms.

Read these terms carefully as they constitute a binding agreement between you and IPA Energy + Water Economics Limited ("IPA").

Any use of this report/document other than as a whole and in conjunction with this disclaimer is forbidden. Unless IPA has provided express prior written consent, this report/document may not be reproduced, distributed or communicated in whole or in part to any third party.

This report and the information and statements herein are based in whole or in part on information obtained from various sources. While IPA strives to ensure the accuracy of the information in this report/document, IPA provides no claims, promises, warrantees or guarantees about the accuracy, completeness or adequacy of the information, contents, conclusions, estimates, or opinions contained therein nor is IPA is responsible for any typographical, pictorial or other editorial errors.

This report is provided as is. Nothing in this report/document will confer any legal rights or obligations on any third parties or members of the public. IPA expressly disclaims liability for the content of this Report/document and for the consequences of any actions taken on the basis of the information provided. IPA will not be liable for any claims or damages of any kind incurred by you (including without limitation; loss of or damage to profits, income, revenue, use, production, anticipated savings, business, contracts, commercial opportunities or goodwill) due to your use of or reliance on this report/document.

EXECUTIVE SUMMARY

The Commission for Energy Regulation ("CER") and the Utility Regulator ("UR") are delivering economic analysis of the DS3 System Services Review, and have commissioned IPA Energy + Water Economics ("IPA") to provide economic, financial and technical consultancy services to support supply side analysis and economic appraisal of the DS3 system services.

This is IPA's Final Report covering the items which were reviewed under two work packages. This Final Report provides:

The first work package comprised:

- *A review of the DNV KEMA study ("the KEMA study")*, the aim of which was to assess whether the costs of generation and network plant enhancements to provide additional system service products presented within the KEMA study are in line with costs obtained from other publically available information and are appropriate for use within the supply side analysis;
- *A review of the industry submissions*, the purpose of this analysis was to qualitatively supplement the data presented in the KEMA study with information provided by industry participants in order to provide a broader understanding of the supply-side issues associated with system services; and
- *Desktop analysis*, to validate the overall costs of providing additional system services under DS3.

The second work package comprised:

- *Review of TSO modelling results*, the results of which were used by the Transmission System Operators ("TSOs") to determine the value of an adequate level of system service products in achieving the 75 per cent System Non-Synchronous Penetration ("SNSP") level of wind penetration. The TSOs looked at the value of these services on a production cost basis and market cost basis, and used the results to assign an illustrative value to the pot of expenditure to be allowed by the SEMC for the procurement of system services by the TSOs. The TSOs also developed a value based methodology for allocating the total expenditure pot between individual system service products. We compared the values for the system benefits of enhanced system services to the corresponding supply side costs. We found that the system benefits exceeded the costs of providing system services, and this will be an important consideration for the RAs in setting the level of allowed expenditure for the procurement of system services; and
- *Analysis on the procurement options*, in which we developed procurement mechanisms which include elements of price discovery in the context of the limited number of system services suppliers in Ireland. We believe this approach can be designed to be consistent with the ISEM proposals as they evolve and which provides a stable platform for the introduction of new system service products as the level of wind penetration increases. Our approach also provides incentives for the TSOs to procure system services efficiently.

Conclusions from work undertaken or instigated by the TSOs

Our review of the submissions in response to the Call for Evidence issued by EirGrid regarding the finance arrangements under the DS3 Systems Services Consultation found that there were no significant differences in views that we could attribute to the type or size of respondent. The confidential submissions focused on the technical capabilities and overall capex costs of individual units rather than on the costs per product provision and, with the exception of one respondent, related to units that are still in the development phase and require financing. We found that there were three overarching concerns. These were:

- the value approach to determining the aggregate pot of funds for the procurement of ancillary services
- treatment of the Rate of Change of Frequency ("RoCoF"), and
- financial feasibility of generator investments to provide new system services.

EirGrid commissioned DNV KEMA to identify the additional capital investment required to meet the new system service requirements from a range of different technologies. We compared that the level of costings identified in the KEMA study for normalised build costs in generation units and grid solutions. In summary we consider that KEMA's cost estimates for conventional generation technologies are reasonable, although their cost estimate for OCGTs is approximately 25 per cent higher than we would expect, partly reflecting the smaller size of plant selected by KEMA. We agree with KEMA's result that the cost of providing system services from grid technology solutions is, in general, significantly higher than providing the services from generation solutions. We found very little evidence in the public domain surrounding generation enhancement costs. Thus we were unable to comment on the values proposed by KEMA. We consider that attention should now be focused on determining the availability of system service products from demand customers.

The TSOs carried out modelling to determine the value of adequate system service products in achieving the 75 per cent SNSP level of wind penetration in 2020. They looked at the value of these services on a production cost basis and market cost basis. The TSOs recognised that the expenditure ultimately allowed by the SEMC in relation to system services may be less than the calculated system values. They proposed that the allowed expenditure should be allocated to individual system service products based on the relative market benefit of each product.

Our review of the TSO work indicated that there is much uncertainty over the required volumes for each of the system service products to meet the SNSP levels expected in 2020. There is also uncertainty over the inter-changeability of products in meeting the range of operational conditions that need to be managed by the TSOs. As the RES target of 40 per cent is approached the costs and benefits of different scenarios need to be examined more closely in order that the target is achieved cost effectively. The modelling results show that whilst procuring system services to achieve a 75 per cent SNSP level will meet the 40 per cent target, aiming for a 70 per cent SNSP level would provide a system that is very close to achieving the 40 per cent target.

The TSOs' analysis of production cost savings from the levels of wind in 2020 (4.6 GW scenario) are €231 million per annum in the 70 per cent SNSP case and €241 million per annum in the 75 per cent SNSP case. The estimated cost of investments to provide the system services from generation technologies to achieve this level of wind penetration (75 per cent SNSP) is in the range €70- 84 million per annum. The shape of the costs curve is not known, but for example if a linear cost curve were assumed the cost to achieve 70 per cent SNSP would be around €50 million per annum. We therefore consider it important to investigate the shape of the cost curve in order to establish the least cost approach to meeting the RES target.

CCGT manufacturers are improving the performance of their machines in response to network requirements worldwide for greater flexibility (shorter start times, higher turn down ratios and higher ramp rates) The TSO analysis shows that if CCGTs implement lower minimum generation levels the system savings increase to €260 – 266 million per annum. . The on-going work by manufacturers may mean that some or all of these benefits may be able to be captured from proven technology. We therefore recommend further work to better understand the costs and benefits of reducing the minimum load levels.

The TSOs' analysis of market cost shows lower system benefits than the production cost savings. This is because of the additional infra-marginal rents captured by generators, some €93 million in the 70 per cent SNSP case and €84 million in the 75 per cent SNSP case. This feature is amplified in the cases where lower minimum load enhancements have been assumed for CCGTs where the additional infra-marginal rents captured by generators total €219 million in the 70 per cent SNSP case and €187 million in the 75 per cent SNSP case.

It would appear that if the annual cost of providing system services is of the order of €70 – 84 million per year (based on 20 year plant life and a pre-tax WACC of 6.6 per cent), then these costs will be recovered by generators as a whole through higher infra-marginal rents. However, it needs to be recognised that the allocation of these rents is unlikely to be reflective of the costs of providing system services and unlikely to be properly targeted at the providers of these services.

Key conclusions

The generation plant costs proposed by KEMA are reasonable and can be considered a reasonably robust estimate of the likely unit capital costs. Attention should now be focused on determining the availability of system service products from demand customers.

The estimated production cost savings from additional system services is a measure of the value of systems services, and the TSO proposes that this value is used to determine the expenditure to be allowed for system services procurement. Without any further adjustment this approach probably significantly overstates the costs to generators of providing these services. We consider that a robust estimate of the cost is required in order to be able to adequately incentivise the TSO to procure system services efficiently.

There is much uncertainty over the required volumes for each of the system service products to meet the SNSP levels expected in 2020. There is also uncertainty over the inter-changeability of products in meeting the range of operational conditions that need to be managed by the TSOs.

Recommendations in relation to the procurement of system services

We have developed our proposals for the procurement of system service products against the following objectives:

- A reliable availability of products in adequate volumes in the short- and long-term;
- Incentives on the TSOs for efficiency;

- Robust product prices;
- Reasonable set-up and transaction costs;
- Aligns with ISEM developments; and
- Aligns with EU target model.

Our recommendations are as follows:

- For procurement purposes, the system service products should be grouped into four groups as proposed by Pöyry as follows:
    - Group 1: Grid stability services;
    - Group 2: Ramping services;
    - Group 3: Fast reserve services;
    - Group 4: Slow reserve services.

This more granular approach will allow the TSO to make trade-offs between individual products within each group and will simplify the price determination process.

- The TSOs should provide greater transparency in relation to the volumes of system services (by group) required in the year ahead and over the period to 15 years ahead. The TSO should also publish an estimate of the surplus/deficit profile in system services (by group) over the 15 years period. Although it is acknowledged that significant further work would be required to define and agree the assumptions and scenarios required for such a forecast.
- We recommend separate mandatory auctions are developed for the procurement of each group of services (sealed bid, pay-as-cleared design) on a 1 year ahead basis.
    - The arrangements for each group can be introduced to a separate timeline, with regulated tariffs retained in the meantime.
    - Groups 3 and 4 have potential interactions with the energy market and we recommend that auctions for these for groups are introduced prior to the new ISEM market arrangements.
    - The TSO would be required to set the volume required for each group of services as part of the selection process. Consideration should be given the benefit of temporarily shaped requirements.
- New licence conditions and bidding codes are likely to be required to ensure that the objectives of the ancillary services market are not frustrated by the lack of competition.
- We recommend that 5 and 10 year contracts for the procurement of new system services capacity are introduced to ensure that adequate capacity is available in future years. These contracts would be for the purpose of rewarding investment in new system services capacity through an auction process. The TSO should, to the extent possible, provide

estimates of system service capacity requirements up to 15 years ahead to be used as the basis of volume selection.

- To encourage efficiency in the procurement and utilisation of system services, we recommend that the TSOs are incentivised to optimise the costs of procurement. We propose that there should be a single sliding scale incentive scheme for ancillary services procurement by the TSOs. The reported performance of the TSOs under the sliding scale incentive over a sequence of years will inform the resetting of the target allowance from year to year, thereby protecting the interests of customers.

- We recommend a total target allowance in the region of €150 million per annum and that the TSO develops computer models to aid the setting of this target. This, and the other parameters of the sliding scale scheme, would need to be discussed with the industry.

  - Where 5 or 10 year contracts have been procured the equivalent annual cost would be included in the allowance evaluation.

  - An Income Adjusting Event ("IAE") provision could be included in the TSO licences to provide protection to the TSOs in the case of an event or set of circumstances (e.g. a force majeure event under the Trading and Settlement Code ("TSC")) that result in unanticipated ancillary service costs, and provide protection to consumers in the case of unanticipated cost savings

- Strong signals that investments to provide enhanced system services will be remunerated are desirable by the end of 2014 with the associated mechanisms implemented in 2015. To meet this timetable we consider that the key arrangements should be put in place across all system services products on the selected implementation date, rather than introducing the new framework on a phased basis.

Key recommendations

The TSOs should, to the extent possible, provide greater transparency in relation to the volumes of system services (by group) required in the year ahead and over the period to 15 years ahead.

We recommend separate mandatory auctions are developed for the procurement of each group of services (sealed bid, pay-as-cleared design) on a 1 year ahead basis.

We recommend that 5 and 10 year contracts for the procurement of new system services capacity are introduced to ensure that adequate capacity is available in future years.

To encourage efficiency in the procurement and utilisation of system services, we recommend that the TSOs are incentivised to optimise the costs of procurement. We propose that there should be a single sliding scale incentive scheme for ancillary services procurement by the TSOs.

1. INTRODUCTION

IPA has been commissioned by CER and UR (the Regulatory Authorities ("RAs")) to provide economic, financial and technical consultancy services to support supply side analysis and economic appraisal of the DS3 system services. IPA's terms of reference involved the following:

- *A review of demand side analysis*, which involved reviewing the TSO[1] modelling results. This refers to additional demand side analysis[2] carried out by the TSOs in February/March 2014 in line with the requirements and terms of reference set by the SEM Committee, in which a revised counterfactual was used (60 per cent SNSP);
- *A supply side analysis*, which involved analysing the supply side costs and related volumes. This included assessing the costs of enhancements based on previous work by KEMA and our own analysis in conjunction with volumes provided by the TSOs; and
- *An analysis on the options for procurement mechanisms*, in terms of the approaches available and recommendations surrounding these options.

1.1. Context

Both Ireland and Northern Ireland have set targets for renewable penetration of 40 per cent of electricity consumed by 2020. In order to achieve these targets, a significant amount of new wind is required to come onto the system between now and 2020.

Following the Facilitation of Renewables Study ("FORS") and Sustainable Power Systems ("SPS") Report, the TSOs implemented DS3 – Delivering a Secure, Sustainable Electricity System Programme. DS3 is a long-term programme of analysis, proposals, consultations and actions in a wide number of areas aimed at ensuring the electricity system on the island of Ireland can continue to operate in a safe, secure and reliable manner, while minimising curtailment of wind and taking account the changing portfolio of plants. The overall programme contains 11 separate work streams, including the system services work stream. The system services work stream, which is the focus of this report, involves putting in place the correct structure and framework for the procurement of system services by the TSOs to support high levels of variable generation, whilst protecting the interests of consumers.

The FORS and subsequent studies indicated that it will only be possible to securely operate the power system by addressing the issues of inertia, frequency response, ramping capability and voltage control. The TSOs identified that the most appropriate all-encompassing single metric that approximated to the magnitude of the impact of each of these issues was the SNSP level.

As most wind turbines use asynchronous generators, increasing wind generation increases the SNSP level. To meet the renewable targets will see the SNSP limit increasing from

[1] Transmission System Operator (TSO)

[2] DS3: System Services Valuation, Further Analysis

the current limit of around 50 per cent to 75 per cent by 2020. Studies by the TSOs[3] have shown that this increase in non-synchronous power will require the procurement of additional system services (relating to both frequency and voltage control) to ensure the secure and reliable operation of the system.

It is noted that a separate but related issue regarding the implementation of system services under DS3 is the requirement to introduce a new RoCoF standard via a modification to the Grid Code. This change is required to bring the allowed wind penetration from 50 per cent SNSP to 60 per cent SNSP, and to facilitate the increase to 75 per cent SNSP when the enhanced system services are introduced. Prior to implementation, the RAs have asked generators to carry out technical studies to determine their capabilities in relation to the proposed new standard[4]. The results from this work are not expected until 2015.

Following a review of the work done so far on the System Services Review, the SEM Committee decided that that further economic analysis was required to support a decision on the procurement and remuneration of system services. The RAs commissioned IPA to provide economic, financial and technical analytical support in aspects of the delivery.

IPA has conducted:

- *A review of demand side analysis* – The RAs agreed modelling scenarios and assumptions for the demand side modelling being carried out by the TSOs. IPA reviewed and interpreted these results;
- *A supply side analysis* – IPA carried out the required financial analysis to determine the costs of the "supply" curve for system services; and
- *An analysis on the options for procurement mechanisms* – IPA provided assistance in determining the appropriate framework for procuring system services and advised on these options in light of the results of the demand and supply side analyses.

1.2. Final Report structure

This Final Report is structured as follows:

- Section 2 – DNV KEMA Study
- Section 3 – Industry Evidence Submissions
- Section 4 – International Evidence
- Section 5 – Review of TSO modelling results
- Section 6 – Procurement options
- Section 7 – Conclusions and recommendations

[3] DS3: System Services Review, TSO Recommendations, Report to the SEM Committee, May 2013.

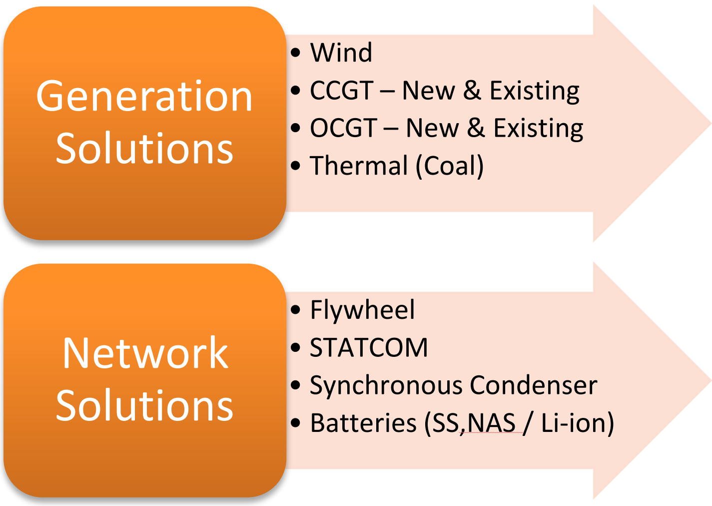
[4] Rate of Change of Frequency (RoCoF) Modification to the Grid Code, CER/13/143, 28 June 2013.

- Appendix 1 – Modelling methodology
- Appendix 2 – Benefit allocation methodology
- Appendix 3 – Mandatory bidding rules
- Appendix 4 – System service procurement proposal
- Appendix 5 – Procurement options and objectives

2. DNV KEMA STUDY

In this section we review the KEMA study, which identified the additional capital investment required to meet the new system service requirements from a range of different technologies. The aim of this review was to assess whether the costs of enhancements presented within the study are in line with other publically available information and therefore are relevant for use within the supply side analysis conducted. This study was commissioned by EirGrid, who specified two principle areas of necessary asset upgrades, relating to generation and network solutions. For both generation and network solutions, DNV KEMA first identified the technical features of each enhancement and technology type and then calculated the cost implications using reference projects within their company. The KEMA study considers enhancements to both existing units and the cost of enhancing new builds, providing indicative costs for wind, CCGT, OCGT, coal fired power plants, flywheel, STATCOM, synchronous condenser and batteries.

Figure 1: Asset upgrade categories



Source: IPA analysis.

We have used the KEMA study as a benchmark in terms of both technologies and capital costs identified. We have then conducted our own research in order to compare these costs with similar costs internationally, using the same two categories of asset. We also reviewed supporting documents and spreadsheets from the KEMA study provided by EirGrid.

2.1. System service products provided

The KEMA study outlines both a normalised build cost for each asset type, and then an estimated additional investment required in order for the unit to provide enhanced ancillary services.

Within these technological enhancements, a number of additional system services are capable of being provided. For the conventional technologies described above, these can be separated out into three main groupings as per the supplementary information provided by DNV KEMA:

- Reduced minimum load, extending the range of loads/wind generation outputs over which synchronised plant provides system inertia;
- Frequency response; and
- Ramp-up time improvement.

It should be noted that the feasibility and cost of enhancements to improve the inertial response of each unit at each load level is not addressed in the KEMA report.

While the above enhancement costs are a useful reference point in terms of the cost effectiveness of different unit-types in providing enhanced system services, it should be noted that each technology type has different system service product capabilities, which are described in further detail in Table 1 below.

Table 1 identifies which types of enhancements are possible for a given type of unit, and the types of system services that each unit is capable of providing.

Table 1: Possible enhancements

Technology	Enhancements	System services product	Cost
Generation solutions			
Wind	Enhanced active power response by software upgrade. Enhanced reactive current response by installing STATCOM. Enhanced reactive power range provided by above STACOM.	Faster fault ride through Voltage control.	€139/kW Enhancement
CCGT New	Burner and related equipment changes. Additional auxiliary boiler and related equipment.	Inertia support though reduced minimum operating load. Improved start-up/ramp-up time. Enhanced frequency response.	€30/kW Enhancement
CCGT Existing	Burner and related equipment changes. Additional auxiliary boiler and related equipment.	Inertia support though reduced minimum operating load. Improved start-up/ramp-up time. Enhanced frequency response.	€122/kW Enhancement
OCGT New	Burner and related equipment changes.	Inertia support though reduced minimum operating load.	€74/kW Enhancement
OCGT Existing	Burner and related equipment changes.	Inertia support though reduced minimum.	€143/kW Enhancement
Thermal (coal)	Burner and related equipment changes. Update control system.	Inertia support though reduced minimum operating load. Improved start-up/ramp-up time.	€83/kW Enhancement
Network Solutions			
Flywheel	Combined flywheel with synchronous generator/motor.	Fast Frequency Response Inertia response.	€766/kW Total installed
STATCOM	Power electronics device.	Reactive power response Voltage control.	€109/kVAR Total installed
Synchronous Condenser	Conversion of deactivated generation unit.	Reactive power response Voltage control. Inertia response.	€63/kVA Total installed
Batteries (Li-ion)	Li-ion selected for response characteristics.	Frequency response.	€829/kW Total installed

Source: IPA analysis and KEMA study.

2.2. Generation asset upgrades

The KEMA report examined the capital costs associated with building additional system service capability into new and existing generation technologies. These costs, and the additional enhanced system service investments expressed as a proportion of normalised build costs, are provided in Table 2:

Table 2: Generation technologies

Technology	Capacity [MW]	Normalised build cost €	Total add enhanced costs €	Enhancements as % of normalised build cost
CCGT-New	450	360,000,000	13,446,172	3.7
CCGT-Existing	450	360,000,000	54,690,497	15.2
OCGT-New	50	32,500,000	3,699,440	11.4
OCGT-Existing	50	32,500,000	7,163,575	22.0
Thermal (Coal)	650	845,000,000	53,663,920	6.4

Source: KEMA study.

The cost of enhancements is proportionately lowest for a new CCGT unit, estimated at 3.7 per cent of its normalised build cost. This is because the inherent characteristics of the CCGT cycle facilitates flexible operating modes (including the ability to balance output between the GT and steam cycles) and the improvements in technology which are becoming available to meet the additional flexibility required by electricity grids world-wide[5]. This additional expenditure allows a new CCGT to provide a reduced minimum load, additional frequency response, and improved ramp up times. Thermal units have the second lowest proportional enhanced costs, estimated at 6.4 per cent of normalised build cost. However, even with the enhancements, thermal plant is unable to provide the improved ramp-up times available from CCGTs.

The following table provides a breakdown of the enhancement costs by the system service products provided.

[5] An important consideration is burner design in determining the minimum conditions at which gas turbines are able to operate within environmental limits, particularly those for NOx and CO emissions.

Table 3: System enhancements by product

Technology	Capacity [MW]	Reduced minimum load €	Frequency response €	Ramp-up time improvement €
CCGT-New	450	5,074,950	20,000	8,351,222
CCGT-Existing	450	43,311,750	496,250	10,882,497
OCGT-New	50	3,659,940	39,500	not needed
OCGT-Existing	50	7,124,075	39,500	not needed
Thermal (Coal)	650	34,153,920	19,510,000	not proven

Source: KEMA study

Reduced minimum load facilities can be provided by all fossil-fuelled generators, at varying levels of increased costs; this ranges from 1.4 per cent of normalised build cost for a new CCGT to 21.9 per cent for an existing OCGT. The cost of retrofitting an existing CCGT to provide reduced minimum load facilities is estimated at €43,311,750 for a 450 MW station, or roughly 12 per cent of the normalised build cost. As the majority of electricity demand is met by gas in the SEM (47.7 per cent in 2012[6]) this cost is particularly noteworthy.

Frequency response can also be provided by all conventional generation units, the enhanced investment costs of which are significantly lower than for providing reduced minimum load services. These range from 0.01 per cent of normalised build costs for a new CCGT to 2.3 per cent in the case of a thermal unit.

The KEMA study also indicates that at present there are no proven technological enhancements that can be made to any conventional generator in order to provide further inertia to the system, and that there are not proven technological enhancements to improve ramp-up times in thermal units. OCGTs are already able to sufficiently provide fast ramp up, and therefore no improvements are necessary for this technology.

The KEMA study proposes that wind assets are enhanced beyond the recently updated Grid Code standards to provide:

- Enhanced fault ride through, which is provided by active power and reactive response; and
- Enhanced voltage control, which is provided by additional reactive power.

[6] http://www.allislandproject.org/GetAttachment.aspx?id=d5ba273d-7c40-434b-a4f4-81c539901c43

The costs associated with providing these capabilities are outlined in Table 4. The data in this table is based on the costs provided in the supplementary information provided by the TSOs and the KEMA study itself[7].

Table 4: Generation technology

Technology	Capacity [MW]	Normalised build cost €	Total add enhanced costs €	Enhancements as % of normalised build cost
Wind	2	4,200,000	325,600 - 480,000	8 - 11.4

Source: IPA analysis and KEMA study

Table 5 breaks down the cost of the difference types of additional services that wind power is expected to be able to provide. Reactive power appears to be significantly less expensive to provide than reactive response, which in turn is half the cost of providing additional active power to the system.

Table 5: Wind system enhancements by product

Technology	Capacity [MW]	Active Power €	Reactive response €	Reactive power €
Wind	2	316,500	144,000	20,000

Source: IPA analysis and KEMA study

2.3. Network asset upgrades

System service provision is also possible through network based solutions, which include the following:

- **Flywheels** primary capability is the delivery of Fast Frequency Response ("FFR"). They are also theoretically capable of delivering inertia to the grid; however this is not yet commercially feasible. Improved inertia response can be obtained by attaching the flywheel to a synchronous machine connected to the grid.

- **STATCOMs** can be used to regulate voltage, support critical loads and improve transient stability providing power oscillation damping. They are typically placed in areas of the grid where there are issues with interruptible loads or generations (for example, as a result of wind).

[7] KEMA noted on 9 April 2014 that in the spreadsheet the STATCOM costs for the reactive response are neglected (1.3c). The STATCOM was already installed for supplying active power during a fault (ride through) (1.2c), and is capable of providing both services without the need for increasing capacity.

- **Synchronous condensers** provide reactive power and generation in and towards the system. This results in voltage control, short circuit power capacity and inertia response. The conversion of non-profitable or deactivated power station is currently seen as the most cost effective option applying synchronous condensers.

- **Batteries** can be used for frequency response (Li-ion), peak shaving and energy storage (NaS). This is somewhat similar to the potential services which can be provided by pumped hydro and Demand Side Management ("DSM"). KEMA assumed that for the provision of system services, the Li-ion battery solution is relevant.

These investments are exclusively to provide system services and therefore the costs do not represent plant enhancements but full installation costs.

Given that additional inertia is a service which cannot be provided for through wind-based generation solutions, it is a key element for consideration from network solutions for system services.

Table 6: Grid technology solutions

Technology	Capacity	Normalised build cost	Auxiliary equipment
Flywheel	20 MVAR	14,000,000	478,000 – 1,328,000[8]
STATCOM	50 MVAR	4,500,000	928,000
Synchronous Condenser	75 MVA	2,000,000	2,726,500
Batteries (sodium-sulphur, NaS)	40 MW	90,000,000	3,170,000
Batteries (Li-ion)	40 MW	30,000,000	3,170,000

Source: IPA analysis and KEMA study

[8] KEMA noted on 9 April 2014 that in the report, the flywheel was attached to a synchronous machine to provide the additional functionality needed (short time direct inertia). Considering the size of the flywheel, the synchronous machine was estimated around €850k.

As Table 6 above illustrates, network solutions tend to be much more costly than generation solutions and there is likely to be less operational experience world-wide with network solutions to support the engineering development required for installation on a significant scale.

Conclusions

The main findings from our analysis of the DNV KEMA Study are as follows:

- We have disaggregated the cost of total enhancements for each solution in order to outline the type of system service that is provided for each level of investment, and provided the range wherever possible. This allows us to consider the types of system services that are capable of being provided by all assets in the supply side analysis at a more detailed product-specific level.
- A significant element of the enhancement costs for conventional plant is for operating at lower minimum load levels. The TSOs should assess the proportion of the conventional generating plant that needs to have this enhancement feature.

2.4. IPA validation of KEMA results

In an attempt to validate the costing values identified within the KEMA study, IPA undertook a desktop analysis of the grid technology solutions and itemised grid enhancement solutions outlined above. Following a wide ranging data review[9] we identified three documents that provided cost data against which to benchmark some of the KEMA results. In part, due to the specific nature of the plant requirements addressed by the KEMA study and, in part, due the lack of publically available information, we were unable to find comparable cost data for the enhancements considered by KEMA. In some respects, the SEM is at the frontier of system services, facing higher levels of wind penetration than most other power markets and therefore similar problems have not yet been faced extensively elsewhere. Section 4 outlines approaches currently taken in other power systems internationally.

For those KEMA asset types where we identified comparable data, we have disaggregated the findings in terms of:

- Normalised build costs;
- Enhancement costs; and
- Operating costs.

[9] We have considered documents from academic literature, working papers from universities, research institutes, public sector documents and presentations, and industry sources.

2.4.1. Normalised build costs

In this section we present the capital costs of generating units (exclusive of enhancements) as proposed by KEMA and the costs for similar technologies which we have extracted from the following recent publications:

- **Reference A:** Electricity Generation Cost Model - 2013 Update of Non-Renewable Technologies, Prepared for Department of Energy and Climate Change by Parsons Brinckerhoff, April 2013.
- **Reference B:** Outlook for new coal fired power stations in Germany, the Netherlands and Spain, A report to DECC prepared by Pöyry Management Consulting (UK) Ltd, April 2013.
- **Reference C:** DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA, Prepared by Sandia National Laboratories, USA, July 2013[10].

The following Table summarises the costs for fossil-fuelled generating plant in the KEMA study and those obtained from Ref A, Ref B and Ref C.

Table 7: Conventional generation technologies

Technology	Source data	Capacity (MW)	Build cost €/MW	Comment
CCGT New	KEMA Report Ref A Ref C	450 900 1100	800 600 – 790 805	The KEMA costs are at the higher end of our reference range.
OCGT New	KEMA Report Ref A Ref C	50 561 – 608 100	650 266 – 400 525	The KEMA costs are significantly higher than our reference range but this would in part at least reflect the much smaller size of plant selected.
Thermal (coal)	KEMA Report Ref B	650 800 - 1600	1300 1100 - 1800	The KEMA costs are towards the lower end of our reference range.

Notes: Exchange rate assumptions €1= 0.82GBP, 1US$= 0.6GBP (based on current rates), Grid connection cost are assumed to be excluded.

Source: IPA analysis of identified sources.

The following table summarises the costs for network technologies that provide system service products as set out in the KEMA study and as obtained from Reference C.

[10] This is sensitive to exchange rate fluctuations.

Table 8: Grid technology solutions

Technology	Source data	Capacity (MW)	Build cost €/MW	Comment
Flywheel	KEMA Report Ref C	20 MW 20 MW	766 per kW 1580 per kW	The KEMA study costs are approximately 50% lower than our reference costs. [11]
STATCOM	KEMA Report	50 MVAr	109 per kVAr	We have not been able to obtain sound STATCOM cost data but we have some evidence[12] that KEMA's cost estimate is low (about 50% of current costs).
Synchronous condenser	KEMA Report	75 MVA	163 per kVA	Costs will be dependent on the condition and configuration of the plant being modified so reference costs are not appropriate.
Batteries (NAS)	KEMA report Ref C	40 MW 50 MW	2329 per kW 2247 per kW	Our reference cost aligns with KEMA's cost estimate.
Batteries (Li-ion)	KEMA report Ref C	40 MW 1 – 10MW	830 per kW 1195 – 3660 per kW	Li-ion battery design and configuration need to be tailored to the particular duty required and the costs vary accordingly.

Source: IPA analysis of identified sources.

In summary we consider that KEMA's cost estimates for conventional generation technologies are reasonable, although their cost estimate for OCGT's is approximately 25 per cent higher than we would expect, partly reflecting the smaller size of plant.

---

[11] We have not considered the supplementary spreadsheet as the workings to convert to €/kw from kVAR are not provided.

[12] National Transmission Network Development Plan (NTNDP) 2012 (Transend networks). A 100MVAr static synchronous compensator is estimated to cost AUD30m (€20m).

As regards the grid technology solutions we consider that KEMA's cost estimates for flywheels and STATCOMs are low. With Li-ion batteries the variability of cost with the operational duty should be noted. We are not able to comment on the cost estimate for synchronous condensers. In Table 18 we consider the capital costs to provide new system services in greater detail.

2.4.2. Enhancement costs

As discussed above, very little applicable data is currently available in the public domain. The proposed enhancements are specific solutions to deal with the SEM's unique position with regards to its ancillary service needs. As a small market with few interconnection options and limited hydro resources, it is unable to manage the effects of wind on the system in the same way as other countries with high wind penetrations such as Denmark, or the ERCOT system in the US. These and other systems are outlined further in Section 4.

The KEMA study notes that their cost figures are not exact estimates but provide a generic picture for each technology considering the portfolio in Ireland and Northern Ireland. Without detailed investigations on each specific asset in Ireland and Northern Ireland it is not possible to address local issues necessitating specific modifications with associated costs.

2.4.3. Operating costs for Network Solutions

The KEMA study does not consider the operating costs associated with enhanced network based solutions. If these solutions were to be progressed we believe that operating costs should be included in the assessment as they can be significant.

For example, the fixed O&M costs for the flywheel and battery solutions are in the range €4 – 8 per kW. With the battery solutions the cost of battery replacement (every five years) has a cost of the order of €100 – 400 per kW per year.

Fixed O&M costs for a CCGT are in the range of €22 – 31 per kW[13]. This does not include the additional O&M costs which would arise as a result of enhanced system service capability, as these are not presently known.

[13] Adapted from 2013 Update of Non-Renewable Technologies, Prepared for Department of Energy and Climate Change by Parsons Brinckerhoff, April 2013, using current exchange rates.

Conclusions

The main conclusions from our desktop analysis of the KEMA Study are as follows:

- We compared that the level of costings identified in the KEMA study for normalised build costs in generation units and grid solutions. In summary we consider that KEMA's cost estimates for conventional generation technologies are reasonable, although their cost estimate for OCGTs is approximately 25 per cent higher than we would expect, partly reflecting the smaller size of plant selected by KEMA.
- As regards the grid technology solutions we consider that their cost estimates for flywheels and STATCOMs are low. With Li-ion batteries the variability of cost with the operational duty should be noted. We are not able to comment on the cost estimate for synchronous condensers.
- We found very little evidence in the public domain surrounding generation enhancement costs. Thus we were unable to comment on the values used within the KEMA report beyond the investigation of the results based on the supplementary information provided in the spreadsheets.
- Finally we believe that it is important to note that the KEMA study does not factor operating costs of enhancements into their values. However we believe these costs will not have an impact.
- Overall, our analysis suggests that the KEMA study values are appropriate and reasonably robust estimates. The overall costs of providing system services and the total system volume requirement assumptions are presented in Section 5. This feeds into the procurement mechanism recommendations in Sections 6 and 7.
- We have used these cost estimates to derive an estimate of the annual costs of procuring system services. This is used as a benchmark for incentivising the TSO to procure system services efficiently.

3. INDUSTRY SUBMISSIONS

In Section 3.1 we have conducted a high level review of the responses to the Call for Evidence issued by EirGrid regarding the finance arrangements under the DS3 Systems Services Consultation[14]. In total 26 responses were received by the TSO. Of these responses, 21 were non-confidential and provided responses to the consultation questions, and the remaining five responses provided details of their ability to provide system services. In subsection 3.1 we highlight the common issues raised by respondents in respect of each of the consultation questions. In subsection 3.2 we then present detailed tables summarising the responses to each question categorised by type of respondent, and a final table summarising the product related responses. Additional miscellaneous comments were made within the submissions; however these are described in full in the TSO's analysis of the submissions[15]. In Section 3.2 we also summarise the key points from the confidential responses. The purpose of this analysis was to qualitatively supplement the data presented in Section 2 in order to provide a broader understanding of the supply concerns associated with system services. Findings from this section have informed our supply side analysis and procurement options recommendations, Sections 5 and 6, where relevant.

3.1. Overview of consultation responses

The consultation responses varied substantially in terms of both opinion and focus. However, some issues that were addressed consistently were:

- The value approach to determining the aggregate expenditure;
- The treatment of RoCoF;
- Financial feasibility of capital investments required; and
- The coupling of capacity payments from system service payments.

3.1.1. Value approach to determining the aggregate expenditure

Overall respondents agree with the value approach to determining the aggregate available expenditure for system services. However, some of the respondents noted that the calculation should include all benefits from the system services rather than just value of avoided future wind curtailment. The additional benefits mentioned include[16]:

- The benefits associated with meeting RES;
- An emissions trading benefit as a result of reduced carbon dioxide emissions;

[14] Non-confidential responses can be found on the EirGrid Communications webpage, http://www.eirgrid.com/operations/ds3/communications/consultations/

[15] Refer to TSO's Recommendation Paper http://www.eirgrid.com/media/SS_May_2013_TSO_Recommendations_Paper.pdf

[16] Some of which were mentioned by the TSOs in the Consultation on Financial Arrangements paper http://www.eirgrid.com/media/System_Services_Consultation_-_Finance_Arrangements.pdf

- The increased effectiveness of wind farm plant output as their capacity factor increase with the reduced levels of dispatch down; and
- The benefits relating to general system stability.

3.1.2. Treatment of RoCoF

There was concern that the proposed methodology assumed that the RoCoF issues had already been resolved. This concerned many respondents due to the fact that achieving the RoCoF targets is a large part of achieving the overall benefits of DS3. Some respondents stated that it is still not certain that these RoCoF targets can be achieved by the current fleet of thermal generators, and that before the value of the different services and products can be determined, the necessary tests and assessments on the RoCoF capabilities of the conventional generation fleet need to be carried out. Furthermore, some respondents felt that the clear value in attaining a higher RoCoF more than justifies the funding for such a study, and that the value should feed into this analysis for completeness. This would ensure that the RAs are planning for the future on the basis of the most accurate set of assumptions.

3.1.3. Financial feasibility of required capital investment

An overriding concern of respondents was that system service payments may not provide investors with sufficient certainty to make the required capital investments. This was seen directly in responses to the question *"to what extent, if any should the capital costs inform the decision regarding future System Services?"* to which the majority of respondents answered that it was necessary that capital costs be taken into account. Some respondents noted that operation and maintenance costs should also be considered in the system service payments. The concern in relation to financing was also identified in responses to questions on contractual arrangements and dispatch versus capability payments. In the responses to the contractual arrangements question, many respondents felt that seven year contracts with reviews every three to five years would not provide investors with sufficient certainty. With regards to dispatch versus capability payment, the key argument for capability payments is to provide investors with sufficient certainty to justify their capital investments.

3.1.4. Coupling of capacity payment and system service payments

There was a general consensus amongst respondents that system service payments should be decoupled from capacity payments. The main justification for this is that without decoupling, incentives for generation adequacy and flexibility would not be independently targeted. In particular, capacity payments are targeted at generation adequacy and system service payments should be targeted at providing generation flexibility. If the payments are coupled, then an attempt to correct for scarcity of capacity, for example, could lead to an increase in the provision of system-wide flexibility.

3.2. Responses by category

In this subsection, we provide a summary of responses by question and by respondent category. We have divided the respondents into six categories:

- Companies with a large generation portfolio (> 500 MW);
- Small generation portfolio (< 500 MW);
- Companies with predominantly renewable portfolio;
- Research institutions;
- Demand side; and
- Other, which comprises of a supplier, a mutual company and GE, an equipment manufacturer.

All the categories include between three to five respondents with the exception of Demand Side, which only has one respondent, Activation Energy. We felt that as a demand side company, Activation Energy provided a rather different point of view and had a separate set of incentives and therefore was best categorised separately. We present the responses by category in order to capture whether certain approaches or opinions are category specific, such as whether large players have distinctly different views to small scale generation or renewables in particular. It is interesting to note that there were no strongly identifiable trends in the responses, and that on the whole the views of the respondents were held independently of whether they belonged to the large generation, small generation or renewable categories. Table 9 identifies our grouping of respondents within each category.

Table 9: Respondents by category

Large Generation Portfolio (>500 MW)	Small Generation Portfolio (<500 MW)	Renewables	Research Institutes and Representative Groups	Demand Side	Other
AES	Tynagh Energy	RES	UCD	Activation Energy	Mutual Energy
SSE	Grange Back-up Power	PHES	Frank Burke		Power NI Energy
Bord Gais	Shannon LNG	Bord na Móna[17]	IWEA		GE[18]
Energia	Ipower	Wind prospects[19]	EAI		
ESB					

Source: *Non-confidential responses can be found on the EirGrid Communications webpage, http://www.eirgrid.com/operations/ds3/communications/consultations/*

[17] Bord na Móna are classified as "Renewables" due to the fact that they own wind assets and co-fire with biomass in their peat asset, Edenderry.

[18] GE do not own any wind assets in the Irish market and as manufacturers are classified as "Other"

[19] Wind prospects are primarily developers rather than generators, however we believe that their incentives are aligned

Table 10: Consultation responses

Value of System Services to the Electricity System	Large Scale Generators (Five respondents)	Small(er) scale generators (Three respondents)	Renewables (Four respondents)
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?	Yes Concerns over: • division of pot, • whether funds will be sufficient to cover the required investment. Bord Gáis state that RoCoF should be included in the value calculation.	Mainly yes Shannon LNG doubtful that the 75% target is desirable or achievable and concerned that cost of new systems may be understated.	Mainly yes All respondents agree need to ensure that investors receive sufficient funds to make necessary investments. IWEA and Bord na Móna have concerns that consumers will be exposed to addition costs if RES targets are not met. Additionally, concern that established technologies such as pumped storage are discounted (p41 of consultation 3).
Financial Modelling and Analysis Approach			
Do you agree with the proposed methodology for determining the aggregate available pot for System Services?	Aggregate pot should include the value of present system services therefore both existing and new system services should be included. SSE note that, with regards to the modelling methodology, concern over assumption that all generations connections are firm.	Concern that the value of pot will not be sufficient to allow companies to recoup capital costs. Tynagh believe that external values should be included in final calculation of the valuation. Ipower opposed to any dilution of capacity payments as a means of financing the new services.	Yes Bord na Móna would want to extended and applied to the existing Harmonised Ancillary Services ("HAS"). PHES note that pumped hydro is only large scale storage with perhaps CAES which can handle the increased renewable energy volume needed to meet the legal requirements of reduced carbon imprint
To what extent, if any, should the capital costs inform the decision regarding future System Services?	General concerns about the KEMA cost figures, but also that operation and maintenance costs have not been included. Mixed views on role of costs in determining future system services. AES states it is vital to consider costs because cost recovery time is key to capital investment decision. ESB thinks capital costs and operational costs should be used to determine revenue requirement. SSE highlights that considering costs could effectively result in technology pre-selection, lack of competition and ultimately higher total cost.	Capital and operating costs should considered	PHES thinks capital costs should inform them to a high degree where capital intensive projects are possible Bord na Móna notes that capital costs and operating costs should be considered. RES does not think the wording is clear, in particular, the word "decision".
Allocation of System Services Revenue			
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?	Option 3 One respondent (BG) highlighted that it will be important to also note the cost of delivering the different system services.	Shannon LNG preference for Option 3 to weight products, other two respondents do not directly respond.	Option 3 PHES states that option 4 could also be a preferred solution
Remuneration Approach			

Table 10: Consultation responses

Value of System Services to the Electricity System	Large Scale Generators (Five respondents)	Small(er) scale generators (Three respondents)	Renewables (Four respondents)
Is the rationale for proposing dispatch-dependent payments clear and is there further justification, not included in earlier consultation responses, for adopting a more capability-based approach?	Respondents vary significantly on this point. The general agreement is that there should be a decoupling of capability payments for ancillary services and capacity payments. AES favours a combination of capability and dispatch. BG and Energia favour capability payments. SSE favours dispatch dependent payments however notes that for some services dispatch dependent payments may not be appropriate and that capability based means may be better suited.	Opinion is split between capability payments and dispatch payments	Opinion split between capability-based approach decoupled from the CPM and combination of dispatch-dependent payments and capability or availability type payments (primarily capability or availability type payments). Bord na Móna prefers capability payments (acknowledging however that it may not be optimum for specific services that must be delivered at or close to 'real-time') while PHES and Wind Prospects prefer a combination dispatch-dependent payments and capability. RES notes that if the capital cost figures were divided by the average capacity factor relevant to that technology then one would see that some technologies have much higher effective capital costs to repay.
Contractual Arrangements and Payments			
Are the proposed general contractual and payment arrangements clear?	2/5 respondents believe that seven years is too short and support contracts of 10+. AES on the other hand stated that seven years may be too long due to operating limitations from IED legislation requirements 2016. SSE recommends that the RAs should consult on the range of contractual arrangements that are necessary to provide sufficient investment. SSE is also concerned with the punitive nature of the performance scalar and thinks that it might be more appropriate to develop scalar calculations for the different services. ESB does not think the proposed contractual and payment arrangements are clear and would like much more information.	Grange Back-Up Power and Tynagh state that seven year contracts with reviews after three years are too risky, more certainty is required to promote investment. Shannon LNG believes that in general rates should not be static, but rather tailored to be weighted for when they are most required.	RES states that it is unclear how wind farm comprising several wind turbine sources of reactive power will be treated and also "The definition of an adequately performing AVR as described in section 8.2.1 must be clearly stated so that allocation of the Product Scalar 2 is unambiguous and not restricted to synchronous generators." Bord na Mona, states that contract periods need stability and defined immutable terms.

Source: IPA analysis of non-confidential responses can be found on the EirGrid Communications webpage, http://www.eirgrid.com/operations/ds3/communications/consultations/

Table 11: Consultation responses continued

Value of System Services to the Electricity System	**Supplier/Mutual company (2 respondents)**	**Demand Side (1 respondent)**	**Research/Institutes (3 respondents)**
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?	Power-NI concerned that value based approach is extremely volatile and introduces considerable uncertainty for the setting of future rates. This is evident by the volatility of the estimated value when stress tested by varying exogenous factors such as commodity prices. Mutual Energy states that a sufficient amount of funds to meet RES is necessary.	Yes	Mainly yes EAI thinks that system services provide value additional to minimising curtailment, such as system stability which have not been included in the value calculation. IWEA thinks the value calculation should include the benefit of avoiding penalties due to un-met targets, and the benefit of future emissions trading permits. In terms of costs the EAI mentions that the TSO does not consider operating and maintenance costs, which should be included.
Financial Modelling and Analysis Approach			
Do you agree with the proposed methodology for determining the aggregate available pot for System Services?	Yes Mutual energy is concerned about the impact on the modelling results of the assumption that interconnector flows are determined by the ex-ante run and are a fixed input in the constrained run. (Also Moyle's NI-GB capacity appears to have been assumed to be 300 MW. While this is the case at present, this is due to fall to 80 MW in 2017)	Yes This is the lowest cost option as currently calculated and so sets the standard for any other technology to meet.	EAI says aggregate pot should include the value of present system services therefore both existing and new system services should be included.
To what extent, if any, should the capital costs inform the decision regarding future System Services?	Mutual Energy states that an appropriate potential return on capital is necessary to sufficiently incentivise generation sources to provide the necessary System Services.	It could be more prudent to have on-going monitoring of funding requirements as capital costs are likely to vary significantly over the coming years (based on changes in the economy, new technologies, and economies of scale).	All three respondents state that it is necessary that payments need to cover all costs, capital and operating
Allocation of System Services Revenue			
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?	Mutual energy prefers a combination of Options 2 and 3. While Option 3 is preferred there is a risk that an allocation based solely on model outputs does not fully capture any interactions between different services and any idiosyncrasies of the system that experienced TSOs would be aware of. Similarly, while Option 2 would capture such issues, reliance on TSO experience/judgement lacks transparency. A method whereby allocation is informed by modelling as described in Option 3 but the final decision is made by TSOs as per Option 2 (with allocations which	Option 2 or 3	Option 3

IPA
Energy + Water Economics

Table 11: Consultation responses continued

Value of System Services to the Electricity System	Supplier/Mutual company (2 respondents)	Demand Side (1 respondent)	Research/Institutes (3 respondents)
	deviate significantly from the model outputs to be explained and justified for transparency) seems preferable."		
Remuneration Approach			
Is the rationale for proposing dispatch-dependent payments clear and is there further justification, not included in earlier consultation responses, for adopting a more capability-based approach?	Mutual Energy would like more clarity needed on how investment risk will be reduced. Power NI Energy does not agree with dispatch dependent payments	Unclear how "dispatch dependant" payments will affect demand side units. These customers are rarely "dispatched" but are generally available to be dispatched. Further information on providing a fair system with regard to demand side units is required.	EAI believes capability based payments are preferred if the link between capacity payments and ancillary service payments is broken. Payments should be structured so that CPM deliver adequacy and AS deliver flexibility. Frank Burke responded that the meaning of dispatch dependent payments and the basis of their calculations is not clear in the paper. IWEA mentions that further clarity is required on exactly what is meant by Dispatch dependent and an example of how this would work should be provided. Clarity is also required as to whether the less certain dispatch-type payments would have to be higher (than it if was capability based) in order to be sure of incentivising service providers.
Contractual Arrangements and Payments			
Are the proposed general contractual and payment arrangements clear?		Confusion over whether the seven year period means that EirGrid only tender for new providers ever seven years so that a new provider would have to wait for the next tendering period, in advance of which they would have no knowledge of what the winning tender price would be.	IWEA states that reviewing every three to five years does not provide sufficient certainty for to obtain financing.

Source: IPA analysis of non-confidential responses can be found on the EirGrid Communications webpage, http://www.eirgrid.com/operations/ds3/communications/consultations/

Conclusions

The purpose of this section was to qualitatively supplement the data presented in Section 2 in order to provide a broader understanding of the supply concerns associated with system services. The main findings from our analysis of the Industry Submissions are as follows:

- IPA's review of the industry submissions included the 26 responses received by the TSO. Of these responses, 21 were non-confidential and provided responses to the consultation questions, and the remaining five confidential responses provided details of their ability to provide system services. We categorised the responses into six categories:
    - Companies with a large generation portfolio (> 500MW);
    - Small generation portfolio (< 500MW),
    - Companies with predominantly renewable portfolio;
    - Research institutions;
    - Demand side; and
    - Other, which comprises of a supplier, a mutual company and GE, an equipment manufacturer.
- We found that there were no significant differences in response based on type or size of respondent.
- We found that overall, there were three overarching concerns. These were:
    - The value based approach to determining the aggregate pot of funds; overall respondents agreed with the value approach to determining the aggregate available pot for system services. However, some of the respondents noted that the calculation should include all benefits from the system services rather than just value of avoided future wind curtailment.
    - Treatment of RoCoF; there was concern that the proposed methodology assumed that the RoCoF issues had already been resolved. Some respondents stated that it is still not certain that these RoCoF targets can be achieved by the current fleet of thermal generators, and that before the value of the different services and products can be determined, the necessary tests and assessments on the RoCoF capabilities of the conventional generation fleet need to be carried out; and
    - Financial feasibility of required generator investments, with most respondents concerned that system service payments may not provide investors with sufficient certainty to make the required capital investments.
- These concerns are addressed in decisions relating to the supply side analysis and procurement options in Sections 5 and 6.

3.3. Confidential responses

In this section we provide an overview of the confidential consultation responses received. The aim of this section was to highlight key points made in these responses and how they are relevant to DS3 supply side analysis and procurement options. Confidential responses were submitted in relation to the provision of system services. The key points from these have been taken into consideration in Section 6. Additionally three responses were received regarding Pöyry's procurement options. The table below outlines the confidential respondents by technology type and type of consultation response received.

Table 12 – Removed (Confidential)

Summary of key submission points by respondent

Removed - Confidential

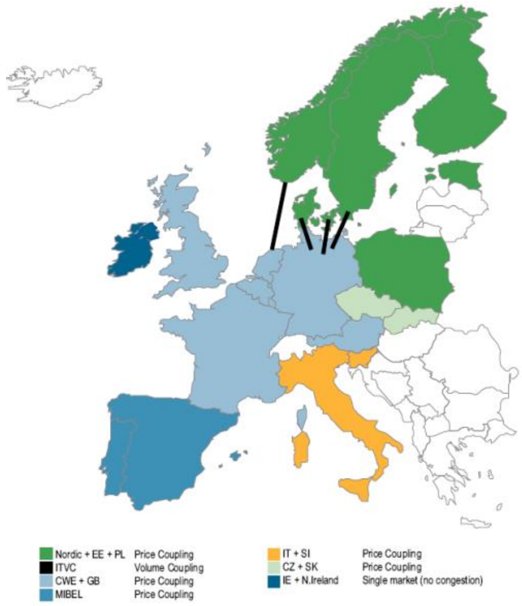
4. OTHER SYSTEM APPROACHES

In many respects, the SEM is in a unique position with regards to its ancillary service needs. As a small market with few interconnection options and limited hydro resources, it is unable to manage the effects of wind on the system in the same way as other countries with high wind penetrations. This means that system operation with higher penetration of non-synchronous generation will require new and increased levels of system services. In this section we provide a brief description of a number of other power markets that are dealing with significant and growing variable generation on their grids, albeit not to the same extent as the SEM from an SNSP perspective. The aim of this section is to highlight the differences and similarities between the Irish system and in the following countries:

- Texas (ERCOT);
- Spain
- Germany; and
- Denmark;

With the exception of Texas, the focus of this Section is on European markets where grids have become increasingly integrated, largely to facilitate further development of variable generation. Figure 2 below presents the level of market coupling in Europe in 2011. This section highlights that the SEM will indeed be a pioneer in ancillary service enhancements due to its unique circumstances. We focus on the AS developments in greater detail within the Danish market section, as Denmark is more aligned with the EU target model than Ireland and has clear AS procurement arrangements.

Figure 2: Market coupling in Europe 2011

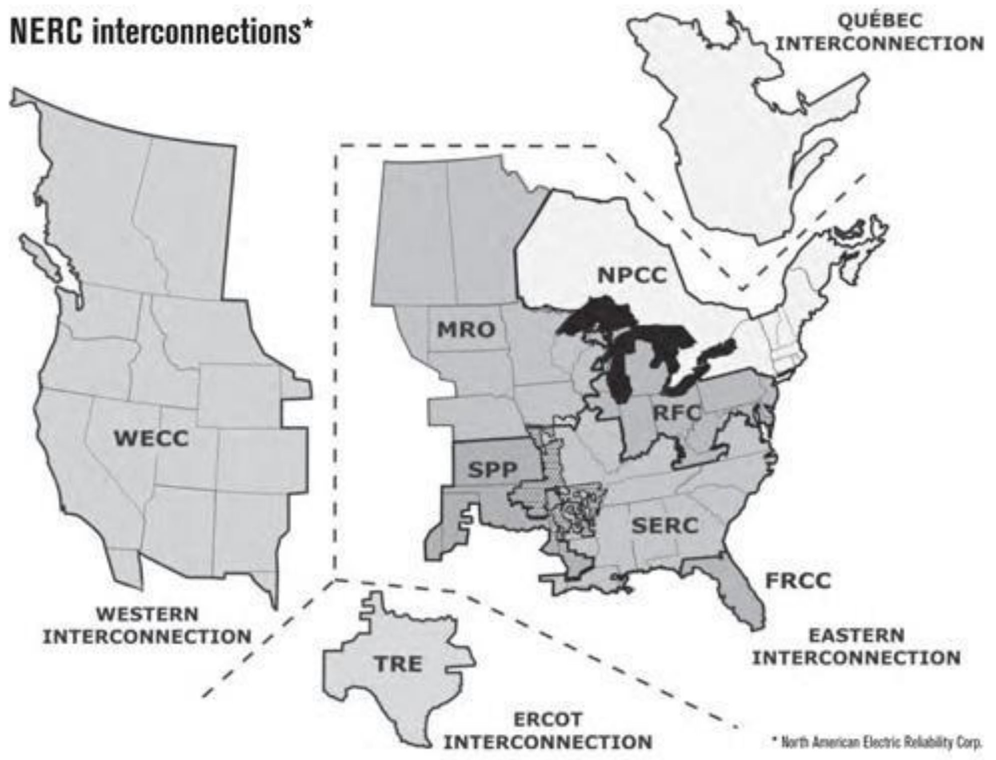


Source: ACER (2012, figure 16)

4.1. Texas

The Electric Reliability Council of Texas ("ERCOT") is an Independent System Operator ("ISO") that serves over 23 million customers in Texas, and represents 85 per cent of the state's electric load. The Public Utility Regulatory Act of Texas designates ERCOT as the Independent System Operator and as such ERCOT operates the ERCOT interconnect transmission system and wholesale electricity market. As defined by NERC standards, ERCOT is a single interconnection Balancing Authority ("BA"), which means it cannot generally rely on any neighbouring BA's for assistance during system events and emergencies.

Figure 3: NERC interconnections



Source: Re-Charge Texas, http://rechargetexas.com/the-ercot-power-grid-an-island-unto-itself/

With approximately 11,000 MW of installed wind capacity in the ERCOT market alone, Texas has the highest levels of installed wind generation capacity of any state in the United States and expects continuing growth of renewables in the foreseeable future. ERCOT's load currently varies from a peak of slightly below 70 GW in the summer to minimum of 22 GW during off-peak seasons. The combination of huge seasonal variance in system load and high penetration of variable renewable generation resources, such as wind generation, increases ERCOT's operational challenges significantly. Nevertheless, ERCOT has been successfully operating the system with high wind penetration over the past years.

In December 2010 ERCOT implemented the current ERCOT Nodal Market. Within this, market resource scheduling and dispatch became resource-specific as opposed to the portfolio-based approach in the previous Zonal Market. This change has led to improved efficiencies in unit commitment and dispatch across the ERCOT system. The introduction of the Nodal Market was one of the key factors contributing to the successful integration of intermittent resources into the ERCOT system. Resource-specific dispatch with 5-minute resolution allows ERCOT to closely follow net load variations and is one of the main reasons why ERCOT has been successful in integrating renewables with minimal increase in AS capacity.

However, as the generation mix continues to evolve, some of the new resources expected to be added to the ERCOT system bring with them additional challenges and at the same time, some of them bring with them new capabilities in providing AS. ERCOT is therefore recommending the transition to the following five AS products:

1. Synchronous Inertia Response Service (“SIR”);
2. Fast Frequency Response Service (“FFR”);
3. Primary Frequency Response Service (“PFR”);
4. Up and Down Regulating Reserve Service (“RR”); and
5. Contingency Reserve Service (“CR”).

The revised AS set, adds and/or redefines specific AS products currently used by the ERCOT system; and, additionally, subsumes different elements within the current Responsive Reserve and Non-Spin Service into several of the newly defined services. With certain exceptions described below, ERCOT visualises an AS market procurement process similar to the existing process and continued use of the current market systems. Similarly to the new SEM products, the new ERCOT AS products will be incorporated in ERCOT’s daily AS Plan and the required AS services will be procured in the Day Ahead Market just as they are in today’s market. However, if the SEM were to further align to the ERCOT model it would require the use of nodal pricing. This may prove inappropriate, as Locational Marginal Prices (“LMPs”) can result in increased volatility of wholesale electricity costs and in particular can reduce the price of generation located further away from demand centres (i.e. wind in SEM).

4.2. Spain

Having formed its own electricity market in 1998, Spain came together with Portugal in 2007 to form the MIBEL, the second regional market in Europe.[20] The Iberian market is organised as a sequence of markets: a forward bilateral contracts market, a voluntary day ahead market, several mandatory intraday markets, a real-time (i.e., balancing) market, a financial derivatives market and an ancillary services (reserves) market. The day ahead and intraday markets are pool-type markets into which generators and load submit offers and bids and some complex economic and technical conditions. While participation in the day ahead pool market is not compulsory, since market participants are allowed to enter into bilateral contracts, generators have an incentive to participate since they are eligible for capacity payments only if they participate in the day ahead market.

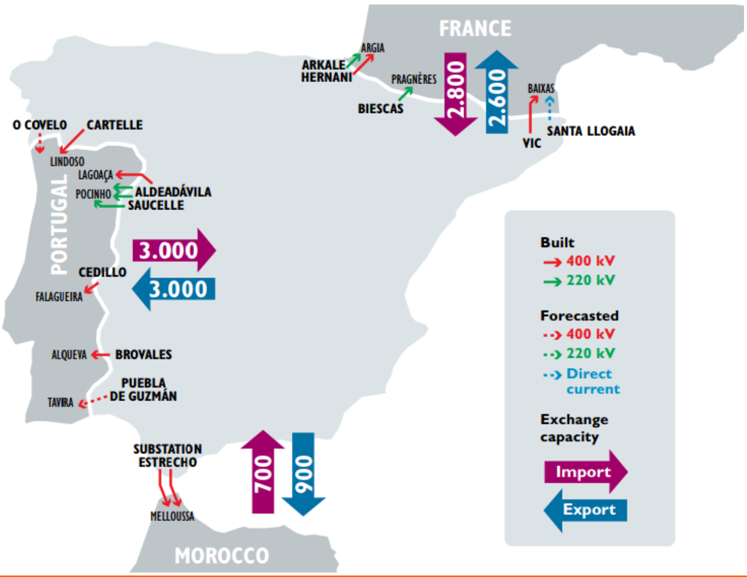
While MIBEL has supported the integration of intermittent generation on the grid, the peninsula's isolation from the rest of Europe is one of its most relevant structural features driving further development. Spain currently has one of the lowest interconnection ratios in the European Union, with commercial exchange capacity only representing 3 per cent of installed generation capacity.[21] The lack of sufficient interconnection capacity has prevented the Spanish system from taking advantage of cross-border exchanges for the integration of RE, as these enable electricity exports when the surplus of renewable production cannot be properly dispatched in the system, thus diminishing renewable energy curtailments and increasing the overall efficiency.

Figure 4 below shows Spain's forecast development of new interconnectors and commercial exchange capacities to 2016.

[20] The first European regional market became operational in 1996. This is called the Nord Pool and is currently formed by Sweden, Norway, Finland, Denmark Estonia and Lithuania.

[21] The European Union recommends 10 per cent.

Figure 4: Development of new interconnectors and forecasted commercial exchange



Source: REE 'Electricity interconnections: a step forward towards a single integrated European energy market' (2012)

Lack of interconnection means that Spain has had to focus on coordinating, aggregating, and controlling the overall production that is fed into the grid to ensure a certain volume of non-RE units are dispatched for security and technical reasons. The fact that RE plants tend to be far more distributed and dispersed than conventional power plants complicates this task.

To deal with this issue, the system operator in Spain established the Spanish Control Centre of Renewable Energies ("CECRE"), whose objective is to monitor and control RE production, maximising its production while ensuring the safety of electrical system. CECRE was established in June 2006 as wind generation started to become a relevant technology in the Spanish electrical system. It is composed of an operational desk where an operator continuously supervises RE production. Renewable energy control centres collect real-time information and channel to the CECRE. To minimise the number of points of contact dealing with the TSO, the renewable energy control centres act as the only real-time speaker with the TSO.

Balancing services in Spain are primary reserves, secondary reserves, tertiary reserves, and imbalances management. Primary reserves are not influenced by wind-power penetration. The use of secondary reserves is affected slightly by wind-power ramping, but the required level of reserves remains unchanged. Tertiary reserves are influenced by wind power variability when wind power ramps are opposite to load ramps but, even so, the required level of reserves has only marginally been increased due to wind. Conversely, the use of and the required levels of imbalances management have experienced a significant increase due to wind power uncertainty. These reserves are offered in day ahead markets as a function of wind power forecast error, guaranteeing balancing reserves from day ahead to real-time.

4.3. Germany

The German electricity market is Europe's largest, with an annual power consumption of around 550 TWh and a generation capacity of 125 GW. As the country aims to shut nine nuclear reactors within a decade, they have established national targets to generate 35 per cent of electricity from renewables by 2020, and 80 per cent by 2050. Germany still generates approximately half its power from coal-fired plants, but also around 23 per cent from renewables. At one point on 3 October 2013, solar and wind energy supplied nearly 60 per cent of electricity in use across Germany, meaning Germany has already had to manage very large flows of variable generation into, and around, its grid area.

Until recently, with the increasing level of solar photovoltaic power plants (“PV”) in the south of the country, almost all variable renewable generation (i.e., wind power) has been in the middle and north of the country. The lack of balance between rural areas with high wind energy shares and principal consumption areas all over Germany has led to transmission congestion between these different areas.

This challenge is compounded by growing flows of variable electricity from outside Germany’s borders. Germany’s immediate neighbour to the north is Denmark, which targets 50 per cent wind power. Moreover, wind penetration is likely to be highest in the Jutland Peninsula, which is part of the same power system as Germany (i.e., the synchronous grid of continental Europe). Instantaneous shares in Jutland can already rise above 100 per cent today. Grid congestion in the border region during times of high wind is likely to increase without reinforcement.

To date, the focus for accommodating further wind has been on relieving the transmission constraints by expanding the transmission system. While the German public generally supports the deployment of green energy, investment in the necessary supporting infrastructure has not always been forthcoming. One way of accelerating this investment that has been suggested is the introduction of nodal pricing of electricity. At present, the entire country is one price area which means that a surplus of electricity in one area while supply is tight in another is not signalled by corresponding low or high prices. Such price differences are an important signal to potential investors who, if they were to reinforce connections between two neighbouring areas, would stand to profit from resulting flows.

At present, there are four transmission system operators in Germany forming the German grid control cooperation:

- Amprion (formerly RWE Transportnetz Strom GmbH),
- EnBW Transportnetze AG,
- TenneT TSO GmbH (formerly E.ON Netz GmbH); and
- 50Hertz Transmission (formerly Vattenfall Europe Transmission GmbH).

The transmission system operators are members of the joint Association of Transmission System Operators (VDN). Figure 5 below presents the four German TSOs geographically.

Figure 5: German TSOs

Source: The European Network of Transmission System Operators for Electricity (ENTSO-E)

After the liberalisation of German spot markets, ancillary service markets were created in 2001 when the regulator was forced to replace bilateral contracts between generators and TSOs with public procurement auctions. Since late 2007, the four German TSOs tender control power as pay-as-bid auctions on their common platform[22]. The TSOs work together to provide three types of control reserve:

- Primary control reserve ("PC");
- Secondary control reserve ("SC"); and
- Tertiary (minute) control reserve ("TC").

Bidders have to prove that they can deliver control power according to the requirements before bidding. PC+/- is traded as symmetric (positive and negative) capacity for the entire auction period (base). SC is auctioned separately as positive and negative power for peak and off-peak periods. TC is auctioned as positive and negative power in blocks of four hours. Hence, there are four SC products and twelve TC products, adding a level of complexity similar to that faced with the new SEM DS3 products.

[22] www.regelleistung.net

All auctions are pay-as-bid auctions. In contrast to uniform (marginal) pricing as on spot markets, bidders receive the price they bid. Bids are accepted based on their capacity price only; activation is done according to the energy price. The auction design is determined by the energy regulator, Bundesnetzagentur. In June 2011, auction rules were significantly altered in order to promote market entry of new actors. Since then, the number of prequalified suppliers has greatly increased.

Table 12 and Table 13 describe the key features of the three types of control reserve.

Table 12: Control power market design in Germany since 2011

	Primary Control	**Secondary Control**	**Tertiary Control**
Platform		www.regelleistung.net	
Price		Pay-as-bid	
Auction period	week	week	Day
Number of products	1 (base, symmetric)	4 (positive/negative; peak/off-peak)	12 (positive/negative; blocks of 4 hours)
Program time unit	week	week (peak/off-peak)	4 hours
Capacity payment	yes	yes	Yes
Energy payment	no	yes	Yes
Minimum bid	1 MW	5 MW	5 MW
Number of suppliers	14	17	35
Pooling possible	yes	yes	Yes

Source: Hirth et al. 'Control Power and Variable Renewables: A Glimpse at German Data' (2013)

Table 13: Control power specifications

Specification	Primary control reserve	Secondary control reserve	Tertiary control reserve
Time for activation	30 s	5 min	15 min
Availability	Up to 15 min	15 min to 1 hr	Minimum of 15 min
Previously required min. bids by regulator	5 MW	10 MW	15 MW
Newly required min. bids by regulator*	1 MW	5 MW	5 MW (10 MW)
Tendering period	monthly		Daily
Tendering period (as of April 13, 2012)	weekly		
Focus on new technologies	Flexible/controllable plants, battery storage systems, renewable energy systems at direct marketing		

*Changes occurred in April 2011 for PCR and SCR and October for TCR

**As transition bid amount before definite reduction to 5 MW

Source: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety

The German operating philosophy, with its emphasis on automatic reserves, differs from Denmark’s operating philosophy, which places the emphasis on manual regulating power. Consequently, compared with Denmark, the German TSOs purchase many automatic reserves and few manual reserves relatively speaking.

The German manual reserves market is larger than the Danish one – the German TSOs' total demand is 2,000-2,500 MW of both upward and downward regulation reserves. The market consists of daily auctions (except for weekends and public holidays, when bidding is held on the last working day for the following days). The TSOs can purchase capacity in four-hour blocks at the auctions.

The players' bid is a combination of reserve price (€ per MW) and activation price (€ per MWh). The TSOs choose on the basis of the reserve price and the players receive the bids they made in settlement (pay as bid). The activation sequence depends on the activation prices bid. The reserved bids receive the activation price upon activation. At present, only reserved capacity is activated, and Germany only activates the manual reserves when they want to relieve the secondary reserves, which make up their primary balancing resource.

Conclusions

In Europe and the US, power markets have been dealing with the challenges of integrating renewables into their systems. Many of the issues they face are similar to those found in the SEM.

Like the SEM, Texas has a relatively small, deregulated market with increasing levels of wind to manage on its system with very little existing interconnection. The market has not yet experienced any problems but is updating its AS services strategy to enhance its ability to accommodate intermittent generation. Thus ERCOT is adapting its AS at lower levels of penetrations than those presently experienced in the SEM and are therefore not facing the same issues.

Spain has a control centre for renewable energy, which is a centralised system, where it has a single point of contact with the grid operator. The control centre tracks all of the output from the renewable generation and it is able to manage very large amounts of wind power on its system. The SEM already has a centralised approach to managing wind, and wind forecasts and dispatch are managed through the Control Centres.

In contrast, Germany has struggled with renewable integration because it has a smaller area in which to balance the system and less flexibility. Furthermore, Germany does not have locational marginal pricing. As a result there is no financial signal to reflect congestion on the system. The SEM is already reinforcing its grid to remove the main areas of congestion.

Denmark, for instance, has had very high penetrations of wind energy on its system and has been able to handle it relatively well. Some of that is because it operates in a large power pool and has a lot of flexibility in that the country has, for instance, access to Norway's hydro plants as well as combined heat and power, which can serve as a form of thermal storage and provides additional flexibility. The SEM could consider further interconnection both with the GB market and further afield in order to deal with increased wind in a similar fashion to Denmark.

In conclusion, there are several approaches to facilitating higher penetrations for wind, many of which are present in SEM. For example, the East-West Interconnector came online increasing interconnection with the GB market, and reinforcements to the transmission network are taking place under the GRID25 investment programme. Whilst these developments can mitigate the need for some system services, the main requirement remains for locally sourced products. Therefore international experience is not directly relevant in the procurement design of system services.

5. REVIEW OF TSO MODELLING RESULTS

5.1. Introduction

The aim of this section is to review the TSO's modelling results for the demand side analysis of system services. This demand side analysis is used to identify the requirement for system services and the value of these services measured by lower production or market costs. We have compared the value of enhanced system services, based on the TSO's modelling to the corresponding supply side costs. We have examined the net benefit attributable to providing additional system services and the TSOs proposed allocation of this benefit between system service products.

The TSOs have identified that to meet the RES-E targets whilst operating the system securely requires additional sources and types of system services (inertia, frequency response, ramping capability and voltage control).

Several metrics were examined during the TSO studies and an all-encompassing metric for system services issues was found to be the SNSP level. The TSOs found that for the current system a prudent maximum SNSP limit of 50 per cent should be observed, but that if mitigation measures were put in place, a real-time operational limit of 75 per cent SNSP would be possible. New system services and an enhanced generation portfolio capability were found to be an essential component of being able to move from the current maximum SNSP limit of 50 per cent to a future limit of 75 per cent.

In 2012/13 the TSOs carried out studies to determine the value and costs of enhanced system services. The value of the additional system services was calculated by comparing the system variable operating costs for a system with a 75 per cent SNSP in which new system service products enabled reduced wind curtailment levels and lower dispatch balancing costs with a counterfactual (a system with a 50 per cent SNSP).

The SEMC decided that further economic analysis was required to inform decisions on the procurement of additional and new system services. This section reviews the additional demand side analysis[23] carried out by the TSOs in February/March 2014 in line with the requirements and terms of reference set by the SEM Committee, in which a revised counterfactual was used (60 per cent SNSP).

It is important to note that the 60 per cent SNSP case assumes that the proposed change to the RoCoF standard in the Grid Code is implemented. We note that this proposed change is currently the subject of a detailed technical study and that some consultation respondents do not consider that implementation of this change will be feasible in some cases (see Section 3). However, for the purposes of our analysis we assumed that the new RoCoF standard will be implemented.

[23] DS3: System Services Valuation, Further Analysis

5.2. System service products

The existing system services are shown in the following table and are to be retained with the definitions of the steady-state reactive power ("SRP") and replacement reserve products ("RRD" and "RRS") modified to be consistent with the proposed new products.

Table 14: Existing system service products

SRP	Steady-state reactive power
POR	Primary operating reserve
SPR	Secondary operating reserve
TOR1	Tertiary operating reserve 1
TOR2	Tertiary operating reserve 2
RRD	Replacement reserve (De-synchronised) (previously called De-synchronised Replacement Reserve in TSO Recommendations paper)
RRS	Replacement reserve (Synchronised)

Source: SEM-13-098

The studies[24] carried out by the TSOs identified that five new system services were required, with the ramping margin service having three components, as shown in the following table. These system services were reviewed and approved by the SEM Committee in December 2013.

Table 15: Proposed new system services products

SIR	Synchronous inertial response
FFR	Fast frequency response
DRR	Dynamic reactive response (previously called Dynamic Reactive Power in TSO Recommendations paper)
RM1	Ramping margin 1 hour
RM3	Ramping margin 3 hour
RM8	Ramping margin 8 hour
FPFAPR	Fast post-fault active power recovery

Source: SEM-13-098

In the latest analysis by the TSOs[25], it has been assumed that the RoCoF standard in the Grid Codes has been increased to 1 Hz per second. The required volumes of system services calculated in the analysis are therefore assumed to reflect this new standard.

[24] DS3: System Services Review, TSO Recommendations

[25] DS3: System Services Valuation Further Analysis, March 2014

5.3. Sources of system services products

Analysis of the TSO Recommendations paper indicates that the bulk of the new products will come from new or existing CCGTs or OCGTs, suitably enhanced. The following table shows the main sources of system services products assumed by the TSOs.

Table 16: Sources of system service products

Product	Main generation sources of product
DRR	CCGT
FFR	CCGT, Interconnector, Pumped storage
FPFAPR	CCGT
POR	CCGT, Interconnector, Pumped Storage
RM1	OCGT
RM3	OCGT
RM8	CCGT
RRD	OCGT
RRS	CCGT, Pumped storage
SIR	CCGT
SOR	CCGT, Interconnector, Pumped Storage
SSRP	CCGT, Wind
TOR1	CCGT, Interconnector, Pumped Storage
TOR2	CCGT, Interconnector, Pumped Storage

Source: IPA analysis

The cost of enhancing existing CCGT/OCGTs is approximately 60 – 70 per cent more than the cost of enhancing new plant as indicated in the analysis in Section 2.2. It is unlikely to be economically efficient to replace old plant with new plant purely to gain efficiencies in the provision of system services. However, if there is a system-wide short-fall in the provision of system services, perhaps because it is technically or economically infeasible to enhance sufficient existing plant, the replacement of existing CCGTs with new CCGTs may need to be encouraged.

The All-Island Generation Capacity Statement ("GCS") 2014-2023 says that there is no significant new conventional generation planned for Northern Ireland over the next 10 years. The following table shows the new conventional generation planned for the Ireland up to 2023[26].

[26] Note that these units have accepted connection offers.

Table 17: New conventional generation planned for Ireland up to 2023

Plant	Capacity (MW)
Great Island CCGT	431
Dublin Waste to Energy	62
Nore OCGT	98
Suir OCGT	98
Cuileen OCGT	98
Ballakelly OCGT	445

Source: GCS 2014 – 2023

The Grid Capacity Statement states that of the plant in above table, only Great Island CCGT has a firm commissioning date in the next year, and that EirGrid has taken the prudent view that not all of the other plant in the table above will be commissioned. The plants at Ballakelly OCGT and one of the other OCGTs (e.g. Cuileen 98 MW) were not included in their generation plant mix.

It should be noted that because the GCS 2014 – 2023 report had not been completed when the TSO analysis was undertaken, the TSOs used the generation plant assumptions the GCS 2013 – 2022 report, which had higher levels of new plant than the later report. For our analysis we have therefore removed the Caulstown OCGT (55 MW) from the TSO's plant mix, in addition to removing the plant at Ballakelly and Cuileeen as above.

5.4. Cost of enhanced system services requirements

A TSO consultation paper[27] provided estimates of the cost of providing the new system services in the 75 per cent SNSP case. The TSOs examined the costs of providing the services from generation technologies and alternatively from network technologies as shown in the following table. The individual technology costs have been reviewed in Section 2.

[27] DS3: System Services Consultation, Finance Arrangements.

Table 18: Capital costs to provide new system service products

Technology	Volume	Capital cost (€million)
Generation technology solution		
Enhanced wind	1300 MW	181
Enhanced CCGT & OCGT	2850 MW	288
Network assets	STATCOM & synchronous condenser	68
Total capital cost		**537 (535)**
Network technology solution		
Flywheel + Synchronous generator	840 MW	643
Enhanced OCGT	400 MW	320
STATCOM	2500 MVAr	303
Total capital cost		**1266 (1206)**

Source: DS3: System Service Consultation, finance arrangements

Note: There are unexplained differences in the total cost values between the above table and the TSO report. The values recorded in the TSO report are placed in brackets above.

This table shows that the cost of providing new system services from network solutions is over twice the cost of providing equivalent services from generation technologies. This corresponds to costs considered previously in Table 8. We understand that at the time of these calculations, the increase in the RoCoF standard to 1 Hz per second had not been assumed, and therefore the costs may be higher that would apply if the new standard is approved. Our analysis in Section 2 of the technology costs suggests that the network technology solution could be considerably higher than proposed in the above table.

The quantities of the various system service products listed in Table 15 and Table 16 that would be provided by the above investments are not specified by the TSOs, although we have carried out our own volume analysis as described in section 5.6. We consider that the TSOs should do further detailed modelling to provide information on the volumes of services needed for the scenarios considered in their latest modelling work.

We have therefore looked at an alternative approach to the calculation of the cost of system services, based on the assumption that all new conventional plant from 2014 onwards would need to include the enhancements proposed by KEMA, and that all CCGT and OCGT plant commissioned since 2005 would need to undergo enhancements. We have selected the year 2005 on the assumption that the enhancement of older plant would not be feasible or would be significantly more costly than KEMA propose.

The following table shows the quantity of plant to be enhanced and the costs, based on the KEMA report results. We have assumed that the network assets included by the TSOs in the generation case will still be required.

Table 19: Alternative cost analysis approach

Plant type	Volume (MW)	Cost of enhancement €/MW	Capital cost (€ million)
CCGT Units (2005 - 2013)	2044	122,000	250
CCGT units (2014 - 2020)	431	30,000	13
OCGT (2005 - 2013))	353	143,000	50
OCGT (2014 - 2020)	196	74,000	15
Wind (2014 and later)	1300	163,000	212
Network assets	STATCOM & synchronous condenser		68
TOTAL			**608**

Source: IPA analysis

Notes:

Based on the GCS 2014 – 2023 generation plant mix for 2020.

The total amount of CCGTs and OCGTs proposed for enhancement = 3024 MW

Some 53 per cent of existing CCGTs and 32 per cent of existing OCGTs are assumed to be enhanced (MW basis).

The volume of wind to be enhanced (1300MW) is assumed to be the same as specified above by the TSOs. We have assumed a higher unit cost of wind enhancements based on our analysis of the KEMA work.

The total cost of €608 million is higher than that proposed by the TSOs (€535 million) partly because additional units of CCGT and OCGTs are proposed for enhancement (an additional 174 MW) and because of the higher unit cost of wind enhancements assumed. If all new wind plant from 2014 onwards were enhanced then the total cost would rise from €608 million to €762 million.

As noted above, the interconnectors are assumed to be able to provide certain system services, particularly FFR. The TSOs have confirmed that they are satisfied the interconnectors can provide the FFR product as they are already providing static reserve to the system within the FFR timeframe.

The use of the interconnector to provide system services within a contractual framework will incur a cost to the TSOs, but the provision of the services by the interconnector would avoid some capital expenditure on the enhancement of generation and network assets.

The sizes of the interconnectors are 500 MW for Moyle and 500 MW for the East-West Interconnector ("EWIC"). As the Moyle interconnector is currently restricted to 250 MW for technical reasons, we have assumed a total interconnector capacity of 750 MW.

Assuming that use of the interconnector reduced the volume of CCGTs required to be enhanced by 750 MW the capital cost of the generation solution would fall to €516 million. A further reduction in cost may be possible as the new RoCoF standard is introduced.

Clearly many assumptions have been made in coming to these cost estimates and the cost uncertainties discussed in Section 2 in relation to the KEMA costs estimates also need to be taken into account. However, at this stage we consider that it may not be unreasonable to assume that the cost of providing the new system services will be in the guideline range €500-600 million to achieve the 75 per cent SNSP level.

Further work will be necessary in order to determine the likely cost of system service provision at 70 per cent SNSP as this was not part of the original terms of reference. At this stage it may be appropriate to assume that in the 70 per cent SNSP case, the cost would be at or below (and possibly substantially below) this range, as the duty required will be lower than in the 75 per cent SNSP case, and the plant to be enhanced will be optimised with new RoCoF standard.

To express the enhancement costs in annual terms we have assumed for simplicity that the same ratio of annual to capital costs applicable to the Best New Entrant ("BNE") calculation (SEM-12-078) also applies to these system services costs. The ratio of annual to capital costs from the BNE calculation[28] is 13.9 per cent. This calculation embodies the WACC which is appropriate for generation assets and an operating cost assumption which we consider to be reasonable to apply in the context of this high-level assessment. Whilst the plant life assumption of 20 years in the BNE calculation may be somewhat long in relation to the remaining life of existing generation plants as a whole, we have not made an adjustment for this as the enhancements will generally only be made to newer plants and we believe that the addition of these enhancements may length the operating lives of these assets through their continued ability to provide system services to the TSO.

Based on the above methodology, the annual charge for generation enhancement investments in the range of €500-600 million is €70 – 84 million per annum.

5.5. Valuing the benefits of ancillary services

The TSO analysis was carried out for the forecast All Island system in the year 2020, with assumptions and inputs updated in line with the All Island Generation Capacity Statement (GCS 2014 – 2023).

The benefit of enhanced system services were estimated by assessing the cost of operating the system with enhanced system services compared against a counterfactual (representing how the system might be operated without the enhanced services).

The main counterfactual explored was based on an assumption that the RoCoF standard had been increased to 1 Hz/s, and that the change in RoCoF standard would allow SNSP levels to be raised to 60 per cent (referred to as the "RoCoF resolved" scenario).

[28] Calculated as €88.14/kW p.a./ €633 per kW

Two different approaches were examined to determine the value of enhanced system services. These approaches were respectively based on:

- **The production costs**. The production costs were calculated from the heat rate curves of the generators and the associated price of fuel plus the constraint costs[29];
  and
- **The market charges to energy consumers**. These are the production volumes at system marginal price plus the dispatch balancing costs operating (This is equivalent to the sum of the dispatch production cost and the infra-marginal rent).

Details of the modelling methodology employed are given in Appendix 1.

The key results are shown in the following table.

Table 20: System costs of different wind cases and of counterfactual

Wind connected (GW)	SNSP (%)	SEM production costs (unconstrained schedule) €m p.a.	Constraint costs €m pa	SEM production costs (constrained schedule) €m p.a.	Infra-marginal rent €m p.a.	IC costs €m p.a.	SEM market costs €m p.a.
Counter-factual 3.5	60%	1479	96	1575	1459	130	2904
4.6	70%	1281	64	1344	1552	149	2747
4.6	75%	1274	59	1334	1543	150	2727
4.6L	70%	1280	34	1315	1678	166	2827
4.6L	75%	1276	33	1309	1646	162	2793
5.7	70%	1126	68	1194	1758	175	2778
5.7	75%	1110	66	1176	1759	175	2760

Source: Table 4 of TSOs Further Analysis report and accompanying spreadsheets.

Notes:

SEM market costs = SEM production costs (constrained) + Infra-marginal rent – IC costs (interconnector costs).

The 4.6L cases refer to the 4.6 GW wind case where enhancements have been introduced to allow lower minimum operating loads on CCGTs.

Currently there is roughly 2.5 GW of wind connected on the island with over 3.0 GW contracted in ROI and further plant proposed in NI. The 5.7GW case is assumed to be a realistic high wind case.

[29] Note: Constraint costs are implicitly included in the production costs where constraints are included in the model (e.g. dispatch runs)

We note that the TSOs have deducted interconnector costs in calculating the SEM market costs. Under the ISEM proposals, the use of the interconnectors should become more efficient and potentially reduce market costs. If the particular values for the market costs are used to determine ancillary service tariffs, then a range of interconnector costs should be considered in the analysis.

The benefits of making enhancements to provide the new system services were calculated for each of the two approaches (production cost and market cost) by subtracting the costs calculated for case concerned from the corresponding costs calculated for the counterfactual case. The resulting benefits are shown in the following table.

Table 21: System operating cost benefits under different wind scenarios

Wind connected (GW)	SNSP (%)	Benefit of enhancements based on production costs (€million p.a.)	Benefit of enhancements based on SEM market costs (€million p.a.)
Counter-factual 3.5	60%		
4.6	70%	231	157
4.6	75%	241	177
4.6L	70%	260	77
4.6L	75%	266	111
5.7	70%	381	126
5.7	75%	399	144

Source: IPA analysis

The above table shows that the benefits to the system in terms of lower production costs are estimated to be €231 million in the 4.6 GW 70 per cent SNSP case and €241 million in the 4.6 GW 75 per cent SNSP case. They are significantly higher in the 5.7 GW case.

Reducing the minimum load level on CCGTs gives an added benefit of €25 – 30 million, although investments to enhance the plant capabilities will be needed to achieve this. However, it was noted in Section 2 that the plant modifications needed to achieve reduced minimum loading can be the most significant element of the enhancement costs.

The benefits in terms of market costs to consumers are significantly lower than the production cost benefits because of the higher infra-marginal rents captured by generators. We believe that this is because of higher shadow prices caused by high volumes of part-loading and by higher uplift costs from an increase in no-load plants on the system. This is further demonstrated by the fact that the market costs in the 5.6 GW case, although higher than in the 4.6 GW case, are still significantly lower than in the 4.6L case.

The TSOs have developed a methodology for allocating the total benefits of system services to each of the system service products. Details of this methodology are given in Appendix 2.

In conclusion, we find that there is a net value gain in providing system services; however the allocation of this gain between consumers and producers is for the RAs to determine.

5.6. Volume analysis

As discussed in Section 5.3, the TSOs have not been able to provide information on the volumes of the individual system service products required under the different scenarios. However, the TSOs have provided spreadsheets which provide information which we have used to derive illustrative volumes for the existing system service products in order to gauge the magnitude of the increase in requirement between 2012 and 2020 as the level of SNSP increases. The analysis is summarised in Appendix 3.

Our analysis shows that by 2020, the TSOs are expecting the requirements for most existing service products to increase by a factor between 2.6 and 2.9. However, the factors for Replacement Reserve (synchronised and de-synchronised) and for Steady-state reactive power are expected to increase by a factor of about 14.75.

In the year 2012/13 a total of €54.2 million of payments were made for existing system services products[30]. Applying the above factors to the costs for system services, based on the 2012/13 tariff levels, would give a figure for total payments of €384 million in 2020. If replacement reserve and steady-state reactive power were assumed to increase by a factor of three, similar to the factors for the other existing products, then the total payments in 2020 would be €152 million instead. These payments include the costs of providing the current level of ancillary services. There would need to be further payments in respect of the new system service products not included in this analysis.

The TSOs' analysis[31] of the constraint costs attached to each product shows that out of a total cost of €290 million, €166 million can be attributed to existing products. This suggests that the factors we have derived for replacement reserve and steady-state reactive power are high and that the volumes for these products should be reviewed.

[30] EirGrid/SONI Ancillary Services Monthly Report, 2012/13

[31] DS3: System services consultation, finance arrangements.

5.7. Key results

Table 22: System operating cost benefits under different wind scenarios

Wind connected (GW)	SNSP (%)	Benefit of enhancements based on production costs (€ million p.a.)	Benefit of enhancements based on SEM market costs (€ million p.a.)
4.6	70%	231	157
4.6	75%	241	177
4.6L	70%	260	77
4.6L	75%	266	111

Source: IPA analysis

- As presented in Table 22 the TSOs have calculated the benefits (in terms of lower production costs) of making enhancements to generation assets to deliver the new system service products to be €231 million per annum in the 70 per cent SNSP case and €241 million per annum in the 75 per cent SNSP case. If CCGTs implement lower minimum generation levels these benefits increase to €260 – 266 million per annum.
- In terms of the market costs to consumers the TSOs have calculated the benefits to be €157 million per annum in the 70 per cent SNSP case and €177 million per annum in the 75 per cent SNSP case. If CCGTs implement lower minimum generation levels these benefits reduce to €77 - 111 million per annum. This can also be seen in Table 22.
- The cost of implementing the system service enhancements is estimated to be in the range €70 – 84 million per annum, although it is not clear whether the introduction of the new RoCoF standard will reduce these costs (see Section 5.4). The current cost estimates are approximately half of the production cost benefits and of the same order as the market cost benefits.
- These costs do not include the costs of providing the existing system service products, estimated to be €60 million from contracted service providers.
- In the 4.6 GW wind case the additional infra-marginal rent captured by generators is €93 million in the 70 per cent SNSP case and €84 million in the 75 per cent SNSP case (Table 20). We believe this because of higher SMP price in certain trading periods in the higher wind cases.
- This feature is amplified in the cases where lower minimum load enhancements have been assumed for CCGTs (the 4.6L cases) where the additional infra-marginal rents captured by generators are further increased by €126 million in the 70 per cent SNSP case and by €103 million in the 75 per cent SNSP case. The total additional infra-marginal rents in the 4.6L cases are €219 million in the 70 per cent SNSP case and €187 million in the 75 per cent SNSP case (Table 20).
- If these results are validated, it would appear that if the annual cost of providing system services is of the order of €70 – 84 million per year as proposed above, then these costs will be recovered by generators as a whole through higher infra-marginal rents. It needs to be recognised that the allocation of these rents is unlikely to be reflective of the costs of providing system services and unlikely to

be properly targeted at the providers of these services. However, the new market design under ISEM could well affect these results.

- Generators gain the additional infra-marginal rents because of lower overall production costs associated with higher levels of wind combined with higher SMP values driven by greater quantities of part-loaded plant and higher uplift costs from plant on stand-by to provide additional system services. Based on our system-wide analysis under the current SEM design, if generators were to retain the full benefit of the additional infra-marginal rent, generators in aggregate are likely to be adequately compensated for these services, not taking into account any specific payments they may receive for providing ancillary services. It is important that SEMC ensure that there are no energy market interactions with the system services contracts under ISEM, and that the market design is appropriate for a system with high levels of wind.
- We note that, for the scenarios investigated, the impact on the production cost benefits of equalising the carbon price between the SEM and GB is small (an increase of €13 million).

5.8. Assessment of enhanced system services requirements

In order to cost the system services used in each of the scenarios modelled, we asked the TSOs for information on the quantities of each system service product used in each scenario. The TSOs were unable to provide this information from their modelling results and pointed out that operationally there would be many different solutions involving different product quantities that would maintain a secure system. In practice the TSO would need to optimise its choice of products and associated quantities based on the cost and availability of each product.

We appreciate that the analysis of these new system service products is still at an early stage, and raise the following issues for possible inclusion in future modelling studies required for the preparation of the ancillary services section of the GCS:

- In Table 2 of the DS3: System Services Valuation Further Analysis report (Full EOC case) no maximum RoCoF value is specified because of the assumed availability of the new system services products. We believe that in calculating the volumes required from the new system services products full use of the RoCoF capabilities imposed on generators under the Grid Code should be made.
- Greater clarity is required on the role of inertia in relation to other system services products (particularly DRR and FPFAPR) in operational timescales. In planning timescales an important consideration is whether some plant providing operating reserve (POR, SOR or TOR) can also provide system inertia (in a synchronous condenser mode), for example on a seasonal basis, as high levels of wind at low demand periods can be a particular problem.
- One of the options considered in the KEMA study was to make improvements to CCGT/thermal plant minimum load levels to provide higher levels of system inertia over a wider spectrum of operational conditions. KEMA did not provide information on the resulting quantities of inertia. This case had been examined by the TSOs as one of their sensitivity analyses. If this option were feasible at low cost we recommend that further analysis of the potential of this option is undertaken and presented in the GCS.

- The TSO's results show that there are four scenarios at the 4.6 GW wind level and a further two scenarios at the 5.7 GW wind level which meet or are close to meeting the required targets for renewables and wind (40 per cent dispatch of renewables and less than 5 per cent wind curtailment). However, the analysis appears to have been carried out for a single demand pattern and wind generation pattern. We suggest that in carrying out further optimisation a selection of demand and wind patterns should be analysed and combined within a sound statistical framework to determine whether the wind targets are deemed to be met under each plant scenario.
- As a sensitivity analysis, we suggest particular investigations are carried out into the different system services products and quantities of products required under the four scenarios shown in the following table, which also shows the level of wind curtailment and renewable generation.

Table 23: Proposed scenarios for further investigation for the GCS

Wind connected (GW)	SNSP (%)	Wind curtailment (%)	Wind generation (%)	RES (%)
4.6	70%	2.8	32.3	39.7
4.6	75%	1.4	32.7	40.1
4.6L	70%	2.2	32.5	39.9
4.6L	75%	1.2	32.8	40.2

Source: Table 4 of TSOs Further Analysis report and accompanying spreadsheets.

5.9. Impact on capacity payments

The TSO report calculates the impact of the procurement of the new system service products on the Capacity Payments Mechanism ("CPM") pot. The CPM pot is based on the cost of the BNE generator.

The TSOs calculate that the value of the system services provided by the BNE under the 75 per cent SNSP scenario to be €5.97/MW/year, and this amount is expressed as a percentage of the BNE cost and applied to the CPM pot to determine the system services adjustment to the pot.

However we believe that the €5.97/MW/year includes the value of existing system service products as well as the value of new products. We understand that the calculation of the BNE cost in SEM-13-056 already includes an adjustment for the existing system services, and therefore the calculation by the TSOs overstates the savings to the CPM pot. We suggest that the calculation of the impact on capacity payments is reviewed.

We note that based on the existing methodology the BNE plant was determined to be distillate fuelled. However, we understand that distillate fuelled OCGTs are not able to provide the flexibility that gas-fired OCGTs are able to provide. Given the need for added flexibility from new plant to accommodate higher levels of wind, we suggest that consideration should be given to including flexibility in the criteria for the selection of the BNE plant in future work.

It should be noted that the BNE calculation is likely to change or be replaced under the ISEM Capacity Remuneration Mechanism ("CRM") proposals. In particular, in the reliability options, capacity is incentivised to be available at times of scarcity when prices are expected to be high and this could conflict with the provision of system services.

Conclusions

The main conclusions from our analysis of the TSOs' demand side modelling are as follows:

- There is much uncertainty over the required volumes for each of the system service products to meet the SNSP levels expected in 2020. There is also uncertainty over the inter-changeability of products in meeting the range of operational conditions that need to be managed by the TSOs.
- As the RES target of 40 per cent is approached the costs and benefits of different scenarios need to be examined more closely in order that the target is achieved cost effectively. The modelling results show that whilst procuring system services to achieve a 75 per cent SNSP level will meet the 40 per cent target, a 70 per cent SNSP level would provide a system that is very close to achieving the 40 per cent target. Noting that the 70 per cent scenario has not been analysed as robustly as the 50 per cent and 75 per cent scenarios, we recommend that a sound statistical methodology is put in place to underpin the calculation of the expected RES percentage (for example, taking into account weather and wind variabilites and interactions over a long run of years) and that the mechanism for procuring system services recognises that adjustments to the SNSP constraint could potentially reduce the requirement for system service products whilst still achieving the RES target.
- The cost of providing additional system services from generation technologies is substantially less than from network technologies; although some network technologies may be required to address specific or local issues on the network.
- The TSO's analysis of production cost savings from the levels of wind in 2020 (4.6 GW scenario) are €231 million per annum in the 70 per cent SNSP case and €241 million per annum in the 75 per cent SNSP case. The estimated cost of investments to provide the system services from generation technologies to achieve this level of wind penetration (75 per cent SNSP) is in the range €70- 84 million per annum(annualised over 20 years, and assuming a pre-tax WACC of 6.6 per cent). The shape of the cost curve with SNSP per cent should be investigated to determine the optimum benefit to consumers.
- If CCGTs implement lower minimum generation levels these benefits increase to €260 – 266 million per annum. We recommend further work to better understand the costs and benefits of reducing the minimum load levels.
- The TSOs' analysis of market cost shows lower system benefits than the production cost savings. This is because of the additional infra-marginal rents captured by generators, some €93 million in the 70 per cent SNSP case and €84 million in the 75 per cent SNSP case. This feature is amplified in the cases where lower minimum load enhancements have been assumed for CCGTs where the additional infra-marginal rents captured by generators total €219 million in the 70 per cent SNSP case and €187 million in the 75 per cent SNSP case.
- If these results are validated, it would appear that if the annual cost of providing system services is of the order of €70 – 84 million per year, then these costs will be recovered by generators as a whole through higher infra-marginal rents. However, it needs to be recognised that the allocation of these rents is unlikely to be reflective of the costs of providing system services and unlikely to be properly targeted at the providers of these services.
- The methodology for calculating the BNE cost may need to be reviewed to take into account a requirement for the additional operational flexibility desirable from new plant and the potentially higher infra-marginal rents available to generators.

6. PROCUREMENT OPTIONS

The aim of this section is to consider options relating to the procurement options for ancillary services, based on the supply side and demand side analysis undertaken. Ancillary services provide an essential set of system service products for one buyer, the TSO. The design of the procurement mechanism for ancillary services must also recognise that the availability of these products is limited and special measures may need to be taken to protect the interests of consumers from the excessive pricing of products.

In Section 5 we reviewed the requirements for system service products calculated from the analysis presented by the TSOs in the TSO Recommendations report. We have concerns that in this presentation the TSOs have not published explicitly their estimates of the volume requirements for each system service product together with metrics that would guide suppliers in assessing the interchangeability of different products to meet system requirements. This lack of transparency means that potential providers of system service products will not be clear as to the contribution that their products offerings can make to the overall requirement and may not encourage market entry. In Section 5 we have reviewed the costs of providing system services from generation plant but no assessment has been made of the future potential for demand side customers to contribute to the provision of system services and the associated costs. Our review also noted that as the 40 per cent RES target is approached the cost of making marginal improvements to the RES percentage actually achieved may not be justified by the costs involved, particularly taking into consideration that there may be uncertainty over the precise calculation of the RES percentage delivered by the network.

Given these uncertainties we consider that the design of the procurement mechanism should provide incentives for the TSO to procure system services efficiently in terms of both volumes and costs. The TSOs has proposed product pricing based on a valuation approach. As proposed this does not have an incentive element and does not provide for price discovery over time. Our high level assessment in Section 5 showed that the cost of providing system services from generating plant was significantly less than the value in reduced operating costs facilitated by the additional system services.

We consider it reasonable for the benefits of procuring additional system services to be shared between service providers and customers.

Objectives of procurement mechanisms

We have developed our proposals for the procurement of system service products against the following objectives:

- A reliable availability of products in adequate volumes in the short- and long-term;
- Incentives on the TSOs for efficiency;
- Robust product prices;
- Reasonable set-up and transaction costs;
- Aligns with ISEM developments; and
- Aligns with EU target model.

This section focuses on developing approaches which we believe can be designed to be consistent with the ISEM proposals as they evolve and which provides a stable platform for the introduction of new system service products as the level of wind penetration increases. Important considerations in delivering these approaches is that they should not be unduly complex and that they should have a high degree of consistency across product types.

In this section we have considered the short-term costs of providing ancillary services separately from the long-term costs associated with providing the new investment to provide new system services capacity.

6.1. Interactions with other markets

There is the potential for the system services market to interact with the energy market and the capacity provided by the capacity payments mechanism. In the energy market the introduction of Balance Responsible Parties ("BRPs") under ISEM means that the energy produced by generators providing system services to the TSOs will be accounted for under the TSOs energy account. One possibility to be considered in the ISEM detailed design would be for energy contracted to the TSOs to take priority in the calculation of BRP imbalances.

In the capacity payment mechanisms the quantity of plant to be contracted includes an assumption about the quantity of reserve plant required to meet system security standards. The extent to which the mechanism achieves this objective will determine the quantity of generation capacity available to service the system services market.

6.1.1. Energy market

There are potentially strong interactions between the procurement of system services and the energy markets under ISEM. This is because by offering an ancillary service (except for black start) the provider is reducing their opportunity to participate in these markets. Therefore the price offered or tendered for an ancillary service or set by the regulator will need to reflect this opportunity cost plus any specific costs incurred in providing the ancillary service concerned. This particularly applies to the ISEM options involving a separate balancing mechanism (ISEM options 1 and 3) because, for example, capacity committed by a generator under the balancing mechanism may not be available to provide ramping services or reserve generation if needed. Such issues can be addressed through the contractual and regulatory framework and tested as part of the ISEM detailed design.

It should be noted that the quantity of system services products required by the TSOs will in part depend on the tightness of the balancing regime that is implemented under ISEM.

The following table summarises the metrics used to calculate the volumes utilised and the generator performance together with an indicator of whether the product interacts with the energy market.

Table 24: System service products and interaction with energy market

Product (Note 1)	Volume utilised	Performance factors (Note 2)	Interaction with energy market (Y/N)
Voltage control			
DRR	% of the registered capacity (MVar)	Availability	N
SRP*	Dispatchable reactive power range (MVar)	Availability	N
Inertial response			
SIR	Kinetic energy delivery rate (MWh/s)	Availability	N
FFR	Increase in MW output (2-10 s)	Availability	N (assumed, given short timescale)
FPFAPR	Based on MW output	Availability	N
Reserve			
POR*	Increase in MW output	MW output, availability	Y
SOR*	Increase in MW output	MW output, availability	Y
TOR1*	Increase in MW output	MW output, availability	Y
TOR2*	Increase in MW output	MW output, availability	Y
Ramping			
RM1	Increase in MW output	MW output, availability	Y
RM2	Increase in MW output	MW output, availability	Y
RM3	Increase in MW output	MW output, availability	Y
Slow Reserves			
RRD	Increase in MW output	MW output, availability	Y
RRS	Increase in MW output	MW output, availability	Y

Source: IPA analysis

Note 1: Product types marked with a * are required to be provided under the Grid Code

Note 2: For all products, an important metric is compliance with dispatch instructions.

We consider that the provision of mandatory system services under the Grid Code should be rewarded by the appropriate system service payments derived from the regulated/market price as at present where, in relation to a particular service, the Grid Code requirements on different types of User are different (e.g. the reserve requirements in relation to fully and partially dispatchable generators). The appropriate system service payment may need to reflect the different services provided by the different Users.

6.1.2. Capacity payment mechanism

The ISEM High Level Design ("HLD") includes five options for the CPM. CPM Option 1 (Strategic Reserves) does not interact with a system services procurement as the contract will be outside the market and may possibly include system service provision as part of the contract. The other CPM options require system services income as an input to determine the appropriate price of capacity. The calculation of these income streams will be more complex under competitive market arrangements for system services compared to regulated price arrangements. We assume that the details of these calculations will form part of the detailed design phase of ISEM.

6.2. Previous work

6.2.1. Pöyry

The Pöyry report[32] described four high-level approaches to the procurement of ancillary services. These were:

- **Mandatory provision**. Mandatory participation with payments based on ex-ante regulated prices. The report notes that in some countries no specific payment is made for mandatory services with providers expected to recover their costs through the energy market. As this results in distortions to the merit order, we do not consider the non–payment method is appropriate.
- **Regulated provision**. The TSOs procures system services through a mandatory bidding process with contracts allocated on the basis of an agreed set of quality criteria. The price for the service is regulated.
- **Regulated competition**. Voluntary participation and contracts awarded based on price and quality. The TSOs may procure services within a total cost cap.
- **Fully competitive market**. System service contracts allocated based on price only (subject to meeting minimum quality criteria). The main differences from the regulated competition approach are the price determination process and the ability to transfer the obligation to deliver to another party.

Grouping of system services

Pöyry grouped system services products into four groups and proposed that products for all but one of the groups should be procured through the regulated competition approach and that products for the other group (ramping services) should be procured on a fully competitive basis.

The four groups specified by Pöyry for procurement purposes are shown in the following table.

[32] Procurement options for system services, A note from Pöyry Management Consulting to the SEM Committee, December 2013

Table 25: Proposed system service groups

Group	Products	Price determination proposals
Group 1 Grid stability services	SIR; FFR; DRR; FPF; SRP	• Long-term, capacity based contracts. • Pay-as-bid pricing proposed since variance in quality factors between bids.
Group 2 Ramping margin services	RM1; MR3; RM8	• Short-term, capacity based contracts. • Pay-as-cleared pricing proposed.
Group 3 Fast reserve services	POR; SOR; TOR1; TOR2	• Long-term, capacity based contracts. The length of the procurement contracts to align with investment life, subject to NCEB[33]. • Pay-as-bid pricing proposed since variance in quality factors between bids. • Option to allow co-provision of services within Group 3. • Potential for fully competitive and short-term market based on marginal pricing.
Group 4 Slow reserve services	RRD; RRS	• Long-term, capacity based contracts. The length of the procurement contracts subject to ENBC rules. • Pay-as bid pricing proposed since variance in quality factors between bids. • Option to allow co-provision of services within Group 4. • Potential for fully competitive and short-term market based on marginal pricing.

Source: Pöyry Paper on Procurement Options

[33] The Energy Balancing Network Code has a requirement for a market based procurement and that contracts should be for no longer than 1 year without regulatory approval for Balancing Capacity (capacity available for balancing load fluctuations in the transmission grid).

We propose that these groups are retained for the development of contractual arrangements for each group. This will allow participants, where appropriate, to offer combinations of products within each group to provide the equivalent system resource for the TSO. The TSOs' proposal for product scalar could be used as the basis for developing a set of equivalence relationships between the individual products within each group. However, we recognise that the TSOs will need to do further work to develop these scalars to a state where they can be used in the commercial procurement of system services.

We also propose to retain the product volume definitions set out in Appendix 2 of the TSO Recommendations.

There is a case for having similar price determination mechanisms for each group where products are procured competitively. This minimises market complexity and potentially avoids conflicts between the procurement arrangements for different groups.

Use of competition in procurement

Pöyry proposed that for Group 1, 3 and 4 the contracts would be long-term (5-10 years) and awarded on the basis of pay-as-bid tenders. The contracts would be awarded until a monetary cap was reached (cap to be approved by the SEMC).

For Group 2 the contracts would be short-term (within day) and awarded on the basis of pay-as-cleared bids. The volumes would be set in real time by the TSO. Secondary trading would also be permitted and units would be required to balance their position in each trading period.

This approach has the advantage that it provides for price discovery. However it is potentially complex and, given the number of participants in the ancillary services market, we consider that the Pöyry proposals need to be modified to include a higher level of regulatory intervention in the price determination process to ensure an efficient outcome for consumers.

6.2.2. TSOs

The TSO proposed an option for procurement arrangements in the TSO Recommendations paper (May 2013). Under this proposal there would be a fixed payment rate set for each system service product. The rates would be set with reference to the total value of system services (calculated by the TSOs to be €355 million per annum). Each rate would also be subject to a rate scalar, product scalar and performance scalar. The rate scalar is designed such that those units that run more frequently would receive higher payments than units less likely to run. The product scalar increases the payments for specified variants of the approved products. The performance scalar reduces payments to underperforming units.

The value and rates would be recalculated every five years. The five-year period attempts to strike a balance between stability and ensuring the rates reflect the value of system services. Units would be offered long-term contracts (greater that five years) but the payment rates would change every five years. The TSOs would offer contracts according to its assessment of the needs of the system.

Whilst straightforward to implement, this approach does not provide price discovery, as prices will be calculated relative to the value of system services. They will not be adjusted for scarcity or to reflect increased efficiency by providers. In addition some providers have argued that five years is too short a period to secure financing for the associated investment.

6.3. Market Participation

The following table gives a breakdown of the current ownership of the non-wind assets which are expected to provide system services in 2020. Non-wind assets in particular will be the main source of the new system services to be provided in 2020.

Table 26: Non-wind sources of system services (2020)

Technology	Capacity	Ownership
CCGT	4271MW	ESB, AES, SSE, Bord Gáis, Tynagh, Viridian
OCGT	1177MW	ESB, AES, SSE, Bord Gáis
Thermal (incl peat)	2447MW	ESB, AES, SSE, Bord na Móna
Pumped storage	292MW	ESB
Moyle Interconnector	250 MW	Mutual Energy Limited
East West Interconnector	500MW	EirGrid Interconnector Limited

Source: IPA analysis

This table shows that there are seven sources of system services to the TSO on the basis of asset ownership. Not all owners will be able to provide the full range of system service products.

It is possible that in future years (in the 2020s) the number of providers will increase as older plants are retired and new plants are constructed potentially with a wider range of ownership. In principle, there may also be sales of existing assets to new owners. However, for the purpose of this report we assume that the number of potential participants in any proposed market based mechanism will be seven at most.

In the short-term, market concentration can be lowered if demand-side participation can be encouraged.

Market concentration (as measured by the Herfindahl-Hirschman index ("HHI") for example) is a useful indicator of the degree of competition in a market. With just seven participants, including one participant (ESB) which is dominant, the market concentration is currently high in the ancillary services market and therefore competitive mechanisms will need to be developed within a strong regulatory framework.

Table 16 presented the main generation sources of system services. Using this information, and taking the plant mix for 2020 from the 2014 Generation Adequacy Report, we have calculated the HHI for product group, assuming that the current owner is still in owner in 2020. In all cases we have considered the parent company as the owner. For example, Dublin Bay Power is owned by ESBI, which in turn is affiliated with ESB. In the case of wind, in order to present a worst case scenario with regards to potential market concentration, we have assumed that all enhanced units will be owned by ESB.

Table 27: Potential market concentration by group

Product Group	Main generation sources of group	Group HHI
Group 1	CCGT, Pumped storage, Interconnector, Wind	2,864
Group 2	CCGT, OCGT	2,391
Group 3	CCGT, Pumped Storage, Interconnector	2,009
Group 4	CCGT, OCGT, Pumped Storage	2,572

Source: IPA analysis

According to the EU Commission, a market could be viewed as 'concentrated' if its HHI exceeds 1,000 and 'highly concentrated' if its HHI exceeds 2,000[34]. Our analysis indicates that each system service represents a highly concentrated market – the lowest HHI calculated at 2,009 – and therefore competitive procurement arrangements would need to have a strong regulatory supervision.

If a new player were to enter the market between now and 2020, this could result in a reduction of market concentration. In Great Britain, Centrica is currently considering selling three of its CCGT units. If something similar were to happen within the SEM, and three of the largest CCGTS (Aghada, Coolkeeragh and Poolbeg) were divested, this would result in group HHI reductions to levels shown in Table 28. In all cases, this reduction in concentration still results in product groups which are considered to be 'concentrated' by EU Commission standards.

Table 28: Optimistic potential market concentration by group

Product Group	Main generation sources of group	Group HHI
Group 1	CCGT, Pumped storage, Interconnector, Wind	1,684
Group 2	CCGT, OCGT	1,593
Group 3	CCGT, Pumped Storage,	1,374

[34] EC Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations utilise these HHI thresholds.

Table 28: Optimistic potential market concentration by group

Product Group	Main generation sources of group	Group HHI
	Interconnector	
Group 4	CCGT, OCGT, Pumped Storage	1,406

Source: IPA analysis

Whilst the market may be highly concentrated at present, the divestment of generation assets to new parties and the introduction of demand side participation will reduce the market concentration over time and it is likely that the degree of regulatory supervision can then be reduced.

6.4. Capacity market options

Currently ancillary services are procured by the TSO on a per MWh basis (MVarh basis for reactive power)[35]. The unit rates have tended to remain unchanged or fall over recent years. However, we understand that the total expenditure on system services has been broadly flat although volumes have increased slightly over recent years.

The current level of system service payments appear to be based on a historical representation of the costs of providing these services from existing plant. However, as old plant is retired and the requirement for system services increases this approach is unlikely to be sustainable[36].

It is expected that system service products in the future will be provided by mixture of:

- Existing capabilities;
- Enhancement to existing generation units;
- New generation plant designed with enhanced capabilities; and
- New network assets (e.g. STATCOM).

The investment costs to deliver these services depend on the bundle of services required and the assets available to be installed/enhanced. Some products can substitute (at least in part) for other products and the over/under provision of one service can decrease/increase the need for another. The specific requirements also vary with system conditions and some products may need to be provided in certain locations.

[35] Payments are expressed on an hourly basis, although settlement is carried out on a half hour trading period basis.

[36] The Grid Code only places obligations on Users in relation to certain system services and wind plant has different obligations to thermal and GT-based plants.

The requirement to provide for ancillary service capacity has similarities with the requirement for a CRM. A recent consultation paper[37] taking forward the development of ISEM discussed the regulated and market options that could form the basis of the CRM under ISEM.

6.5. Price based mechanisms

In these mechanisms, the price per unit of each system service product is determined by the TSO, and approved by the RAs. This approach is particularly suited to circumstances where the market concentration is high, but has the potential disadvantages of not encouraging new participants or innovation.

The issues for development in relation to this mechanism are the method of calculating the unit tariffs and the method for selecting the required volume on the day from the volumes offered and accepted from providers.

- Cost based tariffs;
- Value based tariffs;
- Shaped products over the year[38]; and
- Address existing providers and new providers (different cost structures and contract length issues).

Whilst the TSO has the primary role in determining volume requirements, the RAs have a role in monitoring the quantities for which tenders are accepted.

6.5.1. TSO recommendations

The TSOs have recommended[39] procuring system services based around long-term contracts (say, 5 years) at a regulated price (rather than through dynamic price discovery through competitive procurement). This proposal is an extension of the present arrangement for the procurement of the Harmonised Ancillary Services ("HAS").

This approach is designed to provide some long-term certainty to providers of the service who will in some cases be required to make significant investments. The cost of providing this certainty has to be balanced against the cost of risk which make be factored into short-term pricing.

The TSOs propose both payments on a capability or dispatch dependent basis, depending on the type of system service. They propose that reserve type products

[37] Integrated Single Electricity Market (I-SEM) High Level Design for Ireland and Northern Ireland from 2016, Consultation Paper, 5 February 2014, SEM-14-008

[38] Note: The TSOs' proposal for a product rate scalar achieves a time-shaped effect.

[39] DS3: System services review, TSO Recommendations

be paid on a dispatch dependent basis, while voltage and stability related products be based on a capability basis, applying a rating scalar. The TSOs have proposed a performance scalar to recognise that the capability to provide a product needs to be combined with the plant availability to deliver the service when required. Table 29 shows the TSOs' recommendations for the division of dispatch dependent and capability based payments for the different system services.

Table 29: TSOs proposals

Product	**Capability Basis (with rate scalar)**	**Dispatch Dependent Basis**
Reserve Type Products		
Fast Frequency Response		X
Primary Operating Reserve		X
Secondary Operating Reserve		X
Tertiary Operating Reserve 1		X
Tertiary Operating Reserve 2		X
Replacement Reserve		X
Ramping Margin (1,3 and 8 hours)		X
Non-Energy Products		
Synchronous Inertial Response	X	
Static Reactive Power	X	
Dynamic Reactive Response	X	
Fast Post-Fault Active Power Recovery	X	

Source: TSO

Under the current HAS regime, the regulators set a total allowance for ancillary service payments in each year (with separate Northern Ireland and Ireland (Republic) components). The TSOs set the individual system service product charges with a view to not exceeding this allowance. The TSOs have not suggested how large the total allowance should be in 2020, but have noted that the value of system services (including the proposed new services) in facilitating the 75 per cent SNSP level of wind generation is calculated to be €355 million per annum (including the €60 million per annum allowance for existing system services).

The TSO has taken a value based approach to determining how much of the total expenditure allowance is allocated to procure each product. The methodology used to determine the allocation was to consider each product individually and allocate the total based on their relative impact on Dispatch Balancing Costs ("DBC"). Table 30 summarises their pot division based on the modelling results. The TSOs then also calculate rates by product, assuming the TSOs' recommended split of capability and dispatch products as per Table 29.

Table 30: Product Rates and Implied Volumes

Product	Unit	Pot Size (335) EURO	Product Rates EURO/Unit	Annual Volume Million Units (2020)
SIR	MWs2h	8.00	0.000517	15,473.89
FFR	MWh	41.00	4.928911	8.32
POR	MWh	39.00	3.545921	11.00
SOR	MWh	24.00	1.581099	15.18
TOR1	MWh	29.00	1.865658	15.54
TOR2	MWh	27.00	1.690429	15.97
RR	MWh	6.00	0.0937575	63.99
Reactive Power	Mvarh	38.00	0.136009	279.39
Dynamic Reactive	MWh	35.00	0.194727	179.74
FPFAPR	MWh	62.00	0.39409	157.32
Ramping RM1	MWh	9.00	0.13837	65.04
Ramping RM3	MWh	18.00	0.284923	63.17
Ramping RM8	MWh	19.00	0.174247	109.04

Source: TSO and IPA analysis

An alternative approach is a cost based to approach where the tariff is based on marginal operating costs and annualised enhancement costs. These costs were estimated in Section 5 at €140-164 million per annum (including the €60 million per annum allowance for existing system services), less than half the estimated system value.

There are three concerns with the TSOs' proposed approach. These are as follows:

- Given the large disparity between the costs of providing system services and their value to the system an element of price discovery is necessary in the procurement process in order to protect the interests of customers;

- The five year contract duration may not provide sufficient assurance to investors; and

- There are no incentives on the TSOs to improve their efficiency in the procurement and use of system services. We consider such incentives are necessary to protect the interests of customers.

6.5.2. Purchasing procedure

Ancillary services may need to be purchased using a European call for tenders procedure, with publication of documents on the relevant European Union websites.

It is likely that a notice will need to be published specifying the required volumes for each service and inviting interested providers to apply. Candidates for inclusion in the tendering process will need to pass a number of qualifying criteria.

6.6. Quantity based mechanisms

The mechanisms are designed to enable the TSOs to procure the required volumes of each product at least cost, where possible through a competitive process.

There are two important categories of product:

- Category 1 products are those where the provision of the service does not interact with the energy or capacity markets; and
- Category 2 products are those where the provision of the service does interact with the energy or capacity markets.

The product prices tendered should not frustrate the objectives of the competitive process. For products within the respective product categories should be reflective of the following:

- Category 1 products: the costs incurred in providing the service; and
- Category 2 products: the opportunity costs observed elsewhere in the wholesale market in relation to the capacity impairment arising from provision of the product concerned.

The procurement mechanism must address the differing perspectives of existing providers and new providers (different cost structures and contract length issues).

The important features of a market design are that it:

- Recognises the current market concentration (see Table 27);
- Is attractive to new entrants to maintain/improve competitiveness over the medium/long term; and
- Is robust against collusion.

6.6.1. Possible mechanisms

Competitive options for procuring system services fall broadly into one of the following categories:

- Open/sealed bids;
- Ascending/descending bids; and
- First/second price winning bids.

In an open auction, each participant's bids are publically known, whereas in a sealed price auction bids are not known until after the bidding period is over, and even then only the winning bid is often identified.

In an ascending auction, the price would begin low and increase until the amount of supply offered is equal to demand for system services. In contrast, in a descending auction, the price would start high and fall until the amount of supply being offered is equal to the demand.

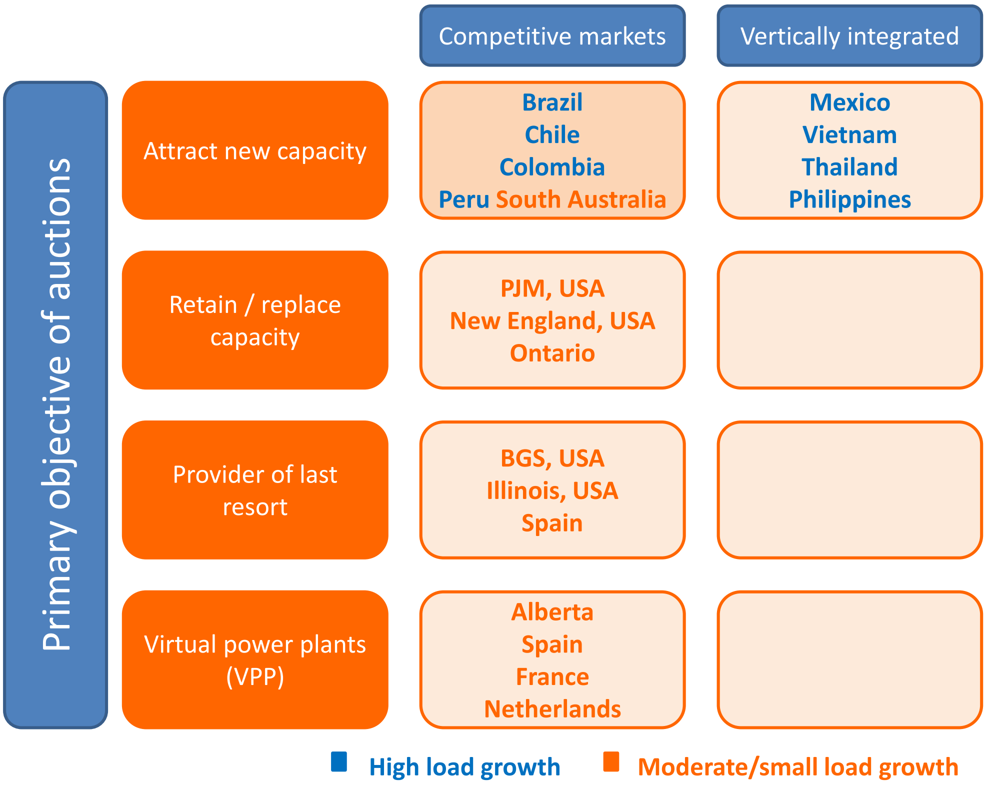
In a first price auction your bid (if winning) is the price that you pay, whereas in a second price auction the price paid is the price of the second highest bidder (in an ascending auction).

Klemperer (2001)[40] highlights the importance of local circumstances in the practical design of auctions. The most important feature of the design of any auction surrounds competition policy, and the prevention of collusive, predatory and entry-deterring behaviour. This work found that ascending and uniform (demand) price auctions are highly vulnerable to collusion and likely to deter entry. While sealed bid ascending (demand) auctions may prove more competitive, this is highly dependent on the presence of effective anti-trust policy.

Figure 6 outlines some existing electricity procurement auctions, categorised by the auction's primary objective. Within this, countries in blue text represent markets with high load growth, whereas orange text represents slower load growth. While this is not for specifically for ancillary services, it highlights auctions can be used to procure a variety of services in different circumstances although the choice of design will be important in achieving the objective. The auction design also needs to take into account specific local circumstances.

[40] http://www.nuff.ox.ac.uk/users/klemperer/wrm6.pdf

Figure 6: Goals of procurement auctions



Source: IPA analysis of World Bank Electricity Auctions Study

Depending on the circumstances, competitive auctions may not always be feasible for structural reasons. This could apply in a situation where the product is very complex and difficult to specify ex-ante.

Where market concentration is high the market design must allow for a degree of regulatory oversight and for transparency in the bid selection process.

6.6.2. Application to the SEM

The following table provides an assessment of the main design options in the context of Ancillary Services in the SEM. In this section we are considering the application of auctions in the context of short-term costs. The rewarding of long-term investment costs is considered in the next section.

Table 31: Design options for multiple unit auctions

Auction design	Bidding rules (structure and timing of bids)	Price determination (selection of winning price(s))	Advantages/ disadvantages	Assessment in the context of AS in the SEM
Pay-as-bid	Sealed bid	Bilateral contracts (no price discovery)	Handles weak competition Simple to implement	Possible option Potential for cost inflation of bids
Pay-as-cleared (uniform price)	Sealed bid	Market clearing (no price discovery in short term)	Handles weak competition Simple to implement Attracts small bidders Viewed as fair	Mandatory bidding appropriate where small number of participants
Descending clock	Open/dynamic	Price discovery	Suitable for multiple products Less vulnerable to corruption than sealed bid Possibility of collusion when competition in weak	Too few players in SEM to be suitable
Hybrid (descending clock followed by pay-as-bid phase)		Price discovery	Speeds auction convergence Second phase complex to implement Exposure problem with multiple products	Complexity could be an issue for financial contracts
First/second price winning bids	Hybrid sealed bid/open	Price Discovery	Good price discovery with strong competition	Complex and too few players in SEM to be suitable

Source: IPA analysis

Given the market concentration in the SEM, we consider that a mandatory auction would be more appropriate than a voluntary auction[41]. However, this would require strong bidding rules which would need to be overseen by the RAs. For example, an

[41] As an example, Ofgem are proposing a mandatory auction to develop wholesale power market liquidity

additional licence condition[42] may be necessary to require participants to submit bids in the market and to require that bids submitted are consistent with the objectives of the market. These objectives would need to be developed through a consultation process. For example, we would expect that all bidders who we capable of providing individual system service products would include these products in their group-wise bids. Appendix 3 outlines the current bidding rules that exist within the SEM. These may provide a useful starting point in terms of a mandatory auction approach within the procurement of system services.

The most appropriate auction design from those described in the above table is a uniform price, sealed bid auction (also known as a Vickrey auction when the cleared price is that of the second highest bid, as this encourages sound bidding) because it:

- Handles weak competition;
- Is simple to implement;
- Attracts smaller bidders; and
- Is viewed as fair.

This could be similar to the bidding structure currently in place within the SEM wholesale pool market. This has proven successful; however the pool has not faced issues regarding under-capacity because of the CPM. Likewise it is essential that the procurement framework includes additional features to encourage investment in new system services.

We recommend that an independent party such as SEMO is appointed to administer and manage the auction process.

6.6.3. Incentives for new investment

An important decision is whether there should be separate auctions for new capacity (requiring investment) and for existing capacity, or whether to have a single auction.

The GB capacity mechanism, which distinguishes between new and existing units, is structured as follows:

- It is volume based, as determined by TSO annually;

  Auctions are run November each year for delivery in four years' time; however supplemental auctions are held one year before the year in question (to bring up to the full required capacity, allow DSM etc.). Thus, there will be an auction in November 2014 for 2018, along with a further supplemental auction in 2017, again for 2018.

[42] Applicable to generators and to suppliers offering demand side system services

- Participation in the GB capacity auction is not mandatory; meaning that all generators may opt out if they do not wish to provide capacity.
- New participants are Price Makers whereas existing participants will usually default to being a Price Taker in the auction.
- The terms of capacity payments are as follows:
    - One year (for existing plant);
    - Three years (for refurbishment); and
    - Ten+ years contracts (for entire new investment).
- The price determination for the auction is pay-as-cleared, with caps on three-year and ten-year contracts.

We consider that this general approach could be developed for application to the procurement of system services in the SEM. In Appendix 4 we set out our initial proposals for 1, 5 and 10 year system service products. We suggest that these proposals would benefit from a consultation process with the industry in order to ensure that the final arrangements are robust.

6.6.4. Compliance with objectives

We have reviewed the procurement options considered in the TSO Recommendations proposal, the Pöyry proposal and our proposal as described above. We consider that the TSO proposal does not include price discovery and both the TSO proposal and the Pöyry proposal do not include incentives for efficiency. There are also concerns that the TSO and Pöyry proposals may not fully comply with the EU target model. We consider that our proposal meets the objectives set out in Section 6. Our assessment of the different options is presented in Appendix 5.

6.6.5. Market information

In an efficient market requires service providers make forecasts of the demand for their services. In a fully competitive market each supplier would generally carry out their own market research across the customer base. However, in the case of system services with only one buyer (the TSOs) it is appropriate for the TSOs to make forecasts of their joint requirements for system services, to carry out market research into the availability of the supply of services and to make summaries of these forecasts available to the market, whilst respecting commercial confidentiality. Detailed product level forecasts for the year ahead should be provided and less detailed forecasts at the group level provided for years further ahead.

We propose that the TSOs should carry out further analysis to refine the requirements for the volumes of each system service product and also seek information from generators and demand side customers on their ability to provide system services, and that this information is summarised by the TSOs and presented in the next edition of the All-Island Generation Capacity Statement (expected to be published in early 2015).

It should be noted that under the Grid Codes, generators are required to provide information to the TSOs on their capabilities in relation to the provision of system services. (e.g. see the Grid Code – Planning Code Appendix PC.A4 of Eirgrid's Grid Code). The detailed data requirements of this appendix may need to be reviewed in the light of the new system services now required.

6.6.6. Back-stop contracts

As a contingency measure prior to the market becoming established, consideration might be given to allowing the TSOs to enter into bilateral contracts with providers for specific system service products on a 1 year basis, subject to RA approval. The requirement for the use of this facility should be seen as a failure in the market mechanisms and an investigation should be carried out by the RAs to modify the procurement mechanisms as appropriate. Such an investigation should also identify why the capacity provided under the bilateral contract was not provided to the TSO under the market mechanisms.

6.7. TSO incentives

The new system services will considerably complicate the TSOs' task of operating the system. Currently the TSOs spend around €50 million on system services; this has been stable over a number of years. The new system services required under DS3 are expected to increase the requirement of system services by approximately a factor of three (see the analysis of the data related to the TSO recommendations report in section 4).

Though much research has been done into the costs of generation and network capital investments that are needed for the system to be able to provide the system services, there is still uncertainty as to what the cost of procuring the additional new services will be. This will depend on the procurement options and how the TSOs manage the system. For example, in a grid event, the TSOs have the option to choose between a number of different services and quantities to deal with the event. The total cost of dealing with the event will therefore depend to a large extent on the decisions of the TSOs.

Given the likely increasing level of expenditure by 2020 we consider the benefits of introducing financial incentives on the TSOs to minimise procurement costs, rather than allowing cost pass-through as at present.

Depending on whether a group of system services is procured through a regulated tariff or through a more competitive procurement option such as an auction, the TSOs will be making different optimisation choices. In the case of regulated tariffs the aim is to incentivise the TSOs to minimise costs by optimising the volumes of system services procured. In the case of a more competitive procurement method, the TSOs will be incentivised to minimise costs by optimising between price and volume considerations.

To provide a framework for the TSOs cost optimisation, we propose the introduction of a sliding scale incentive mechanism for the new system services, similar to that in place for DBC.

6.7.1. Sliding scale based incentives

We have proposed a scheme for procuring products based on administered prices and an alternative scheme for the procurement of products through an auction process. One approach may be more appropriate for one (or more) group(s) of products than for others. In principle, a market based approach is preferred where the products interact significantly with the wholesale energy market although, as discussed above, the developing ISEM arrangements assume that ancillary services procurement will be separate from the energy market.

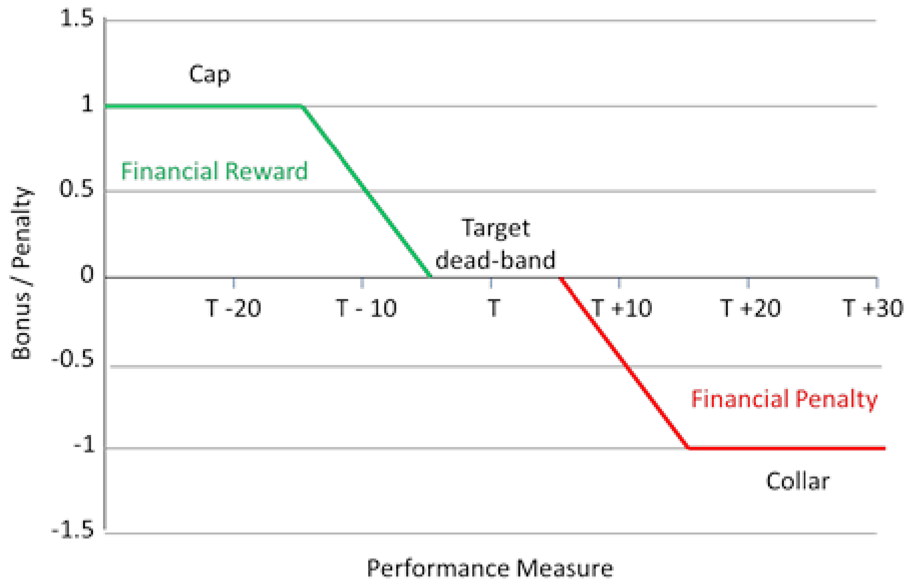
Under both administered and auction based approaches there is uncertainty about the efficient level of prices and quantities for each product, and therefore the regulator lacks the information to determine a reasonable target level for the total cost to the TSOs. However, the parties can reveal this information by their actions, if incentivised by the potential for additional profits generated through a form of sliding scale regulation. Under sliding scale regulation a single point estimate is not required and a likely range of performance is set instead, which recognises the imperfections in the available data.

The purpose of an incentive scheme is to facilitate price and volume discovery for system services products. In the absence of other information it may be appropriate, initially, for the sliding scale to be symmetric about the target value. It also may be appropriate to have a dead-band around the target value to recognise the normal variability in the requirement for system services from year to year. With the price and volume discovery over time, the incentive scheme parameters can be refined to target specific behaviours or products.

It is important that the design of the scheme does not expose the TSOs to any undue risks. For example, caps and collars on the rewards/penalties can be introduced to limit the financial risks to the TSOs. As part of this consideration, an IAE provision could be included in the TSO licences to provide protection to the TSOs in the case of an event or set of circumstances (e.g. a force majeure event under the TSC) that result in unanticipated TSOs ancillary service costs, and provide protection to consumers in the case of unanticipated cost savings.

The following figure illustrates a typical sliding scale arrangement.

Figure 7: Sliding scale arrangement



Source: IPA analysis

Note: In this diagram the cap and collar and sliding scales are symmetric, but that need not be the case.

The following table shows the scheme parameters selected for the DBC scheme. The total of the costs incentivised under the DBC scheme is around €185 million.

Table 32: 2012/2013 DBC incentive

€m	Lower Bound	Dead Band	Upper Bound	Below Target	Above Target
Dispatch balancing costs	7.5-20% below baseline	7.5% below and above baseline	7.5-20% above baseline	TSOs retain 10% of every 2.5% below	TSOs penalised 5% of every 2.5% above

Source: SEM - Incentivisation of All-island Dispatch Balancing Costs

The success of the procurement arrangements in encouraging new market entrants will depend in part on good volume forecasts being prepared and made available by the TSOs. We have considered the possibility of introducing an additional incentive on the TSOs related to the quality of their forecast volumes for system service requirements. However, at the moment there is no track record to guide such an incentive scheme and we suggest that initially the quality of forecasting is monitored by the RAs. Where significant forecasting errors are identified these reviews should inform the selection of the method for protecting the interests of customers (including an additional incentive scheme, if appropriate).

Sliding scale incentive schemes are also used in GB. Ofgem applies sliding scale cost incentives to the GB system operator (NGET). There are separate sliding scale schemes for internal costs (mainly staff costs) and for external costs. Ofgem has set SO incentives in broadly this form since 2001.

- As regards internal costs, Ofgem recognises the informational imbalance between NGET and Ofgem and so Ofgem has developed the IQI mechanism[43] which modifies the sliding scale approach to address this.
- As regards external costs, the overall scheme target is a combination of three separate targets:
  - A target for NGET's energy balancing costs;
  - A target for NGET's constraint management costs;
  - A target for the costs incurred in procuring black start services.

  The system operator has a licence obligation to develop and update the models which are used to set a target under a scheme. Two sets of models are used by NGET in accordance with the agreed methodologies to generate a scheme target. These are the energy models that forecast the energy costs (costs of balancing the system and of ancillary services) and the constraints model that forecasts the costs of managing transmission constraints. These models use historical data to derive linear relationships between explanatory variables and costs.

6.7.2. Number of pots

We suggest that the total target allowance (expected to be in the range of €150-355 million[44], based on the analysis in Section 6.5.1) would be built up from consideration of the requirement for individual products or groups of products. There would therefore be potential benefits in having separate targets for each product or group of products. However, the extent to which products can be substituted across product groups is not clear and having separate incentive schemes would probably be unduly complex at this stage. Reporting to the RAs by the TSOs on an individual product and group basis would provide much of the benefit of having separate incentive schemes.

We propose that there should be a single sliding scale incentive scheme for ancillary services procurement by the TSOs. The reported performance of the TSOs under the sliding scale incentive over a sequence of years will inform the refinement of the setting of the of the target allowance from year to year, thereby protecting the interests of customers.

[43] The Information Quality Incentive ("IQI") mechanism is designed to provide incentives to network companies to provide robust expenditure forecasts in their business plans. Ofgem uses the IQI to set the strength of the upfront efficiency incentives each company faces according to the difference between the company's forecast and Ofgem's assessment of its efficient expenditure requirements.

[44] The €150m is our cost based estimate for the 2020 AS requirement; the €355m and the value-based TSO estimate is (€290 million + €60 million.

It should be noted that the sliding scale arrangement shown in Figure 8 does not limit the amount of expenditure by the TSOs on system services. Within the cap and collar it provides a defined amount of cost and benefit sharing between the TSOs and customers. Where outturn expenditure is outside the cap or collar, then the regulatory monitoring would be expected to determine the reasons and the sliding scale parameters adjusted by the RAs, if necessary, for subsequent years.

6.7.3. Setting the target allowance

The path of system service volume requirements over the period to 2020 should be examined by the TSOs. Our analysis estimates that the total volume requirement will increase by a factor of three between now and 2020. However, we consider that the rate of increase in volumes over the next two years could be mitigated by the introduction of the new RoCoF standard.

We would support the development of a system services model by the TSOs to support the setting of the target allowance. However, we recognise that whilst a start can be made on this, the model will need to be finalised only when the detailed design of the selected ISEM option has been completed. Nevertheless there may be merit in developing a model based on the current SEM, since the lessons learnt in developing this model may facilitate the modifications necessary to align with the selected ISEM option.

Given our comments on the impact of the new RoCoF standard, it may be acceptable (in the absence of a robust model in the short-term) to assume a linear growth in system services volumes in the next few years, so that the system services volumes required in 2016 could be assumed to be 1.4 times the current volume requirement. A view on product pricing would not need to be taken until late 2015 or early 2016. Clearly the TSOs would need to be consulted on these proposals.

6.7.4. Regulatory oversight

Given the high level of uncertainty surrounding the cost of procuring the system services we propose that expenditure targets(s) are set to an initial value(s) by the RAs, with annual monitoring of the TSOs spend by RAs. For initial years at least, the TSOs should provide monthly reports to the RAs on product volumes and costs. This will enable the RAs to better set the pot value in subsequent years.

Given the rapid growth in wind plant on the system which can significantly affect the requirement for system services, we recommend that the target allowance is updated by the RAs on an annual basis.

6.8. Transitional considerations

Under the Gate 3 process for the management of new connections in the context of constrained network capacity, 3900 MW of renewable connection offers were made and 80 per cent were accepted at the close of the window in 2009. However, since the Gate 3 process demand projections have fallen substantially and the requirement for new capacity is therefore smaller.

Within the offers there was a total of 1600 MW for conventional plant in the first phase[45] and of these 500 MW have been accepted. It is uncertain which of the conventional plants will go forward to completion by 2021 as required, but it will be important that if they do go forward the plant specifications should include the enhancements to provide added flexibility.

The final investment decisions in relation to Gate 3 projects will be made in the next year or so. This is because to come within the REFIT support schemes, wind plants need to be operational by 2017. As regards conventional plant, the designs are likely to be finalised in 2015/16 for 2020/21 completion.

Therefore strong signals that investments to provide enhanced system services will be remunerated are desirable by the end of 2014 with the associated mechanisms implemented by the end of 2015. To meet this timetable we consider that the key arrangements should be put in place across all system services products on the selected implementation date, rather than introducing the new framework on a phased basis.

[45] 2,000 MW of conventional offers issued in phase 1 (1,600 MW of generation plant plus one interconnector), sufficient to maintain security of supply for the short and medium term even if there were some project attrition (Direction on Conventional Offer Issuance Criteria and Matters Related to Gate 3, CER/09/191, 18th December 2009)

6.9. Recommendations

We have developed our proposals for the procurement of system service products against the objectives set out in Section 6. Our recommendations are as follows:

- For procurement purposes, the system service products should be grouped into four groups as follows:
  - Group 1: Grid stability services;
  - Group 2: Ramping services;
  - Group 3: Fast reserve services; and
  - Group 4: Slow reserve services.

This more granular approach will allow the TSOs to make trade-offs between individual products within each group and will simplify the price determination process.

- The TSOs should provide greater transparency in relation to the volumes of system services (by group) required in the year ahead and over the period to 15 years ahead. The TSOs should also publish an estimate of the surplus/deficit profile in system services (by group) over the 15 years period.
  - We recommend separate mandatory auctions are developed for the procurement of each group of services (sealed bid, pay-as-cleared design) on a one year ahead basis.
- The arrangements for each group can be introduced to a separate timeline, with regulated tariffs retained in the meantime.
- Groups 3 and 4 have potential interactions with the energy market and we recommend that auctions for these for groups are introduced prior to the new ISEM market arrangements.
- The TSOs would be required to set the volume required for each group of services as part of the selection process. Consideration should be given the benefit of temporarily shaped requirements.
  - New licence conditions and bidding codes are likely to be required to ensure that the objectives of the ancillary services market are not frustrated by the lack of competition.
  - We recommend that 5 and 10 year contracts for the procurement of new system services capacity are introduced to ensure that adequate capacity is available in future years. These contracts would be for the purpose of rewarding investment in new system services capacity through an auction process. The TSOs should provide estimates of system service capacity requirements up to 15 years ahead to be used as the basis of volume selection.
  - To encourage efficiency in the procurement and utilisation of system services, we recommend that the TSOs are incentivised to optimise the costs of procurement. We propose that there should be a single sliding

scale incentive scheme for ancillary services procurement by the TSOs. The reported performance of the TSOs under the sliding scale incentive over a sequence of years will inform the resetting of the target allowance from year to year, thereby protecting the interests of customers.

  - We recommend a total target allowance in the range of €150-355 million per annum. Whilst a central value of €250 million would seem attractive, this and the other parameters of the sliding scale scheme would need to be discussed with the industry.

- Where 5 or 10 year contracts have been procured the equivalent annual cost would be included in the allowance evaluation.
- An IAE provision could be included in the TSO licences to provide protection to the TSOs in the case of an event or set of circumstances (e.g. a force majeure event under the TSC) that result in unanticipated ancillary service costs, and provide protection to consumers in the case of unanticipated cost savings
  - Strong signals that investments to provide enhanced system services will be remunerated are desirable by the end of 2014 with the associated mechanisms implemented in 2015. To meet this timetable we consider that the key arrangements should be put in place across all system services products on the selected implementation date, rather than introducing the new framework on a phased basis.

7. CONCLUSIONS AND RECOMMENDATIONS

This work has been carried out in two parts. The first part reviews the work carried out or instigated by the TSOs to understand the quantity of system services required as wind penetration approaches the 75 per cent SNSP level towards the year 2020 and the generating plant options for providing the new services required in this period. Building on these results and on our experience we have developed proposals for the procurement of system services in a timeframe which aligns with the implementation of the new market arrangements to be put in place under ISEM.

7.1. Conclusions from work undertaken or instigated by the TSOs

Our review of the submissions in response to the Call for Evidence issued by EirGrid regarding the finance arrangements under the DS3 Systems Services Consultation found that there were no significant differences in views that we could attribute to the type or size of respondent. The confidential submissions focused on the technical capabilities and overall capex costs of individual units rather than on the costs per product provision and, with the exception of one respondent, related to units that are still in the development phase and require financing. We found that there were three overarching concerns. These were:

- The value approach to determining the aggregate expenditure allowance for the procurement of ancillary services
- Treatment of RoCoF, and
- Financial feasibility of generator investments to provide new system services.

EirGrid commissioned DNV KEMA to identify the additional capital investment required to meet the new system service requirements from a range of different technologies. We compared the level of costings identified in the KEMA study for normalised build costs in generation units and grid solutions. In summary we consider that KEMA's cost estimates for conventional generation technologies are reasonable, although their cost estimate for OCGTs may be somewhat high. We agree with KEMA's result that the cost of providing system services from grid technology solutions is, in general, significantly higher than providing the services from generation solutions. We found very little evidence in the public domain surrounding generation enhancement costs. Thus we were unable to comment on the values proposed by KEMA. We consider that attention should now be focused on determining the availability of system service products from demand customers.

The TSOs carried out modelling to determine the value of adequate system service products in achieving the 75 per cent SNSP level of wind penetration. They looked at the value of these services on a production cost basis and market cost basis. The TSOs recognise that the total expenditure allowed by the SEMC in relation to system services may be less than the calculated system values. They proposed that the allowed total expenditure should be allocated to individual system service products based on the relative market benefit of each product.

Our review of the TSOs' work indicated that there is much uncertainty over the required volumes for each of the system service products to meet the SNSP levels expected in 2020. There is also uncertainty over the inter-changeability of products in meeting the range of operational conditions that need to be managed by the TSOs. As the RES target of 40 per cent is approached the costs and benefits of different scenarios need to be examined more closely in order that the target is achieved cost effectively. The modelling results show that whilst procuring system services to achieve a 75 per cent SNSP level will meet the 40 per cent target, aiming for a 70 per cent SNSP level would provide a system that is very close to achieving the 40 per cent target. The TSOs' analysis of production cost savings from the levels of wind in 2020 (4.6 GW scenario) are €231 million per annum in the 70 per cent SNSP case and €241 million per annum in the 75 per cent SNSP case. The estimated cost of investments to provide the system services from generation technologies to achieve this level of wind penetration (75 per cent SNSP) is in the range €70- 84 million per annum. The costs to achieve 70 per cent SNSP may be substantially less.

If CCGTs implement lower minimum generation levels these benefits increase to €260 – 266 million per annum. We recommend further work to better understand the costs and benefits of reducing the minimum load levels.

The TSOs' analysis of market cost shows lower system benefits than the production cost savings. This is because of the additional infra-marginal rents captured by generators, some €93 million in the 70 per cent SNSP case and €84 million in the 75 per cent SNSP case. This feature is amplified in the cases where lower minimum load enhancements have been assumed for CCGTs where the additional infra-marginal rents captured by generators total €219 million in the 70 per cent SNSP case and €187 million in the 75 per cent SNSP case.

It would appear that if the annual cost of providing system services is of the order of €70 – 84 million per year, then these costs will be recovered by generators as a whole through higher infra-marginal rents. However, it needs to be recognised that the allocation of these rents is unlikely to be reflective of the costs of providing system services and unlikely to be properly targeted at the providers of these services.

Key conclusions

The generation plant costs proposed by KEMA are reasonable and can be considered robust estimates of the required capital costs. Attention should now be focused on determining the availability of system service products from demand customers.

Rephrase There is much uncertainty over the required volumes for each of the system service products to meet the SNSP levels expected in 2020. There is also uncertainty over the inter-changeability of products in meeting the range of operational conditions that need to be managed by the TSOs.

7.2. Recommendations in relation to the procurement of system services

We have developed our proposals for the procurement of system service products against the following objectives:

- A reliable availability of products in adequate volumes in the short- and long-term;
- Incentives on the TSOs for efficiency;
- Robust product prices;
- Reasonable set-up and transaction costs;
- Aligns with ISEM developments; and
- Aligns with EU target model.

Our recommendations are as follows:

- For procurement purposes, the system service products should be grouped into four groups as proposed by Pöyry:
  - Group 1: Grid stability services;
  - Group 2: Ramping services;
  - Group 3: Fast reserve services; and
  - Group 4: Slow reserve services.

This more granular approach will allow the TSOs to make trade-offs between individual products within each group and will simplify the price determination process.

- The TSOs should provide greater transparency in relation to the volumes of system services (by group) required in the year ahead and over the period to 15 years ahead. The TSOs should also publish an estimate of the surplus/deficit profile in system services (by group) over the 15 years period.
- We recommend separate mandatory auctions are developed for the procurement of each group of services (sealed bid, pay-as-cleared design) on a one year ahead basis.
  - The arrangements for each group can be introduced to a separate timeline, with regulated tariffs retained in the meantime.
  - Groups 3 and 4 have potential interactions with the energy market and we recommend that auctions for these for groups are introduced prior to the new ISEM market arrangements.
  - The TSOs would be required to set the volume required for each group of services as part of the selection process. Consideration should be given the benefit of temporarily shaped requirements.
- New licence conditions and bidding codes are likely to be required to ensure that the objectives of the ancillary services market are not frustrated by the lack of competition.
- We recommend that 5 and 10 year contracts for the procurement of new system services capacity are introduced to ensure that adequate capacity is available in future years. These contracts would be for the purpose of rewarding investment in

new system services capacity through an auction process. The TSOs should provide estimates of system service capacity requirements up to 15 years ahead to be used as the basis of volume selection.

- To encourage efficiency in the procurement and utilisation of system services, we recommend that the TSOs are incentivised to optimise the costs of procurement. We propose that there should be a single sliding scale incentive scheme for ancillary services procurement by the TSOs. The reported performance of the TSOs under the sliding scale incentive over a sequence of years will inform the resetting of the target allowance from year to year, thereby protecting the interests of customers.
- We recommend a total target allowance in the range of €150-355 million per annum. Whilst a central value of €250 million would seem attractive, this and the other parameters of the sliding scale scheme would need to be discussed with the industry.
  - Where 5 or 10 year contracts have been procured the equivalent annual cost would be included in the allowance evaluation.
  - An IAE provision could be included in the TSO licences to provide protection to the TSOs in the case of an event or set of circumstances (e.g. a force majeure event under the TSC) that result in unanticipated ancillary service costs, and provide protection to consumers in the case of unanticipated cost savings
- Strong signals that investments to provide enhanced system services will be remunerated are desirable by the end of 2014 with the associated mechanisms implemented in 2015. To meet this timetable we consider that the key arrangements should be put in place across all system services products on the selected implementation date, rather than introducing the new framework on a phased basis.

Key recommendations

The TSOs should provide greater transparency in relation to the volumes of system services (by group) required in the year ahead and over the period to 15 years ahead.

We recommend separate mandatory auctions are developed for the procurement of each group of services (sealed bid, pay-as-cleared design) on a 1 year ahead basis.

We recommend that 5 and 10 year contracts for the procurement of new system services capacity are introduced to ensure that adequate capacity is available in future years.

To encourage efficiency in the procurement and utilisation of system services, we recommend that the TSOs are incentivised to optimise the costs of procurement. We propose that there should be a single sliding scale incentive scheme for ancillary services procurement by the TSOs.

APPENDIX 1: MODELLING METHODOLOGY

In the TSO Recommendations paper[46], a base case model for 2020 was developed for the system services review 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.

The PLEXOS model is designed to be consistent with the TSC. PLEXOS models each trading period (30 minutes). However, in PLEXOS, instead of generators' commercial offers being input to the formulation of the unconstrained schedule and associated half-hourly SMPs, as would happen under the TSC, the schedule is derived based on a direct calculation is made of generators' costs. These costs are derived from fuel and carbon prices assumptions, heat rate curves and variable O&M costs.

The TSOs say that a three-stage process was used, with a PLEXOS run at each stage to determine certain network inputs at each stage. The three PLEXOS runs are:

1) Ex-ante market (unconstrained) run – determines interconnector flows
2) Dispatch (constrained) run – replicates the actual dispatch based on the operational scenario
3) Ex post market run – determines SMPs and market quantities (wind curtailment removed by reducing availability)

The ex-ante run is the least constrained and attempts to mimic the current ex-ante market schedule. The key inputs are the demand, the wind profile and the generator prices.

For the system services review four main constraints were imposed in deriving the dispatch schedules:

- fixed interconnector flows based on market schedule;
- operating reserve to cover loss of largest in-feed;
- maximum SNSP limit; and
- minimum synchronous inertia level.

The dispatch run includes operational constraints, which vary by scenario, to approximate the actual dispatch that would be expected. The interconnector flow determined in the ex-ante market run is a fixed input for the dispatch run. The constraints are described below:

- Demand

  The total annual demand was updated to 38,691 GWh, corresponding to the median demand forecast in the Generation Capacity Statement (GCS) 2014 – 2023, scaled up for a full calendar year. The TSOs note that this is approximately a 10 per cent reduction of the demand forecast used for the original modelling.

[46] DS3: System Services Review, TSO Recommendations

- Installed Wind Capacity

  Limits on the quantity of wind generation by region may be required in order to avoid the problem of voltage-dip induced frequency dips which would arise at high wind penetration levels following a severe fault. The Fast Post-Fault Active Power Recovery and Dynamic Reactive Response products are specifically designed to mitigate this problem.

  Two scenarios were modelled by the TSOs in detail. These were:

  - Base case: 50 per cent of future wind capacity constructed (4572 MW)
  - Low wind case: 25 per cent of future wind capacity constructed (3474 MW)
  - Minimum inertia and minimum number of generators

    These constraints ensure that there is sufficient synchronous generation synchronised to ensure the transient, dynamic and voltage stability of the system following contingencies such as loss of generation and transmission faults.

    The maximum RoCoF is modelled in PLEXOS by ensuring that there is sufficient inertia relative to the size of the large infeeds and outfeeds such that the RoCoF limit will not be breached. With an increase in the RoCoF standard to 1 Hz/s, it is assumed that lower system inertia can be tolerated (since the allowable RoCoF will be higher).

  - Operating Reserve

    The operating reserve requirement is dynamic (time-varying) based on the largest infeed and there is a minimum spinning reserve floor, consistent with current operational policy.

    To realise the full benefit of the higher RoCoF standard faster reserves will be required by means of the Fast Frequency Response product. Alternatively, it will be necessary to increase the primary reserve requirement so that a more rapidly falling frequency can be arrested before under-frequency load shedding is activated.

APPENDIX 2: BENEFIT ALLOCATION METHODOLOGY

A TSO paper[47] describes the methodology for allocating the system benefits between system services products.

The PLEXOS model of the 2020 system with the GCS 2013 – 2022 plant portfolio was used. To provide a baseline, a "relaxed" dispatch scenario was considered, where the only operational constraint was the 75 per cent SNSP limit. Further sensitivity scenarios were examined, with constraints added separately and in turn for each product (e.g. POR requirement for primary operating reserve, inertia constraint for SIR product) and in the increase in costs calculated. The results are shown in the table below.

Table 33: Constraint cost ascribed to each system service

Product	Constraint cost impact €m	Constraint cost expressed as a %
DRR	29	9.86
FFR	33	11.55
FPFAPR	50	17.46
POR	32	10.99
RM1	7	2.54
RM3	15	5.07
RM8	16	5.35
RRD	3	1.13
RRS	2	0.56
SIR	7	2.25
SOR	20	6.76
SSRP	31	10.70
TOR1	23	8.17
TOR2	22	7.61

Source: DS3: System services review, finance arrangements, DS3: System serviced valuation, Further analysis.

Taking a total product pot of a certain size (e.g. €100 million), the percentages in the above table enabled the TSOs to allocate the total pot to each system services product.

These percentages are assumed to apply to the total cost of system service, including the cost of existing services.

To determine the volume of system services, the 4.6 GW 75 per cent SNSP case was utilised to determine each service provider's hourly MW output. We assume that a factor was applied to the MW output to determine the hourly product volume of each service provider. The total product volume over the year was then calculated. Whilst probably adequate for the current analysis we recommend that this analysis is updated with the GCS 2014-2023 data and to

[47] DS3: System services consultation, finance arrangements

accommodate the new RoCoF standard. The sensitivity of the results to a 70 per cent SNSP should also be explored.

The notional charge rates were determined by taking the ratio of the total product pot value to the total annual product volume. These are shown in the following table.

Table 34: Product charge rates per €100 million total system services pot

Product	Units	Charge rates per €100 m total system services pot € per unit
DRR	MWh	0.194727
FFR	MWh	4.928911
FPFAPR	MWh	0.394090
POR	MWh	3.545921
RM1	MWh	0.138370
RM3	MWh	0.284923
RM8	MWh	0.174247
RRD	MWh	0.092242
RRS	MWh	0.095273
SIR	MWs2h	0.000517
SOR	MWh	1.581099
SSRP	Mvarh	0.136009
TOR1	MWh	1.865658
TOR2	MWh	1.690429

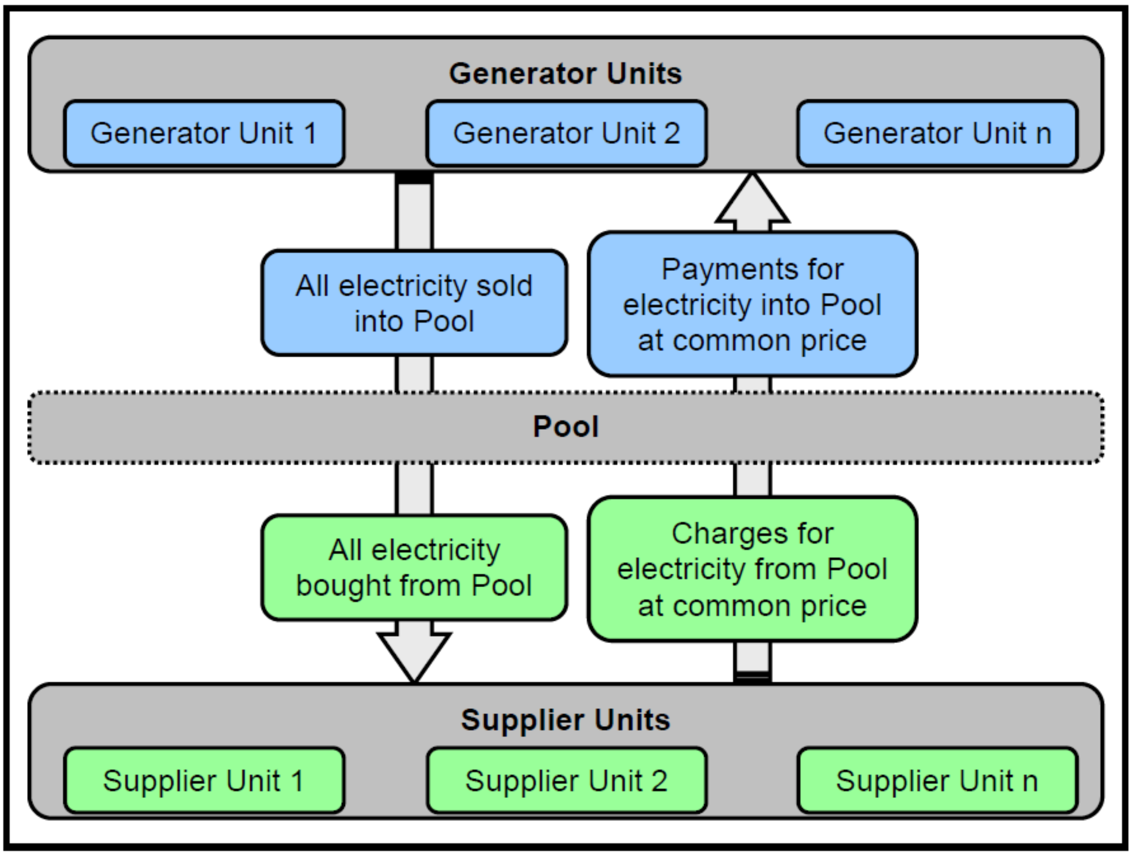
Source: DS3: System serviced valuation, Further analysis.

APPENDIX 3: MANDATORY BIDDING RULES

An example of a mandatory auction is present in the current design of the SEM gross pool market arrangements. This mandatory auction features day ahead and within day complex bidding, and participant's bids are sealed with a uniform price received by all successful offers.

The SEM acts as a spot market which, given its mandatory nature for generators (above 10 MW) and suppliers, is fully liquid. In this pool, electricity is bought and sold through the market clearing mechanism, whereby generators bid in their Short Run Marginal Cost ("SRMC") and receive the System Marginal Price ("SMP") for the electricity which they generate in each trading period, in addition to supplementary revenue streams. Suppliers purchasing energy from the pool pay the SMP for each unit of electricity in each trading period along with other supplementary costs.

Figure 8: SEM Pool



Source: SEM-13-067 Amended TSC Helicopter Guide Version 2.0

One of the methods through which competition is promoted in the SEM is through the Market Monitoring Unit ("MMU"), which is responsible for short and long- term SEM outcomes such as prices and quantities, and participant behaviour. The MMU reports to the SEM Committee on these matters on an ongoing basis, and produces internal and public reports as part of its function. For example the MMU has issued a Bidding Code of Practice[48].

According to the Market Operator (SEM, 2010), conventional generators must bid price and quantity pairs relating to the electricity they can provide for the following day. The price which generators bid is expected to reflect the marginal cost of generating the quantity of electricity specified, and as such is expected to include fuel and carbon prices. While each generator will most likely have hedged fuel costs, the market rules state that the bids should reflect the opportunity cost of the fuel, meaning the spot price at the time of the bid (CER, 2007). The marginal unit during each trading period sets the price which all units receive for that period, meaning every other unit that is dispatched receives above the price it bids in at. Generators do not simply receive their bid price as this would act as an incentive to submit bids based not on their marginal cost but their expected value of the break-even price of electricity[49].

The participants are required to submit offers, which hold for 48 trading periods, thus eliminating the potential to increase bids strategically during periods of increased or peak demand.

Two types of information are required by participants:

- **Technical offer data** must be submitted – this relates to the capabilities of the plant with regards to parameters such as ramp rates, minimum load levels, etc.
- **Commercial offer data** must be submitted – this includes:
  - No load cost;
  - Start-up cost; and
  - Price-quantity pairs.

These costs are a function of a unit's technical capabilities and therefore, while complex, this information allows for clarity and comparability (by the System Operator) across bids.

[48] Harmonised Ancillary Service Arrangements and the Bidding Code of Practice, Consultation Paper, 12/11/2010

[49] Kirschen and Strbac, 2005, Fundamentals of Power System Economics.

APPENDIX 4: SYSTEM SERVICE PROCUREMENT PROPOSAL

In this appendix we set out our initial proposals for 1, 5 and 10 year system service products.

1 year product

HAS tariffs are currently reset on an annual basis and are procured from existing plants which in some cases have been in operation for many years. We consider that the tariffs are aimed at reflecting the marginal costs (including opportunity costs) of procuring system services. In practice cost reflective tariffs for system service products are difficult to calculate and a balance has to be struck between the benefits of price discovery and the benefits of simple regulated tariffs. The prices or tariffs could be structured into the four groups proposed in Section 6.

We leave open here the option as to whether the 1 year products should be based on regulated tariffs or auction based tariffs. A switch from regulated prices to an auction based approach could be made at any time, provided sufficient design and implementation work had previously been carried out.

However we would expect that all parties with the capability to provide one or more system services would be required to submit an application to provide the relevant system service. This includes parties holding 5 or 10 year product contracts.

Under the regulated tariff approach the TSO would need rules for selecting the volumes assigned to each party (e.g. pro-rata to applications), whereas under the auction approach selection would be price based.

We believe these proposals are consistent with the ENC requirements for the procurement of ancillary services.

5 and 10 year products

The purpose of these products is to reward new investments made specifically to provide system service products. Parties will recover their opportunity costs through the 1 year tariffs/auction prices if they are successful in that process. The 5 and 10 year products would be for delivery three years, say, after acceptance.

The cost of enhancing existing plants to provide additional system services is higher on a per unit basis than for providing the same capacity from new plant (see Section 2). At the same time existing plant is likely to have a shorter life than new plant. We therefore propose that all parties who need to make investments to provide system services are free to bid for either 5 or 10 year products.

Given the different quantities of different service products likely to be offered by different providers a pay-as-bid auction design is preferable. The TSO would need to develop and publish a methodology for assessing complex bids against one another.

5 and 10 year products would not be available for system services required to be provided under the Grid Code.

Once a plant has received a 5 or 10 year product then, at the end of the contract, the plant would be free to apply for a further 5 or 10 year product but the offer price (per annum) would be capped at the previously accepted price.

It may also be appropriate to have an overall cap on the price per unit of capacity provided.

There may be a case for a 5 year product for existing plants requiring no new investment as a way of providing a guaranteed income, but with any contract payment offset against any payments received under the 1 year contracts.

Volume requirement

In order to inform the market, the TSO should provide annual forecasts of the their requirements for system services for the year ahead and for the period of 15 years ahead, and the forecasts should also show the likely total availability of system services in that period. The volume of 5 and 10 year products accepted by the TSO should reflect the forecast surplus/deficit in system services availability over the 15 year ahead period.

Development of approach

We suggest that these proposals would benefit from a consultation process with the industry in order to ensure that the final arrangements are robust and meet the objectives set out in Section 6.

APPENDIX 5: PROCUREMENT OPTIONS AND OBJECTIVES

Table 35: Procurement options and objectives

Option	**Key features**	**Compliance with objectives (IPA assessment)**
TSOs proposal	• RAs set expenditure allowance pot based on production cost benefit of higher % SNSP • Pot allocated to individual products based on marginal contribution to system benefit • Product tariffs derived from product pot and product volumes • Tariff proposed as fixed for 5 years • Scalars proposed adjust payments for product characteristics, availability and cost relative to reference price	Reliable availability ✓ Incentives for efficiency **X** (none proposed) Robust product prices **X** (no price discovery) Reasonable set-up & transaction costs ✓ Aligns with ISEM ✓ Aligns with EU target model **X** (>1yr contract)
Pöyry proposal	• Procurement based on 4 groups • Within day bids for ramping products with award based on pay-as-cleared bids • For other products proposed 5-10 year contracts on based on pay-as bid tenders • TSOs procurement subject to an expenditure cap	Reliable availability ✓ Incentives for efficiency **X** *(none proposed)* Robust product prices ✓ Reasonable set-up & transaction costs ✓ Aligns with ISEM ✓ Aligns with EU target model **X** *(>1yr contract)*
IPA proposal	• Procurement based on 4 groups • TSOs product scalars to be developed to provide product equivalence within each group • Where a plant has the necessary capability mandatory bidding to provide services by group • 1 year contract proposed with shaped or seasonal bids by group • 5 and 10 year contracts proposed to reward investment in new system services capacity • TSOs procurement subject to a sliding scale expenditure incentive.	Reliable availability ✓ Incentives for efficiency ✓ Robust product prices ✓ Reasonable set-up & transaction costs ✓ Aligns with ISEM ✓ Aligns with EU target model ✓