CAPACITY PAYMENT MECHANISM
MEDIUM TERM REVIEW

A Report to CER and NIAUR

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Contact details

Name	Email	Telephone
David Omom	david.omom@poyry.com	+44 (0)1865 812234
Brendan Cronin	brendan.cronin@poyry.com	+44 (0)1865 812209
Dr. Gareth Davies	gareth.davies@poyry.com	+44 (0)1865 812204

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EXECUTIVE SUMMARY

The Capacity Payment Mechanism (CPM) within the Single Electricity Market (SEM) was designed to encourage the provision of adequate capacity, and of the right type to meet an acceptable level of reliability. In March 2009, the SEM Committee published a consultation paper (SEM-09-023) signalling its intention to carry out a medium term review of the CPM to determine whether the mechanism could meet its objectives more efficiently and effectively. This report has been produced to assist the Regulatory Authorities (RAs) in understanding:

- the efficiency of the capacity payment signal;
- the distribution of payments across generators;
- impact on entry and exit decisions; and
- predictability and transparency of the mechanism.

The performance of the current CPM design

We have reviewed the performance of the current design in 2008 (the last full year for which data was available at the start of the study) and evaluated it based on an assessment criteria agreed with the RAs. We find that the overall performance of the current CPM design appears satisfactory when considered in the context of its competing objectives. However there are several issues with the current mechanism:

- The relationship between the average capacity payment and ex-post system margin is not strong, the level of payments is not always highest when capacity is scarce and the variance between the lowest and highest payments is low. This is due to the diluting effect of (a) the monthly distribution of the pot; (b) use of a Flattening Power Factor (FPF) which reduces the spread of ex-ante and ex-post payments between high and low LOLP periods; and (c) the high weighting placed on ex-ante and fixed payments under the current mechanism.
- The CPM does not provide the right incentives to plants available during system peak. It appears to over-reward intermittent generators which contribute less to peak demand and does not differentiate substantially between generators with different levels of controllability as a consequence of the current split in payments. As a result, payments do not fully reflect the full value of lost load at peak times.
- There is significant uncertainty in future payments due to annual changes to BNE price and the capacity requirement which increases the risks for new entrants. The impact of limited predictability and transparency could be reflected in a higher cost of capital.
- There are concerns over the level of exit inefficiencies particularly plants with low load factors which are unavailable when called to run and are not adequately penalised.

The performance of the CPM in future years

The electricity market in the SEM is expected to change significantly in the medium term. The Republic of Ireland and Northern Ireland have set a target of 40% for renewable generation by 2020 to meet broader EU renewable energy targets. In light of the dominance of wind as a renewable resource, it is likely to be the primary driver in pricing and dispatch in the SEM.

The impact of increasing intermittency is likely to be two-fold:

- It will alter the volume and mix of generation available at any point in time. This makes (a) the ex-post constituent of capacity payments more volatile; and (b) the level of aggregate payments less predictable thereby increasing risks in the market.
- Intermittency shifts the nature of capacity required in the system, and compounds the difficulties of having a single signal for capacity and flexibility. It may also change the roles and relationship between ancillary services and capacity payments in delivering flexibility and availability at peak.

Our analysis of the medium term performance of the CPM finds that there are no significant changes in the performance of the current design in this new environment. Wind changes the distribution of aggregate capacity payments but does not materially mitigate or exacerbate the overall performance of the mechanism. It results in (a) variability of revenues; and (b) leads to low load factors for conventional plants which increases the uncertainty of energy revenues and a greater reliance on capacity payments for cost recovery. Moreover, the underlying concerns identified in 2008 remain and would need to be addressed going forward.

Options for reform

There are several different ways to address the concerns identified. These include:

- Changing the parameters or algebra in the current design. Selected variables include (a) the weighting between ex-post and ex-ante payments; (b) the flattening power factor; or (c) the monthly split of the annual ACPS pot.
- Changing the parameters and process of BNE price calculation. This involves (a) increasing the transparency of the calculation process, inputs; or (b) fixing or indexing the BNE price or constituents of the BNE for several years.
- Introducing a new entrant capacity price or guarantee.
- Introducing generator/technology adjusted payments or capacity credits which weight fixed payments towards generators likely to be available in times of system tightness.
- Increasing the size and types of contracts under Ancillary Services to reward flexibility appropriately.
- Improving ease of entry or exit by among other means imposing a penalty mechanism for plants which declare themselves available but fail to respond when called upon.

Reform packages

The reform options listed above address the concerns identified. However, they are specific and do not take into account the impact on other objectives of the CPM such as the trade-off between efficiency of the capacity payment signal and price volatility. As a result, we have developed a package of reform options from these changes. Underpinning all four options is an emphasis on re-balancing the weighting between ex-post and ex-ante payments to 50:50 and increasing the flattening power factor to 0.5.

Table 1 describes the main features of the reform packages.

Table 1 – Overview of the proposed reform packages

Scenario	Main features
Ex-post –ex-ante, re-balancing scenario	▪ Changes the weighting between ex-post and ex-ante payments to 50:50. ▪ Increases the flattening power factor to 0.5. ▪ Splits the ACPS to monthly pots based on forecast demand and sharing intra-monthly split evenly across all trading periods. ▪ The scenario is technology neutral and applies equally to new entrants and existing players.
Capacity credit scenario	▪ Applies the re-balancing methodology. ▪ De-rated capacity credit specific to each technology applied to the ex-ante payment.
New entrant scenario	▪ Provides a BNE price guarantee for new entrants over a fixed period, de-rated by technology-specific capacity credit. ▪ Applies re-balancing methodology to the residual pot shared by all existing plants.
Payments for flexibility scenario	▪ Sets aside a percentage of ACPS for flexibility which is combined with ancillary services to reward reliability. ▪ Applies re-balancing methodology to the residual pot.

The performance of the reform packages

The four reform options address some of the main shortcomings of the current CPM design, in particular strengthening the link between capacity payment and scarcity compared to the status quo. They also provide higher levels of payment during periods of minimum system capacity and to varying degrees change the distribution of capacity payments across generator types in favour of those generators likely to be available during system need. In addition, the performance of all the reform options considered improves relative to the current design in future years compared to 2008.

We have assessed each alternative package against performance indicators developed and agreed with the RAs based on the objectives set forth in the SEM and the objectives of the regulatory agencies. We have also evaluated all four packages against the status quo mechanism. Table 2 provides a high level summary of the relative change across all four scenarios, relative to the current design.

Table 2 – Comparisons of reform packages with the status quo mechanism

Assessment criteria	Rebalancing scenario	Capacity credit scenario	New entrant scenario	Payments for flexibility
Capacity adequacy	=	=	✓	✓
Reliability of the system	✓	✓	×	✓
Price stability	×	×	✓NewGen ×ExGen	×
Simplicity	=	×	×	×
Efficient price signals for long term investments	✓	✓	✓	✓
Susceptibility to gaming	=	=	=	?
Fairness	=	=	×	=
Minimise regulatory risks	=	×	×	=

Key	Better	Same	Worse
	✓	=	×

Notes: ExGen refers to existing plants, while NewGen refers to new entrants under the new entrant scenario.

There is a major trade-off between various CPM objectives particularly the efficiency of price signals and price volatility. Improved efficiency of capacity price signals increases the volatility of price and by implication diminishes the predictability of payments, and increases risk and uncertainty for investors. To the extent that efficiency of signals is a higher priority to the SEM, the re-balancing scenario seems to provide improved efficiency without significantly increasing the volatility of prices.

The remaining packages analysed build on the re-balancing scenario. The capacity credit scenario can be viewed as a further extension of the re-balancing scenario, providing improved efficiency but at the expense of increasing complexity, regulatory risk, price volatility and decreasing predictability of payments. Similarly, the flexibility payments scenario improves flexibility in the system but, depending on its design could result in increased complexity, price volatility and decreasing predictability of payments.

The new entrant scenario provides significantly improved incentives for new build; however it increases the risk of exit for existing generators. It is also the most complex of the reform packages, with the highest level of regulatory risk and other costs outlined.

1. INTRODUCTION

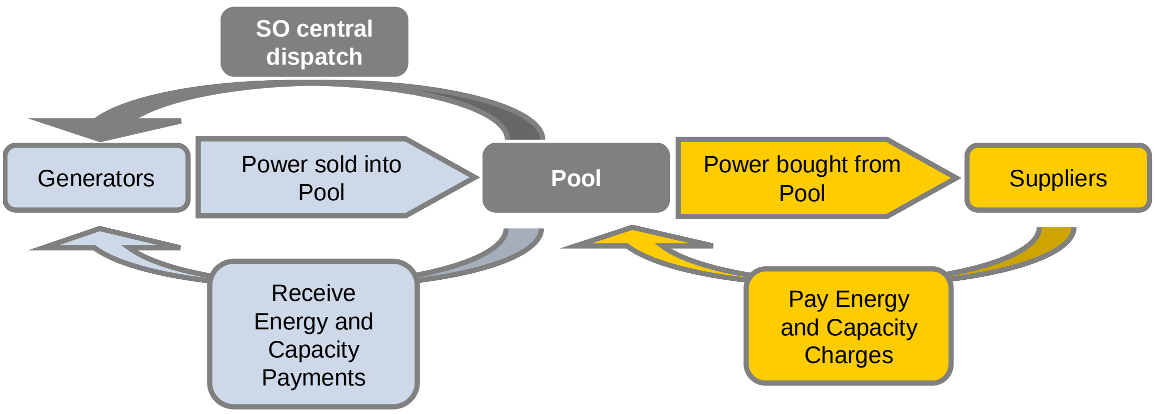
The Single Electricity Market (SEM) went live on 1 November 2007, providing the opportunity to trade wholesale electricity in the Republic of Ireland and Northern Ireland on an all-Island basis for the first time. The objectives of the SEM are to protect the interests of consumers of electricity, wherever appropriate by promoting effective competition and to ensure sustainability and security in the supply of electricity in the island and regulatory consistency in meeting these objectives.

To achieve this, the SEM was designed as a compulsory gross pool with centralised dispatch, with generators receiving payments for the energy produced and the capacity they provide to the system. Capacity payments are determined in an explicit capacity payment mechanism (CPM) intended to encourage the provision of the right amount and type of capacity. The specific objectives set for the CPM are:

- **capacity adequacy/ reliability of the system (reliability)** – to ensure provision of adequate installed generating capacity to meet a defined reliability standard;
- **efficient price signals for long term investments** – to ensure that the CPM delivers adequate reliable capacity at the lowest reasonable cost and efficiently;
- **price stability** – to reduce market uncertainty, price spikes and reduce risk premiums to investors;
- **simplicity** – that the system should be transparent, predictable and simple to administer;
- **susceptibility to gaming**– to ensure individual market participants, acting in their own best interests do not cause outcomes inconsistent with overall market objectives; and
- **fairness** – that the system should not unfairly discriminate between participants, and should maintain reasonable proportionality between the payments made to achieve capacity adequacy and the benefits received from attaining capacity adequacy.

Figure 1 provides an overview of the overall market structure.

Figure 1 – Single Electricity Market (SEM) market design



1.1 The Medium Term Review of the CPM

There is continued support within the SEM Committee (SEMC) that a capacity mechanism is appropriate, however there are some concerns over whether the current design has been meeting the objectives efficiently and how robust it will be to changing market structures. The regulatory authorities (RAs) have therefore instigated a medium-term review to look at several aspects of operation and to examine if the current design of the CPM can be further improved to optimally meet the objectives set out in the Trading and Settlement Code (TSC).

On 9 March 2009, the SEMC published a consultation paper presenting options to introduce further stability in the CPM and signalling the scope of the medium term review. Specifically, the RAs wished to understand the impact of the CPM on:

- the distribution of capacity payments on availability, particularly at times when capacity is needed most;
- the incentives/signals to enter and exit the market;
- the type of plant planned or being built and the diversity of generation and security of supply, now and in future; and
- prices, customers and the use of current and planned interconnectors.

The RAs also wanted to review the relationship between the CPM and ancillary services, now and in future, to evaluate the impact of changes and processes in the calculation and distribution of the CPM and to identify and assess improvements in the system.

This report has been commissioned to assist the RAs specifically in assessing:

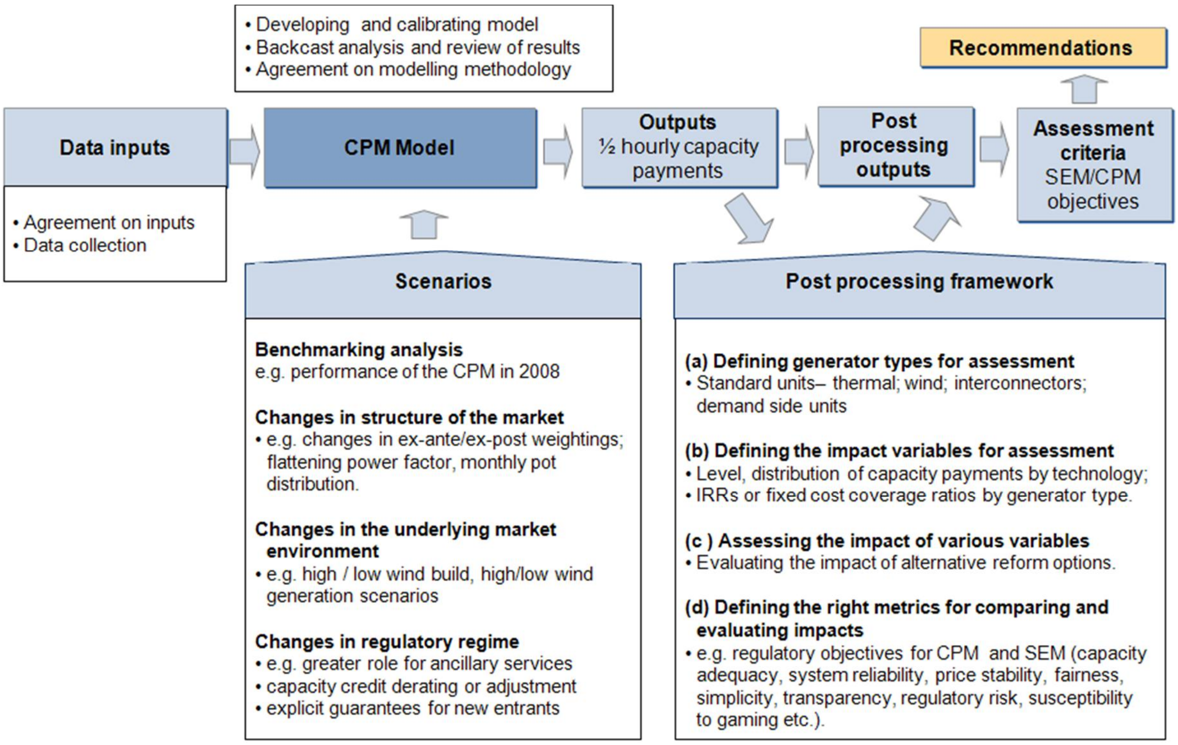
- the treatment of generator types in the CPM;
- the BNE calculation methodology;
- incentives for generators;
- timing and distribution of capacity payments; and
- impact of CPM on customers.

1.2 Approach to the analysis

Our approach to the analysis is described in Figure 2 and consists of four phases:

- Phase I: reviewing the current CPM and its performance against an assessment criteria developed with the RAs;
- Phase II: identifying concerns in existing design;
- Phase III: considering and developing options for reform drawing on lessons from international experience and discussions with the RAs and stakeholders; and
- Phase IV: modelling and assessing reform options against an agreed assessment criteria.

Figure 2 – Approach to analysis



The CPM had undergone two full years of operation at the time of commissioning of this study in November 2009. We selected 2008; the last full year and 2020 as the benchmark current and future years for the analysis.

1.3 Structure of the rest of the report

The remainder of this report is structured as follows:

- Section 2 assesses the performance of the current design of the CPM;
- Section 3 considers the possible changes in performance of the current design in future years;
- Section 4 details our analysis of options to address the shortcomings of the CPM design;
- Sections 5-8 assesses alternative reform options that have been identified; and
- Section 9 provides recommendations and conclusions.

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2. PERFORMANCE OF THE CURRENT CPM DESIGN

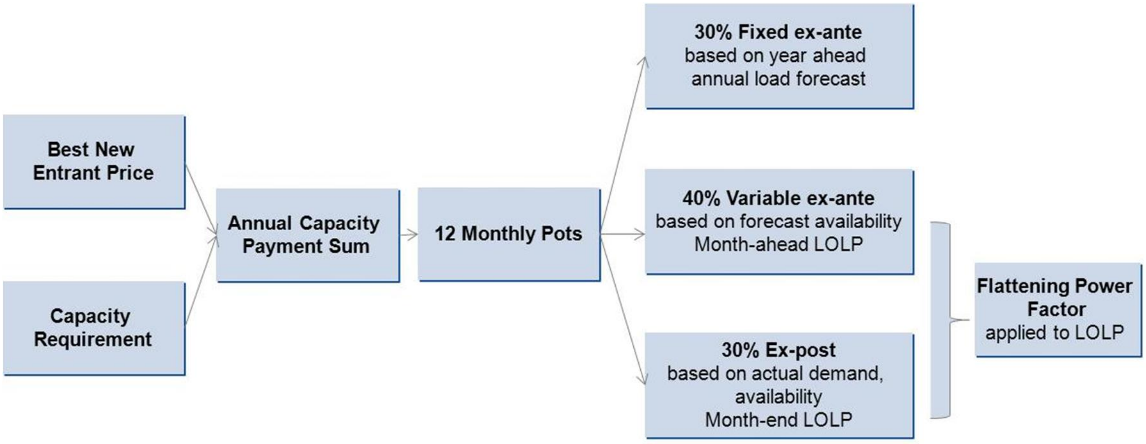
To understand where potential improvements in the current CPM may be achieved, it is necessary to review the performance of the regime against the objectives of the CPM and the SEM. This section assesses the performance of the current design in relation to an assessment criteria agreed with the RAs and with reference to other economic models of capacity pricing. The aim is to highlight the strengths or weaknesses of the current system as a means of providing context for the evaluation of alternative reform options covered in the remainder of the report.

2.1 Constituents and operation of the CPM

The capacity payments that an individual generator receives are intended to both reward generators for providing capacity at periods of high loss-of-load expectation and provide a stable set of investment signals to encourage sufficient new generation.

Figure 3 provides an overview of how the CPM operates.

Figure 3 – Calculation and constituents of the CPM



The total capacity payment available to generators is called the Annual Capacity Payment Sum (ACPS) and it is the product of two elements:

- the Best New Entrant (BNE) Price – this is the annual cost per kW of a new entrant peaking generator (net of expected receipts from ancillary services and infra marginal rents); and
- the Capacity Requirement – this is a measure of the total kW of capacity required to meet the all-island generation security standard (allowing for outages and an assumed wind capacity credit).

The calculation of the BNE price involves identifying an appropriate technology which is used as the basis for calculating the estimated financial costs (cost of capital over life of plant); investment costs (equipment, site) and operational and maintenance costs (service agreement, transmission charges, insurance). From this annualised cost, infra-marginal rents and ancillary services payments are deducted. Infra-marginal rents are defined as implicit capacity payments embedded in the short run marginal costs and are calculated from modelling energy payments (SMPs) in the SEM with and without the BNE plant. Similarly ancillary services payments are deducted based on existing EirGrid / SONI rates.

The capacity requirement is based on an annual Adequacy Assessment process conducted by the TSO. This assessment reviews the existing capacity, the demand forecast and the probability distribution of generation availability and compares the Loss of Load Expectation for the year with a security standard. The results are used as inputs for establishing the total capacity requirement for the year.

The combination of the two variables ensures that from year to year, the ACPS is not (heavily) dependent on the short-term level of system margin, though the payments to individual generators are (as the ACPS will be shared between less MW of capacity when the system margin is tight). However, both elements are revised annually by the regulators, introducing some uncertainty into the long-term value of the ACPS

To incentivise investment and availability when needed, the annual pot is first allocated across months according to peak to trough demand with a larger sum going to months with higher levels of demand. Then, within each month, capacity is remunerated through three payment elements:

- a fixed ex-ante component, consisting of 30% of the total, allocated based on the year-ahead annual load forecast;
- a variable ex-ante component consisting of 40% of the total allocated on forecast availability (month-ahead Loss of Load Probability); and
- an ex-post component consisting of 30% of the total allocated based on actual demand and availability (month-end Loss of Load Probability).

The variable ex-ante and the ex-post capacity payments are linked to the system margin via a Loss of Load Probability (LOLP) curve. The LOLP curve is used as a proxy of the relationship between the margin and the security of the system and is used to weight capacity payments in each trading period. It is calculated annually.

When the system was designed, this structure of payments was deemed to be too volatile. To counter this, a Flattening Power Factor (FPF) was introduced. It is applied to the LOLP curve to make it either ‘steep’ or ‘flat’ and is currently used to reduce volatility in the capacity payments.

The capacity payments are funded through capacity charges on suppliers based on their metered consumption in each half hour and reflect their proportion of total consumption. Although there is a balance between the total capacity payment sum paid to generators and received from suppliers in each month, the ‘capacity prices’ for generation and demand within each half hour in the month will follow different patterns. However this is a distortion as the incentive to reduce consumption and increase supply are asymmetric.

Further details of the CPM algebra are provided in Annex A.

2.2 Indicators of performance

In order to understand how the CPM has performed, it is necessary to have appropriate benchmarks or indicators that reflect the main objectives that the regulators have set out for the mechanism. As part of this study, we have reviewed the objectives in the SEM's Trading and Settlement Code and the wider policy objectives of the RAs and agreed with the RAs the following set of indicators outlined in Table 3.

Table 3 – Indicators of performance

Indicators / Objective	Definition
Capacity adequacy	▪ Ensuring there is enough capacity to meet consumer demand at reasonable cost. ▪ Ensuring that enough capacity is available to meet demand up to the necessary security standard calculated by the SOs.
System reliability	▪ Ensuring that plants are available at times of system tightness.
Efficient price signals for long term investments	▪ The capacity payment should reflect the value to the system of the capacity provided.
Price stability	▪ Ensuring that prices have the necessary stability to minimise end-user risk. ▪ Ensuring that prices are not so volatile that it becomes an overbearing risk to investment.
Fairness	▪ Ensuring that all types of generators are rewarded fairly on a non-discriminatory basis.
Simplicity	▪ Ensuring transparency in methodology. ▪ Ensuring that the payment structure is easy to understand. ▪ Ensuring that prices can be predicted to a reasonable level. ▪ Ensuring the design encourages new entrants and promotes competition.
Susceptibility to gaming	▪ Ensuring that the methodology is robust enough to withstand any attempts at gaming by generators. ▪ The CPM should not encourage behaviour that gives individual generators an advantage at the cost to the system as a whole.
Regulatory risk	▪ Promoting continuity in regulatory decisions. ▪ Ensuring that the whole market works efficiently to provide generators with the required level of remuneration.

Annex B provides a detailed table mapping out our full assessment criteria and methodology.

2.3 Performance of the current design

The main historic assessment of performance was carried out by the RAs[1] in July 2010. For the avoidance of duplication of analysis, we have focussed on four areas:

- the efficiency of the capacity payment signal;
- the distribution of payments across generators;
- impact on entry and exit decisions; and
- predictability and transparency of the mechanism.

2.3.1 Efficiency of the capacity payment signals

The CPM is designed to ensure there is enough capacity to meet consumer demand. It aims at recognising the contribution of all capacity providers for their investments. It is also designed to ensure that capacity is available when required. The former objective is targeted at the quantum of payments, while the latter is to ensure that generators who are available during periods of system stress are paid more than those who are unavailable.

Under optimal capacity planning, the expected value of unserved load can be estimated by the marginal value of unserved load (VOLL) times the probability or fraction of time that load must be curtailed due to insufficient capacity.[2] However, there are several issues with this economically 'efficient' measure of capacity including the practical difficulties in ascertaining the Value of Lost Load. In addition, under this design, the total ACPS pot in 2008 would have increased from €572.2 million to €1,246 million. This is because the system margin in 2008 was comparatively tighter than previous years leading to a higher Loss of Load Probability than what would be expected at equilibrium.

The current CPM mechanism is designed to provide a level of efficiency closer to this idealised version at a 'realistic' cost while meeting the other CPM and SEM objectives specified. However, for the efficiency of the capacity payments to be met, there needs to be a strong relationship between capacity payments and scarcity.

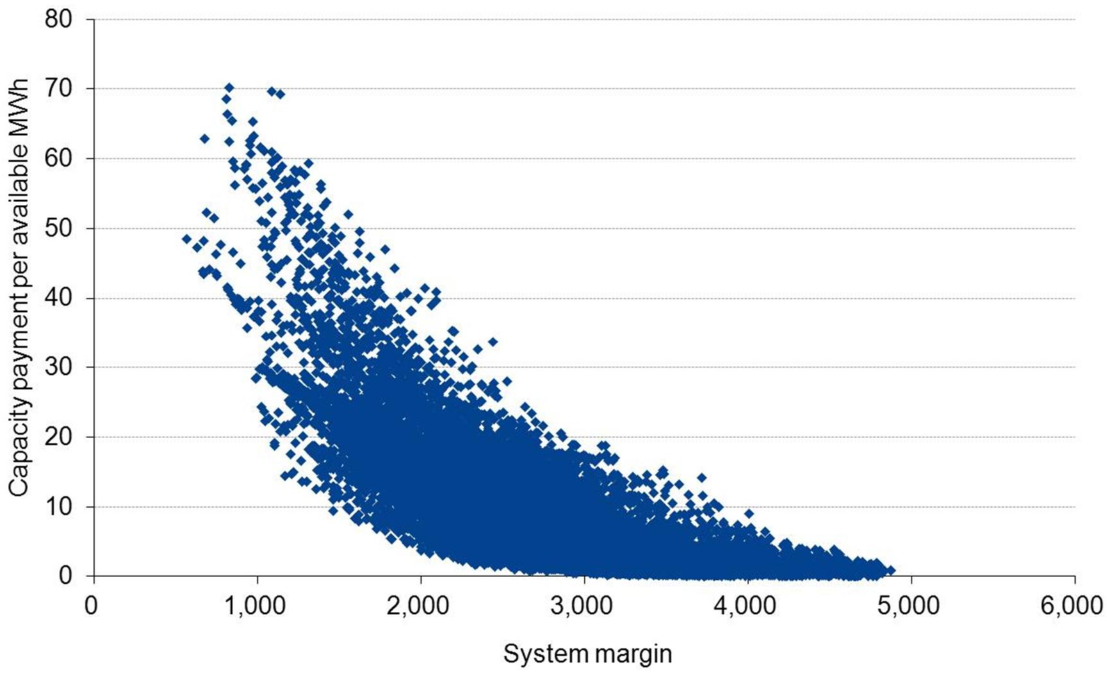
1 See CER, NIAUR, 'CPM Medium Term Review Work Packages 1 to 5 Historical Analysis of CPM And Proposed Decisions,' Discussion Paper, July 2010.

2 See for example, Shmuel Oren, 'Capacity Payments and Supply Adequacy in Competitive Electricity Markets,' VII Symposium of Specialists in Electric Operational and Expansion Planning, May 21-26, 2000.

2.3.1.1 Relationship between capacity payments and system margin

Figure 4 shows the relationship between capacity payments per available MWh and ex-post margin in 2008 under the current CPM design.

Figure 4 – Capacity Payments in € per available MWh vs. ex-post margin, 2008, under the status quo design



There is a relationship between the average capacity payment and ex-post system margin under the current design. However it is diluted and could be stronger. This weakened link between system margin and capacity payments and the relatively small variance between the lowest and highest payments in the current design is a consequence of three factors:

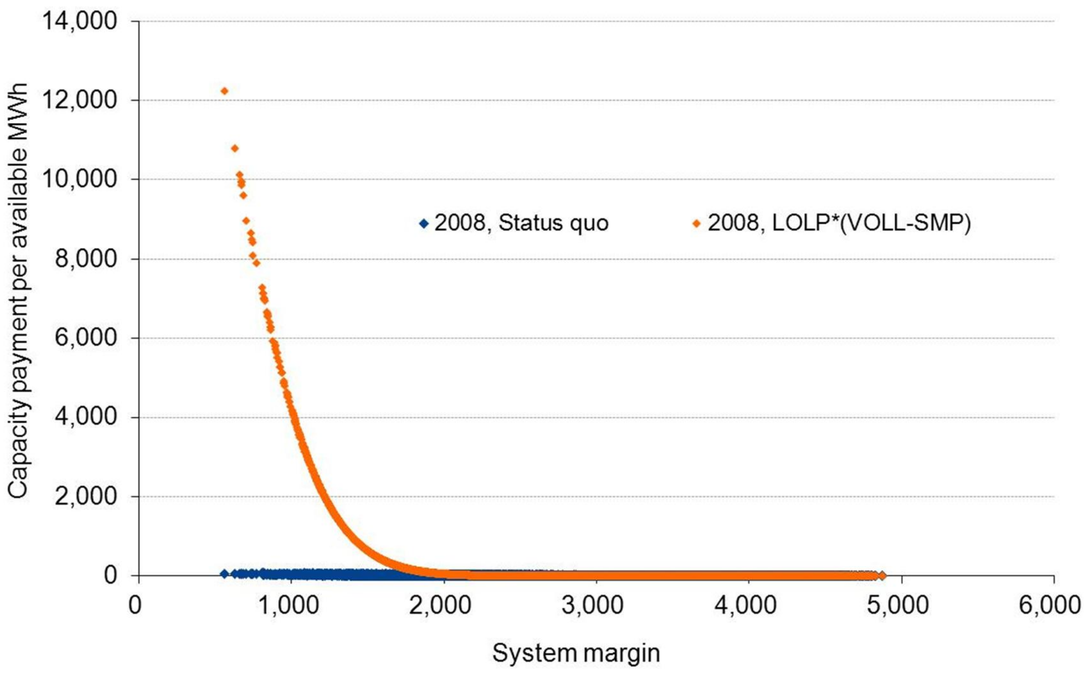
- The monthly distribution of the pot – most of the pot is placed in the winter months, however in 2008 the month with the highest aggregate LOLP was in fact June.
- The use of a Flattening Power Factor (FPF) which reduces the spread of ex-ante and ex-post payments between high and low LOLP periods.
- The high weighting placed on ex-ante and fixed payments under the current mechanism.

To assess the extent of the dilution in the link between system margin and capacity payments; and the limited variance between the minimum and maximum payments, we have compared the status quo design with the 'efficient economic price for capacity' defined by LOLP × (VOLL – SMP). Capacity payments under this regime are calculated using outturn margins and LOLP IN 2008 and a Value of Loss of Load set at €10,000/MWh within the SEM. [34]

3 See for example, CER, NIAUR, 'The Value of Lost Load, the Market Price Cap and the Market Price floor, A Response and Decision Paper,' AIP-SEM-07-484, 18 September 2007, which sets VOLL at €10,000/MWh.

As Figure 5 illustrates, the relationship in this design is non-linear and is defined by a large number of periods with very low prices and a small number of periods with very high prices. The maximum price of €12,232 per MWh corresponds to the period with the tightest margin.

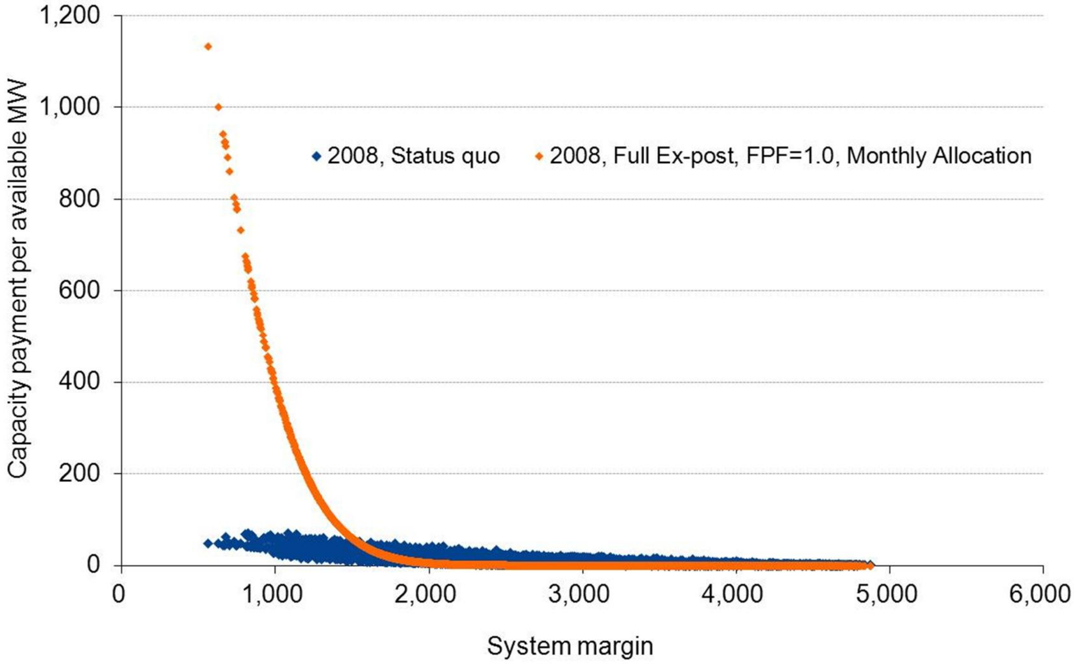
Figure 5 – Capacity Payments in € per available MWh vs. ex-post margin, 2008, under the LOLP × (VOLL-SMP) benchmark design



Although the design significantly strengthens the link between system margin and capacity payments, the overall size of the ACPS under this regime would need to increase from €572 million to €1,246 million. Since the level of ACPS is a constraint, we have considered a secondary benchmark model which would retain the current overall size of the pot. In this benchmark full ex-post model, we assume that plants would be remunerated based solely on their outturn availability with all the payment smoothing mechanisms in the current design (such as Flattening Power Factor and monthly pot allocations removed). Figure 6 shows how this relationship would look like compared to the performance of the current design.

4 There are other markets which have attempted to price VOLL, e.g. the National Electricity Market in Australia. In a survey of VCR for VENCorp in 2003, Charles River Associates (CRA) found an average value of customer reliability of AU$29,600/MWh across customer types in Victoria, see CER, NIAUR, 'The Value of Lost Load, the Market Price Cap and the Market Price floor, A Consultation Paper,' AIP-SEM-07-381, 02 July 2007.

Figure 6 – Capacity Payments in € per available MWh vs. ex-post margin, 2008, under the benchmark full ex-post design



The relationship under both benchmark models shows a strong link between system margin and capacity payments and a high variance between the minimum and maximum payments compared to the status quo. However, there is a trade-off between improved efficiency of capacity payment signals under the comparator designs and price volatility which is higher compared to the status quo design. We therefore need to take into account the performance of the status quo on other objectives.

2.3.1.2 Level of capacity prices, and variations across different levels of system margin

Table 4 shows the maximum price and price when system margin is tightest under the current design and the two comparator designs. The comparison with the LOLP × (VOLL-SMP) design allows us to assess the performance of the current design against the theoretical, efficient benchmark. Similarly, comparisons with the benchmark 100% ex-post allows to assess the performance of the current design but within the constraints set by the fixed ACPS pot.

Pricing under LOLP × (VOLL-SMP) and under the benchmark ex-post design produces a much stronger relationship between scarcity and payments; a larger number of trading periods with near-zero capacity payments and a small number of periods with very high capacity payments. The average payment at minimum system margin increases from €49 under the status quo design to €1,132 per available MWh under the benchmark full ex-post design and €12,232 per MWh under LOLP × (VOLL-SMP). The spread in level of payments between high and low system margin also increases significantly under the two comparator designs, while the relationship between capacity payments and system margin becomes stronger.

Table 4 – Capacity payments in € per available MWh, 2008, under the status quo, LOLP × (VOLL-SMP), and the benchmark full ex-post design

	Status quo, 2008	Benchmark 100% Ex-post, 2008	LOLP*(VOLL-SMP)
Maximum price	70.15	1,131.91	12,232.14
Price at minimum	48.50	1,131.91	12,232.14
Number of trading periods per price group			
€0-25	16,605	16,227	13,582
€25-50	880	523	871
€50-75	81	223	458
€75-100	0	151	328
€100-125	0	95	232
> €125	0	347	2,095

As Table 4 shows, price at the lowest system margin under the current design is not always the trading period with the highest payments unlike in the other two designs. In 2008, this price was €48.50 per MWh compared to a maximum payment of €70.15 per MWh. Moreover, there were at least 94 trading periods with higher system margins and higher capacity payments than the period with the tightest margin. Similarly, the spread of prices between high and low margin periods is low. The average payment was €9.43 per available MWh with only 81 periods or 0.5% of the total with payments greater than €50 per available MWh.

This analysis suggests that the link between capacity payments and system margin under the current design is not as strong as it could be. However, the current regime is designed to meet multiple objectives and thus it is more useful to compare against the aggregate performance across these objectives.

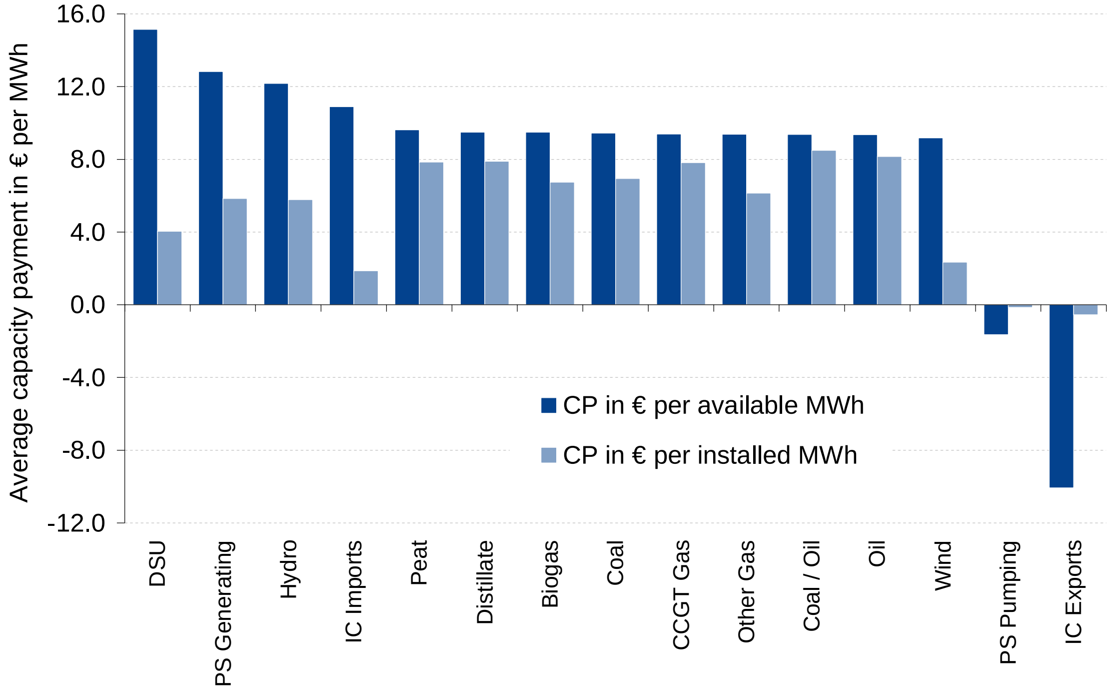
2.3.2 Distribution of payments across generator types

The current CPM design aims to maintain reasonable proportionality between the payments made to achieve capacity adequacy, reliability and the benefits received. Thus the payments made to any technology ought to be commensurate to the adequacy and reliability it provides. The aim is to ensure that generators are treated fairly and without discrimination against specific technologies, and that system reliability is maintained without over-rewarding generators.

Figure 7 compares capacity payments across technologies under the current design in 2008 on two bases:

- per installed MW – defined as the total annual capacity payment divided by the total installed MW for each technology; and
- per available MW – defined as the total annual capacity payment divided by the total available MW for each technology.

Figure 7 – Capacity payments in € per installed and available MWh in 2008, across technologies under the status quo design



Pump storage and interconnector units are treated differently since they can act as both generation and demand. They are eligible for payments during periods when they generate or import (for interconnectors) and accrue charges when they are pumping or exporting. We have presented the two payment streams separately.

The average capacity payment on an available MW basis is approximately €9.40 per available MW across most technologies except for pumped storage, DSU unit, hydro and interconnectors. Wind receives similar level of payment for each MW of available output even though it is less likely to be available at peak.

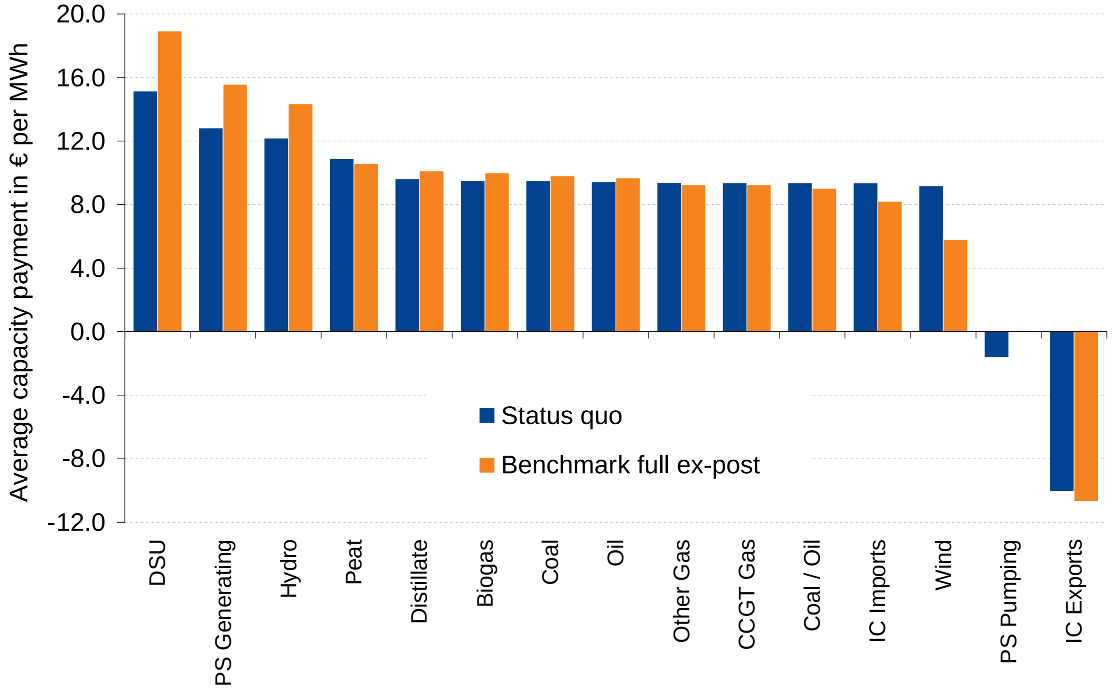
There are significant variations across technologies on an installed capacity payment per MW basis as would be expected given wide variance in capacity factors across technologies. Similarly, there is very little distinction between the payments to most types of generator on an available MW basis. In theory, we would expect similar levels of payments to all plants providing the same service. We would specifically expect to see the same level of ex-post payments since these are paid only to plants that are available at the time.

However, the overall payment per available MW presented in Figure 7 takes into account the fixed and ex ante payments components as well as ex-post. Moreover, the average payment is across all periods, some of which less reliable generators are unlikely to be available. Thus simply looking at variations in capacity factors and comparing across the payment per available MW, provides an indication that wind is over-compensated (since it is not providing the same level of service during system tightness).

To assess whether the payments to different generators are in line with the value they provide, we have compared the payments under the status quo design with those under the benchmark full ex-post design.

Figure 8 compares the average capacity payments per available MW across technologies under both designs.

Figure 8 – Capacity payments in € per available MWh across technologies, 2008, under the status quo and the benchmark full ex-post designs



The main difference between the two designs is that under the benchmark full ex-post system where generators are paid solely on the basis of their outturn availability, the average payments for wind would decline while pumped storage (when generating), demand side units and hydro plants would experience increased payments. Average wind and interconnector import payments per MW would decline by 37% and 12%, while hydro, DSU and pumped storage payments per MW would increase by 18, 25 and 21% respectively.[5]

Figure 8 provides additional evidence that there is a diluted relationship between contribution to system reliability and capacity payments, particularly for a few plants. Wind and the interconnector when it is importing are currently paid a higher amount than the measure of reliability and firmness that they provide to the system. However it is important to note that the pattern of historic interconnector imports is certainly a function of the existing CPM status quo. Thus we would expect the availability or flow pattern for interconnectors to be materially different under the benchmark model. This effect has not been explored in further quantitative depth as it is outside the scope of the study.

The analysis suggests that controllable plants operating during peak times such as Demand Side Units, pumped storage (when generating) and hydro units are currently not remunerated in proportion to their contribution during times of system stress. The

5 There is currently no Demand Side Unit operating in the SEM. The sole plant accredited under this status, has on-site generation and has since changed its registration status to that of a conventional generator.

comparison highlights that the current level of payments made to other conventional generators is relatively similar to what they would receive under a full ex-post. This is because they are generally available at all times and controllable; therefore the generator is able to ensure it accesses capacity payments. Separately, if wind is available, then LOLP will be higher and therefore there will be less payment received. Given the amount of wind generation expected to come online by 2020, this disparity could become a bigger concern in future. The impact of wind is discussed in detail in Section 2.4

This analysis suggests that reliable plants, particularly controllable peak units are being compensated less than their true economic value. However, the total amount of payment for most conventional plants is not significantly more or less than what they would receive under a more efficient pricing model.

2.3.3 Predictability and transparency of the mechanism.

The CPM is intended to provide a stable revenue stream for generators to help cover their fixed costs and reduce their exposure to variable energy prices. In doing so, it ensures that end-prices are not so volatile that it becomes an overbearing risk to investment. In addition this should ensure that prices are more readily predictable for investors and end-users and that, they do not present consumers with volatility risks.

There is debate whether the current design provides adequate signals for new entrants. The Annual Capacity Payment Sum (ACPS) and its constituents, the BNE price and capacity requirement are calculated on an annual basis. Generators are therefore only certain about the current level of payments, with a risk that future payments could be substantially different.

Table 5 highlights the changes in the annual pot, the BNE price, capacity requirement and ACPS between 2007 and 2011. In nominal terms, the size of the pot rose annually over the first three years, from €450.6 million in 2007 to €640.9 million in 2009, then fell significantly to around €550 million for both 2010 and 2011.

The overall pot has varied significantly due to the annual re-calculation of the BNE price and changes in the annual capacity requirement. The year on year variability in the calculation provides significant regulatory risks for new entrants. The risk to investors is compounded by the fact that neither the re-calculation process, nor the changes are fully transparent or fully predictable for new entrants.

Table 5 – Annual Capacity Payment Sum (ACPS) and constituents, nominal terms

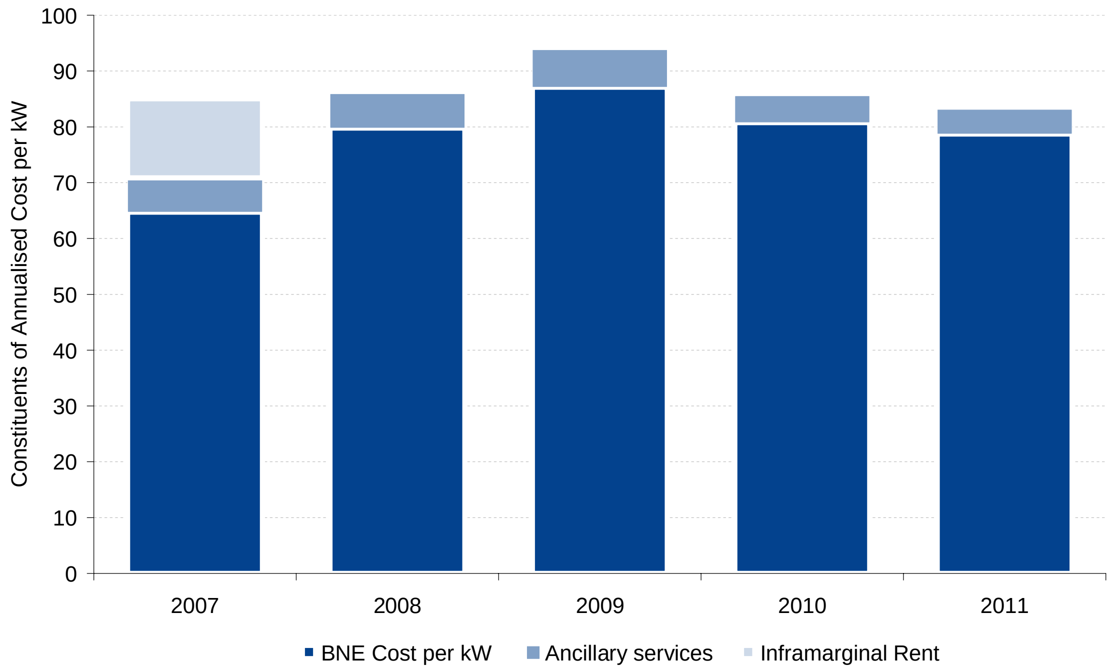
	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€ million)
2007	64.73	6,960	450.5
2008	79.77	7,211	575.2
2009	87.12	7,356	640.9
2010	80.74	6,826	551.1
2011	78.83	6,922	555.0

Source: All Island Project

Figure 9 shows the changes in BNE price and its constituents. The BNE price increased by 23% in 2008 due primarily to increases in EPC and plant costs, more than outweighing the resulting exclusion of any infra-marginal rent for the BNE plant. Fixed costs increased by 46% between 2007 and 2010 driven largely by increases in steel and other input costs while recurring costs broadly declined. Similarly the BNE price increased by 9% in 2009 due to changes in fixed costs before declining by 7% in 2010.

The capacity requirement as noted in Table 5 increased annually by 2-4% then declined by 7% in 2010 and experienced a minor change in 2011.

Figure 9 – BNE price in €/kW, 2007-2011



These changes highlight the risk to new entrants that the annual regulatory changes entail and the uncertainty of capacity revenues from year to year. The longer term impact of limited predictability and transparency could be reflected in limited efficiency of signals for long term investments and a higher cost of capital.

2.3.4 *Impact on entry and exit decisions*

Since the go-live date of the current SEM/CPM design, close to 900 MW of new wind capacity have been added and by January 2013[6], 1,370 MW of new conventional capacity is likely to come online, while 1025 MW of capacity will be have been decommissioned.[7] Table 6 provides a list of conventional plants expected to come online and offline.

6 European Wind energy Association (EWEA), '2007 Wind Map'; Irish Energy Wind Association, 'Current Installed Capacity as of May 31, 2010';

7 For details of conventional capacity, see EirGrid, 'Generation Adequacy Report 2010-2016.'

Table 6 – New conventional generation capacity with grid connection agreements; and plant de-commissioning

Plant	Date	Capacity
New conventional capacity		
Aghada CCGT	Jan 2010	432 MW
Whitegate CCGT	Jun 2010	445 MW
Edenderry OCGT	Jul 2010	111 MW
Dublin Waste-to-Energy	Aug 2010	72 MW
Meath Waste-to-Energy	Jan 2011	17 MW
Nore OCGT	Nov 2011	98 MW
Cuileen OCGT	Jul 2012	98 MW
Suir OCGT	Jan 2013	98 MW
Plant de-commissioning		
Poolbeg 1 & 2	Mar 2010	219 MW
Great Island	Dec 2012	216 MW
Tarbert	Dec 2012	590 MW

Sources: EirGrid, Generation Adequacy Report 2010-2016

There is limited evidence to support a causal relationship between the CPM and new investments. Most of the plants listed were already planned for construction as of going live, thus it is difficult to make the case that the CPM has been a major driver behind these investment decisions.

Further, much of the new entry has been driven by factors other than the capacity payment system. The incremental wind capacity is mostly driven by remuneration from SMP and contributions from the Renewable Energy Feed-In Tariff (REFIT) in the Republic of Ireland and the Northern Ireland Renewables Obligation scheme. Of the conventional capacity coming online between 2008 and 2015, the two largest plants, the Aghada CCGT and Whitegate CCGT were also driven in part by government commitments to ensuring energy security.

However this does not imply that the CPM is unimportant. We estimate that in 2008, capacity payments comprised 14% of total revenues for a typical CCGT compared to 87% for a typical distillate peaking plant in the SEM. Thus the CPM is an important source of revenue for all plants, specifically peaking plants.

The recent decrease in demand and entry of 800 MW of new plant coming online with more on the way as Table 6 shows, suggests that the market has ‘surplus’ near term capacity. However, the limited history of the CPM and the direct influence of other drivers in delivering this new capacity suggest there is no robust causal relationship of the CPM providing insufficient or too much incentive for new build.

2.3.4.1 Exit inefficiencies in the current design

The CPM is designed to maintain capacity adequacy and deliver efficient investment signals. One implication of this is that it should not distort entry or exit decisions. Although the current 'surplus' in capacity due to the decline in demand and entry of a large amount of new capacity may suggest that the exit signals in the CPM are not performing adequately, the reality is that 1,000 MW of conventional capacity is expected to exit the market between go-live and 2012. Thus the current 'balance' will be somewhat restored. However, the exit of the plants in question have little to do with the CPM, given that they have been planned, in some cases since the formative stages of the SEM.

The case for whether there are plants kept on the system due to a generous CPM mechanism is complicated. There are a number of peaking plants in the SEM with very low load factors and/or low run time. These include, according to our estimates, peaking units at Killroot, Ballymford and Rhodes averaged 3-8% in 2008. Thus it is useful to compare the level of capacity payments received with plant fixed costs.

We estimate that a 190.1MW distillate peaking plant running for 10 hours a year (with no outages), and receiving the average €7.89 per MWh for distillate plants would receive up to €12.7 million a year in revenues from capacity payments. Of these revenues, €15,000 would be based on ex-post availability with the remainder resulting from eligibility for the variable ex-ante and fixed ex-ante constituents of capacity payments (or 70%) for each trading period. The annualised CAPEX cost of the BNE plant for 2011 (a distillate plant with identical capacity) is estimated by the RAs at €10.91 million a year.[8] Our own estimates based on assumptions from the dispatch principles results in a CAPEX estimate of €11.8 million (see Annex C).

Thus based on this simple analysis (using the CAPEX estimate as a proxy for total fixed costs), it is likely that plants that remain on the system receive a higher or comparable level of payment to their fixed costs. However, this simplified analysis ignores other fixed costs which should be taken into account in making the case or not for whether the CPM is keeping plants that should be decommissioned.

Similarly, there is a concern that the current system does not adequately penalise plants which declare themselves available but fail to respond when called upon. The current market arrangements require all generators to be available when called upon and mandates the ISO to conduct random testing of low load factor plants, constraining them on to check that they can deliver. The grid code specifies a penalty for being unavailable when called to run. Any such plant is forced to declare itself unavailable for that period, losing the energy payments and capacity payments for the period. The plant may also be liable for uninstructed imbalance payments, for negative deviation from its dispatch schedule, beyond the set tolerance bands.

In comparison, under a benchmark ex-post mechanism or a (LOLP × (VOLL-SMP) regime, if a plant is unavailable to run especially during system scarcity, a large share of the total pot flows to those period and to its competitors, and thus it suffers more heavily compared to the current design. Assuming a plant is unavailable in the trading period with the lowest system margin, and forfeits all its capacity payments for the particular trading period and no more, a 400 MW plant would lose €2.4 million under the LOLP × (VOLL-

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8 The BNE price for 2011 assumes a peaking plant running for 4 hours a year (see CER, NIAUR, 'Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement and Annual Capacity Payment Sum for the Calendar Year 2011,' Decision Paper, August 11, 2010, SEM-10-053). Similarly, most of the plants with very low load factors reviewed similarly rarely run if after all.

SMP) regime; €230,000 under the benchmark ex-post regime and only €9,700 under the current design. With the strong ex ante components under the current design, the impact of the penalty is limited. In Section 4.4 we explore the alternatives for the status quo penalties in detail.

2.4 Conclusions

The analysis presented in this section suggests that the overall performance of the current design appears satisfactory when considered in the context of the competing objectives of the CPM. However, there are several concerns which need to be addressed going forward. The relationship between payment for reliability and value is diluted through focus on ex-ante payments, and the existing monthly pot and flattening power-adjusted distribution. This link could be improved to address concerns that the current CPM structure does not appropriately reward generators' contribution to system peak. However, any of the possible changes discussed should not be viewed in isolation, but in the context of a balance against other objectives, with a weighting of the pros and cons of further change. The uncertainty in future payments due to the annual changes in BNE price and the ACPS, and concerns over the level of exit inefficiencies, or rewarding plants even when they are unavailable, are similarly issues that need to be addressed. Table 7 summarises our initial assessment of the performance of the current CPM design compared to the assessment criteria agreed with the RAs.

Table 7 – Performance of the current CPM mechanism in 2008

Reform option	Performance
Capacity adequacy	▪ There is currently sufficient capacity in the SEM due to significant new entry since go-live. However, the role of the current CPM design in so far has been limited compared to other drivers such as renewable incentives. ▪ It is unclear that the full value of capacity is available to generators under this system. Under a LOLP × (VOLL-SMP) regime the ACPS would have risen in 2008 from €572 million to 1,246 million.
System reliability	▪ The current system does not differentiate substantially between generators with different levels of controllability as a consequence of the current split in payments.
Efficient price signals for long term investments	▪ The CPM does not reflect the full value of lost load at peak times. ▪ There is concern that plants with low load factors which are unavailable when called to run are not adequately penalised.
Price stability	▪ Prices are stable in the current regime. The monthly pot allocation and the FPF reduce the variability in prices.
Fairness	▪ The current design appears to over-reward intermittent generation that contributes less to peak demand. However, there is no blatant discrimination; as such the efficiency of the charging may be the best place to raise the distributional impacts.
Simplicity	▪ The status quo design is transparent and simple to understand. ▪ It is difficult to predict the level of payment in future years as this is subject to regulatory determination.
Susceptibility to gaming	▪ The risk of outright gaming is small.
Regulatory risk	▪ It is difficult to predict the level of payment in future years as this is subject to regulatory determination.

The changing structure of the market in the SEM with increased penetration of intermittent generation is likely to impact the performance of the current design in many ways. It could mitigate the issues identified, although it is more likely to exacerbate them.

In the next section, we review the changes in the market and assess how the current design is likely to perform in future years, in a market driven by intermittency and whether the design will remain fit for purpose to 2020, providing appropriate signals to generators to invest in the right type and levels of capacity required in the market.

3. CURRENT DESIGN IN FUTURE YEARS

Under the EU's 2020 targets for 20% renewable energy, the Republic of Ireland faces a legally binding target of 16% renewable share of final energy demand, with the equivalent figure for the UK of 15%. A large burden for meeting the targets is likely to fall on the electricity generation sector. Indeed, the Irish national target for renewable generation by 2020 was increased from 33% to 40% in 2008. Similarly, the Strategic Energy Framework published by the Department of Enterprise, Trade and Investment (DETI) in 2010 commits Northern Ireland to a 40% renewable generation target by 2020.[9]

In light of the dominance of wind as a renewable resource, these ambitious targets suggest that wind is likely to be the primary driver in pricing and dispatch in the SEM. This section discusses whether this shift is likely to exacerbate or dampen concerns already identified in the performance of the current mechanism. Our analysis for future years focuses on the impacts associated with the heavy build in new wind generation and the impacts associated with variability in wind in any given year or trading period. We discuss these in turn isolating:

- changes in level and distribution of capacity payments due to the increased penetration of wind and variability of wind;
- changes in relative sufficiency of capacity payments in encouraging new investments; and
- impact of changes in revenues on generator profitability.

3.1.1 Assumptions for future years analysis

We have assessed the performance of the market in 2020 and capacity payments received in those years using data and assumptions from the modelling conducted by the dispatch principles workstream. We have not conducted any primary modelling, nor have we considered how the capacity requirement and hence the ACPS may change.The assumptions adopted from the dispatch principles workstream include:

- **Composition of plants** – we assume the commissioning of 2,346 MW in conventional generation and decommissioning of 1,765 in capacity yielding a net new capacity of 581 MW between 2010 and 2020. Additionally, we have assumed that 3,948 MW in wind capacity will come online between 2010 and 2020. Details of the changes in plant mix are provided in Annex C.1.1.
- **Capacity payments** – we assume that the overall pot increases by the same rate as demand from € 572 million in 2008 to €654 million in 2020. BNE price is assumed to remain constant in real terms.
- **Interconnectors** are rewarded on the basis of flows as currently stated. Annual imports are assumed to increase from 1265 GWh in 2008 to 1918 GWh in 2020. Exports increase from 295 GWh to 1672 GWh. As a result, net imports decline from 970 to 246 GWh.
- **Demand side units** are not separately specified in the dispatch principles workstream and are therefore not separated out explicitly in 2020 analysis.

9 Department of Enterprise, Trade and Investment, Northern Ireland, 'Strategic Energy Framework for Northern Ireland – 2010,' see http://www.detini.gov.uk/deti-energy-index/deti-energy-strategic-energy-framework.htm

Table 11 details the growth in demand relative to the growth in ACPS pot and is provided to explain the wider variation in payments we show later on. Details of the changes in the plant mix are provided in Annex C.

Table 8 – Electricity demand in the SEM (TWh), ACPS (€ millions), 2008-2025

	Average Load (TWh)	ACPS in € Million
2008	40	575,221,470
2010	35	551,131,240
2015	41	590,989,913
2020	45	653,876,442
2025	49	710,997,036

3.2 The SEM in 2020 and beyond

3.2.1 Impact of a heavy build in wind

The large amount of intermittent generating capacity coming online is likely to have several impacts on the electricity market in Ireland, including:

- Increasing the frequency of extreme events, days or trading periods, when wind could contribute all of generation (although subject to system operator constraints) or none. This is likely to result in an increased frequency of price spikes, significant changes in generation patterns, or significant overcapacity within the system.
- Changes in plant operation profiles – higher penetration of low-marginal cost wind generation reduces the 'space' for conventional plant to operate in, thus the running patterns of conventional plant will increasingly become the inverse of wind generation by 2020, with significant impact on plant load factors of conventional thermal plant.
- Increasing number of periods of zero or negative prices and falling average energy prices – with wind bidding at marginal costs (zero in ROI, or the negative value of one ROC, in NI), the frequency of negative prices would likely increase sharply.
- Changes in the profile of demand met by thermal plant – average within-day price profiles are likely to remain broadly similar as wind generation increases, with the pattern of lower prices overnight and higher prices during the day. However, the variance around these prices could become much greater (variability of wind will change the profile of demand supplied by thermal plant, the demand which must be met by non-wind capacity is likely to become much more variable than the current demand profile, additionally, the potential ramping required by the thermal system will increase).
- Increasing price volatility as a result of the increase in extreme events becoming normal (this is because annual average prices will become increasingly driven by wind with higher numbers of low and zero priced trading periods). This is exacerbated by interconnection with the GB market since the SEM will likely import price spikes from GB. The absence of a capacity regime is likely to lead to greater volatility in prices, transmitted to the SEM via the interconnector.
- Increase in reserve requirements as well as requirements for warming, additionally, the amount of cold plant also rises because load factors of CCGTs fall, and they are off for longer periods of time due to being displaced by wind.

- Impact on investment signals – due to an explicit capacity payment mechanism, peaking plant makes reasonable returns – in particular the lower efficiency but cheaper designs (the payments for capacity provision mean that peaking and low-merit plant makes a return on investment even if it only generates infrequently).

The net feature of the heavy build in wind is that it is likely to lead to a decline in energy payments for most generators. The decline in energy revenues is discussed in detail in the 2009 Pöyry intermittency study, cited in Annex C.1[10] In the current review process, the impacts of a heavy wind build are assessed in detail in the dispatch workstream and is outside the scope of this report. In Section 3.2.4.1 we assess the changing revenue mix of selected representative plants for each technology over time, capturing the decline in energy revenues for conventional plants, using date from the dispatch workstream.

A related impact of a heavy build is that risk in the market will increase. This is characterised as both price risk (prices jump between very high and very low levels over very short periods of time) and (for non-baseload plant) as volume risk. This combination of risk is particularly difficult for generators to hedge except within a portfolio of generation which includes wind and is likely to increase the cost of capital for new entrants.

3.2.2 Efficiency of the capacity payment signals in future years

3.2.2.1 Level of payments when capacity is scarce

The changes in the generation mix in 2020 have a significant impact on capacity payments. As Figure 10 shows, the relationship between system margin and capacity payments under the current design seems marginally stronger in 2020 compared to 2008. The price at minimum system margin increases from €48.50 to €245.26 per available MWh. Moreover, this price in 2020 is also the maximum payment under the design. The variance between the highest and lowest prices also increases and is in part due to the high volume of wind on the system such that the payments are spread over a larger volume.

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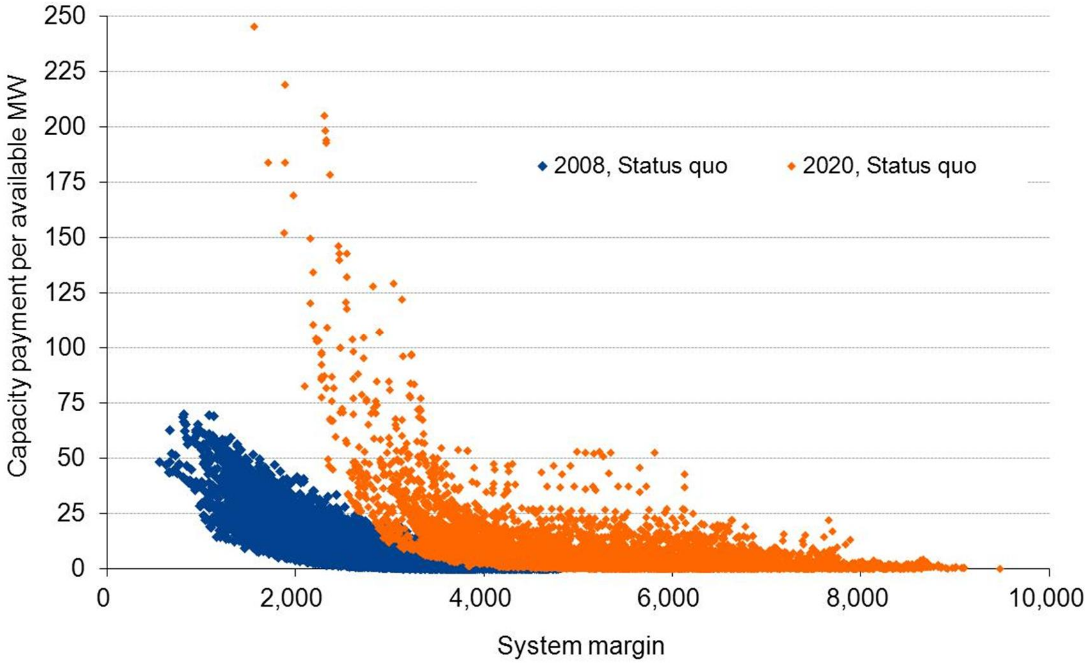
10 Pöyry Energy Consulting, 'Impact of Intermittency, How Wind Variability Could Change the Shape of the British and Irish Electricity Markets,' July 2009, see http://www.poyry.com/linked/group/study.

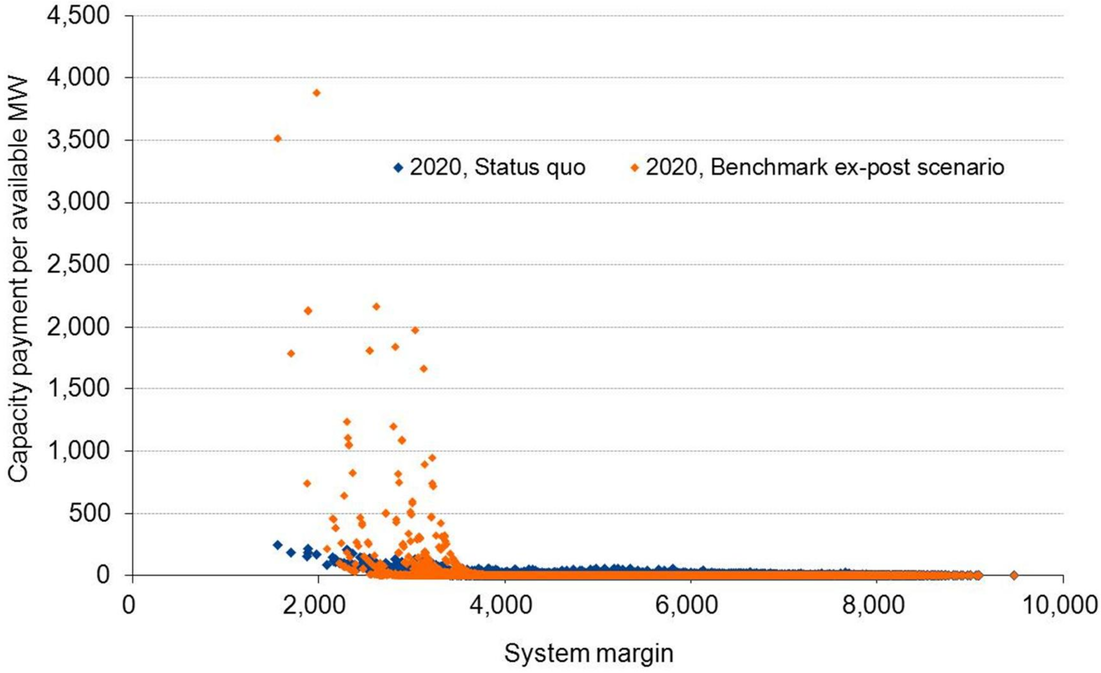
Figure 10 – Capacity Payments in € per available MWh vs. ex-post margin, 2008 and 2020, under the current CPM design



Notes: 2020 analysis assumes net new conventional capacity of 581 MW between 2010 and 2020 and 3,948 MW in wind capacity and a net decline in interconnector import flows from 970 to 246 GWh. Capacity payments are assumed as increasing at the same rate as demand from € 572 million in 2008 to €654 million in 2020.

Compared to the benchmark ex-post design in 2020 shown in Figure 12, the current design does not perform as well and the relationship between capacity payments and system margin is weaker. While the spread of prices rises and the highest price is in the lowest margin periods, the capacity payments still diverge significantly from an efficient benchmark.

Figure 11 – Capacity Payments in € per available MWh vs. ex-post margin, 2020, under the status quo and benchmark full ex-post designs



3.2.2.2 Level of capacity prices, and variations across different levels of system margin

The performance of the current design in 2020 at re-distributing payments to generators available when they are most needed is broadly comparable to 2008 and to the benchmark system. As Table 9 shows, the number of trading periods with capacity payments over €50 per available MWh, increases from 81 in 2008 to 129 in 2020 under the status quo design and 180 under the benchmark full ex-post design. Similarly the average payment at minimum system margin increases from €49 under the status quo in 2008, to €245 in 2020, and €3,514 under the benchmark design. Moreover, the highest price in 2020 is also the price at lowest system margin.

The status quo design's performance relative to the benchmark ex-post in 2020 seems broadly comparable to 2008. The ratio of the highest prices under the two designs remains largely the same at 15 times over the period.

Table 9 – Capacity payments in € per available MWh, in 2008, 2020 under the current CPM design and under the benchmark full ex-post in 2020

	Status quo, 2008	Status quo, 2020	Benchmark full ex-post, 2020
Maximum price	70.15	245.26	3,883.79
Price at minimum system margin	48.50	245.26	3,513.97
Number of trading periods per price group			
€0-25	16,605	17,079	17,321
€25-50	880	358	65
€50-75	81	61	34
€75-100	0	34	27
€100-125	0	14	19
> €125	0	20	100

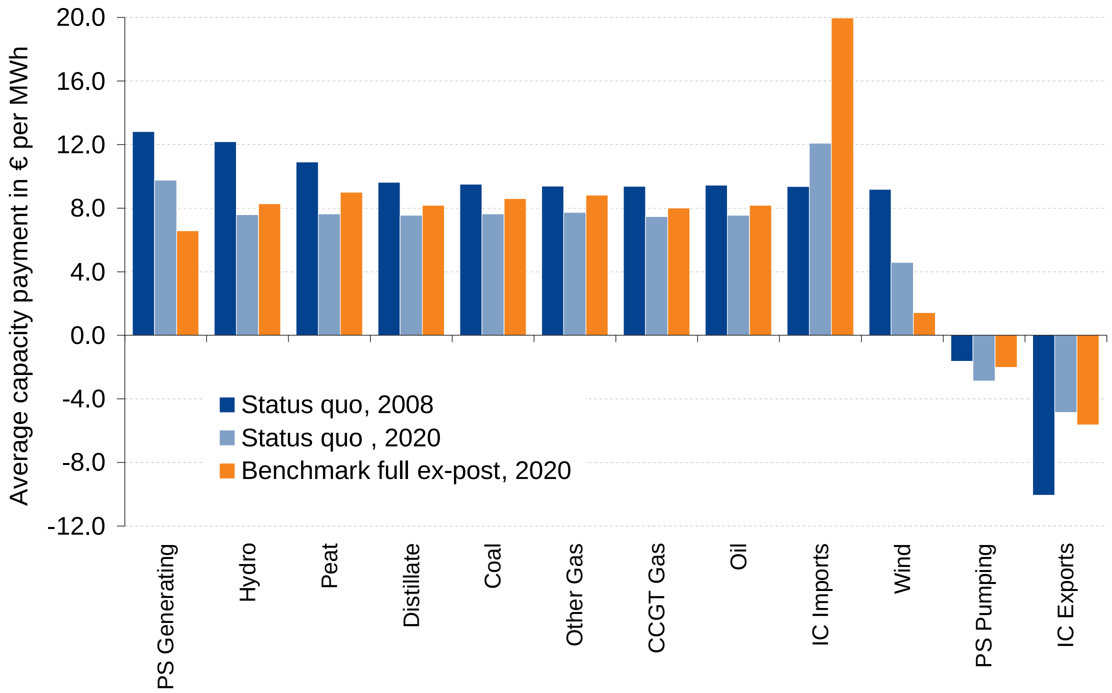
This analysis suggests that while the link between capacity payments and system margin under the current design seems marginally stronger in 2020, compared to 2008, it is not as strong as it could be under a benchmark full ex-post design (which is closer to the true economic pricing of capacity).

3.2.3 Distribution of payments across generators

The average capacity payments per MWh are likely to decline across the board for all technologies in 2020 compared to 2008 except for interconnector imports as Figure 12 highlights. This is due in part to:

- our assumption that capacity payments increase in proportion to demand from €572 million in 2008 to €654 million; and
- a high installed wind capacity – the growth in installed capacity due to wind is higher than the growth in demand, thus we are allocating the pot over a greater capacity, as the MW of wind increases but thermal capacity does not decline as much.

Figure 12 – Capacity payments by technology under the status quo design in 2008 and 2020 and under the benchmark full ex-post design in 2020



Pumped storage, hydro, peat and wind are likely to experience the largest declines in capacity payments under the current regime, while interconnector imports payments increase. The decline in pumped storage is possibly due to fewer hours of operation which counteract the benefits of peakier prices. Conversely, the increase in payments for interconnector imports is due to the fact that it will likely be importing during tight system stress at a higher frequency in 2020 compared to 2008, thus on average receiving a higher payment than it currently does. Our analysis is based on assumptions from the dispatch principles workstream which assumes a net decline in interconnector import flows from 970 to 246 GWh in 2020. Given that interconnector exports pay a charge, the greater shift to exports suggest that on average imports will be paid more.

Compared to the benchmark full ex-post scenario on the other hand, the payments under the current design are broadly comparable with a few exceptions. Wind experiences a large decline relative to the status quo design while the interconnector experiences a correspondingly large gain in payments received as shown in Figure 12. The decline in wind revenues is due in part to its relatively less reliable output on an outturn basis, however it is also due to our modelling assumptions (which assumes a large increase in wind on the system, and a smaller increase in overall ACPS, growing at the same rate as demand, thus in practice the overall increases less than proportionately with possible output levels.

The overall decline in payments across technologies under the current design suggests that the pot should be increased at a greater rate than the level of demand (assumed in our analysis), if it is to provide the same level of remuneration as in 2008. In addition, the performance of wind under the benchmark full ex-post design further illustrates the extent to which less reliable generators are compensated compared to their contribution during tight system margin. Conversely, it suggests that controllable plants that are available during peak hours are not compensated fully according to their economic value.

The implication is that even in 2020, the status quo design performs inadequately compared to the benchmark, on the basis of fairness as it compensates reliable generators at a lower rate than economic theory would suggest. Moreover, all else being equal, this level of payments limits the efficiency of signals for long term investments for reliable plants and could over the long term affect their adequate provisioning. In contrast it could lead to a higher than adequate provision of less reliable plants.

In general, this analysis suggests that the status quo design performs inadequately in encouraging system reliability and in fairness compared to what economic theory would predict. This is because the most reliable generator is unlikely to receive the level of payments that they would under economic pricing, while less reliable generators are likely to receive a higher payout than they would under economic pricing of capacity. This also implies that all other things being equal, the status quo design is more likely to over-incentivise less reliable generators and under-incentivise the most reliable generators, thus affecting the long term signals for provision of adequate capacity, and the mix of future capacity.

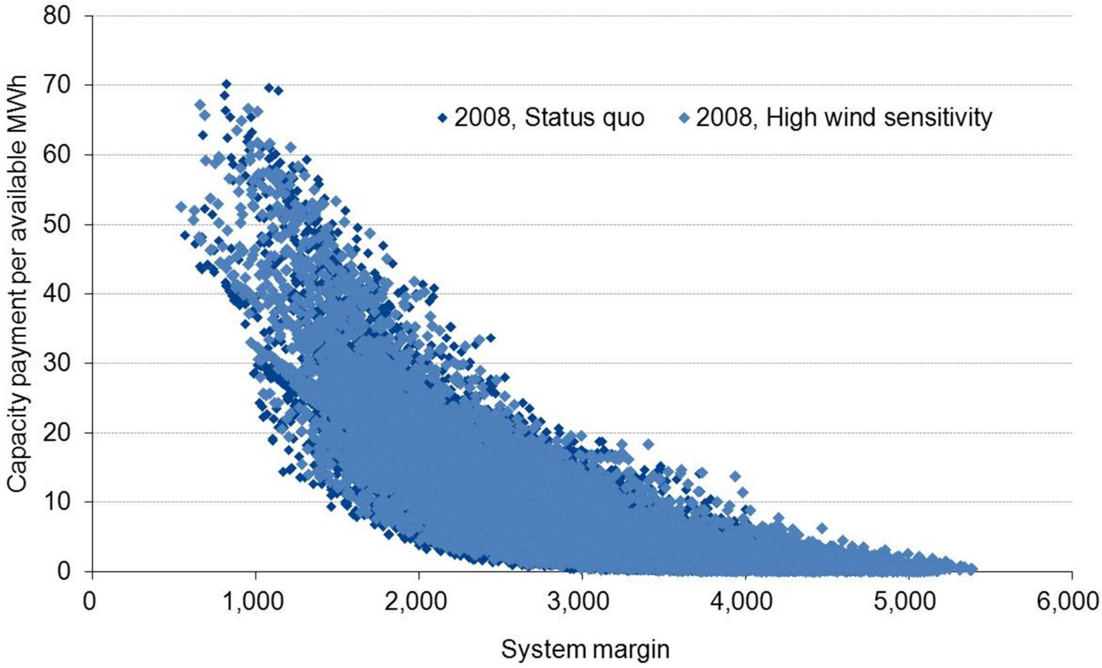
3.2.3.1 Impact of wind variability

The increased penetration of wind will not only lead to declines in average energy payments and lower average capacity payments, but will also increase the variability and uncertainty in the level of payments for conventional generators.

The intermittency of wind coupled with a heavy build in wind, means that periods of very low wind generation (less than 5% of installed capacity) may become more common and may last up to a few days. Equally periods with very high wind generation and low demand will exist. Although wind speeds on average do increase during daytime peak hours, and are higher in winter than in summer this is typically masked by a very significant variation of generation around the averages. This is likely to become more apparent with increased penetration of wind.

We have assessed the impact of a high and low wind year on capacity payments, defined as a 25% increase and decrease in wind generation in 2008 and in 2020. Figure 13 compares the resulting relationship between payments and system margin under the status quo in 2008 and assuming a 25% increase in wind generation.

Figure 13 – Capacity Payments in € per available MWh vs. ex-post margin, 2008, under the status quo and assuming a 25% increase in wind generation

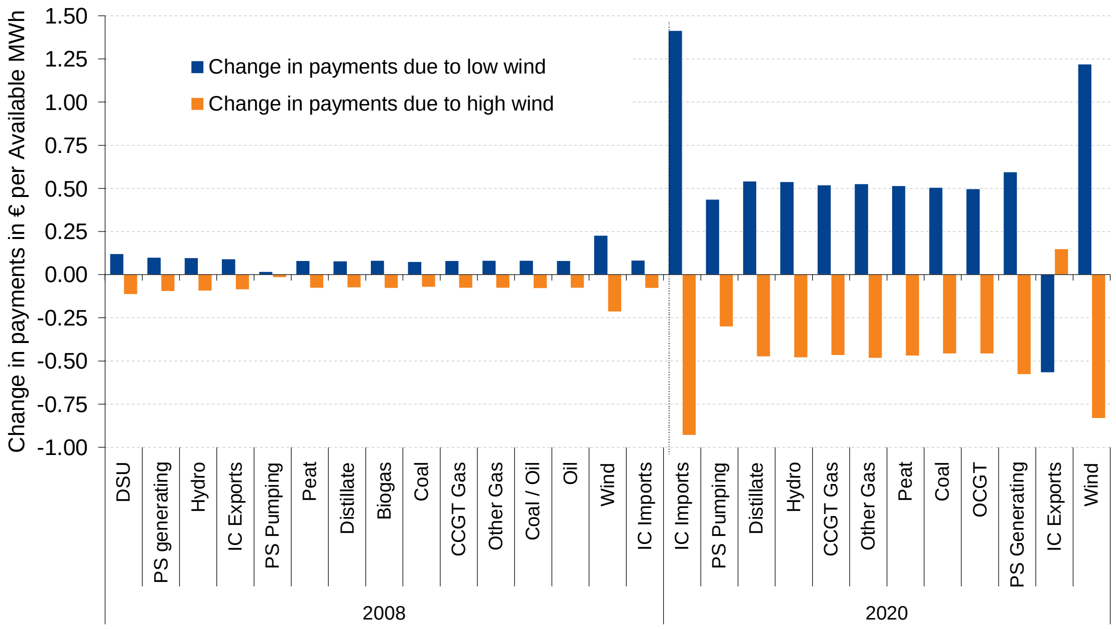


The spread of payments between high and low margin periods is largely unaffected as is the relationship between system margin and capacity payments. This is because of the relatively smaller penetration of wind and due to the structure of the current design which is heavily weighted towards ex-ante payments. Under the current design, a high or low wind year affects only the 30% ex-post constituent of payments. As a result, the average payment across all generators (excluding wind and interconnectors) increases in a low wind year from €10.91 to €11.00, per available MWh, and declines to €10.82 per available MWh in a high wind year.

3.2.3.2 Impact of changes in wind generation on capacity payments

Figure 14 highlights the absolute impact of a low and a high wind year on payment per available MW by generator type under the current design in 2008 and 2020. In 2008, the variance in capacity payments received in a low and high wind year compared to a normal year is minimal, averaging €0.09 per available MW across most generators (except for wind and interconnectors). The average payments for wind increases or declines by €0.22 per available MW or by 2% in a high and low wind year respectively, however, by 2020, the variance is likely to increase to €0.50 per available MW across most technologies (except wind and interconnectors). The variance for wind increases from €0.22 to €1.03 per available MWh in 2020.

Figure 14 – Impact of a 25% change in wind generation on capacity payments, € per available MWh, in 2008, 2020, under the current design



For a CCGT with a capacity of 400MW, this is approximately €242,000 less revenue from capacity payments in a high wind year and an additional €254,000 in a low wind year in 2008, which increases to a loss of €730,000 in a high wind year in 2020 and a gain of €813,000 in a low wind year. The lost revenues may increase as a result of lower load factors not captured in our analysis. On a percentage basis, the level of payments are relatively low, however given the volatility and reductions in energy payments in 2020, these changes in capacity payments are likely to impact the cost of capital and level of investment attractiveness for new entrants.

3.2.3.3 The impact of interconnectors

The increased penetration of wind and its variability is likely to increase the importance of interconnectors in the system. The Moyle Interconnector, between NI and Scotland, is currently the only link between the SEM and the GB market; however this will increase with the on-going plans to develop additional interconnectors. EirGrid is currently working on an East-West interconnector between Wales and the Republic of Ireland which was granted planning permission in 2009. The cable is being manufactured in 2010 and 2011 by ABB with local construction due for completion in the fourth quarter in 2012.[11] A competing project led by Imera Power received an Interconnector licence by Ofgem, the GB regulator, in November 2007 and Third Party Access (TPA) exemption from the CER. However, there has been no recent development in the latter project.

In the current CPM design interconnectors are paid capacity payments on the basis of metered flows and incur negative payment for exports. Our analysis assumes a

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11 See EirGrid, 'East-West Interconnector, Project Activity,' at http://www.eirgridprojects.com/projects/east-westinterconnector/projectactivity/

continuation of this payment regime and that annual imports increase from 1265 GWh in 2008 to 1918 GWh in 2020. Exports increase from 295 GWh to 1672 GWh. As a result, net imports decline from 970 to 246 GWh. The increased export and thus higher negative payments for the interconnector, combined with an increase in wind capacity in the SEM in 2020 has a significant impact on overall interconnector revenues. As Table 10 shows, average capacity payment under the status quo design increases from €9.35 per MWh in 2008 to €12.08 per MWh when importing. Similarly, the 'charges' for export decline from €10.07 per MWh in 2008 to €4.85 per MWh in 2020.

Under the benchmark full ex-post model, the interconnector would experience lower revenues for importing in 2008. However, these would increase from €8.20 per MWh in 2008 to €19.97 per MWh in 2020. Similarly, the 'charges' for export would be marginally higher at €10.69 per MWh in 2008, declining to €5.64 per MWh in 2020 compared to the status quo design.

Table 10 – Interconnector capacity payments in € per available MWh, in 2008, 2020

Imports	**2008**	**2020**
Status quo	9.35	12.08
Benchmark full ex-post	8.20	19.97
Exports		
Status quo	-10.07	-4.85
Benchmark full ex-post	-10.69	-5.64

Variability in wind has a significant impact on interconnector capacity payment revenues. In 2008, a high and low wind (defined as a 25% in variability in wind generation) leads to a marginal change of €0.09 per MWh in 2008 when importing and €0.08 per MWh when exporting. However this increases substantially in 2020. Thus a low wind year (defined as 25% less than normal) results in a €1.41 per MWh increase in payments when it is importing, and a charge of €0.57 MWh when it is exporting. Conversely, a high wind year leads to a €0.93 per MWh decline in payments when it is importing and a €0.15 per MWh increase in payments when it is exporting (for a variance of €2.34 per MWh when importing and €2.05 per MWh when exporting).

Interconnection with the GB market complicates the impact of wind variability for other generators. The GB market is likely to experience similarly high levels of increasing wind penetration. However, since it is an energy only market, the impact of wind is likely to lead to higher and more frequent price volatility and price spikes. This is likely to result in outflows from the SEM at times, as generators seek to capture high and spiky prices in GB. Thus the advantage of interconnection is that the potential price spikes and dips may have a lower correlation to wind generation in Ireland than would be the case absent interconnection. Conversely, the SEM is likely to 'import' high prices from GB.

The interconnector workstream set as part of the overall medium term review is reviewing existing trading barriers, how to maximise interconnector use and ensuring compliance with congestion guidelines and other EU access rules. In particular it is reviewing the interconnection with BETTA and with Europe specifically:

- market coupling and intra-day trading on interconnectors; and
- the need to address identified market misalignments between the SEM and BETTA that frustrate interconnector usage such as triad charges and Transmission Entry Capacity (TEC) charges applying to generators (including interconnectors exporting to GB).

Recent developments on this front include a move towards abolishing triad charges. The workstream is also reviewing other issues likely to affect the impact of interconnection now and in 2020 such as whether capacity payments should be based on metered flows, installed capacity or real time availability profile, and whether interconnector owners or users should be paid.

3.2.3.4 The impact of Demand Side Units and Demand Side Management

Demand Side Units and DSM schemes in the SEM play an important role in reducing overall demand, flattening peaks and generally contributing to the provision of security of supply in the SEM. DSU units are among the highest remunerated units in the CPM, with average payments of €15.15 under the status quo design in 2008. However, as the benchmark full ex-post sensitivity shows, their contribution to system security is even higher. The higher contribution and their higher remuneration is partly because their availability is sculpted to the higher value peak hours.

Table 11 – Demand Side Unit capacity payments in € per available MWh, in 2008

	Capacity payments in € per available MW
Status quo	15.15
Sensitivities	
Benchmark 100% ex-post	18.92
High wind year	15.03
Low wind year	15.03

There is currently no DSU operating in the SEM. The sole plant accredited under this status, has on-site generation and has since changed its registration status to that of a generator. The main reason is that the trade-offs, as presently designed are less valuable to DSUs. Demand sites have a choice of registering as a DSU, subjecting themselves to central dispatch and receiving capacity payments. Alternatively, they can voluntarily reduce their load at times when the demand is high and capacity prices are highest (irrespective of the needs of the system at that time). The second choice at a minimum involves fewer transaction costs and processes, and potentially higher premiums, thus is currently seen as more attractive.

The main DSM-related issues for the CPM in the medium term is whether to

- offer greater DSM response through the CPM, or encourage growth in existing non-market levers; and
- whether the interactions with bidding and dispatch of load in the SEM may impact SMP and hence the overall revenues paid to generators.

A 2006 consultation paper by EirGrid / SONI examined these issues and concluded that while in the medium to long-term, price signals in the SEM would provide incentives to encourage demand side response, in the interim nonmarket DSM schemes, such as Powersave, WPDRS and Economy 7 would continue to play an important role in ensuring that security of supply is maintained. The on-going DSM workstream set up as part of the medium term review is reviewing DSM schemes, opportunities and risks and developing a high-level vision to 2020 (however, it does not directly comment on capacity payment issues nor does it focus to any great extent on the detail of the schemes in place).

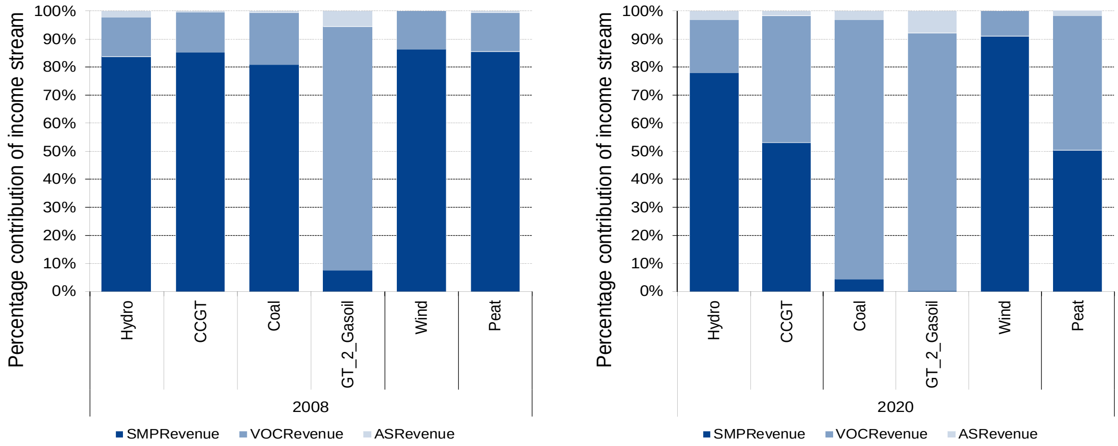
3.2.4 Impact on entry and exit decisions

3.2.4.1 Revenue mix and profitability of generators

The preceding analysis suggests that energy payments and average capacity payments assuming our given ACPS estimate are likely to decline in 2020 compared to current levels. The decline in both revenue streams could result in lower levels of profitability in the sector. Figure 15 shows the changing revenue mix of selected representative plants for each technology. The revenue mix is based on new plant capacity assumptions from the modelling conducted by the dispatch principles workstream which includes net new conventional capacity of 581 MW between 2010 and 2020 and 3,948 MW in wind capacity during the same period.

Energy payments comprise the largest proportion of total plant revenues in 2008; however, these decline across the board for all technologies except for wind. Old OCGTs for instance are likely to operate increasingly as peaking plants, while energy revenues for CCGT and peat plants decline from 85% and 86% of total in 2008 to 53% and 50% respectively in 2020. Capacity payments for CCGTs and peat plants increase as a share of total revenues from 14% to 45-48%. However as noted absolute capacity payments do not necessarily increase (unless the ACPS increases at a higher rate than growth in demand), which implies that the proportionate increase in capacity payments are largely due to even larger declines in energy payments compared to 2020.

Figure 15 – Percentage contribution of each revenue stream (Value of Capacity (VOC), Energy Payments (SMP), Ancillary Services (AS), by technology in 2008, 2020: an illustrative analysis



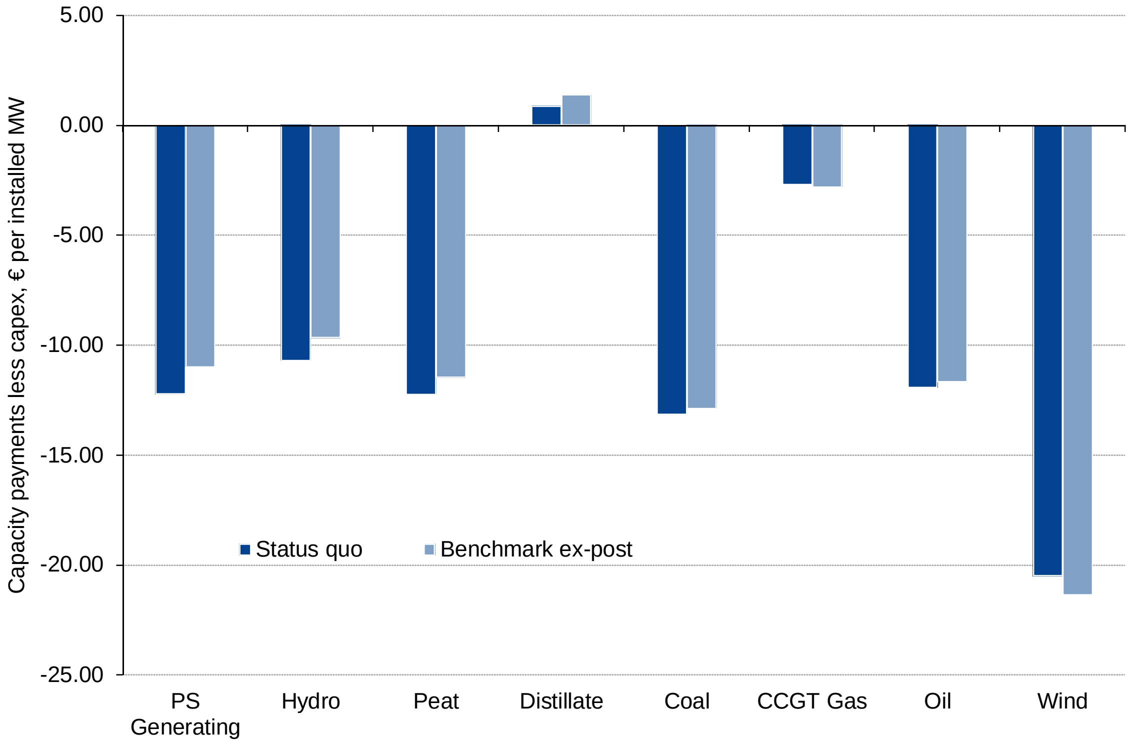
3.2.4.2 *Capacity payments vs. fixed costs in 2008, implications for future years*

Figure 16 shows the difference between capacity payments per installed MW and the estimated CAPEX per installed MW in 2008 across technologies. Distillate plants seem to be the only technology (by this simple estimation) that recovers its CAPEX. Similarly, CCGT's perform relatively well in cost recovery compared to the remaining plants.

The analysis is a high level comparison and is intended for illustrative purposes only; however it does highlight the fact on average plants are unlikely to cover most of their fixed costs, despite the stated aim of the CPM. Wind is significantly worse off; however; it has no variable costs and relies to a great extent on energy payments (SMP) and renewable support mechanisms (REFIT and NIRO) to cover their total costs.

In practice what this means is that an average CCGT plant with an installed capacity of 400MW will earn an estimated €26.07 million in capacity payments a year under the status quo design compared to an estimated annualised CAPEX costs of €37 million. Under the benchmark ex-post design, the unit's capacity revenues would decline by €410,000. By comparison, a 100 MW distillate would earn €6.57 million a year compared to an estimated CAPEX cost of €2.5 million a year. Under the benchmark ex-post, its revenues would increase by €430,000 a year.

Figure 16 – Difference between capacity payments and fixed costs (CAPEX) per installed MW under the status quo and the benchmark ex-post scenarios, in 2008



In general, the decline in new revenues suggests that most new conventional plants will struggle to maintain current levels of profitability and that any new plants over and above those assumed in the dispatch modelling (581 MW of net conventional and 3,948 MW of wind between 2010 and 2020) face significant hurdles in making any comparable returns to 2008 levels. However, 2008 was a high price year due to a tight margin in the market and record high commodity prices.

3.2.4.3 Exit inefficiencies in future years

The CPM is designed to ensure that plants enter or exit the market when it is efficient to do so. The impact of wind penetration in the medium term is likely to accentuate the weakness or strengths of existing entry and exit signals in important ways.

The deteriorating economics described above due to the decline in energy payments could become a bigger deterrent for particular technologies or new entrants such as CCGTs. Similarly, existing OCGTs are likely to see a worsening of their overall profitability as the composition of revenue receipts changes towards greater reliance on capacity payments and ancillary services and with declining energy payments (see Figure 15). Since capacity payments are currently weighted towards ex-ante variable and fixed constituents, such plants could end up in practice becoming peaking plants relying on regular revenue streams and with limited penalties in case they do not run. This would limit the incentives for exit for old or inefficient plants. Thus the 2020 market structure is likely to exacerbate the exit inefficiencies if any in 2020.

Increased intermittent generation also implies that new CCGTs are likely to see an increasing number of starts and a reduced running period. Older CCGTs and coal plants are likely to see even fewer starts as the units are called upon to operate less and less, due to the impact of wind. As the 2009 Pöyry intermittency study highlights (see Annex C.1 for a summary), the larger number of peaking plants in the SEM (probably kept in the market by the CPM) ensures that the start-up profiles are less impacted by wind compared to the GB market, despite a higher wind penetration. Thus the net impact of the CPM on entry and exit in future years is a lot more nuanced.

Separately, there is concern that the current system does not penalise plants which declare themselves available but fail to respond when called upon. The grid code requires all generators to be available when called upon and mandates the ISO to conduct random testing of low load factor plants, constraining them on to check that they can deliver. Thus presumably the incidence of plants failing to run when called upon should be limited. In addition, the code specifies a penalty for being unavailable when called to run. Any such plant is forced to declare itself unavailable for that period losing revenues that includes the energy payments and capacity payments for that trading period. The plant may also be liable for uninstructed imbalance payments, for negative deviation from its dispatch schedule, beyond the set tolerance bands.

The impact of wind in future years is similarly nuanced. Since most plants are likely to rely on capacity payments, and relatively less on energy payments compared to 2008, there is a valid case that the current penalties may not be sufficient to ensure they run when called upon. By comparison, the performance of the full benchmark full ex-post model in incentivising plants to run when called upon becomes more significant in future years compared to the status quo. If a plant is unavailable to run especially during system scarcity, a large share of the total pot flows to those period and to its competitors, and thus it suffers more compared to the current design. A 400MW plant failing to run at the trading period with the lowest system margin in 2020 would lose up to €5.2 million under the benchmark ex-post compared to €49,000 under the status quo design. With the strong ex-ante components under the current design, the impact of the penalty is limited. In Section 4.4 we explore the alternatives for the status quo penalties in detail.

3.3 Conclusions

The analysis, detailed in this section suggests that the performance of the current CPM design is likely to improve, particularly in reference to the benchmark ex-post comparator. However compared to 2008, it remains largely unchanged.

Table 12 provides an overview of the performance of the current design in 2020.

Table 12 – Performance of the current CPM mechanism in 2020

Reform option	Performance
Capacity adequacy	▪ The current design provides significantly lower revenues for generators in 2020 compared to 2008. This is partially due to our assumptions on size of the ACPS pot (assumed to grow at the same rate in real terms as demand). ▪ The performance of the design in ensuring capacity is available when it is needed improves compared to 2008. The link between capacity payments and system margin is better compared to 2008, with the maximum price (being equal to the price at lowest system margin). In addition, the variance between low and high prices improves significantly.
System reliability	▪ The current system does not differentiate substantially between generators with different levels of controllability as a consequence of the current split in payments. This remains unchanged, although the extent is smaller in 2020 compared to 2008.
Efficient price signals for long term investments	▪ The CPM does not reflect the full value of lost load at peak times, a concern which remains unchanged in 2020.
Price stability	▪ Price stability remains unchanged in 2020 compared to 2008. The continued use of monthly pot allocation and the FPF reduces variability in prices.
Fairness	▪ The current design remains unchanged compared to 2008. It continues to over-reward intermittent generation that contribute less to peak demand.
Simplicity	▪ The status quo remains unchanged compared to 2008. It is simple to understand and transparent for the 'operational' year. ▪ It is difficult to predict the level of payment in future years as this is subject to regulatory determination.
Susceptibility to gaming	▪ The risk of gaming remains low and is unchanged compared to 2008. However, there is a risk that plants with low load factors which are unavailable when called to run are not adequately penalised.
Regulatory risk	▪ The regulatory risk under the status quo remains high and unchanged compared to 2008. It is difficult to predict the level of payment in future years as this is subject to regulatory determination.

The analysis on the future years suggests a profound impact of a heavy build in wind and the impact of its variability. This could likely result in a decline of energy payments, and a relatively smaller decline in capacity payments, impacting the profitability of generators. However it also suggests that the CPM could become an important driver for meeting capacity adequacy and system security needs.

Ensuring that the CPM is fit for purpose will therefore be an important means of managing the heavy build of wind and its implications on the market. This will involve ensuring that the CPM is economically efficient and rewards plant fairly, sending correct efficient signals to investors, plant operators and consumers.

The analysis also suggests that while the overall performance of the CPM may be deemed satisfactory, there are several concerns which need to be addressed going forward. These include:

- The relationship between payment for reliability and value which is diluted through focus on ex-ante payments, and the existing monthly pot and flattening power-adjusted distribution.
- Aligning the payment profile more closely to reflect the value provided and concerns that the current CPM structure does not appropriately reward generators' contribution to system peak.
- Uncertainty in future payments due to the annual changes to the BNE price and ACPS.
- Concerns over the level of exit inefficiencies.

The remainder of this report addresses each of these concerns in detail.

4. OPTIONS FOR CHANGE

The review of historic performance against the CPM objectives, alongside consideration of stakeholder concerns and views of changes in the future market environment, has highlighted several areas where performance of the current arrangements may be improved. In this section, we review options for change addressing the individual weaknesses, based on our modelling analysis, consultations with stakeholders and a review of international experience detailed in Annex C. The reform options discussed include:

- ensuring that the level of payments is highest when capacity is scarce;
- ensuring the distribution of payments across generator types benefits reliable plants;
- improving certainty in future payments; and
- addressing concerns over the level of exit inefficiencies

The areas of concern and reform options noted above are on individual objectives and changes in one area may have adverse impacts on other objectives. Thus the aim of this section is to develop a package of overall changes that broadly address the weaknesses highlighted. We assess the overall impact of these packages in later sections.

4.1 Improving efficiency of the capacity payment signal

Within the current design, the highest level of payments is not the period of tightest system margin, although this relationship is obtained in 2020. In the medium term, to ensure that the level of payments is highest when capacity is scarce generators, there are several changes that could be made to the CPM design. These include:

- Increasing the proportion of ex-post payments to reward generators available during system tightness since currently, only 30% of the ACPS pot is directly based on outturn availability.
- Removing or increasing the flattening power factor, thus reducing its impact (see algebra in Annex A.2).
- Revising the distribution of monthly pots either by removing the monthly weightings such that the ex-ante payments are paid solely on the basis of the annual LOLP curve; or alternatively increasing the weighting by demand to months which are likely to experience higher levels of demand and margin tightness.
- Increasing the size and types of contracts under Ancillary Services so as to reward flexibility appropriately.

4.1.1 Increasing the proportion of ex-post payments to reward generators available during system tightness

The analysis of the current design highlights the need to increase the proportion of ex-post payments to reward generators available during system tightness appropriately. We have reviewed the impact of increasing or decreasing the proportion of ex-post payments to 100% and 0% (via a 100% fixed, ex-ante design) respectively. These two extreme choices, compared with the current design allow us to test the likely impact of increasing the proportion of ex-post payments.

As Figure 17 highlights, increasing the proportion of ex-post payments to 100% but retaining the monthly pot allocation and FPF of 0.35 significantly strengthens the relationship between capacity payments and system margin. It aligns payments to provision of capacity when it is needed providing the largest share of payments only to those plants available when capacity is tightest. As a result, the price during the tightest system margin increases from €49 to €569 per available MWh. Similarly, the maximum price during the year increases from €70 to €1,238 per available MWh, significantly widening the spread between high and low margin periods is low.

Conversely, decreasing the proportion of ex-post payments to 0% (a 100% ex-ante, fixed distribution of ACPS) eliminates the incentive to be available at times of stress. This option as expected would remove the link between scarcity and capacity payments as shown in Figure 18. Payments average €9.43 per available MWh irrespective of the system margin.

Figure 17 – Capacity in € per available MWh vs. ex-post margin, 2008, under a 100% ex-post design with 0.35 FPF and monthly pot allocation

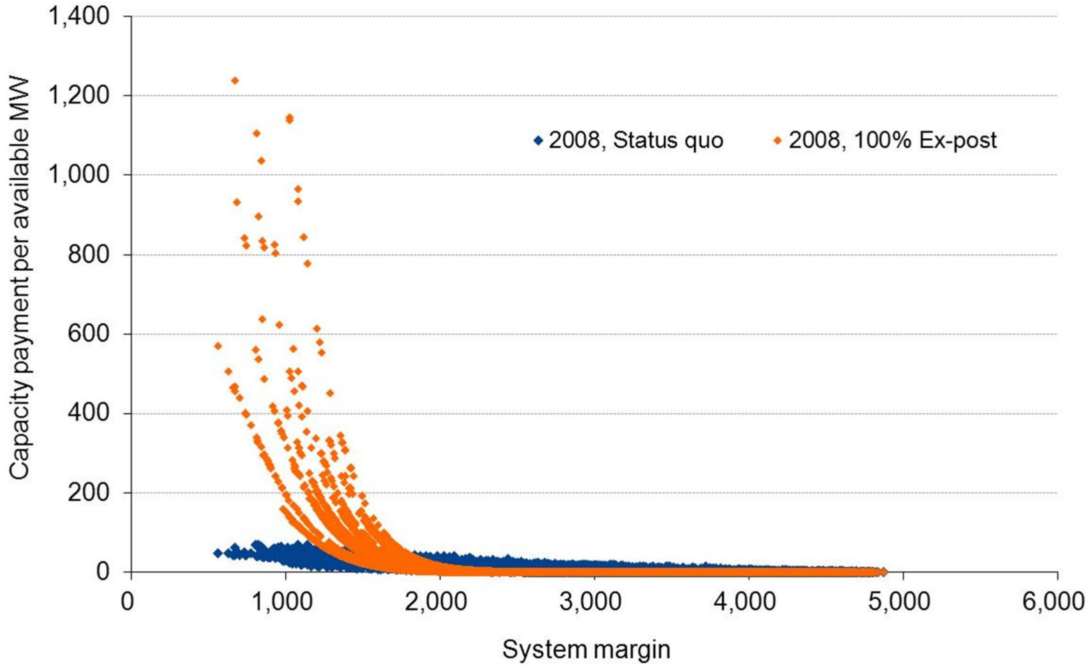


Figure 18 – Capacity in € per available MWh vs. ex-post margin, 2008, under a 100% ex-ante design

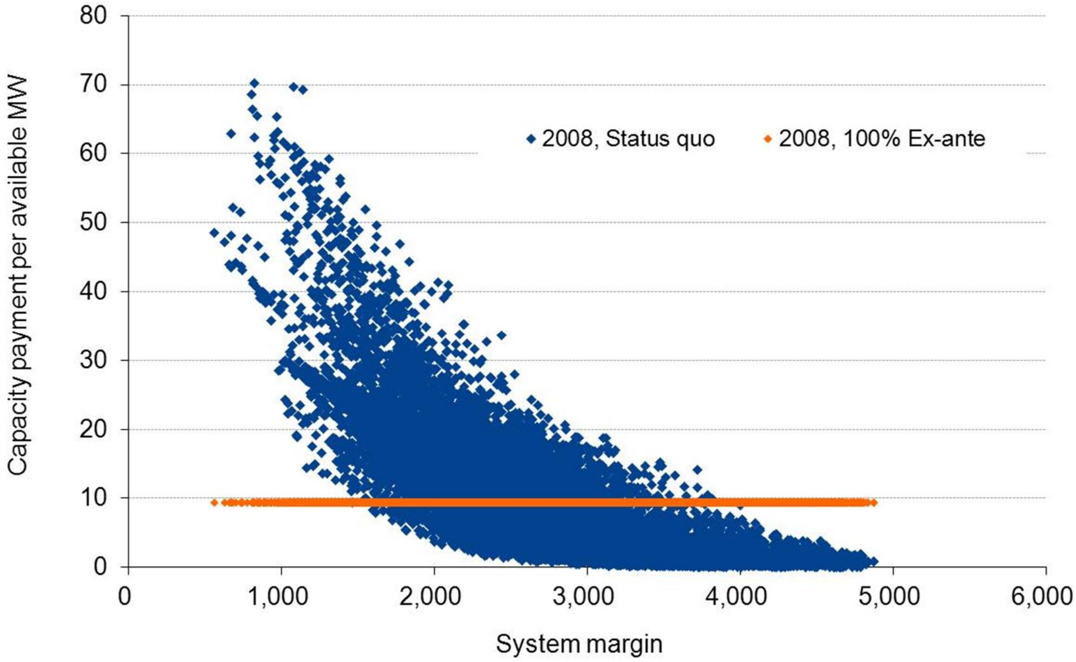


Table 13 summarises the performance of increasing and decreasing the proportion of ex-post payments to 100% and 0% respectively, compared to the status quo design.

Table 13 – Capacity payments in € per available MWh under the current CPM design and 100% ex-post and 100% ex-ante designs

	Status quo	100% ex-post	100% ex-ante
Maximum price	70.15	1,237.75	9.43
Price at minimum system margin	48.50	568.54	9.43
Number of trading periods per price group			
€0-25	16,605	16,078	17,566
€25-50	880	611	0
€50-75	81	300	0
€75-100	0	192	0
€100-125	0	103	0
> €125	0	282	0

This analysis suggests that to reward ‘flexibility’ there is merit to increasing the share of ex-post payments. This is likely to result in higher payments for plants that are available during times when capacity is scarce. This adjustment would also improve the performance of the design regarding fairness (by rewarding reliable generators more in line with their contributions). It would also improve the efficiency of signals for long term investments for reliable plants and could over the long term limit improve their adequate provisioning. However, there are other disadvantages notably increased volatility in payments. In addition, it would result in increased complexity and lack of transparency, declining predictability of payments for generators. Thus there is a greater need to increase the proportion of payments targeted to the ex-post period but with a limited shift in the algebra.

4.1.2 Increasing the flattening power factor to increase payments for 'availability'

In the current CPM design, a Flattening Power Factor of 0.35 is applied to the Loss of Load Probability curve, used in calculation of capacity payments. The FPF shapes the LOLP curve to make it either 'steep' or 'flat' and in the current design, reduces payments when the system is tight to decrease the volatility of payments.

Figure 19 presents the relationship between capacity payments and system margin under the current CPM structure with four FPF alternatives: 0.35, 0.5, 0.75 and 1.0. Increasing the FPF from 0.35 to 1.0, leads to a six-fold increase in the maximum capacity price for a given ACPS pot and an improved link between capacity price and system margin, thereby rewarding generators available during system tightness.

Figure 19 – Capacity in € per available MWh vs. ex-post margin, 2008, under the current CPM design with different FPF parameters

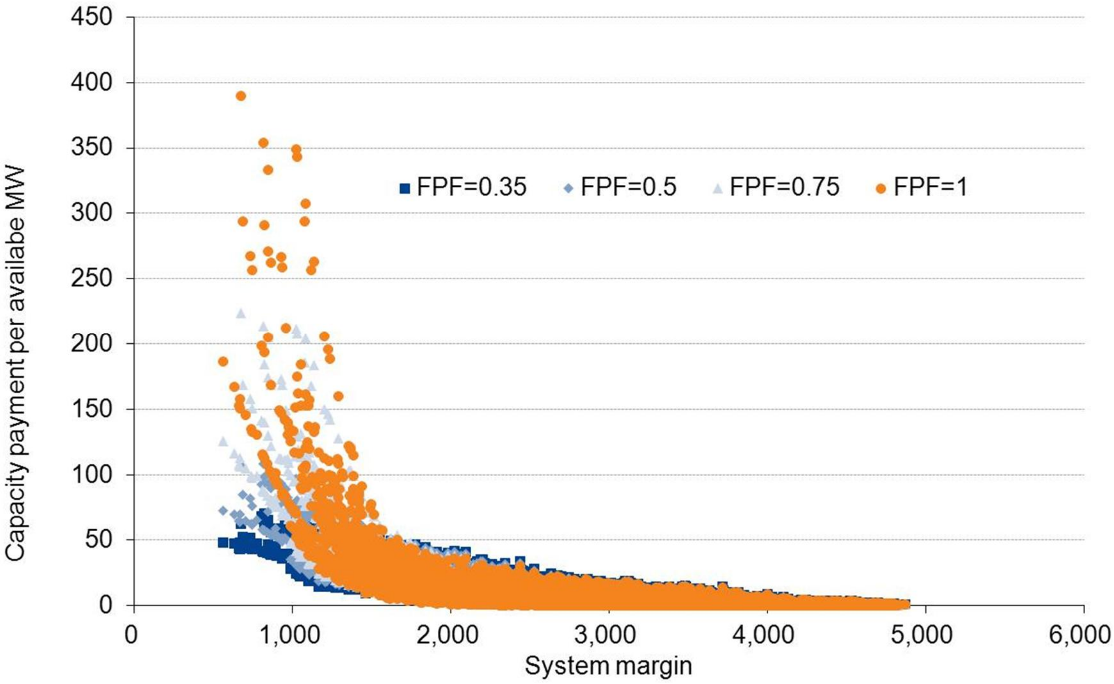


Table 14 details the level of capacity payments as FPF increases. The percentage of trading periods with prices greater than €50 per MWh increases from 0.5% to 1.8%, while the price at time of lowest margin increases from €49 to €186. Although the average prices when there is sufficient margin is similar across the FPF sensitivities, during periods of tightness when margin is below 1,000 MW, an FPF of 1.0 results in significantly higher capacity payments averaging €244 compared to €60 per available MWh under the FPF in the current design.

Table 14 – Capacity payments in € per available MWh under different FPF parameters

	FPF=0.35	FPF=0.50	FPF=0.75	FPF=1.0
Maximum price	70.15	109.66	223.91	389.86
Price at minimum system margin	48.50	72.75	125.24	186.16
Number of trading periods per price group				
€0-25	16,605	16,366	16,347	16,441
€25-50	880	1,024	948	806
€50-75	81	140	151	163
€75-100	0	31	65	71
€100-125	0	5	27	29
> €125	0	0	28	56

Changing the FPF is therefore a potentially useful lever to alter the incentives under the current design, aligning the level of payments closer to system margin and providing incrementally higher payments to firm generators providing service when it's most needed. Relaxing the FPF progressively to 1.0 allows the mechanism to reward reliable plants more in line with their contribution to system scarcity. However, relaxing the FPF would also result in increased volatility of prices.

4.1.3 Revising the distribution of monthly pots by removing the monthly pot allocation or changing their weightings

4.1.3.1 Changing the distribution of monthly pots

The annual ACPS pot is currently split into monthly pots using a formula weighted by peak to trough demand as shown in Table 15. As a result, payments are weighted more heavily to months with higher demand periods. This allocation assumes an enduring relationship between high levels of demand and scarcity in the system.

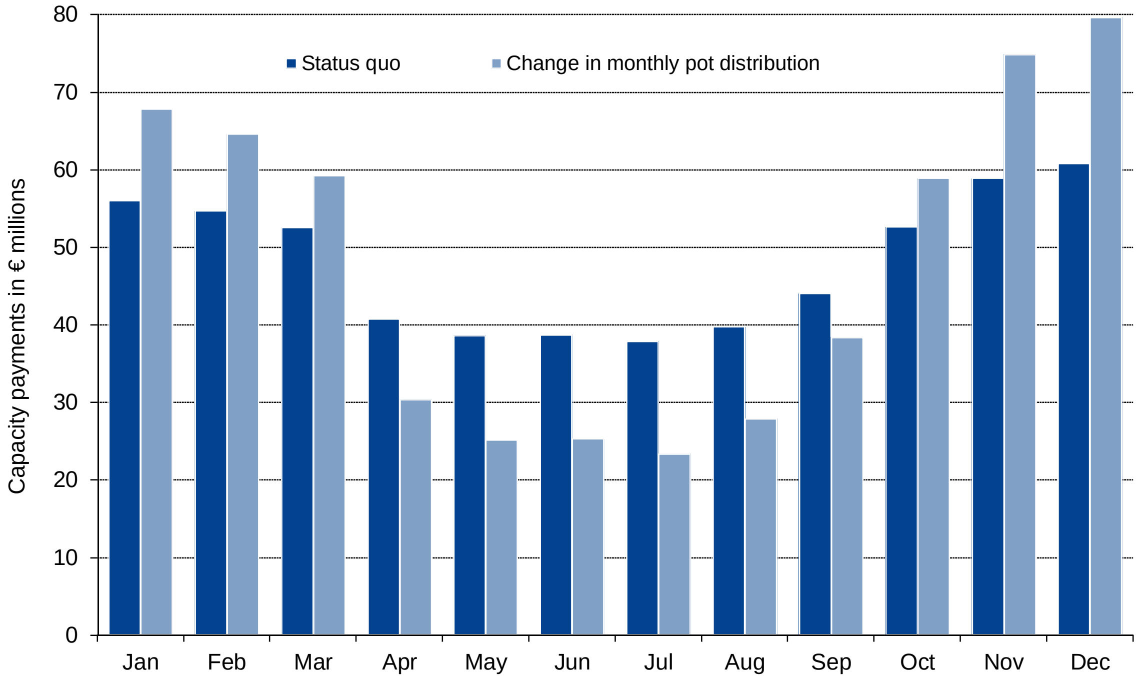
It is possible to strengthen this link further so as to better align payments with periods of higher demand and therefore low system margin, and to increase payments to those plants that are available during those months. For this study we investigated altering the algorithm, changing the reference from the minimum demand in a year to the average demand in a year as shown in Table 15.

Table 15 – Current monthly pot allocation vs. Reform alternative

Current design	Reform option
$WF_c = \dfrac{P_c - MinFD_y}{\sum_{c \text{ in } y}(P_c - MinFD_y)}$	$WF_c = \dfrac{P_c - AvFD_y}{\sum_{c \text{ in } y}(P_c - AvFD_y)}$
Where: WFc is the Weighting Factor for the Capacity Period (Mth); Pc is the peak demand in the Capacity Period; and MinFDy is the minimum demand in the year	*Where:* WFc is the Weighting Factor for the Capacity Period (Mth); Pc is the peak demand in the Capacity Period; and To: AvFDy is the average demand in the year

This change in the within-month variation algorithm enables us to increase the within year variation of the ACPS pot as shown in Figure 20 resulting in increased winter payments. Given that periods in winter currently have the tightest margins on average, this results in greater payment per MWh being made at periods of tighter margin compared to the status quo design.

Figure 20 – Changing the distribution of the monthly pot



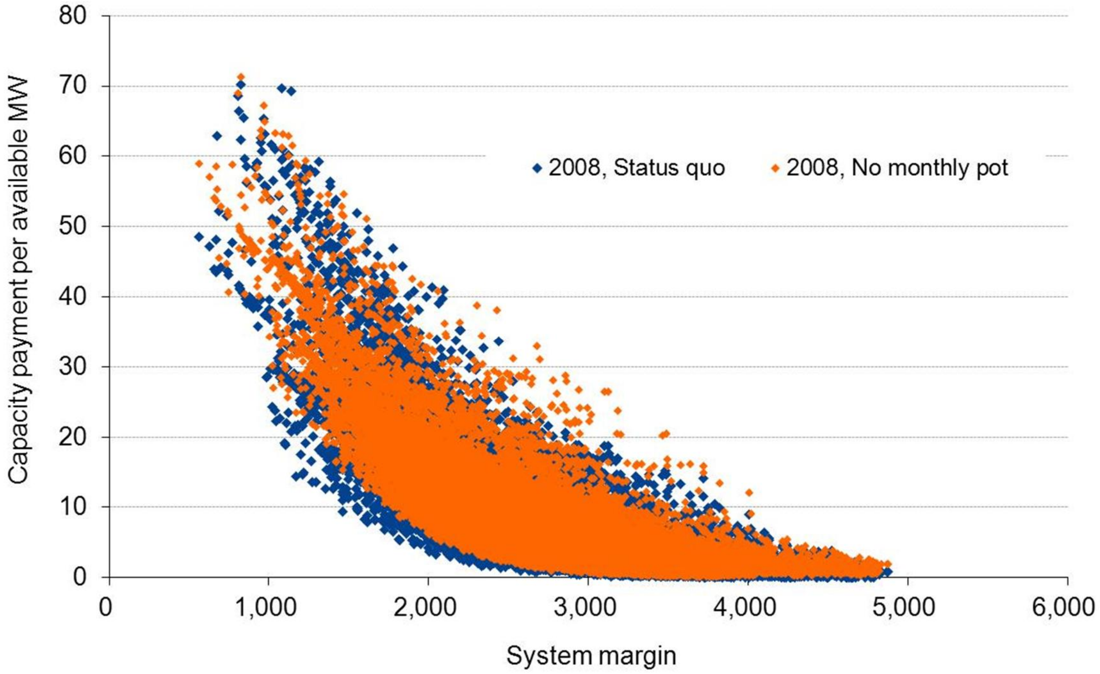
The advantage of changing the monthly pot distribution is that it is administratively easy to change and would improve the alignment between periods of high demand and level of payments as well as increase the amounts paid to firm generators.

The disadvantage of this option is that it rests on the assumption that current patterns of monthly electricity demand and tightness in system margin are strongly correlated. The relationship is significantly weakened when you consider when the top 1% trading periods with lowest system margin have occurred. In 2008 for instance, of the 20 trading periods with the lowest system margin, 60% fell in October (which is not generally considered as the month with the tightest margins). However, an additional 30% fell collectively in the four high-demand months of November to February. A similar analysis of previous years, suggests that while on average the relationship between scarcity and high demand months is strong, the relationship weakens for the top percentile trading periods. Moreover, the increase in wind generation is likely to diminish this relationship further with scarcity having a stronger correlation with periods in which the wind will not be blowing, even though on average these could be periods of lower overall monthly demand.

4.1.3.2 Removing the monthly pot allocation

The current monthly pot allocations are designed to ensure stable and predictable capacity payments to incentivise new entrants. They are also intended to align the level of payments with availability during system scarcity.

Figure 21 – Capacity in € per available MWh vs. ex-post margin, 2008, under the current CPM design with the monthly pot allocation removed



It is possible to change the algorithms for monthly allocations by removing the monthly pot allocation altogether for variable ex-ante payments but using the same algorithms over the whole year. This would closely align the CPM with system margin as 70% of payments would be closely tied to system margin.

Figure 21 highlights the resulting relationship between the status quo as is and the status quo with the monthly pot allocation removed. It is unclear that removing the monthly pot provides any benefits in 2008, although the advantages become clearer in 2020.

Table 16 – Capacity payments in € per available MWh under the status quo design with the monthly pot allocation removed

	Status quo	Status quo, No monthly pot
Maximum price	70.15	71.27
Price at minimum system margin	48.50	58.98
Number of trading periods per price group		
€0-25	16,605	16,400
€25-50	880	1,108
€50-75	81	58
€75-100	0	0
€100-125	0	0
> €125	0	0

Removing the monthly pot allocation however increases the payment at minimum system margin from €49 to €59 per available MWh. It also marginally increases the maximum payments from €70 to €71 per available MWh as shown in Table 16. However, it results in fewer periods with payments greater than €50.

4.1.4 Increasing the size and types of contracts under Ancillary Services to reward flexibility appropriately

Ancillary services (AS) is designed to deliver flexibility in the market and not necessarily peak availability (which is partially the role of the CPM). The current AS incentivises services such as reserve, reactive power and black start. Additional services proposed as a result of the Ancillary Services Harmonisation efforts includes warming contracts, CCGT multimode operation and pre-emptive response. Some of the proposed services such as CCGT multimode operation are targeted at improving system security and incentivising provision for flexibility.

There is therefore a case for using the AS rather than the CPM as it can be targeted at specific services required in the system rather than the CPM which signals a different need. Conversely, the rationale for retaining the current design rather than expanding the AS, is that there are many aspects of flexibility that are already internalised in the energy payments and the higher capacity payments received by flexible generators. Remunerating them via AS would in effect duplicate the remuneration already provided without any significant new benefits. Moreover since the AS, as currently structured is a system of bilateral contracts some flexible plants that are lower on the merit order may lose out, with a disproportionate amount going to a few plants that can provide a variety of ancillary services at lowest cost.

The interaction between AS and CPM is already envisaged by the Ancillary Services workstream initiated by the regulators, which has called for flexibility and fast response to be procured via ancillary services rather than via CPM.[12]

4.2 Improving the distribution of payments across generators

The CPM needs to ensure that generators that provide reliability and flexibility are rewarded accordingly. There are several options that could improve the system's performance in this direction, these includes:

- increasing the proportion of ex-post payments from 30% to a higher level to reward firm generation; and/or
- introducing generator adjusted payments or capacity credits which weight [ex ante and fixed] payments towards firmer generators likely to be available in times of system tightness.

4.2.1 Increasing the proportion of ex-post payments to reward firm generation

We have reviewed the impact of increasing the proportion of ex-post payments from 30% to 100% and as boundary test, reducing its proportion to 0%.

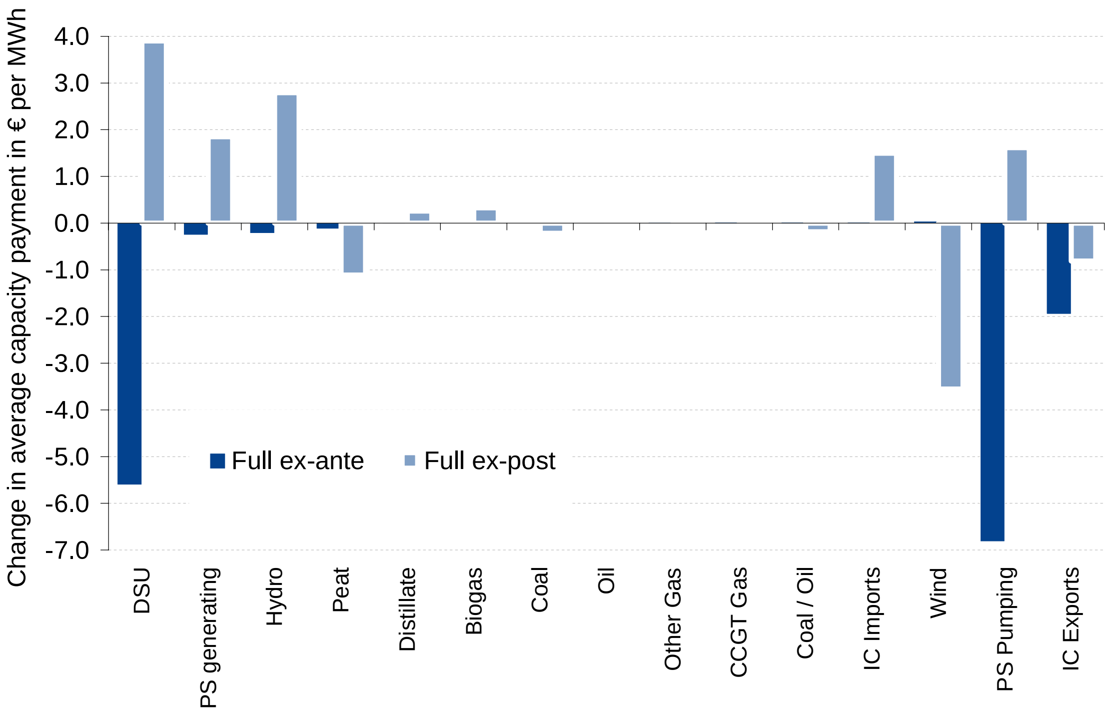
Figure 22 illustrates the change in average capacity payments resulting from change in design from the status quo to a 100% ex-post and 0% ex-post (or 100% ex-ante) designs. Increasing the proportion to 100% re-distributes capacity payments away from wind and

12 CER, NIAUR, 'Harmonised Ancillary Services and Other System Charges Information Note to Service Providers,' June 29, 2010, SEM 10-42.

peat to other generators, specifically pumped storage, hydro and demand side units. Wind and peat experience a 39% and 10% decline in revenues respectively. Payments to hydro, pumped storage, interconnector imports and demand side units increase by 14-26%.

Reducing the proportion of ex-post payments (via a full ex-ante design) re-distributes payments from demand side units and pumped storage when pumping. DSUs experience a 38% decline in revenues. Wind on the other hand experiences an increase of 0.3%.

Figure 22 – Change in average capacity payments under 100% ex-post and 100% ex-ante designs compared to the status quo design

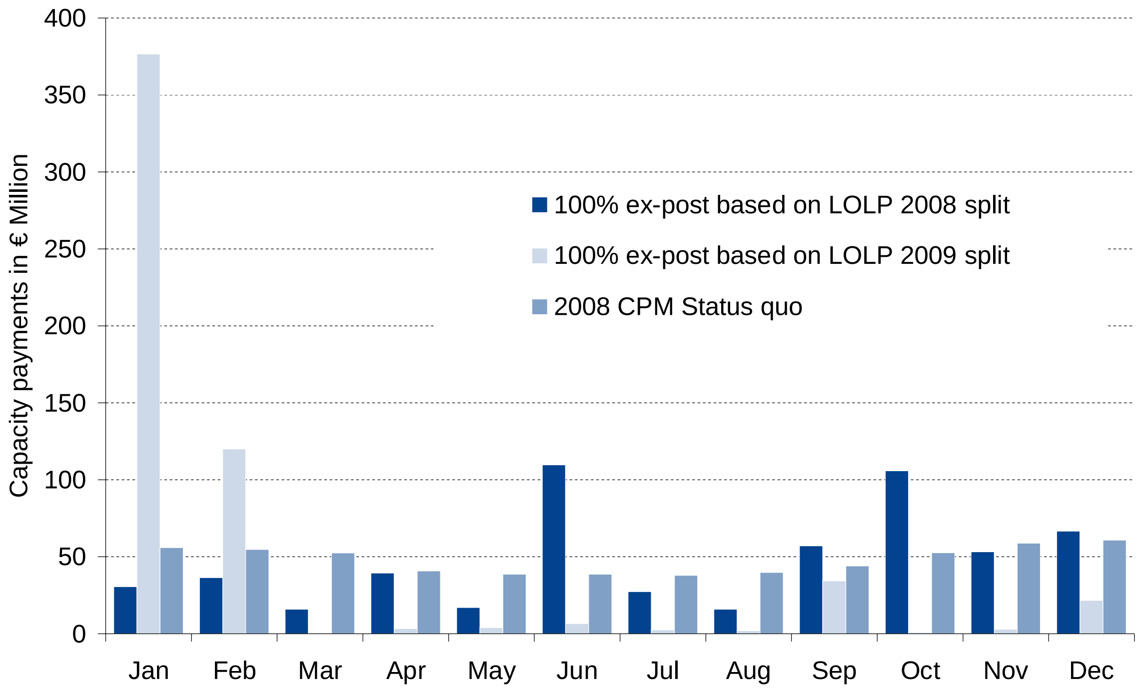


Increasing the proportion of ex-post payments to 100% rewards plants based on their actual availability. It also decreases the complexity and improves the transparency of the mechanism. However, it increases the level of uncertainty in payments for generators and may also adversely affect overall investment incentives and hence capacity adequacy and reliability.

Since payments would depend solely on outturn availability, there is a high risk for plants on scheduled or unscheduled outages. Figure 23 illustrates this uncertainty. We have allocated 2008 capacity payments on a full ex-post basis, based on the Loss of Load Probability for 2008 and 2009 (as proxies for outturn profile for the two years). Those generators unavailable in January 2009 due to a planned or unscheduled outage would have received very little payments for the rest of the year, thus making capacity revenues as uncertain as energy payments. In the extreme, this may impact the cost of capital for new entrants since investors are likely to discount capacity revenues in their investment models, assuming the lowest month (such as August 2008) as the representative payment for the year.

Conversely, decreasing the proportion of ex-post payments (100% ex-ante, fixed distribution of ACPS) eliminates the incentive to be available at times of stress. Each plant receives the same amount irrespective of margin. The risk here is that it weakens the signals for the provision of the right type of capacity since it under-incentivises plants most likely to be available during periods of system stress.

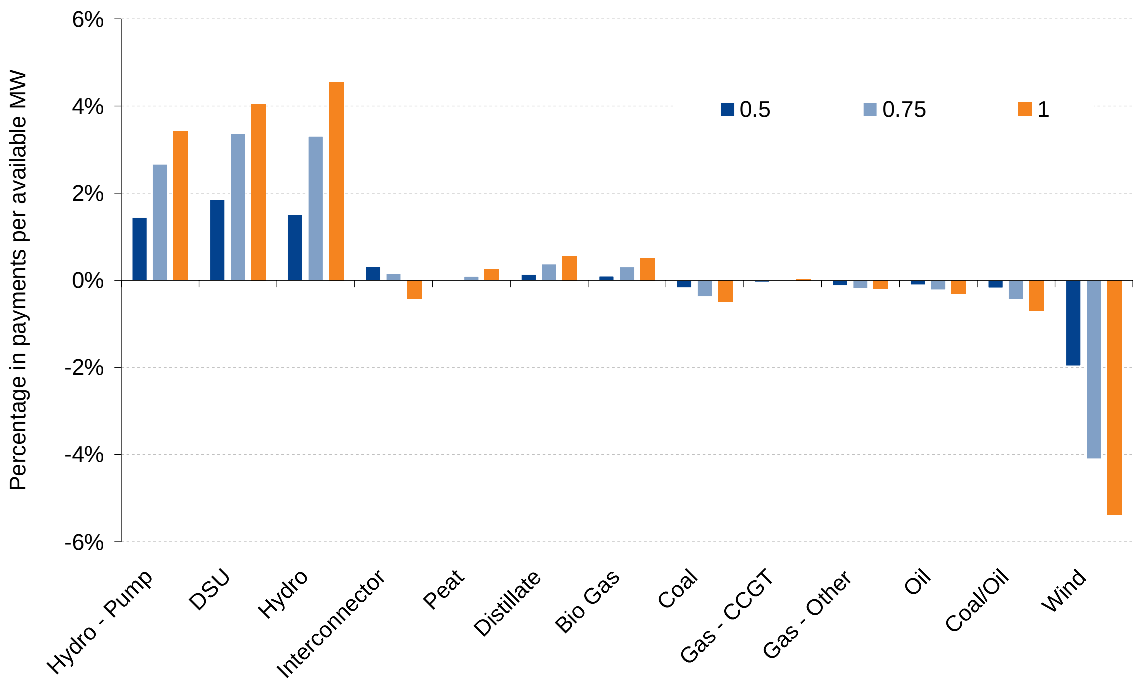
Figure 23 – Capacity payments under a 100% ex-post design, under the 2008 and 2009 LOLP compared with actual historic split



4.2.1.1 *Increasing the Flattening Power Factor to reward firm generation*

We have also reviewed the impact of increasing the proportion of ex-post payments by increasing the flattening power factor. This progressively increases payments to conventional generators, re-distributing value away from wind as shown in Figure 24. Pumped storage, hydro and DSU increase by 1-2% under a 0.5 FPF, by 3% under a 0.75 FPF and 3-5% under a 1.0 FPF. Wind on the other hand declines by 2%, 4% and 5% respectively as FPF increases to 0.5, 0.75 and 1.0.

Figure 24 – Percentage change in capacity payments, € per available MWh under different FPF parameters compared to the status quo design



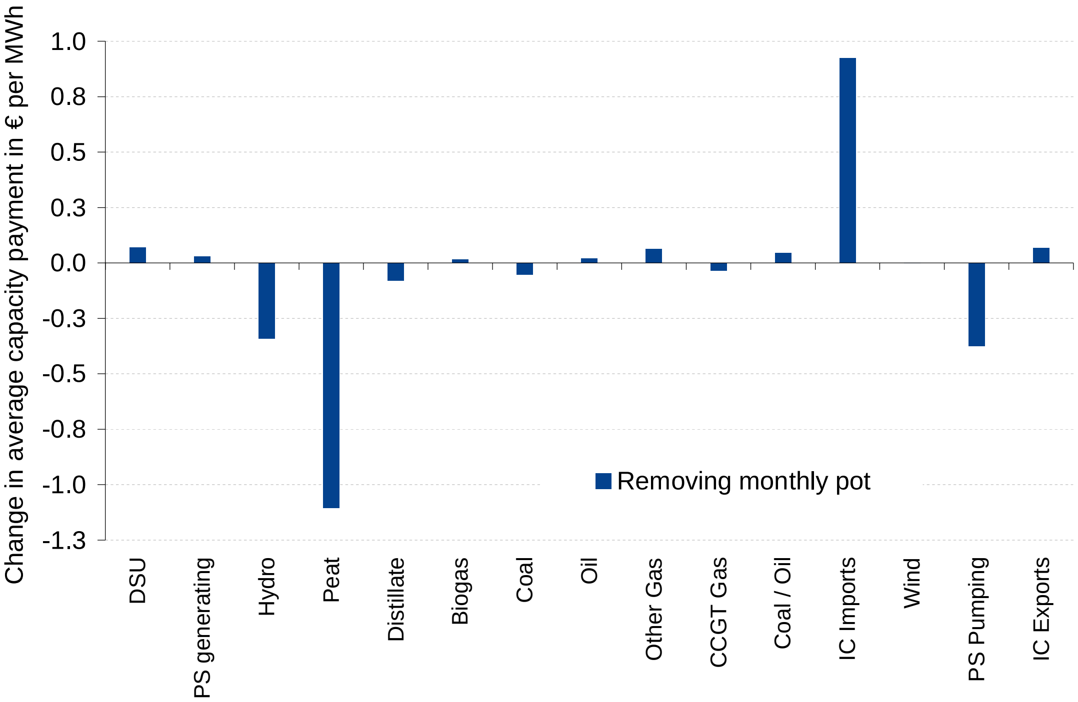
Changing the FPF is therefore a potentially easy means of altering the incentives under the current design, aligning the level of payments closer to system margin and providing higher payments to firm generators providing service when it's most needed.

4.2.1.2 Removing the monthly pot allocation to reward firm generation

The removal of monthly pot allocation as a means of increasing ex-post payments results in a limited re-distribution of capacity payments as shown in Figure 25. Peat and hydro experience significant declines of 10% and 3% respectively. Interconnector imports are the primary beneficiary with a 10% increase in capacity payment per MWh.

For 2008, the benefits of removing monthly pot allocation are limited; however, it does perform marginally better at re-distributing payments to conventional generators that are most likely to be available during low system margin and increases payments at the minimum system margin, advantages which are likely to increase in 2020 with the increased penetration in wind and the impacts of wind variability. Moreover, in doing so, it increases the fairness of the mechanism since it rewards reliable plants more in line with their contribution to system scarcity. Additionally, all else being equal, this change, at the margins, improves adequate provision of those plants that are likely to be reliable.

Figure 25 – Change in average capacity payments in € per available MWh under the status quo design with the monthly pot allocation removed



4.2.2 Introducing generator adjusted payments or capacity credits to reward firmer generators

Generator adjusted payments or capacity credits are a means of recognising the different contribution of the generators to system security. Each plant or generation technology is allocated a 'capacity credit' or adjustment factor applied to overall capacity payments reflecting its contribution to system reliability. The aim is to reward plants or technologies likely to provide flexibility or reliability at a higher rate than intermittent generators.

4.2.2.1 Capacity credit schemes in other markets

There are several capacity markets around the world which have adopted a variant of credit capacity de-ratings to recognise the differentiated contributions of different technologies to system reliability. These are discussed as part of lessons from international experience in Annex D. In the New York energy market, administered by the NYISO, each plant is required to meet a locational reliability threshold and is granted a defined capacity value determined from a mandated test. Thus a plant with an installed capacity of 100MW can be de-rated to 95 MW if its reliability is deemed at that rate and would trade at 95 MW in the capacity market. In addition, all plants are given a secondary adjustment to reflect the proportion of the tested capacity that is likely be available for dispatch at any given time. The secondary adjustment takes into account a unit's forced outage rate over a rolling 12 month average to establish the final capacity credit adjusted capacity. Thus the de-rated 95MW plant with a 12 month forced outage rate at 10%, would not trade as a 100MW unit, but as an 85.5MW plant (i.e. (95MW x (1-10%)).

In the New England capacity market which is similar to NYISO, generators are paid for siting units in New England based on unenforced capacity, defined as the net capacity the unit provides after adjustments to account for forced outages at the unit.[13]

4.3 Improving predictability and transparency of the mechanism

The current CPM involves annual changes to the overall ACPS pot through the review of the BNE price and capacity requirement. The advantage of the annual review is that the capacity pot is closely linked to changes in capacity requirements and system need. In addition, the annual BNE price closely reflects the prevailing investment climate affecting new entrants. However, it leaves new entrants open to risk regarding future payments relative to a more predictable architecture. Greater year-on-year certainty would reduce investment risk particularly cost risk embedded in the BNE price.

The level of payments can and does change annually with the revision of the ACPS and BNE price (such that the average payment at the time a plant begins construction is likely to be significantly different from that received upon commissioning). The result of this uncertainty regarding future payments is that there remains residual risk that will require a higher rate of return for investors. To reduce this risk, there are several options for reforming the system to improve the certainty of future payments and by default decrease the cost of capital for new entrants. These include:

- Making the calculation process of the BNE more transparent. This could involve a combination of several policies such as setting a particular target for capacity requirement, specifying a technology choice and/or a target WACC over a period of several years. These would enable a reasoned prediction of the likely trajectory of future payments.
- Fixing or indexing the BNE price or constituents of the BNE for several years.
- Introducing a new entrant capacity price or guarantee.

4.3.1 Improving the transparency of BNE calculations and fixing or indexing the BNE price or constituents

4.3.1.1 Increasing the transparency of the BNE calculation process

There have been concerns that the capacity requirement calculation is difficult to replicate or uses inputs and parameters that are unclear. Improving the transparency of the calculation process could increase the level of certainty for investors. This may involve:

- Changing the capacity requirement calculation from a reliance on the TSO Adequacy Assessment process to a target capacity margin such as 10% security standard. This would allow new entrants to easily track potential changes to the overall pot from the volume side.
- Settling on a technology type in calculation of BNE over a period of years, or a specific cost of capital (WACC) assumption and life of plant for a period of several years. This would reduce the uncertainty of the overall pot from the price side.

The impact of these changes would be to improve the predictability of the ACPS pot and its constituents and to allow new entrants to more easily estimate the likely size of the pot.

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13 Federal Energy Regulatory Commission, ‘Capacity Markets,’ see http://www.ferc.gov/market-oversight/reports-analyses/overview/capacity-markets-report.pdf

4.3.1.2 Fixing or indexing the BNE price or constituents of the BNE for several years

It is also possible to index or hold constant the BNE price and/or parameters used in the calculation of the BNE price. This would provide certainty to new entrants allowing them to more easily predict future payment streams. The experiences of other markets which fix capacity prices over time rather than for the next year may provide useful insights for the SEM. These are discussed as part of lessons from international experience in Annex D. The New England, PJM and Western Australia capacity markets are based on the provision of capacity in a period three years-ahead (five years-ahead for new capacity in the case of New England). Although all three markets conduct annual reviews, the fact that the payments takes effect several years ahead provides capacity providers, particularly new entrants, relatively greater certainty and ability to respond. Thus a new entrant commissioning a plant in 2013 is assured of the capacity payment at the time of commissioning compared to the SEM where the payment for 2013 is yet to be determined.

Secondly, it would be useful to consider a commitment period greater than one year so that capacity providers have greater certainty as to remuneration for capacity provision through indexing. Parameters that could be indexed includes the BNE price itself, EPC costs etc. Possible indices include a weighted inflation index (combining the impact of CPI in Northern Ireland and the Republic of Ireland) or specialised CPI indices such as the Utilities or Housing and Utilities sub-segments of the CPI. The disadvantage of generic inflation indicators is that they may not capture drivers for specifics costs in power plants such as the cost of specialised components or global commodity drivers that have a disproportionately larger influence on the power sector compared to the larger economy such as changes in steel prices. In that case using specialised indices such as the European Power Capital Cost Index (EPCCI) could be more useful. The EPCCI is a proprietary index that tracks and forecasts the costs associated with the construction of a portfolio of power generation plants in Europe.

Figure 26 provides the results of indexing the BNE price in 2007-2010 compared with the outturn for those years, while Figure 27 compares the impact of indexing selected inputs over 2007-2010 period with the outturn. The performance of indexation depends on three metrics:

- the choice of the inflation index;
- the period of indexation; and
- the selection of subsets to index.

As Figure 26 highlights, the All-island Housing and Utilities sub-sect of CPI provides the closest match both in terms of the absolute level of BNE price and the price profile over time. Similarly the EPCCI and the utilities subset of CPI provide a similar profile, even as the absolute price bears little resemblance to the outturn. Generic inflation indices however seem to perform poorly at approximating the outturn BNE price.

Figure 26 – Indexing BNE price over 2007-2010, comparisons with outturn

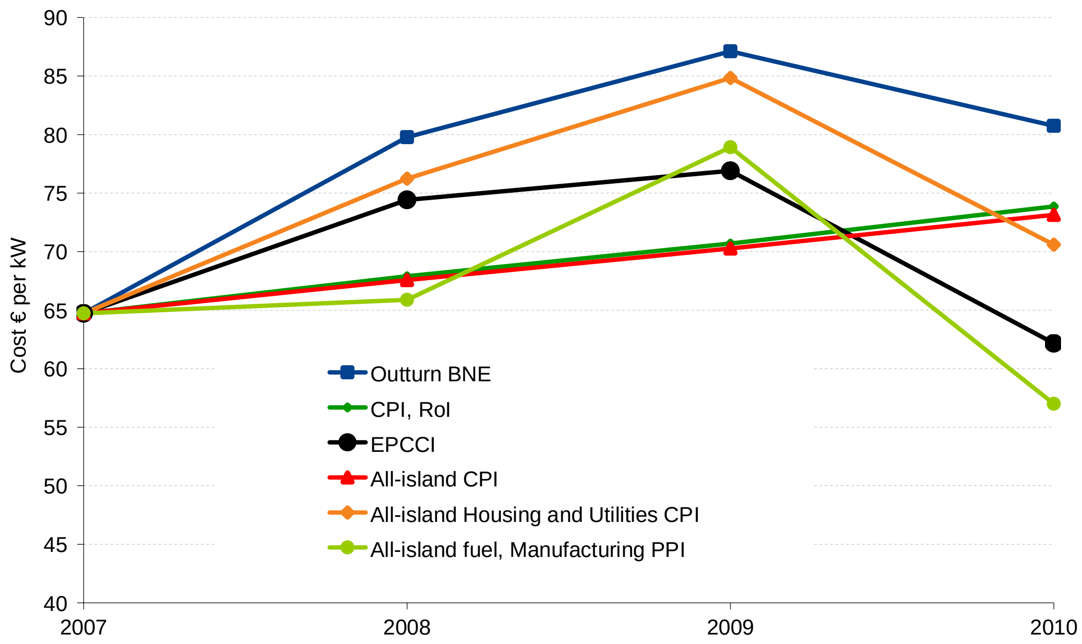
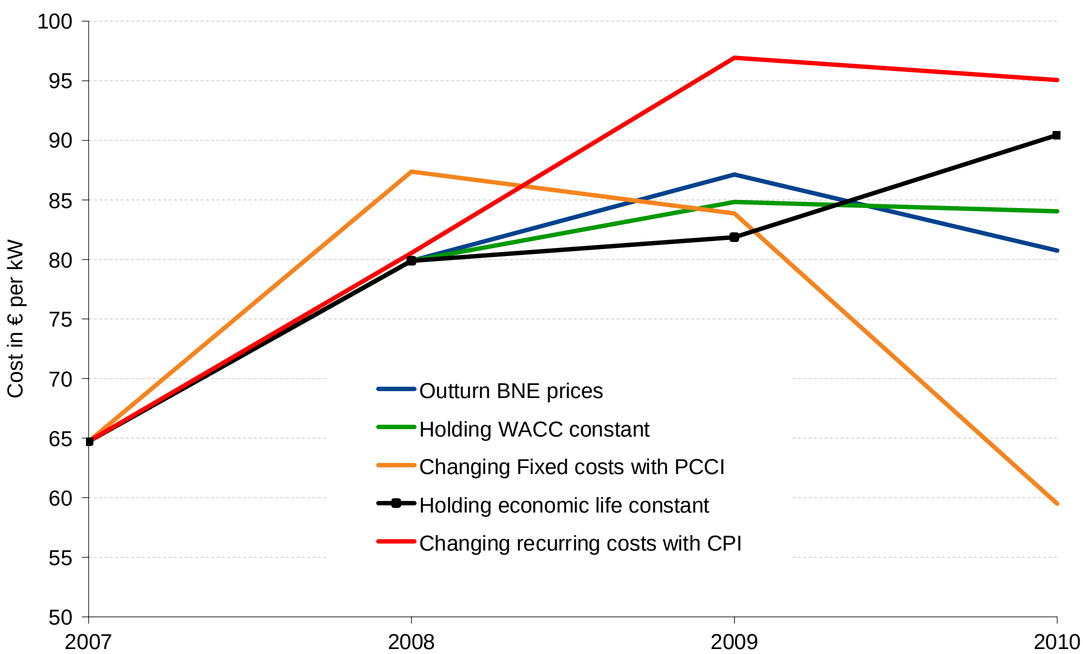


Figure 27 – Indexing selected variables, 2007-2010, comparisons with outturn



The choice of the period of indexation is also important. As Figure 26 highlights, the match between outturn and the indexed prices is closest in 2008, however by 2010, there is significant divergence between the outturn and the indexed price. Even for the best performing index, the All-island Housing and Utilities CPI, the divergence increases from approximately €3.5 per kW to €10.2 per kW. There is therefore need for a balance between short periods of indexation which allow the CPM to broadly track changes in the market and the investment climate, and longer periods which increase the level of investor certainty.

Finally the subset of what to index is important. By definition, indexing the actual BNE price provides the highest level of certainty for new entrants. However, in the event that the RAs opt to index or hold constant specific parameters rather than the final BNE price so as to improve certainty without foregoing their right to set a new BNE price, then as Figure 27 highlights, holding constant the WACC and/or the economic life at current levels all other things being equal, brings a higher level of predictability to the outturn BNE.

Improved transparency in calculations, and/or indexing the BNE price or the constituents of BNE price over a few years may improve the level of revenue certainty for new entrants (and thus the cost of capital). Indexing the BNE price may also reduce the administrative costs and the regulatory risks implicit in the annual cycle of ACPS calculations. The main drawback is that it could weaken the link between the BNE and the prevailing investment climate as well as the link between current need for additional capacity and actual investment, since investors will be basing their decision on BNE prices and presumably capacity requirement calculated a few years before.

4.3.2 Introducing a new entrant capacity price or guarantee

A new entrant guarantee involves providing explicit payments to new entrants and would improve the certainty of payments. In this section we briefly highlight the experiences of other markets from our international markets review detailed in Annex C.

4.3.2.1 New entrant schemes in other markets

There are several markets that provide incentives for new entrants notably Colombia and Spain. In the Colombian market, capacity payments are made through an energy obligation scheme (OEF) which commits the generator to make available the qualifying quantities of energy in periods of scarcity (defined as periods in which the spot price exceeds the pre-defined Scarcity Price). Participating generators are paid a guarantee based on the final prices set by a descending clock auction. New entrants are guaranteed the payment for 20 years, while existing generators are paid on an annual basis, with the possibility of a roll-over in case there are no auctions.

Since 2007, the capacity mechanism in Spain has had two components; an investment incentive intended to encourage investment in new capacity and an availability incentive. Under the investment incentive, new conventional plants larger than 50MW receive an administratively fixed €/MW/year payment over a 10 year entitlement period. The actual value of the guarantee is dependent on the prevailing system margin at the time of investment. Existing generators are only eligible for this payment in cases of significant investment in upgrading their capacity. Renewable and cogeneration plants are not eligible for the investment incentive payment on the basis that they are already supported through other initiatives. The availability incentive on the other hand is intended to secure an availability service in annual blocks through bilateral contracts with the system operator. Under transitional arrangements payments are based on a value of €4.808/MWh. It is intended that only peaking plant and manageable hydro will be eligible to provide this service.

4.4 Improving ease of entry or exit

The concerns about exit inefficiencies relate to (a) paying generators who are unavailable when called upon to provide capacity; and (b) the prolonged life of old unreliable plants that remain on the system by virtue of the availability of the CPM, and beyond an 'economic lifetime' they would otherwise not enjoy in the absence of the CPM. There are three possible options to improve exit efficiencies in general and plant availability when called upon. These include:

- Increasing the proportion of ex-post payments to decrease the payout for unreliable generation, thus a plant that is not available when called upon would automatically lose out on energy payments and a larger chunk of its capacity payments, making such occurrences financially punitive. This option has been already been discussed in detail.
- Introducing a penalty for plants which declare themselves available but fail to respond when called upon.
- Increasing the size and types of contracts under Ancillary Services so as to reward flexibility appropriately.

4.4.1 Introducing a penalty for plants which declare themselves available but fail to respond when called upon

There is a perception that some plants are called upon to run and are unavailable. Not only is this likely to impede exit signals for old plant that should be decommissioned, but it also goes against the fairness objective of the CPM. There are several deterrents applicable, these include mandating a retrospective re-payment of CPM payments for the trading periods that a plant was called and was unavailable or imposing a formal penalty charge.

Capacity payment penalty clauses for generators exist in other markets such as New England and Colombia. In the Colombian Reliability Charge scheme, generators are paid a capacity charge determined by a competitive auction for each MWh of firm energy committed. Generators in turn are obligated to supply energy at a fixed price whenever spot prices exceed a pre-defined 'Scarcity Price', set at $120 MW as of January 2007. In the event of a scarcity period, generators are paid the Scarcity Price for energy supplied under their obligated volume and the spot price for any additional energy supplied. Similarly, generators pay a penalty for failing to supply energy called up under the scheme. The penalty is defined as the difference between the spot price and the Scarcity Price.[14] The energy regulator CREG collects the aggregate obligation fees from suppliers which are used to pay obligated generators a fixed annual 'option fee' for each capacity unit covered under the scheme. In the event that an obligated generator is unavailable during a shortage event, the penalty applies without exception and is charged to the generator with limited recourse for appeal.

In the New England market, all generators are paid for capacity at a price based on the Forward Capacity Auctions. Generators who are unavailable during shortage events are charged a penalty which cannot be greater than the capacity payments they would have

[14] David Harbord, Marco Pagnozzi, 'Review of Colombian Auctions for Firm Energy, Market Analysis Ltd, November 2008,' A report to the Colombian Comisión de Regulación de Energía y Gas.

received. In addition, payments made to the capacity resources that were unavailable is re-distributed to units that were available during the shortage event.[15]

In the SEM context, all generators are currently subject to the grid code which specifies penalties for failing to run when called upon. The grid code mandates the ISO to conduct random testing of low load factor plants, constraining them on to check that they can deliver. Where the plant cannot deliver, the only penalty specified in such cases is that the plant is forced to declare itself unavailable for that period and to lose energy payments that it could have received and capacity payments for that trading period. The plant could also be liable for uninstructed imbalance payments, for negative deviation from its dispatch schedule, beyond the set tolerance bands.

Possible enhancements within the CPM design could take advantage of the existing grid-code system described above rather than instituting a new charge. This could include:

- Formalising the testing frequency for low load factor plants currently conducted by the ISO and increasing the frequency of tests.
- Extending the declared unavailable period e.g., for a month or a week rather than a trading period after the failed test to give it more weight (thus a plant would lose all capacity payments for the extended period).
- Increasing the penalty to include not only the lost energy payment, capacity payment for the trading period (and possibly uninstructed imbalance payments), but also a penalty equal to the cost to the system of getting the next unit to provide cover for the unavailable plant.
- Suggested rebalancing of CPM payments that gives greater weight to ex-post availability and limits the influence of the Flattening Power Factor which would increase the exposure or risk of plant in the event that it is unavailable when called to run.

These changes should go hand in hand with formalising a process of administration covering key issues such as what counts as a valid infringement of the rule and the operation of a possible appeals process. It is also important to highlight that the existing system has other potential tools outside the CPM to ensure compliance. Failure to run when called upon is an infringement of the responsibilities of a plant under the grid code, and implicitly is an infringement of the licensing terms for a generator with far more grave consequences compared to the temporal decline in revenues.

4.4.2 Increasing the proportion of ex-post payments to decrease the payout for unreliable generation and to make such occurrences financially punitive

Increasing the proportion of ex-post payments can be used to decrease the payout for unreliable generation. Thus a plant that is not available when called upon would automatically lose out on energy payments and a larger chunk of its capacity payments, making such occurrences financially punitive.

As noted in Section 2, a 400MW CCGT plant that is unavailable in the trading period with the lowest system margin, currently forfeits all its capacity payments for the particular trading period and no more, thus it loses €9,700 under the current design in 2008. This would increase to €230,000 (under a full ex-post regime with an FPF of 1.0 and the monthly pot allocation removed) and €1.2 million under a LOLP × (VOLL-SMP) regime.

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[15] See Scott M. Harvey, 'ISO-NE FCM Capacity Market Design,' October 2007, http://www.caiso.com/1c72/1c729b3c4f410.pdf

Thus the strong ex ante components under the current design, severely limits the impact of the penalty.

4.4.3 Increasing the size and types of contracts under Ancillary Services so as to reward flexibility appropriately.

As noted there is a case for using the AS rather than the CPM as it can be targeted at specific services required in the system rather than the CPM which is a blunt instrument. Thus AS can be used to reward flexibility appropriately. In general, if the SEM is interested in ensuring there is flexible generation (and not just reliable generation during peak demand), then ancillary services may be a better mechanism for delivery and vice versa.

4.5 Conclusions

The analysis in this section discusses the potential solutions to shortcomings in the current CPM design. We find that changing the inputs or parameters in the current design such as the Flattening Power Factor, the weighting between ex-post and ex-ante payments, the monthly and intra-monthly allocations has important re-distributive impacts that could alter the incentives to existing generators and new entrants. A greater weighting for ex-post availability should address the dilution in the relationship between payment for reliability and value, and should help to remedy higher levels of payments to less firm generation.

There is also scope for changing the parameters of BNE price calculation, or constituents of BNE to provide greater certainty, particularly to new entrants. Finally our review of international experience in delivering adequate capacity provides possible insights to reforming the CPM. This includes reviewing the time horizon of regulatory calculations, and extending it to increase certainty to new entrants. Other lessons include possible inputs or ways to calculate capacity requirement and BNE price; and the experiences of other markets in penalising generators who are unavailable during periods of shortages.

Based on the discussions in this section, we have identified and developed four main reform packages for changing the CPM. These are:

- Exploring a re-balancing package that proxies the combined effects of a shift towards ex-post. In the scenario we would explore an equal weighting between ex-post and ex-ante payments, at 50:50; changing the flattening power factor to 0.5, removing the variable ex-ante and distributing intra-monthly payments evenly across all trading periods. These changes provide for a scenario that captures the advantages of each of the main parameter changes discussed while avoiding their key weaknesses.
- Exploring alternatives to increasing the level of remuneration for conventional generators within the existing system. This could include adjusting payments by a reliability factor such as a capacity credit system.
- In light of the concerns about certainty for new entrants due to the annual cycle of changes in the ACPS and BNE, exploring an indexation option or guarantee for new entrants.
- Exploring alternatives to remunerating plants for reliability through the interaction with the ancillary services pot by expanding the size of the ancillary services pot and the range of products that cover firmness and reliability concerns expressed in this section.

Table 17 provides a more detailed scoping of the reform packages.

Table 17 – Overview of proposed reform packages

Scenario	Main features
Ex-post, ex-ante, re-balancing scenario	▪ Changing the weighting between ex-post and ex-ante payments to 50:50; ▪ Increasing the flattening power factor to 0.5; ▪ Splitting the ACPS to monthly pots based on forecast demand and sharing intra-monthly split evenly across all trading periods; ▪ Scenario is technology neutral and applies equally to new entrants and existing players.
Capacity credit scenario	▪ Applies the re-balancing methodology; *plus* ▪ De-rated capacity credit specific to each technology applied to the ex-ante payment.
New entrant scenario	▪ Provides a BNE price guarantee for new entrants over a fixed period, de-rated by technology-specific capacity credit; ▪ Applies re-balancing methodology to the residual pot shared by all existing plants.
Payments for flexibility scenario	▪ Sets aside a percentage of ACPS for flexibility which is combined with ancillary services to reward reliability; ▪ Applies re-balancing methodology to the residual pot.

The Sections 5-8 highlights each scenario and compares the package with the status quo CPM design and its performance under the assessment criteria in 2008 and in 2020. A re-balancing of payments towards increased ex-post payments underpins all four scenarios, thus Sections 6-8 while exploring significantly different changes to mechanism, are invariably a variant of the re-balancing scenario. In Section 9, we compare all four options based on a comprehensive assessment criteria.

5. PROPOSED ALTERNATIVES: RE-BALANCING SCENARIO

The current CPM design is heavily weighted towards ex-ante payments which account for 70% of the total. The emphasis on ex-ante payments has resulted in a dilution of the link between payments and availability during shortages. It has also resulted in plants available during periods of low system margin not being adequately rewarded in proportion to their contribution to system reliability.

This scenario assesses the impact of re-balancing payments in favour of ex-post availability. It involves changing the weighting between ex-post and ex-ante distribution to 50:50 and changing the flattening power factor to 0.5. Other features include dividing ex-post payments into current monthly pot weightings and applying ex-ante payments evenly across all trading periods. The weightings chosen have been selected following discussions with the RAs and are solely intended to illustrate the performance of such a design.

5.1.1 Efficiency of the capacity payment signals

Figure 28 compares the relationship between capacity payments and system margin under the current CPM design and the re-balancing scenario. The level of capacity payments targeted to periods when system margin is tight increases under this scenario. The new relationship is less flat, with up to 253 trading periods with capacity payments of over €50 per available MWh compared to 81 periods under the status quo. Moreover, the price at minimum system margin increases from €49 to €156 per available MWh, while the maximum payment increases from €70 to €157 per available MWh as shown in Table 18.

Figure 28 – Capacity in € per available MWh vs. ex-post margin, 2008, under the re-balancing and status quo scenarios

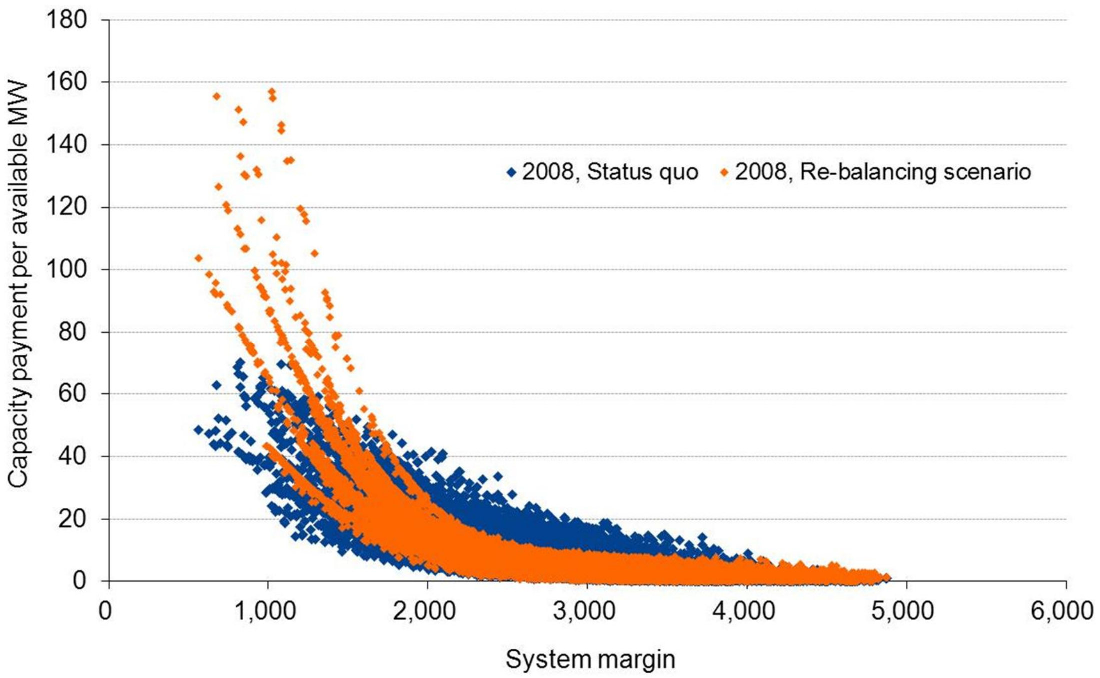


Table 18 – Capacity payments in € per available MWh under the re-balancing scenario vs. status quo CPM design for 2008

	Status quo	Re-balancing scenario
Maximum price	70.15	157.10
Price at minimum system margin	48.50	155.67
Number of trading periods per price group		
€0-25	16,605	16,243
€25-50	880	1,070
€50-75	81	157
€75-100	0	64
€100-125	0	17
> €125	0	15

The re-balancing scenario also improves the remuneration for firm generators compared to the status quo. Most technologies with the exception of interconnector imports, coal, coal /oil plants and wind experience a slight gain in average capacity payments per available MWh. As Table 19 indicates, wind and interconnectors experience a 10% and 1% decline in payments respectively.

Table 19 – Capacity payments in € per available MWh under the re-balancing scenario in 2008

Technology	CP € per available MWh	CP € per installed MWh	Change, € per available MWh vs. current CPM	% Change
DSU	15.31	4.09	0.17	1%
PS Generating	12.85	5.86	0.03	0%
Hydro	12.45	5.91	0.27	2%
IC Imports	10.79	1.85	-0.11	-1%
Peat	9.64	7.87	0.03	0%
Distillate	9.60	7.97	0.10	1%
Biogas	9.58	6.80	0.08	1%
Coal	9.43	6.94	-0.01	0%
CCGT Gas	9.42	7.85	0.04	0%
Other Gas	9.40	6.16	0.02	0%
Oil	9.39	8.19	0.03	0%
Coal / Oil	9.35	8.48	-0.02	0%
Wind	8.30	2.12	-0.88	-10%
PS Pumping	-2.00	-0.18	-0.36	22%
IC Exports	-10.28	-0.56	-0.21	2%

5.1.1.1 Capacity payments in future years

The impact of anticipated changes in the market as the penetration of wind increases is an important litmus test for alternative design options. Figure 29 compares the relationship between capacity payments and system margin under the current CPM design and the re-balancing scenario in 2020. The re-balancing scenario seems to perform marginally better at re-distributing payments to periods when system margin is tight. The relationship is less flat, with up to 198 trading periods experiencing capacity payments of over €50 per available MWh compared to 129 periods under the status quo. In addition, the price at minimum system margin (and maximum price) increases from €245 to €640 per available MWh.

Figure 29 – Capacity in € per available MWh vs. ex-post margin, 2020, under the re-balancing and status quo scenarios

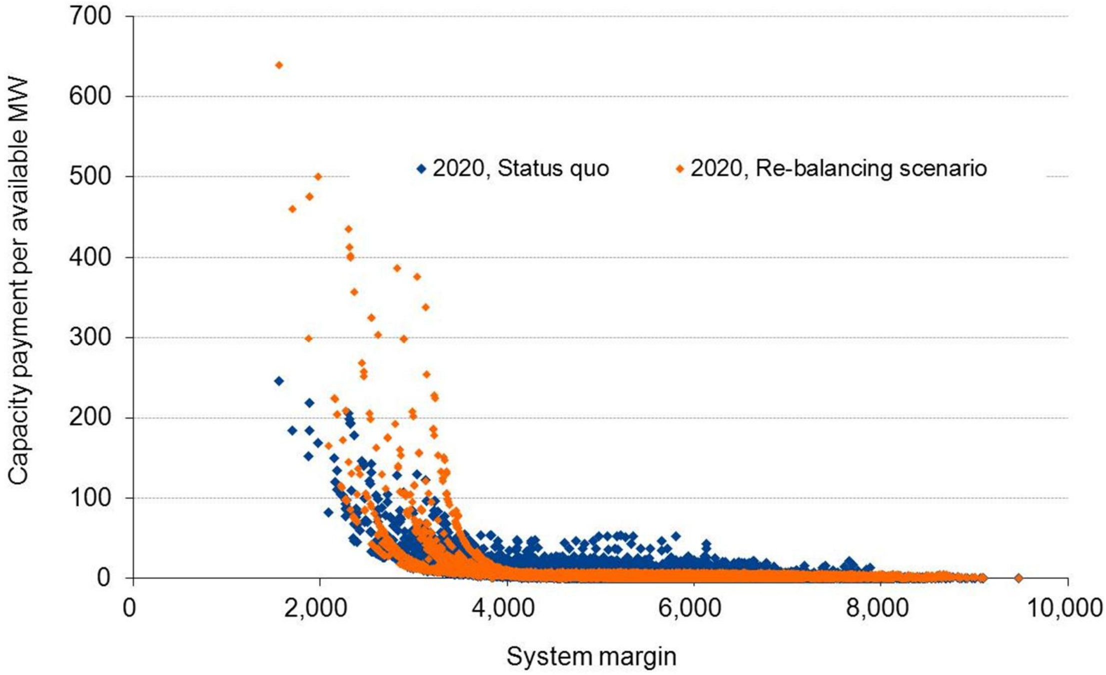


Table 20 – Capacity payments in € per available MWh under the re-balancing scenario vs. status quo CPM design for 2008

	Status quo, 2020	Re-balancing scenario, 2020
Maximum price	245.26	639.67
Price at minimum system margin	245.26	639.67
Number of trading periods per price group		
€0-25	17,079	17,198
€25-50	358	170
€50-75	61	69
€75-100	34	46
€100-125	14	23
> €125	20	60

5.1.2 Distribution of payments across generators

Table 21 shows the capacity payments under the re-balancing scenario and the status quo design in 2020. The performance of the re-balancing in distributing payments to firm generators compared to the status quo improves in 2020. Wind experiences a decline of 3% in 2020 under this scenario compared to the status quo, while CCGTs and pump storage experience marginal reductions in payments of 0.5%. Conversely, interconnector imports experience a gain of 7%, while most other conventional plants experience a marginal gain of 1%.

Table 21 – Capacity payments in € per available MWh under the re-balancing scenario in 2020

Technology	CP € per available MWh	CP € per installed MWh	Change, € per available MWh vs. current CPM	% Change
IC Imports	12.95	2.99	0.87	7%
PS Generating	9.70	5.84	-0.06	-1%
OCGT	7.90	6.71	0.11	1%
Other Gas	7.82	7.17	0.08	1%
Coal	7.73	7.21	0.10	1%
Peat	7.72	6.86	0.09	1%
Hydro	7.65	7.31	0.06	1%
Distillate	7.62	7.19	0.07	1%
CCGT Gas	7.43	6.64	-0.04	-1%
Wind	4.46	1.54	-0.13	-3%
PS Pumping	-3.08	-0.51	-0.20	4%
IC Exports	-5.01	-1.01	-0.16	6%

5.1.2.1 Impact on distribution of payments by technology

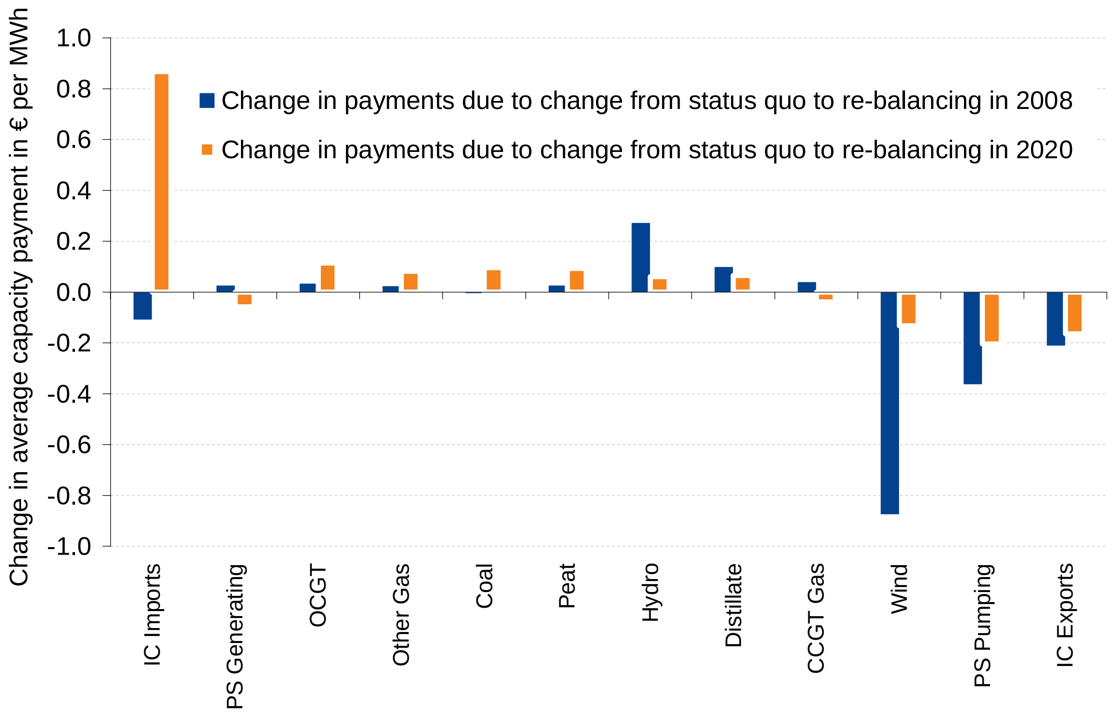
The performance gap between the re-balancing scenario and the status quo design seems to increase in 2020. Figure 30 highlights the overall impact of changing the design from the status quo to the re-balancing in both 2008 and 2020. In 2008, the re-balancing scenario performs marginally better than the status quo in 2008, leading to slight increases in payments across most technologies, at the expense of primarily wind. However, in 2020 the change in design leads to higher levels of remuneration across all technologies except wind.

The biggest changes observed are in wind and interconnectors. The average payments per MWh for wind declines by 3% in 2020 due to the fact that wind revenues are spread over a significantly expanded available capacity. Interconnector imports on the other hand experiences a significant increase in its revenues on a per available MWh basis.

We have also compared the performance of the re-balancing scenario in 2008 and in 2020 to assess its performance to changes in the market structure. As Table 19-Table 21 highlight, there is a significant revenue decline across all technologies. The average capacity payment per available MWh declines from 9.28 to 7.28 (see Table 18 and Table 20). Wind as seen experiences the biggest decline in payments, with higher ‘negative payments’ for interconnectors when exporting and pumped storage when pumping. This suggests that this scenario is likely to perform better at re-distributing the available pot to firm generators compared to the current design. However, it also suggests that there

ACPS may need to increase at a higher rate than demand (as assumed in our analysis) to adequately compensate generators in 2020, given the increased penetration of wind (or at a minimum to provide the same levels of payments as in 2008).

Figure 30 – Change in capacity payments in € per available MWh by technology, due to change from status quo to re-balancing scenario in 2008, 2020



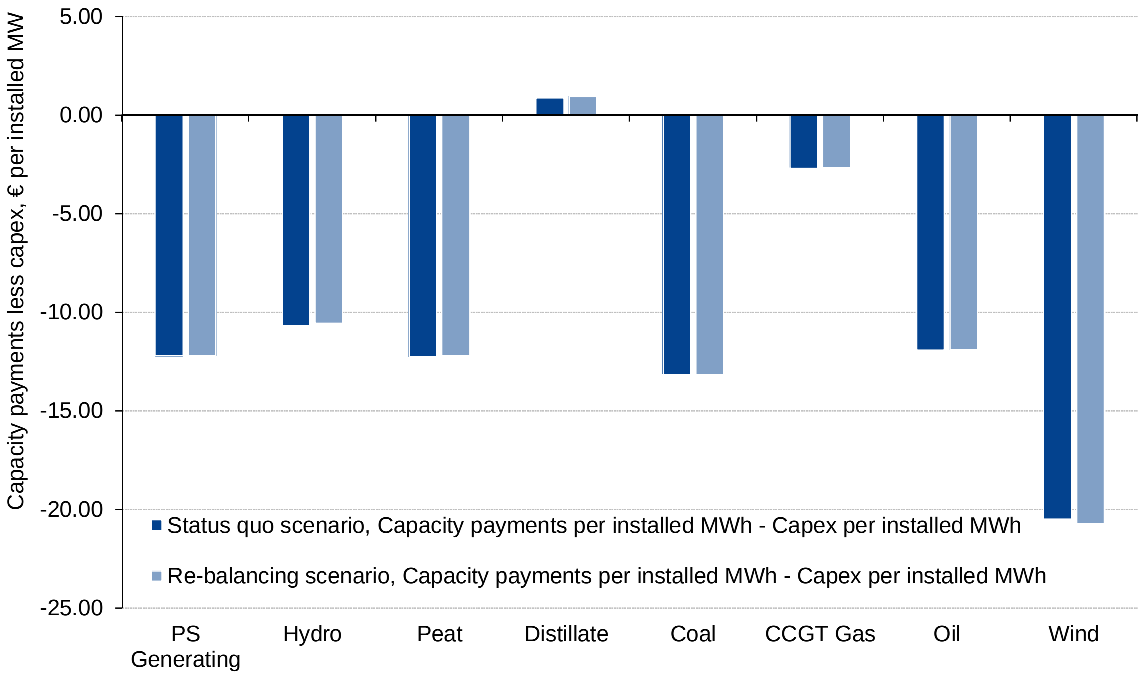
5.1.3 *Impact on entry and exit decisions*

5.1.3.1 Capacity payments vs. fixed costs in 2008

Capacity payments are intended to cover the fixed costs of plants in the system. Thus the strength of the investment signal embedded in the design can be assessed by comparing capacity revenues and fixed costs of generators. Figure 31 shows the difference between capacity payments per installed MW and the estimated CAPEX per installed MW in 2008 across technologies. Distillate plants by our estimates are the only technology which recovers its CAPEX.

This analysis is based on CAPEX assumptions from the dispatch principles analysis and is intended to provide a high level illustration of the performance of both designs. It does highlight the fact that there is not a significant difference in covering fixed costs under this scenario compared to the status quo. Most plants are unable to fully recover their CAPEX under the current design. In practice what this means is that an average CCGT plant with an installed capacity of 400MW will earn an estimated €26.07 million in capacity payments a year under the status quo design compared to an estimated annualised CAPEX costs of €37 million. Under the re-balancing scenario, capacity revenues would increase by €110,000. By comparison, a 100 MW distillate would earn €6.57 million a year compared to an estimated CAPEX cost of €6.17 million a year. Under the re-balancing scenario, capacity revenues would increase by €70,000 a year. The change in design therefore provides additional revenues to reliable plants, although the additional revenues are small in proportion to total capacity revenues.

Figure 31 – Difference between capacity payments and fixed costs (CAPEX) per installed MW under the status quo and the re-balancing scenarios in 2008



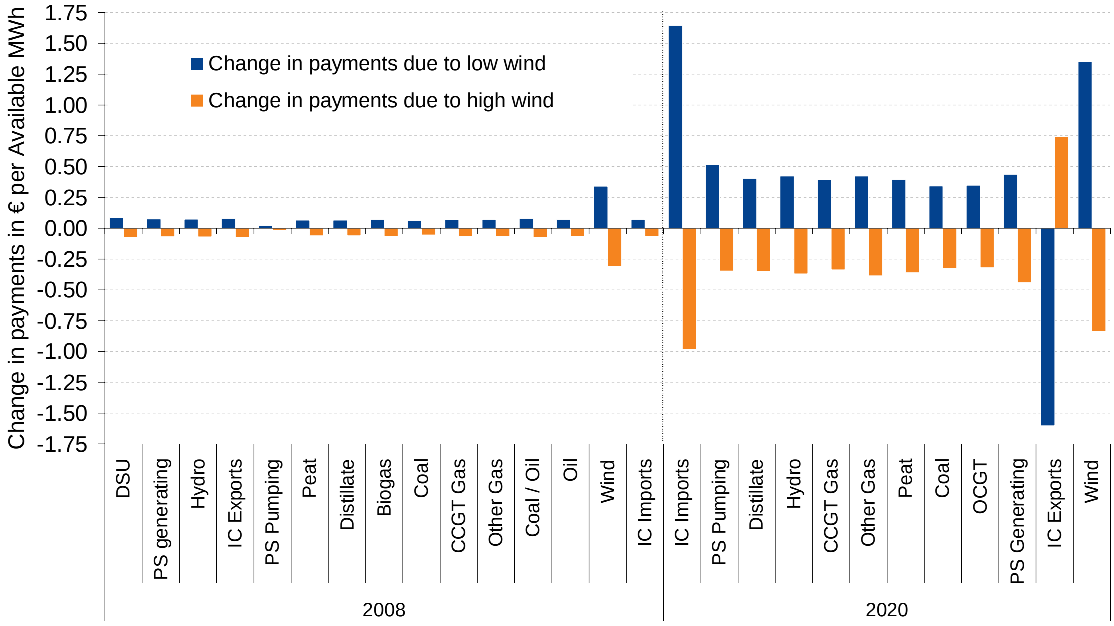
5.1.3.2 Impact of wind variability on investment signals

The increased penetration of wind affects existing generators and new entrants in several ways. It reduces the average capacity payment in 2020 (as noted above) and energy payments for generators affecting their overall profitability. However, it also increases the uncertainty of payments within any given year, further affecting their cost of capital.

Figure 32 shows the impact of a low and a high wind year on payment per available MWh by generator type under this scenario. In 2008, the variance in capacity payments received in a low and high wind year is fairly minimal, averaging €0.13-0.18 across all generators except for wind. For a CCGT with a capacity of 400 MW, this is approximately €205,000 less in a high wind year and an additional €221,000 in a low wind year, a variation of €426,000 in any given year. However by 2020, the change is likely to become more pronounced, especially for interconnectors and wind generators, with an average variation of €0.33-0.40 across most technologies. Interconnectors however experience a variance of €2.32, while wind generators experience a variance of €1.09.

For a CCGT with a capacity of 400 MW, this is approximately a decline of an additional €526,000 in a high wind year and a gain of an additional €612,000 in a low wind year (a variance of €1.14 million).

Figure 32 – Change in capacity payments in € per available MWh by technology in low, high wind conditions, under the re-balancing scenario in 2008, 2020



5.1.4 *Impact of re-balancing scenario on interconnectors and DSUs*

5.1.4.1 Interconnectors

The treatment of interconnectors in the re-balancing scenario is broadly unchanged compared to the status quo in 2008, and more favourable in 2020. Changing the design of the CPM leads to a 1% decline in average capacity payments per MWh for imports; and a 2% increase in 'charges' when it is exporting. In 2020, the re-balancing scenario leads to 7% higher payments to the interconnector when it is importing, and 6% higher 'charges' when it is exporting.

The increased penetration of wind and its variability has significant revenue implications for interconnectors. In 2008, the impact of a 25% increase or decrease in wind leads to a €0.08 per MWh change when it is importing and a €0.07 per MWh change when it is exporting. In 2020, however the impact of wind becomes significantly larger. A low wind year (defined as 25% less than normal) results in a €1.64 per MWh increase in payments when it is importing, and a charge of €1.60 MWh when it is exporting. Conversely, a high wind year leads to a €0.98 per MWh decline in payments when it is importing and a €0.74 per MWh increase in payments when it is exporting (for a variance of €2.63 per MWh when importing and €2.19 per MWh when exporting).

5.1.4.2 Demand Side Units and Demand Side Management

The re-balancing scenario leads to a minor gain for DSUs which experience an increase of €0.17 per MWh or 1% as a result of changes in the CPM design. The increased penetration of wind and its variability has minor implications for DSUs. In 2008, the impact of a 25% increase or decrease in wind is an increase or decrease of €0.08 per MWh (for a variance of €0.16 per MWh or 1% of average payments). In the future years, the impact is more akin to conventional generators discussed in Sections 4.1.2 and 4.1.3.

5.2 Performance of the re-balancing scenario

The re-balancing scenario is an improvement to the current CPM design. Under this scenario, payments would be re-distributed primarily from wind to other generators. Of the 13 technologies assessed, 11 experience a small increase in payments in 2008. In 2020, all technologies except wind experience marginally higher level of payments compared to the status quo. Thus at the margins, by improving the remuneration for most generators, this scenario is likely to ensure that the market can provide a higher level of capacity adequacy compared to the status quo.

By rewarding more reliable generators at a slightly higher rate, this scenario, all else being equal, leads to marginally higher levels of reliability. In this regards, it is also fairer as it provides improved rewards for reliability compared to the status quo.

The re-balancing scenario relies on slight changes to the existing parameters in the current design thus the regulatory risk and the risks of susceptibility to gaming are likely to remain comparable to those under the status quo design. In addition, it is as simple as the current design (as it entails no radical re-design).

Over the long term, the design is likely to lead to marginal erosion in price stability since a greater proportion of capacity payments is now based on ex-post or outturn availability, thus harder to predict. However the incremental payments to most generators except wind should lead to a marginal improvement In the efficiency of price signals relative to the status quo design.

In general, this scenario provides a marginal improvement to the status quo design. Table 22 summarises the comparisons in performance between the two scenarios.

Table 22 – Performance of the re-balancing vs. status quo scenarios

Reform option	Performance
Capacity adequacy	▪ This scenario provides increased capacity payments for most conventional generators in 2008 compared to the status quo. All technologies except wind experience a small increase in 2020.
System reliability	▪ The emphasis on ex-post payments increases the remuneration for reliable generators improving system reliability at the margin.
Efficient price signals for long term investments	▪ The scenario ensures higher payment for conventional generators in 2008, increasing in future years. This could improve their investment case relative to the status quo design. However, the increased payments may not be enough in light of expected declines in their energy revenues due to a higher penetration of wind.
Price stability	▪ Price stability is eroded since a greater proportion is now based on ex-post outturn availability, thus harder to predict.
Fairness	▪ All generators receive equal payment for each MW supplied as in the status quo, however the shift to ex-post leads to higher payments for flexible generators.
Simplicity	▪ A higher proportion of ex-post payments makes it harder to predict the total likely revenue in advance. ▪ The scenario is simple and transparent as the status quo, since it only requires changes to the CPM algorithm.
Susceptibility to gaming	▪ Susceptibility to gaming remains unchanged compared to the status quo.
Regulatory risk	▪ The scenario results in minimal additional regulatory risk compared to status quo as it entails changing only the inputs in the CPM algorithm already specified in the TSC.

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6. PROPOSED ALTERNATIVES: CAPACITY CREDIT SCENARIO

The capacity credit scenario is a way of recognising the different contribution of the generators to system security. In this reform option, each plant or plant type is allocated a 'capacity credit factor' through which ex-ante payments are adjusted to take account of the 'firm capacity' provision of generators. The intention is to reward appropriately, generator contribution at peak demand with a higher capacity credit. The ex-post pot on the other hand is allocated solely on availability in times of need. Thus the reliability-adjusted ex-ante payment is intended to provide long-term investment signals while the ex-post payment provides incentive for generators to declare themselves available when margin is lowest.

The key features of this scenario include a 50:50 split of the overall capacity pot between ex-post and ex-ante payments and changing the flattening power factor to 0.5. We then apply a de-rated capacity credit specific to each technology to the ex-ante payments. The ex-post payments are split to generators based solely on availability and are divided into monthly pots under the current monthly pot weightings. The capacity credit adjusted payments on the other hand are split evenly for each generator across all trading periods.

The weightings chosen are based on discussions with the RAs. We have used a set of capacity credits shown in Table 23 calculated as perfect plant capacity divided by installed plant capacity. Both inputs are provided separately by EirGrid, and are for illustrative purposes to show how this reform option could operate. We expect that the ISO would make similar calculations under the supervision of the RAs.

6.1.1 Efficiency of the capacity payment signals

The capacity credit scenario results in a significant transfer of capacity revenues from intermittent generation to flexible generators. As Table 23 highlights, wind faces a revenue decline of 51% if capacity credits are introduced, compared to the status quo. Similarly, demand side units and pumped storage (when generating) experience a 19-22% decline in payments, although this is possibly an artefact of our capacity credit calculations. The main conventional generators such as CCGTs, peat, distillates experience an increase in their payments with CCGTs in particular experiencing an increase of 7%.

Table 23 – Capacity payments in € per available MWh under the capacity credit scenario in 2008

Technology	Capacity credit	CP € per available MWh	CP € per installed MWh	Change, € per available MWh vs. current CPM	% Change
DSU	50%	11.88	3.17	-3.27	-22%
PS Generating	59%	10.41	4.74	-2.42	-19%
Hydro	92%	12.25	5.82	0.08	1%
IC Imports	90%	10.79	1.85	-0.11	-1%
Peat	89%	10.03	8.18	0.42	4%
Distillate	84%	9.78	8.12	0.28	3%
Biogas	70%	8.90	6.32	-0.59	-6%
Coal	83%	9.55	7.02	0.11	1%
CCGT Gas	91%	10.01	8.33	0.62	7%
Other Gas	75%	9.03	5.92	-0.34	-4%
Oil	75%	9.09	7.93	-0.26	-3%
Coal / Oil	83%	9.53	8.64	0.16	2%
Wind	20%	4.50	1.15	-4.68	-51%
PS Pumping	59%	-3.62	-0.33	-1.98	121%
IC Exports	90%	-10.70	-0.58	-0.64	6%

Notes and sources: Capacity credit assumptions calculated as (perfect plant capacity divided by installed plant capacity). The level of payments depends on capacity credit chosen, as such this example is meant only for illustrative purposes. We recognize that in the event that capacity credits are adopted, that the final set chosen by the RAs may be significantly different from these with different impacts on specific generators.

The link between capacity payments and system margin is stronger in this scenario than in the re-balancing scenario or the status quo design. This is because ex-ante payments are being apportioned according to reliability, while ex-post payments are based on outturn availability, which is more likely to reward firm generators.

6.1.1.1 Capacity payments in future years

The capacity credit scenario performs noticeably better than the existing design in 2020 compared to 2008, increasing the average payment per available MWh across most technologies. As Table 24 highlights, wind experiences a decline of 59% under this scenario in 2020 compared to the status quo. This is re-distributed to conventional generators across the board with average gains of 9%. The sole exception is pumped storage which sees a decline of 12% when generating (most likely an artefact of our capacity credit assumption).

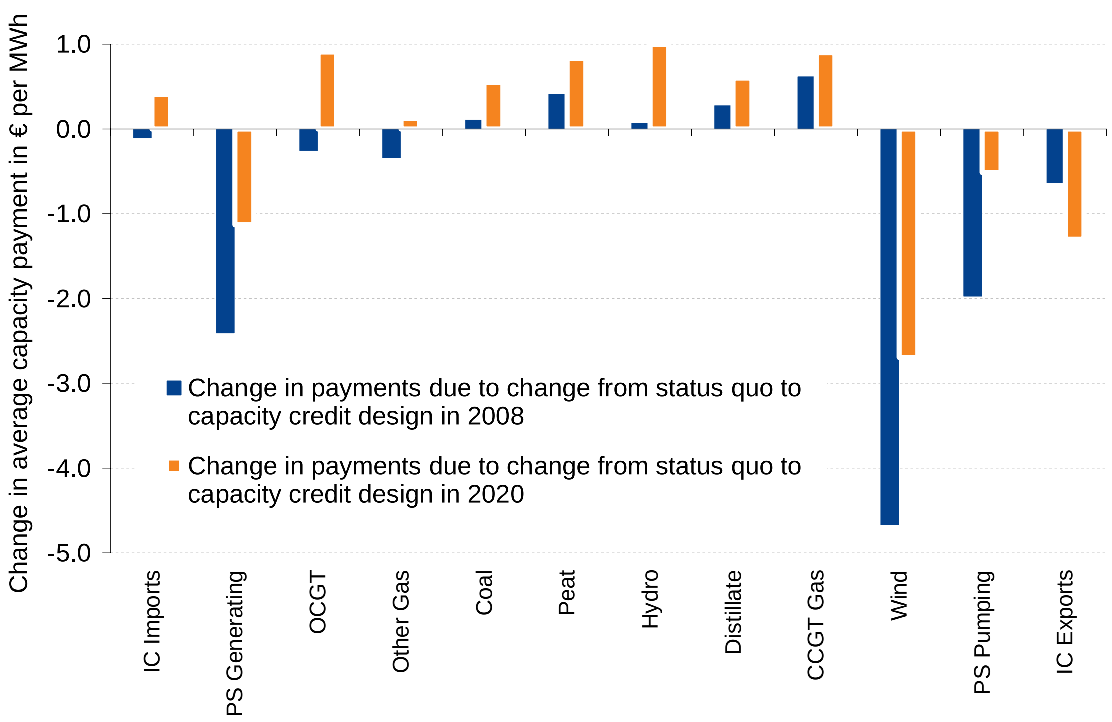
Table 24 – Capacity payments in € per available MWh under the capacity credit scenario in 2020

Technology	CP € per available MWh	CP € per installed MWh	Change, € per available MWh vs. current CPM	% Change
IC Imports	12.49	2.88	0.41	3%
PS Generating	8.63	5.20	-1.13	-12%
OCGT	8.69	7.38	0.91	12%
Other Gas	7.86	7.21	0.12	2%
Coal	8.18	7.64	0.55	7%
Peat	8.46	7.52	0.83	11%
Hydro	8.58	8.21	1.00	13%
Distillate	8.15	7.70	0.60	8%
CCGT Gas	8.37	7.48	0.90	12%
Wind	1.90	0.66	-2.69	-59%
PS Pumping	-3.39	-0.56	-0.51	11%
IC Exports	-6.15	-1.24	-1.30	45%

6.1.2 Distribution of payments across generators

The capacity credit scenario performs marginally better than the status quo at re-distributing payments to reliable generators in 2008 as shown in Figure 33. However its performance against the status quo improves noticeably in 2020 with higher levels of remuneration across all technologies except wind and pumped storage in 2020.

Figure 33 – Change in capacity payments, € per available MWh by technology, due to change from status quo to capacity credit scenario in 2008, 2020



The performance gap between the capacity credit scenario and the status quod design widens in 2020 compared to 2008. However, we have compared the performance of the capacity credit scenario in 2008 and in 2020 to assess its performance to changes in the market structure. As Table 23 and Table 24 highlights, there is a significant revenue decline across all technologies between 2008 and 2020. Average capacity payments per available MWh declines from 9.59 to 6.90 with wind posting a significant decline in payments of over 58%. This suggests a possible need to increase the size of the pot (at a higher rate than demand) so as to reward generators adequately for their contributions in light of increased penetration of wind (and at the same level as 2008).

6.1.3 Impact on entry and exit decisions

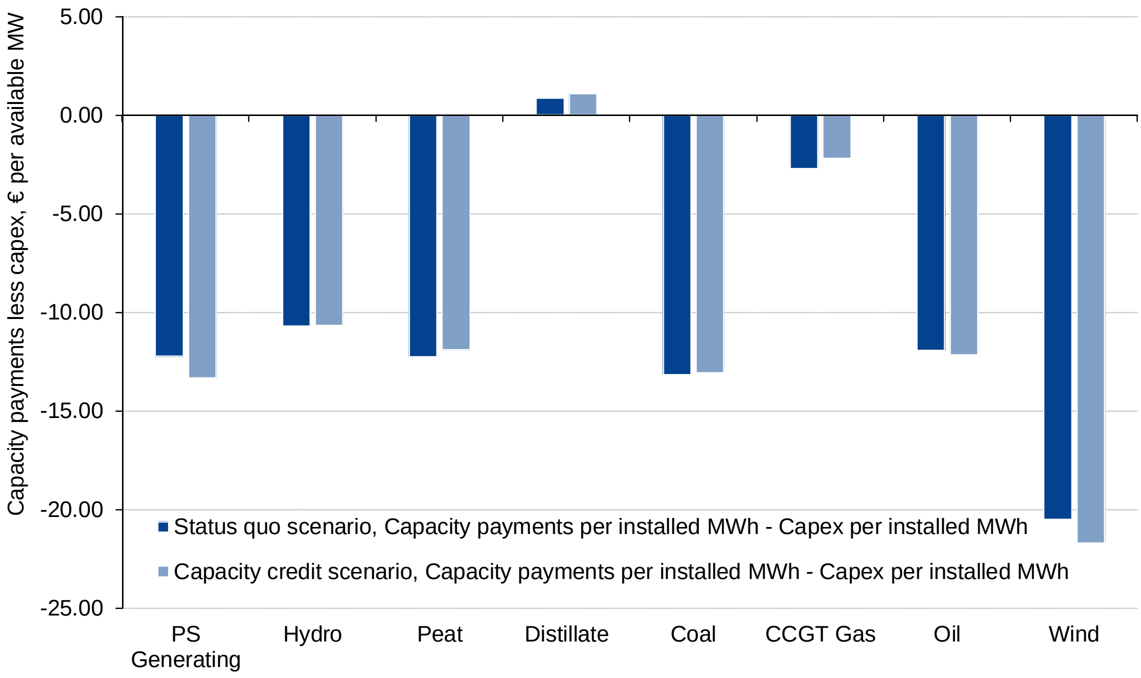
6.1.3.1 Capacity payments vs. fixed costs in 2008

Capacity payments are designed to cover generator fixed costs. Therefore the strength of investment signals due to a shift to capacity credits ought to be reflected in how well it makes this possible. Figure 34 shows the difference between capacity payments per installed MW and the estimated CAPEX per installed MW in 2008.

The capacity credit scenario provides a slight improvement to covering fixed costs for most technologies presented compared to the status quo scenario, except for pumped storage units, oil and wind. To put Figure 34 into context, an average CCGT plant with an installed capacity of 400MW will earn an estimated €26.07 million in capacity payments a year under the status quo design compared to CAPEX costs of €37 million. Under the capacity credit scenario, capacity revenues would increase by €1.73 million a year compared to a similar increase of €110,000 under the re-balancing scenario.

Similarly, a 100 MW distillate would earn €6.57 million a year compared to an estimated CAPEX cost of €6.17 million a year. Under this scenario it would increase its revenues by €195,000 compared costs to an additional €70,000 under the re-balancing scenario.

Figure 34 – Difference between capacity payments and fixed costs (CAPEX) per installed MW under the status quo and the capacity credit scenarios in 2008



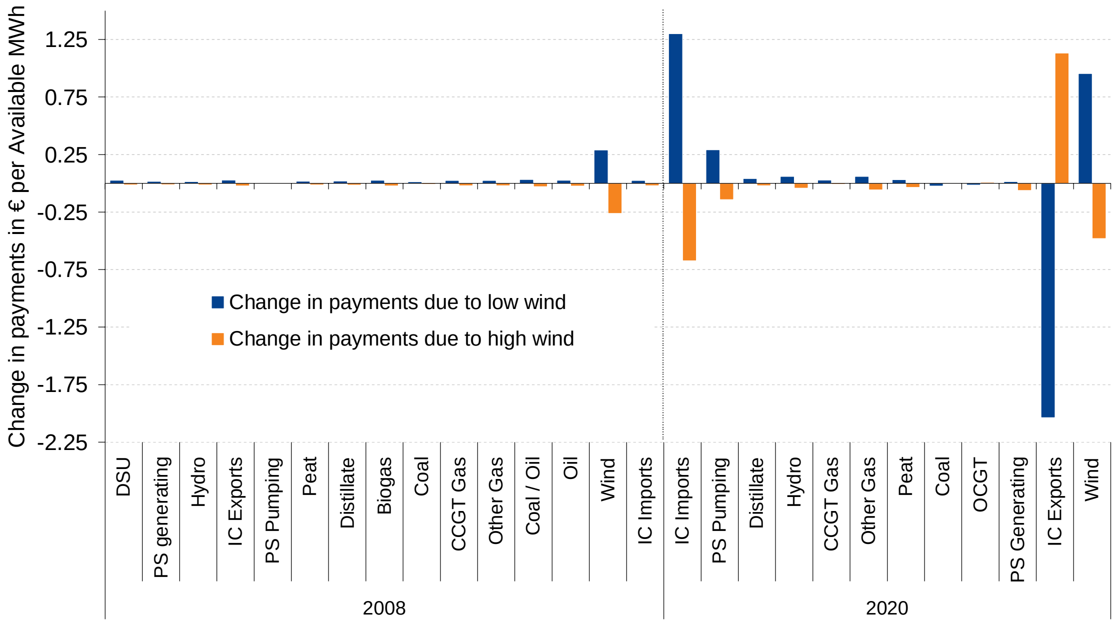
6.1.3.2 Impact of wind variability on investment signals

The increase in wind generation leads to declines in energy revenues over time and the overall profitability of plants. However this is likely to be exacerbated by the variation of wind blowing leading to increased uncertainty regarding the level of capacity payments in any given year.

Figure 35 shows the impact of a low and a high wind year on capacity payments per available MWh by generator type under the capacity credit scenario. In 2008, the variance between payments in a low wind and high wind year is small, averaging between €0.03-0.06 across most generators except for wind generators at €0.55 per MWh. By 2020, the variance due to wind remains small at €0.02-0.06, except for wind and interconnectors. The change is significant for interconnectors with an average variation of €3.17 per MW when exporting, €1.97 MWh when importing and €1.43 for wind generators.

For a CCGT with a capacity of 400 MW, this is a decline of approximately €65,000 in a high wind year and a gain of €78,000 in a low wind year. This remains largely unchanged in 2020, with a decline of €13,000 in a high wind year and a gain of €43,000 in a low wind year. The impact of wind is significantly less in this scenario compared to the re-balancing scenario. This is due to the fact that while a greater proportion of ex-post payments are likely to be paid to firm generators as in other scenarios, ex-ante payments are also adjusted by firmness. Thus the total payments are less influenced by variations in wind.

Figure 35 – Change in capacity payments, € per available MWh by technology in low, high wind conditions under capacity credit scenario in 2008, 2020



6.1.4 *Impact of capacity credit scenario on interconnectors and DSUs*

6.1.4.1 Interconnectors

The capacity credit scenario leads to a €0.11 per MWh or 1% decline in interconnector capacity payments when it is importing, and an additional 'charge' of €0.54 per MWh when it is exporting compared to the status quo design. This is marginally worse than under the re-balancing scenario, but a relatively smaller decline compared to other technologies such as wind, pumped storage (when generating) and DSU's. The scenario, however leads to marginally better outcomes for interconnectors in 2020 leading to an additional 3% or €0.41 per MWh in payments when importing and €1.30 per MWh in additional 'charges' when exporting.

As in the re-balancing scenario, the increased penetration of wind and its variability has significant implications for interconnectors. A 25% change in wind generation in 2008 results in €0.03 per MWh change in revenues when importing or exporting (for a variance of €0.05 per MWh or 0.5% change in capacity payments). This changes significantly in 2020. A low wind year (defined as 25% less than normal), results in a €1.30 per MWh increase in payments when it is importing, and a charge of €2.04 MWh when it is exporting. Conversely, a high wind year leads to a €0.67 per MWh decline in payments when it is importing and a €1.13 per MWh increase in payments when it is exporting (for a variance of €1.97 per MWh when importing and €3.17 per MWh when exporting).

The underlying cause for the high levels of changes in payments is in part due to our 90% capacity credit assumption, which is much higher than its existing payment based on flows. However the re-balancing payment scenario which is based solely on flows seems to produce a similar payment profile and levels of payments.

6.1.4.2 Demand Side Units and Demand Side Management

The capacity credit scenario leads to a significant decline in DSU payments of €3.27 per MWh or 22% compared to the status quo design. This is in part due to the capacity credit assumptions used which assumes that the level of reliability and flexibility provided by DSUs while higher than that of intermittent generation is not as valuable as an OCGT for instance. The increased penetration of wind and its variability has marginal impact on DSU payments. The impact of a 25% change in wind in 2008 is a €0.02 per MWh change (for a variance of €0.04 per MWh or 0.3% of average payments). The impact is similarly marginal in future years.

6.2 Performance of the capacity credit scenario

The capacity credit scenario leads to a significant re-distribution of payments across technologies. Thus its performance across all the objectives of the CPM is more mixed. Under the scenario, wind, pumped storage and hydro plants experience a significant decline in their revenues. Similarly, the interconnector, biogas and oil OCGT units experience a decline in their payments. Conversely, CCGTs, and other remaining conventional generators experience an improvement in their revenues.

The capacity credit scenario is likely to lead to higher levels of reliability since it provides tangible increments in payments for most reliable generators. Similarly, it is likely to make a stronger impact on the economic case for most conventional generators compared to the status quo and the re-balancing scenario (as it provides more money). This is likely to improve the provisioning of adequate capacity. Moreover the gains in 2008 become significantly higher in 2020, thus the scenario is likely to lead to stronger, more efficient investment signals in future years.

The greater remuneration for reliable generators makes the scenario fairer as it rewards flexibility. Moreover, it does so without significantly impacting price stability. Similarly, susceptibility to gaming remains unchanged, so long as the capacity credits are calculated at a technology level rather at plant specific levels.

The capacity credit design however adds a significant layer of complexity to the status quo and is likely to increase regulatory risk in the market as it entails calculation of a new set of inputs (capacity credits) which would be subject to industry consultation and regulatory approval. On balance however, its impact on improving reliability and adequacy of conventional generators, gives it an edge in our estimation compared to the status quo. Table 24 summarises the comparisons in performance between the two scenarios.

Table 25 – Performance of the capacity credit vs. the status quo scenarios

Reform option	Performance
Capacity adequacy	▪ Capacity credits increases incentives for conventional generators and reduce incentives for less reliable generators. In 2008, its performance is mixed, CCGTs, coal, hydro, peat and distillate plants increase, however in 2020 the design performs better than the status quo and could improve the investment case for most conventional generation.
System reliability	▪ An explicit capacity credit adjustment significantly increases the remuneration for 'firm' generators. Complemented by an increased emphasis on ex-post payments this is likely to improve system reliability.
Efficient price signals for long term investments	▪ The scenario ensures improved payments for conventional generators in 2008, increasing in future years relative to the status quo design. However these increased payments may not be enough in light of expected declines in energy revenues due to a higher penetration of wind.
Price stability	▪ Price stability is eroded in this design. The increased ex-post constituent makes payments harder to predict, but the increased link between reliability and payments results in larger predictable payments for non-wind plants.
Fairness	▪ The scenario changes the treatment for generators, allowing reliable plants to receive additional payments for firmness; however payments for ex-post availability are still the same for each MW supplied.
Simplicity	▪ Capacity credits add a layer of complexity to the mechanism.
Susceptibility to gaming	▪ The scenario remains unchanged compared to the status quo. If the capacity credit calculation is plant specific rather than technology specific, there may be scope for gaming by plants seeking to improve their rating.
Regulatory risk	▪ The scenario increases regulatory risk. It entails calculation of a new set of inputs (capacity credits) which would be subject to industry consultation and regulatory approval. It also does not address the regulatory risk resulting from the annual review of the ACPS pot.

7. PROPOSED ALTERNATIVES: FLEXIBILITY PAYMENT SCENARIO

There is an overlap between the services provided by ancillary services and the CPM. The current AS incentivises services such as reserve, reactive power and black start. There are additional services considered in the Harmonised All-Island Ancillary Services consultation such as warming contracts, CCGT multimode operation and pre-emptive response. These services capture some aspects of flexibility. There is a case for increasing the size, number of products and expanding the scope of AS to incentivise flexibility. Section 4 reviews the relationship between AS and the CPM as well as the pros and cons of using either scheme to deliver greater system flexibility.

This scenario reviews the case for a greater role for AS and assesses the impacts of creating a separate payment mechanism for flexibility. This could be accomplished by:

- increasing the role, size and product variety in the ancillary services pot to cater for flexibility in the market;
- creating a separate flexibility pot that is complementary to the CPM but separate from the ancillary services pot, although administered by the ISO; or
- making generator adjustment payments to reward flexibility by adding a flexibility credit to the payment algorithm.

The main features of this scenario involve the creation of a separate pot for flexibility payments either as part of an expanded ancillary services, or complementary to the capacity payment mechanism equal to 25% of the ACPS. We have then deducted the flexibility sum from the ACPS and allocated the remaining capacity pot on the basis of the re-balancing scenario.

The residual pot will be allocated on the basis of (a) a 50:50 split of the overall capacity pot between ex-post and ex-ante payments; (b) setting the flattening power factor to 0.5; (c) dividing ex-post payments into current monthly pot weightings while ex-ante payments are applied similarly across all trading periods. These assumptions and weightings have been selected for illustration following discussions with the RAs.

7.1.1 Efficiency of the capacity payment signals

A separate payment for flexibility if created out of the existing pot would reduce the payments to generators, specifically intermittent generators less likely to provide flexibility such as wind. Flexible conventional generators would be the net beneficiaries as highlighted in Table 26. We have assumed that 25% of the 2008 ACPS would have been used to create a separate pot for flexibility. Most generators are assumed to be eligible for the flexibility payments, receiving in this example a flat allocation per MWh provided. The remainder of the pot would be allocated similar to the re-balancing scenario.

Wind experiences a decline of 32% compared to the current design. Similarly interconnectors when importing and hydro units experience a 26% and 23% decline respectively. Pumped storage, biogas, coal/oil and oil units as well as demand side units all experience gains greater than 20%. This profile of payments partially reflects our assumptions on average AS payments per MWh.

Table 26 – Capacity payments in € per available MWh under the flexibility payment scenario in 2008

Technology	CPM payments € per available MW	Payments for flexibility, € per available MW	Total CP, € per available MW	Change, € per available MW vs. current CPM	% Change
DSU	11.49	9.42	20.91	5.76	38%
PS Generating	9.64	9.42	19.06	6.24	49%
Hydro	9.34	0.00	9.34	-2.84	-23%
IC Imports	8.09	0.00	8.09	-2.81	-26%
Peat	7.23	1.88	9.12	-0.50	-5%
Distillate	7.20	1.88	9.08	-0.41	-4%
Biogas	7.18	4.71	11.90	2.40	25%
Coal	7.07	1.88	8.96	-0.48	-5%
CCGT Gas	7.07	1.88	8.95	-0.43	-5%
Other Gas	7.05	1.88	8.93	-0.44	-5%
Oil	7.04	4.71	11.75	2.40	26%
Coal / Oil	7.01	4.71	11.72	2.36	25%
Wind	6.23	0.00	6.23	-2.95	-32%
PS Pumping	-1.50	0.00	-1.50	0.14	-8%
IC Exports	-7.71	0.00	-7.71	2.36	-23%

Notes: Ancillary Services assumptions underpinning analysis: €10 per MWh (pumped storage when generating); €5 per MWh (OCGTs) and €2 per MWh (for all other conventional units except hydro which receives no AS payments).

The link between system margin and capacity payment is likely to be stronger in this scenario compared to the status quo and the re-balancing scenario. This is because 75% of the pot is being apportioned similar to the re-balancing scenario (with a 50:50 split between ex-post and ex-ante payments) leading to a similar profile compared to the status quo. However, the remaining 25% is paid out as flexibility payments going exclusively to firm generators.

7.1.1.1 Capacity payments in future years

The composition of the SEM in 2020 is expected to change significantly with the increased penetration in wind. With the decline in energy payments for conventional generators, the CPM may need to play a larger role to ensure that investors continue to participate in the market to provide adequate and the right type of capacity.

The payment for flexibility scenario performs marginally better than the status quo design in 2020 compared to 2008. As Table 26 highlights, pumped storage units, and OCGTs experience significant increments in payments of over 40%. Similarly, CCGTs, distillate plants, peat coal and other gas plants experience tangible gains in average payments averaging 3%. However, this is at the expense of wind, hydro and interconnector imports which experience an average decline of over 20% in this scenario.

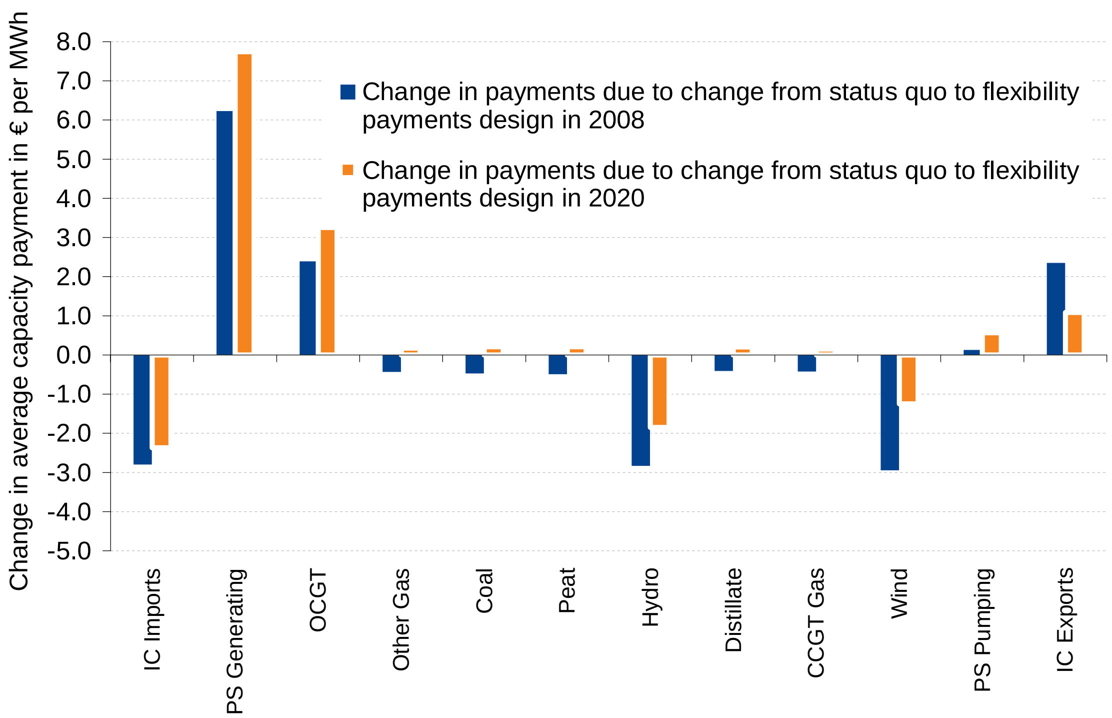
Table 27 – Capacity payments in € per available MWh under the flexibility payment scenario in 2020

Technology	CPM payments € per available MW	Payments for flexibility, € per available MW	Total CP, € per available MW	Change, € per available MW vs. current CPM	% Change
IC Imports	9.71	0.00	9.71	-2.37	-20%
PS Generating	7.27	10.23	17.50	7.75	79%
OCGT	5.92	5.11	11.04	3.25	42%
Other Gas	5.86	2.05	7.91	0.17	2%
Coal	5.80	2.05	7.84	0.21	3%
Peat	5.79	2.05	7.84	0.21	3%
Hydro	5.74	0.00	5.74	-1.85	-24%
Distillate	5.71	2.05	7.76	0.21	3%
CCGT Gas	5.57	2.05	7.62	0.15	2%
Wind	3.34	0.00	3.34	-1.25	-27%
PS Pumping	-2.31	0.00	-2.31	0.57	-20%
IC Exports	-3.76	0.00	-3.76	1.09	-22%

7.1.2 Distribution of payments across generators

The performance of the flexibility payment scenario in 2020 compared to the status quo is relatively mixed (in part due to the assumptions made on which technologies receive the flexibility payments and at what level).

Figure 36 – Change in capacity payments, € per available MWh by technology, due to change from status quo to flexibility payment scenario in 2008, 2020



As Figure 36 shows, the design results in higher payments for pumped storage, biogas, coal/oil and oil units as well as demand side units compared to the status quo. It also leads to lower payments for wind, interconnectors when importing and hydro units.

However, we observe improvements across most technologies in 2020 relative to 2008 except for interconnector exports.

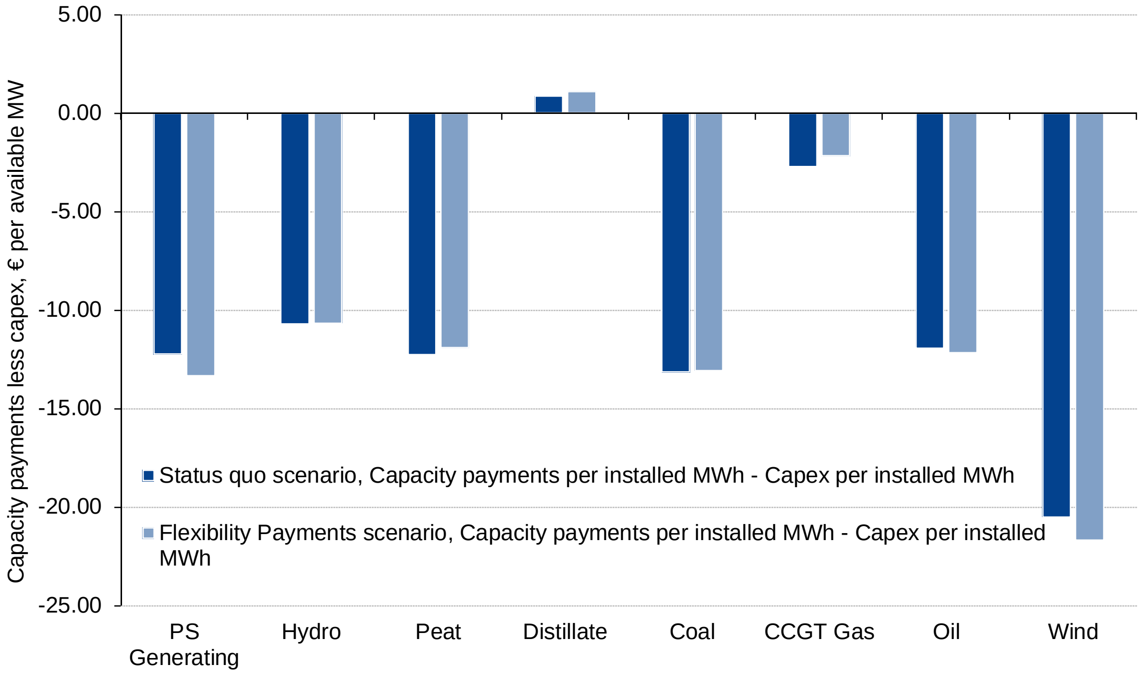
We have also compared the performance of the flexibility payment scenario in 2008 and in 2020 to assess its performance to changes in the market structure. The level of payments per available MWh in Table 26 and Table 27 highlights a significant revenue decline across all technologies in 2020. Wind and hydro plants in particular experience a 40% decline by 2020. The performance of this scenario suggest that it could perform as well or marginally better at re-distributing the available pot to firm generators than the current design. However, it reaffirms the need for a larger pot (increasing at a higher rate than demand) to adequately compensate generators with the increased penetration of wind.

7.1.3 Impact on entry and exit decisions

7.1.3.1 Capacity payments vs. fixed costs in 2008

Capacity payments are intended to cover fixed costs of generators on the system (thus the performance of the design should be assessed in terms of capacity payments relative to fixed costs). Figure 37 shows the difference between capacity payments per installed MW and the estimated CAPEX per installed MW in 2008.

Figure 37 – Difference between capacity payments and fixed costs (CAPEX) per installed MW under the status quo, flexibility payment scenarios in 2008



The implication of Figure 37 is that a CCGT investment with an installed capacity of 400MW will earn an estimated €26.07 million in capacity payments a year under the status quo design compared to CAPEX costs of €37 million. In the flexibility scenario, its earnings decline by €1.2 million compared to the status quo. This is partially due to our assumptions on average flexibility payments across technologies (we assume that these would accrue at a higher rate to controllable peak plants).

By comparison a 100 MW distillate would earn €6.57 million a year compared to an estimated CAPEX cost of €6.17 million a year. This technology would also see a decline of €287,000 compared to controllable peak units.

7.1.3.2 Impact of wind variability on investment signals

The preceding discussion on the ability of capacity revenues to cover fixed costs implies that the CPM will play an important role in ensuring that investors continue to participate in the market to provide adequate and the right type of capacity and to counteract the expected declines in energy payments due to wind. In the event that CPM does play a larger role, the impact of variations in wind is likely to remain a source of uncertainty.

The impact of wind in this scenario is similar to that under the re-balancing scenario, but less pronounced. This is due to the fact that 75% of the average payment is allocated on the same basis as under the re-balancing scenario. Thus the variations in payments due to wind are similar in profile to those under the re-balancing scenario but with comparably smaller sums due to the fact that 25% of payments are independent of wind.

7.1.4 Impact of the payment for flexibility scenario on interconnectors and DSUs

7.1.4.1 Interconnectors

The impact of the payment for flexibility scenario on interconnector capacity revenues is largely similar to that of the re-balancing payments. This is because, 75% of the payments are allocated based on the same basis with the remaining 25% based on reliability during system peak. Thus increasing the share of the flexibility pot from 25% to day 50% would only increase the decline in average capacity payments.

In 2008, this scenario leads to a €2.81 per MWh or 26% reduction in payments for interconnectors when importing, and a reduction of €2.36 per MWh in 'charges' when exporting. The performance in 2020 does not improve with a €2.37 per MWh or 20% reduction for imports, and a reduction of €1.09 per MWh in 'charges' for exports compared to the status quo. This is an artefact of limiting the flexibility pot to 75%. A higher diversion of the existing pot for flexibility would likely lead to a a higher reduction in overall 2020 payments under this scenario.

The impact of increased wind penetration and variability of wind are similar to that of the re-balancing scenario. Thus a 25% change in wind leads to a change of €0.09 per MWh when it is importing and €0.08 per MWh when it is exporting. In 2020, however the impact of wind becomes significantly larger. A low wind year (defined as 25% less than normal) results in a €1.41 per MWh increase in payments when it is importing, and a charge of €0.57 MWh when it is exporting. Conversely, a high wind year leads to a €0.93 per MWh decline in payments when it is importing and a €0.15 per MWh increase in payments when it is exporting (for a variance of €2.34 per MWh when importing and €2.05 per MWh when exporting).

7.1.4.2 Demand Side Units and Demand Side Management

Demand Side Units are classified as flexible plants in this scenario and thus are a big beneficiary of the creation of a separate flexibility pot. DSUs experience an increase of 5.90 per MWh or 39% in payments compared to the status quo. These gains, like for other flexible plants increase significantly in 2020.

The impact of payments made to DSU's regardless of the impact of wind, reduces the impact of wind variability. Thus 75% of the total payment profile will be affected by wind similar to the re-balancing scenario, but the overall impact is diminished. In 2008, the impact of a 25% increase or decrease in wind is an increase or decrease of €0.08 per MWh (for a variance of €0.16 per MWh or 1% of average payments). However this widens considerably in 2020 with increased wind penetration. Thus the absolute amounts resulting from wind remains the same, however the percentage impact becomes smaller.

7.2 Performance of the flexibility payment scenario

The payment for flexibility scenario is by default designed to improve the provisioning of adequate reliable or flexible generators. However its performance under other CPM objectives is mixed. The scenario results in a significant increase in payments for hydro, pumped storage, biogas, coal/oil and oil plants. Other generators experience a marginal decline. CCGTs similarly experience significant gains in 2020, largely at the expense of wind and peat plants. The scenario therefore is likely to lead to an improved economic case for selected, reliable technologies, thus improving their availability during tight system margin and their long term provisioning.

The scenario improves the long term signals for majority of conventional generators. It is also fairer in the sense that it in improves the rewards for reliability compared to the status quo. Moreover, it does so without unduly affecting the overall level of price stability or increasing susceptibility to gaming compared to the status quo.

The main risk is in this scenario lies in the design of the flexibility pot. We have assumed that it is operated within the context of an expanded ancillary services pot. Thus it is less likely to be more complex compared to the status quo, and is unlikely to require significant re-design to the CPM, beyond an expansion of scope and design of new AS products. However, should the RAs design a specific flexibility pot outside the AS pot, then the level of complexity and the regulatory risk could increase for generators.

In general, this scenario is broadly comparable, or marginally better than the status quo. It has the potential to achieve significant benefits on reliability and flexibility, but only if it is designed well with payments targeted accordingly. Table 28 summarises the comparisons in performance between the two scenarios.

Table 28 – Performance of the flexibility payment vs. the status quo scenarios

Reform option	Performance
Capacity adequacy	▪ There is limited impact on balance. Flexibility payments are likely to increase incentives for conventional generators and reduce incentives for wind. The scenario as modelled increases incentives for pumped storage (when generating), OCGTs, and in 2020 all other technologies except for wind, hydro and interconnector imports. This could improve the investment case for conventional generation.
System reliability	▪ An explicit payment for flexibility significantly increases the payments received by 'firm' generators. Complemented by an increased emphasis on ex-post payments this is likely to improve system reliability.
Efficient price signals for long term investments	▪ The scenario ensures improved payments for conventional generators in 2008, increasing in future years relative to the status quo design. However, increased payments may not be enough in light of expected declines in energy revenues due to a higher penetration of wind.
Price stability	▪ Price stability is eroded in this design. The increased ex-post constituent makes payments harder to predict, but the increased certainty of flexibility payments results in larger predictable payments for non-wind plants.
Fairness	▪ All generators receive equal payment for each MW supplied. Any discrimination is outside the CPM and is intended to address fairer remuneration for flexibility compared to the current design.
Simplicity	▪ Assuming the flexibility pot is added to the expanded ancillary services pot, it is less likely to be any more complex to the status quo. A new scheme developed outside the AS could increase complexity.
Susceptibility to gaming	▪ Susceptibility to gaming remains unchanged compared to the status quo.
Regulatory risk	▪ Depending on the design chosen, this scenario may result in minimal regulatory risk compared to status quo as it entails changing only the inputs in the CPM algorithm for the residual and expanding the services delivered by ancillary services. However there is additional uncertainty in specifying the nature, size and products and process for offering flexibility services and payments. ▪ It does not address the regulatory risk resulting from the annual review of the ACPS pot.

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8. PROPOSED ALTERNATIVES: NEW ENTRANT SCENARIO

The current CPM design involves annual review of the overall ACPS pot, the BNE price and capacity requirement. This regulatory process ensures that the capacity pot is closely linked to changes in capacity and system need and that it closely reflects prevailing investment climate affecting new entrants. However, it introduces a significant amount of uncertainty regarding future payments.

The intention of the new entrant scenario is to provide an increased level of stability to new entrants in order to encourage market entry, and also appropriate market exit for older plants. There are several ways to provide a new entrant guarantee, these include:

- Guaranteeing the BNE price at the time of commissioning for all new entrants adjusted by capacity credits, for a few years, and leaving the residual pot to be allocated among existing generators.
- Guaranteeing a BNE price only to conventional generators for a period of several years, and allocating the residual to renewable and existing generators. The rationale for this, which is similar to the Spanish model is that renewable generators are already incentivised through the Renewable Energy Feed In Tariff (REFIT) in the Republic of Ireland and the Northern Ireland Renewables Obligation scheme.

In this scenario, we assess the impact of creating a separate new entrant pot out of the Annual Capacity Payment sum (ACPS). Each new entrant is guaranteed a BNE price for 5 years, adjusted by de-rated capacity credit. The total sum of this guarantee is deducted from the ACPS. The remaining sum is allocated according to the re-balancing scenario on the basis of (a) a 50:50 split of the overall capacity pot between ex-post and ex-ante payments; (b) setting the flattening power factor to 0.5; and (c) dividing ex-post payments into current monthly pot weightings while ex-ante payments are applied similarly across all trading periods. The assumptions and weightings have been selected following discussions with the RAs and are intended solely for illustration.

8.1.1 Efficiency of the capacity payment signals

The new entrant scenario improves the certainty for new entrants and should on balance, help to deliver new capacity when it is needed by reducing the cost of capital. However it is likely to create uncertainty regarding the level of payments for existing generators.

Table 29 provides a sample analysis of a new entrant scenario. We have assumed that each new entrant in 2008 would have been guaranteed the BNE price of €79.77 per kW/year on a flat basis, and adjusted by capacity credit in a similar process as under the capacity credit scenario and adjusted for historic availability. While 2008 and 2020 total capacity remains the same as in other scenarios, we have assumed a net of 2,175 MW in new capacity coming online over a five year period and eligible for the guarantee. This comprises of net change in conventional capacity of 827 MW and 1,348 in wind capacity. Thus the pool of existing generators is defined as the 2008 and 2020 total capacities less 2,175 MW in new capacity.

As Table 29 shows, conventional new entrants receive higher payments than they would under the current design. However, wind, pumped storage, and peaking plants (distillate, coal/oil, oil units) would experience declines in average payments. Removing the capacity credit and availability adjustments to the BNE guarantee, would result in significantly higher payments for new entrants across all technologies at the expense of existing generators. Existing generators on the other hand experience a decline of 14% in their revenues as shown in Table 29 with the exception of wind, interconnectors and pumped storage.

Table 29 – Capacity payments in € per available MWh under the new entrant scenario in 2008

Technology	New entrant guarantee € per MW	Capacity adjusted new entrant guarantee € per MW	Change, € per available MW vs. current CPM	% Change	Existing generator payments, € per available MW	Change, € per available MW vs. current CPM	% Change
DSU	9.08	17.02	1.87	12%	13.15	-2.00	-13%
PS Generating	9.08	9.20	-3.62	-28%	11.03	-1.79	-14%
Hydro	9.08	17.59	5.41	44%	10.69	-1.49	-12%
IC Imports	9.08	8.17	-2.72	-25%	9.26	-1.64	-15%
Peat	9.08	9.91	0.29	3%	8.28	-1.34	-14%
Distillate	9.08	9.19	-0.31	-3%	8.24	-1.26	-13%
Biogas	9.08	8.95	-0.54	-6%	8.22	-1.27	-13%
Coal	9.08	10.24	0.81	9%	8.10	-1.34	-14%
CCGT Gas	9.08	9.93	0.54	6%	8.09	-1.29	-14%
Other Gas	9.08	10.39	1.02	11%	8.07	-1.31	-14%
Oil	9.08	7.81	-1.54	-16%	8.06	-1.29	-14%
Coal / Oil	9.08	8.31	-1.05	-11%	8.03	-1.34	-14%
Wind	9.08	7.11	-2.06	-22%	7.13	-2.05	-22%
PS Pumping	-9.08	-5.36	-3.72	227%	-1.72	-0.08	5%
IC Exports	-9.08	-8.17	1.89	-19%	-8.82	1.24	-12%

Notes and sources: See Annex A for assumptions on AS payments per MWh. The level of payments depends on these assumptions, as such this example is meant only for illustrative purposes. We recognize that in the event that this scenario is adopted, that the final rates chosen by the RAs may be significantly different from these with different impacts on specific generators.

The link between capacity payments and system margin for existing generators in this scenario is similar to that in the re-balancing scenario for existing plants. However it is influenced by outturn level of new entry and whether we retain the capacity credit adjustment for new entrants or not. Higher levels of new entry without any adjustments would result in significantly smaller average payments for each level of system margin. This is because the residual pot once the new entrant guarantees have been paid out is allocated to existing generators under the re-balancing schedule of a 50:50 split between ex-post and ex-ante, and change in flattening power factor to 0.5.

The link between system margin and capacity payments for new entrants is mixed. The reliability adjustment ensures that firm plants are rewarded at higher rates than less firm generators, thus aligning payments with contribution to peak demand. However, other than the decline in energy payments, there is no additional risk for firms that fail to run when called upon or those that run at lower capacity since payments are based on installed capacity.

8.1.1.1 Capacity payments in future years

For new entrants, this scenario performs noticeably better than the existing design in 2020 compared to 2008, increasing the average payment per available MWh across most technologies. As Table 30 highlights, pumped storage and hydro in particular experience significant gains of over 100% compared to the status quo design.

Existing generators however experience declines in their payments except for the interconnector. The extent of the revenue decline depends on the level of new entry and profile of new entrants assumed and whether we make any reliability adjustments. Thus a larger assumption of new conventional capacity coming online would see a significant drop for most generators.

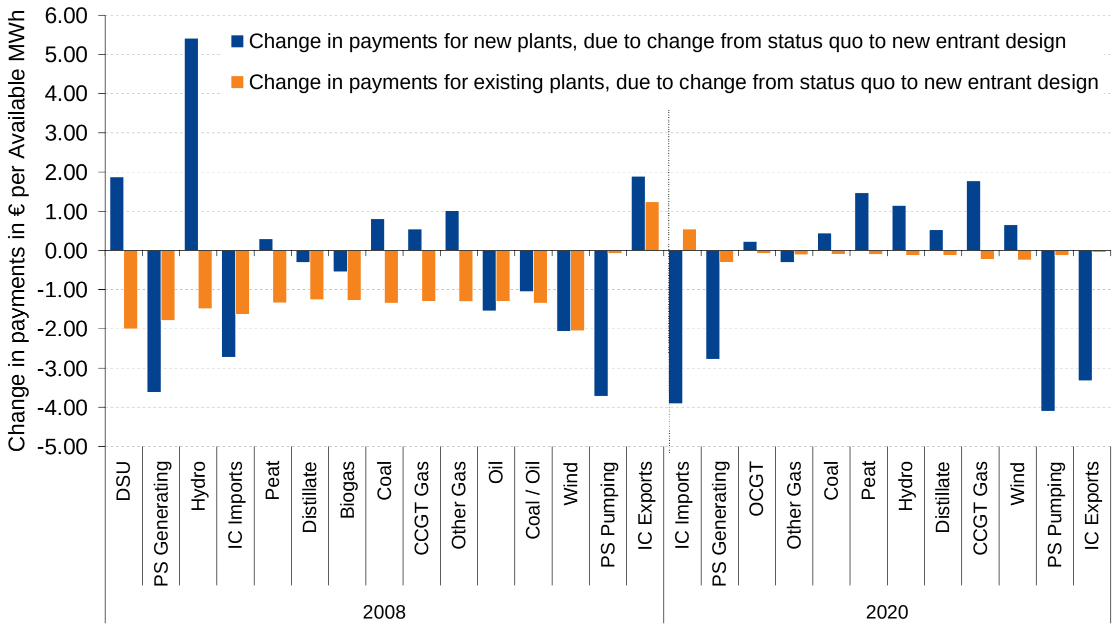
Table 30 – Capacity payments in € per available MWh under the new entrant scenario in 2020

Technology	New entrant guarantee € per MW	Capacity adjusted new entrant guarantee € per MW	Change, € per available MW vs. current CPM	% Change	Existing generator payments, € per available MW	Change, € per available MW vs. current CPM	% Change
IC Imports	9.08	8.17	-3.91	-32%	12.63	0.55	5%
PS Generating	9.08	6.98	-2.77	-28%	9.46	-0.30	-3%
OCGT	9.08	8.02	0.23	3%	7.70	-0.08	-1%
Other Gas	9.08	7.43	-0.31	-4%	7.62	-0.11	-1%
Coal	9.08	8.08	0.44	6%	7.54	-0.10	-1%
Peat	9.08	9.10	1.47	19%	7.53	-0.10	-1%
Hydro	9.08	8.74	1.15	15%	7.46	-0.13	-2%
Distillate	9.08	8.08	0.53	7%	7.43	-0.12	-2%
CCGT Gas	9.08	9.25	1.78	24%	7.25	-0.22	-3%
Wind	9.08	5.24	0.65	14%	4.35	-0.24	-5%
PS Pumping	-9.08	-6.98	-4.10	143%	-3.01	-0.13	4%
IC Exports	-9.08	-8.17	-3.33	69%	-4.89	-0.04	1%

8.1.2 *Distribution of payments across generators*

The performance of the new entrant scheme in distributing the capacity pot is mixed as Figure 38 shows. In 2008, with the exception of hydro and the interconnector, there is marginal re-distribution between technologies. However, in 2020, most conventional new entrants receive on average over €0.75 per available MWh higher than they would under the existing design in 2020. This is influenced by our assumption that new entrants receive in real terms the current equivalent BNE price adjusted by capacity credit in 2020. Existing generators on the other hand perform marginally worse than the current status quo in 2020, receiving less on a per MWh basis across all technologies except for interconnectors.

Figure 38 – Change in capacity payments, € per available MWh by technology due to change from status quo to the new entrant scenario in 2008, 2020 (for new plants and existing plants)



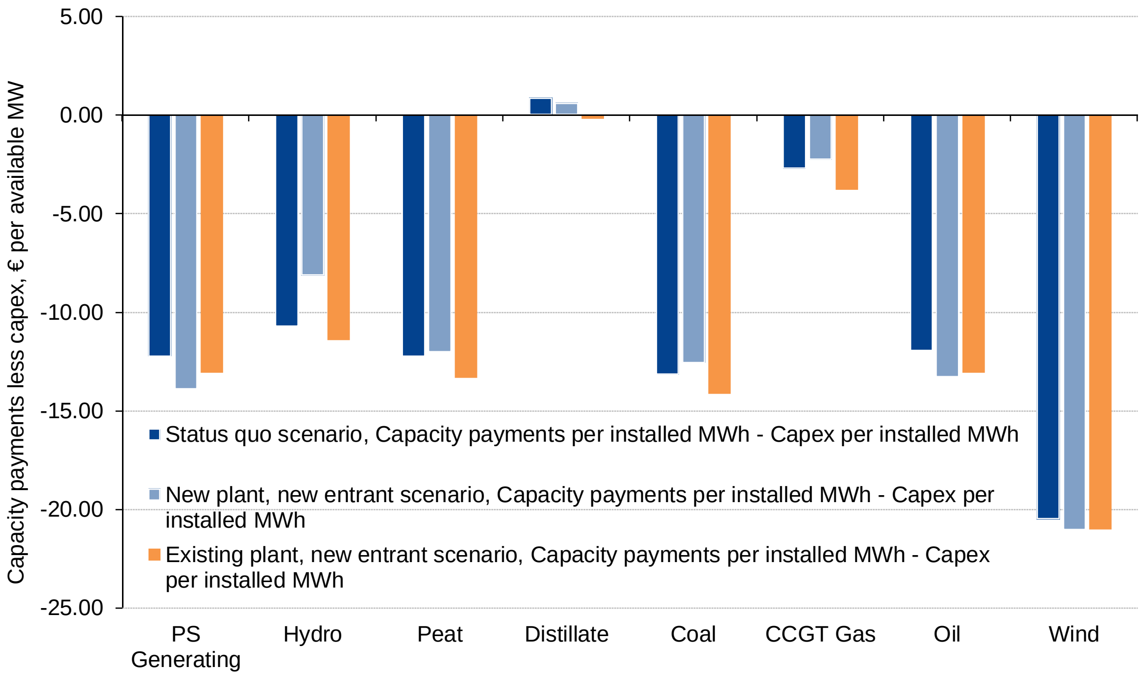
The experiences of this scenario suggests that so long as the number of new entrants is limited, this scenario is likely to perform significantly better at re-distributing available pot to new entrants and marginally worse for firm generators compared to the status quo. However any significant increase in new entry by default reduces the payments for existing generators, making them worse off compared to the status quo design.

8.1.3 Impact on entry and exit decisions

8.1.3.1 Capacity payments vs. fixed costs in 2008

Figure 39 shows the difference between capacity payments per installed MW and the estimated CAPEX per installed MW in 2008. In this scenario, an average CCGT plant with an installed capacity of 400MW will earn an estimated €26.07 million in capacity payments a year under the status quo design compared to estimated annualised CAPEX costs of €37 million. However new entrant CCGTs would receive an additional €1.5 million compared to the status quo while the existing CCGT plants would experience an estimated decline of €3.6 million in capacity payments.

Figure 39 – Difference between capacity payments and fixed costs (CAPEX) per installed MW under the status quo, new entrant scenarios in 2008



8.1.3.2 Impact of wind variability on investment signals

The impact of changes in wind generation is relatively limited under this scenario compared to all others. Increased wind generation is likely to reduce the level of energy payments available to conventional generators. However, for new entrants the provision of higher capacity payments compared to the status quo limits the overall impact on profitability as shown. In addition, for the duration of the guarantee, variations in wind has no impact on overall capacity payments since these are based on installed capacity on commissioning, adjusted for technology reliability and not on outturn plant availability.

For existing generators, the impact of wind is similar to that under the re-balancing scenario. Increased penetration of wind will reduce the already limited average capacity payment (after paying new entrant guarantee) and energy payments for generators affecting their overall profitability. Wind also increases the uncertainty of payments within any given year, further affecting their cost of capital. The variations are similar in profile to those experienced in the re-balancing scenario but with comparably smaller sums due to the smaller size of the overall pot.

8.1.4 Impact of new entrant scenario on interconnectors and DSUs

8.1.4.1 Interconnectors

Assuming that neither of the planned East West interconnector projects under consideration by EirGrid or Imera Power will be eligible for the new entrant payments, the impact of this scenario is largely similar to that of the re-balancing payments but with smaller amount of payments. The level of payments is dependent on the level of new capacity coming online. A larger increase in new capacity would likely result in an even larger decline in average capacity revenues, due to a proportionally larger decline in the residual ACPS pot.

The performance in 2020 and the impact of increased wind penetration and variability of wind is similar to that of the re-balancing scenario, pronounced only by the smaller average payment per MWh, the size of which depends on the volume of new capacity coming online.

8.1.4.2 Demand Side Units and Demand Side Management

The impact of the new entrant scenario on DSUs is more pronounced than that on interconnectors. New DSU units coming online could experience an increase of 1.87 per MWh or 12% increase in payments compared to the status quo.

The increased penetration of wind and its variability has similarly mixed implications. For new DSUs under the guarantee, variations in wind have no impact on capacity payments since these are based on installed capacity on commissioning, adjusted for technology reliability and not on outturn plant availability. For existing DSU units, variability of wind has similar impacts to that under the re-balancing scenario, but with greater relative effects due to the lower levels of payments.

8.2 Performance of the new entrant scenario

The new entrant scenario provides a mixed performance compared to the status quo. For new entrants, it provides reliable, certain payments even when adjusted for reliability. Thus in 2020, under this scenario, payments for most conventional generators would increase by 23-40%. This is ‘sufficient’ to improve the investment case for reliable generators and to boost the investment signals for new capacity at significantly higher rates compared to other scenarios reviewed in this report. For existing generators however this is a sub-optimal scenario as new entrants are likely to gain at their expense, which only gets worse in future years and depending on the extent of new entry.

The overall impact on reliability is mixed and could likely to worsen. New entrants’ payments are relatively certain. However, absent an availability penalty, this scenario diminishes their need to be available during system tightness, compared to the status quo. Moreover, decreased average capacity payments for all existing generators over time, could decrease their availability relative to their reliability under the status quo.

The scenario provides mixed performance on prices and on balance may increase instability. It provides significant certainty for new entrants for the period of guarantee; however for existing generators it increases uncertainty by adding an additional risk to capacity payments – the uncertainty of the size of the final pot due to annual changes, and the annual amount of guarantee, set-aside for new entrants. The risk is similarly higher for new entrants once they have exhausted their guarantee. As a result, the operation and design of the new entrant scheme entails the greatest regulatory risk across all options. Although it partially addresses the regulatory risk of the annual review of the ACPS for new entrants, it increases the risk for existing generators and for new entrants once they exhaust the guarantee. It would also require major changes to the SEM TSC.

The new entrant scenario may also increase the risk of gaming. If the level of new entrant guarantee is linked to system scarcity, there may be risk of withholding entry so as to increase the level of guarantee. Although the payment structure is simple and predictable for new entrants for the period of guarantee, it increases the level of uncertainty for existing generators who will need to estimate the set-aside for new entrants, in addition to the current uncertainties of the annual process.

The scenario's key weakness though is that introduces discrimination to the process as new entrants are treated differently from existing generators. The justification for the discrimination maybe tenuous since there are other less discriminatory ways of encouraging new entrants such as increasing the size of the capacity pot. On balance this scenario seems to perform significantly well for new entrants but is likely to deliver sub optimal results for the market as a whole compared to the status quo design. Table 31 summarises the comparisons in performance between the two scenarios.

Table 31 – Performance of the new entrant vs. the status quo scenarios

Reform option	Performance
Capacity adequacy	▪ The scenario improves adequacy by incentivising and providing certainty to new entrants. However depending on the size of the guarantee it could decrease payments to existing generators and increase premature exit.
System reliability	▪ The scenario's performance is mixed. The capacity adjusted new entrant guarantee ensures reliable generators are incentivised at a higher rate. However it is based on installed capacity and historic availability (thus may require a penalty clause to ensure plants are available when called upon). ▪ For reliable existing generators, the decreased payment as a result of the guarantee reduces their incentives, as does the diminished payments for new entrants once the guarantee is exhausted.
Efficient price signals for long term investments	▪ The new entrant guarantee provides a certain, predictable and (in a few cases) comparably large increment in average payments and is likely to incentivise new entry even in light of expected declines in energy revenues due to a higher penetration of wind. ▪ Lower revenues for existing generators and for new entrants (once they have exhausted the guarantee) could encourage inefficient exit in light of lower energy revenues in future years.

Price stability	▪ The scenario's performance is mixed. It provides significant certainty for new entrants for the period of guarantee; however for existing generators it increases uncertainty by adding an additional risk to capacity payments (the annual amount of guarantee). It also increases the risk for new entrants once they have exhausted their guarantee.
Fairness	▪ The scenario discriminates in favour of new entrants. The justification is debatable since there are other less discriminatory ways of encouraging new entrants such as increasing the size of the ACPS pot.
Simplicity	▪ The payment structure is simple and predictable for new entrants for the period of guarantee. However, it increases the level of uncertainty for existing generators who will need to estimate the set-aside for new entrants, in addition to the current uncertainties of the annual process.
Susceptibility to gaming	▪ The risk of gaming remains unchanged compared to the status quo. However, if the level of the new entrant guarantee is linked to system scarcity, there could be a risk of withholding entry so as to increase the level of the guarantee.
Regulatory risk	▪ The operation and design of the new entrant scheme entails the greatest regulatory risk across all options. It would require major changes to the SEM Trading and Settlement Code. ▪ It partially addresses the regulatory risk of the annual review of the ACPS for new entrants but not for existing generators.

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9. CONCLUSIONS AND RECOMMENDATIONS

The reform options considered in this report address some of the main shortcomings of the current CPM design. All four major scenarios, developed and reviewed strengthen the link between capacity payment and scarcity compared to the status quo, providing higher levels of payment during periods of minimum system capacity. However, the improved efficiency of the capacity price signal is at the expense of increased price volatility across all four options.

The four scenarios to varying degrees also change the distribution of capacity payments across generator types in favour of those generators likely to be available during system tightness. The performance of the new entrant scenario however is mixed. It provides improved certainty and levels of payments for new entrants for the period of guarantee but decreases the aggregate level of payments for most existing generators thereby increasing the risk of exit.

With the exception of the new entrant scenario, none of packages address the uncertainty in future payments due to annual changes to BNE price and the capacity requirement. In addition, none of the packages directly address concerns over the level of exit inefficiencies particularly with regards to plants with low load factors which are unavailable when called to run and are not adequately penalised. The re-balancing which underpins all scenarios however increases the level of ex-post payments and thus increases the financial costs of not being available. Other changes such as an appropriately defined penalty mechanism could be considered as an add-on to any of the reform packages.

The reform options also improve the performance of the CPM relative to the current design in light of anticipated increased penetration of wind in future years. However, assuming as our analysis does that the capacity pot increases at the same rate as demand, then the level of capacity payments per available MWh declines significantly in 2020 compared to 2008 under all four scenarios. This suggests that the capacity pot may need to rise at a higher rate than the change in demand to provide the same level of support that it currently does. Moreover as noted, in light of declining energy revenues across all generators, the ACPS pot may need to increase at an even higher rate to enable conventional plants to recover their fixed costs in future years.

The analysis presented thus suggests that there is a need to make changes that improve the current design as all four options do, while limiting the downsides of doing so. In this section, we summarise the results of all four reform options, reviewing and comparing them against the status quo. The framework for comparison is the assessment criteria developed and agreed with the RAs set out in Section 2 and Annex B. This is based on:

- performance against the objectives set forth in the SEM; and
- performance against the objectives of the regulatory agencies.

Table 32 provides a high level summary across all four scenarios.

Table 32 – Comparisons of reform packages with the status quo mechanism

Assessment criteria	Rebalancing scenario	Capacity credit scenario	New entrant scenario	Payments for flexibility
Capacity adequacy	=	=	✓	✓
Reliability of the system	✓	✓	×	✓
Price stability	×	×	✓NewGen ×ExGen	×
Simplicity	=	×	×	×
Efficient price signals for long term investments	✓	✓	✓	✓
Susceptibility to gaming	=	=	=	?
Fairness	=	=	×	=
Minimise regulatory risks	=	×	×	=

Key	Better	Same	Worse
	✓	=	×

Notes: ExGen refers to existing plants, while NewGen refers to new entrants under the new entrant scenario.

On the basis of the simple comparative metric presented, the re-balancing scenario seems to perform better than all other scenarios in meeting the broad objectives of the CPM at the lowest risk. It is likely to lead to improvements in the reliability of the system, and more efficient price signals for long term investments. It meets all other objectives at the same level as the status quo design. The main weakness of this package is that while it improves payments across all non-wind technologies, and meets or exceeds most objectives, the incremental payments or improvements are small compared to other packages. It also leads to increased price volatility and decreasing predictability of payments.

The remainder of the packages are all extensions of the re-balancing mechanism, with improved features addressing specific concerns. The capacity credit scenario for instance leads to improvements in system reliability and more efficient price signals for long term investments relative to the status quo. It meets most other objectives at the same level as the status quo, but increases the complexity and regulatory risk (as it entails developing a new set of inputs (capacity credits) which would be subject to industry consultation and regulatory approval. It would also lead to increased price volatility and decreasing predictability of payments.

The flexibility payment scenario scores well on improving capacity adequacy, system reliability and more efficient price signals for long term investments relative to the status quo. However it too leads to increased price volatility and decreasing predictability of payments. It also simply ‘outsources’ the complexity and risks of designing the right type and amount of flexibility products to the AS mechanism.

The new entrant scenario leads to an improvement in capacity adequacy and efficient price signals for long term investments compared to the status quo. However, while it partially addresses the regulatory risk of the annual review of the ACPS for new entrants it increases the level of risk for existing generators. It would require major changes to the SEM Trading and Settlement Code. It also actively discriminates in favour of new entrants and would significantly increase the complexity of the CPM.

9.1 Recommendations

There is a major trade-off between various CPM objectives particularly the efficiency of price signals and price volatility. Improved efficiency of capacity price signals increases the volatility of price and by implication diminishes the predictability of payments, and increases risk and uncertainty for investors. To the extent that efficiency of signals is a higher priority to the SEM, the re-balancing scenario seems to provide improved efficiency without significantly increasing the volatility of prices.

The remaining packages analysed build on the re-balancing scenario. The capacity credit scenario can be viewed as a further extension of the re-balancing scenario, providing improved efficiency but at the expense of increasing complexity, regulatory risk, price volatility and decreasing predictability of payments. Similarly, the flexibility payments scenario improves flexibility in the system but, depending on its design could result in increased complexity, price volatility and decreasing predictability of payments.

The new entrant scenario provides significantly improved incentives for new build; however it increases the risk of exit for existing generators. It is also the most complex of the reform packages, with the highest level of regulatory risk and other costs outlined and should be considered with reservations.

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ANNEX A – CPM BACKGROUND

A.1 The Rationale for a Capacity Payment Mechanism

The Capacity Payment Mechanism (CPM) was introduced as part of the SEM in November 2007. The main rationale for its establishment was to encourage provision of adequate capacity. Unlike most other commodity markets, in the event that aggregate supply falls short of demand, it is difficult to discriminate between customers of a supplier fully able to serve its load, from customers of a supplier that fails to meet its obligations. This is due to the fact that demand for electricity is not responsive to price in the short-run, and the consequences of shortages are shared in a way that has nothing to do with a customer or a supplier having arranged an adequate supply. Moreover, physical rationing is the only method for balancing supply and demand in the operating time frame. Although this is true in all electricity markets, a further complication within the SEM is the size of the market and the impact which the addition of a single conventional-sized generator would have on market prices, and the desire to manage price volatility. Ireland has on several occasions in the recent past needed to procure capacity outside the normal operation of the wholesale market, underwritten by the Public Service Obligation, including the award of the Capacity and Differences Agreement (CADA) contracts for Tynagh and Aughinish and the lease and later purchase of 200MW of peaking generation.

As a result, the Regulatory Authorities (RAs) saw a need for a separate mechanism outside of energy price to incentivise delivery of adequate capacity, and of the right type to meet an acceptable level of reliability, defined as an acceptably low level of Loss of Load Probability (LOLP).

The theory of electricity pricing suggests that even in an energy-only market, the price in each period reflects a combination of the short-run marginal cost of generation and the likelihood that there will be insufficient capacity to meet demand and the cost to consumers in this event. Thus a separation of capacity and energy payments is not a market 'intervention' but simply a recognition that these two sources of value should be rewarded separately.

Economic theory states that in competitive markets, providers of the same product or service should receive the same price. In energy-only markets, it can be argued that generators which are available to meet demand but not actually operating are providing capacity for which they are not being paid.

Capacity payments are a feature of many electricity markets although the norm in Europe is for energy-only arrangements, with some contracting by the system operator for reserve capacity. As markets adapt to accept more wind and intermittent generation, the relative cost of providing peak capacity compared to the cost of delivering energy is expected to change, resulting in a need for more low-load factor generation and – dependent on the regulatory regime – higher price volatility. Regulators and policy makers across Europe are now considering the introduction of capacity payments.

Energy-only markets rely on price to signal the need for capacity investments. As a result, energy-only markets can produce very volatile short-term prices or extreme price spikes when more capacity is needed resulting in unacceptable economic impacts for consumers and investors. The CPM was designed to provide a separate remuneration for capacity and therefore to limit the volatility in energy prices. In doing so, it allows the SEM to minimise end-user risk and ensures that prices are not so volatile that it becomes an overbearing risk to investment and that these can be predicted to a reasonable level. In addition such a system would ensure stability of the market for investment and thus providing efficient signals for long term investments in new capacity.

From an administrative point of view, the design of the CPM was also intended to be simple and transparent with a payment structure that is easy to understand; and fair – one that treats all types of generators fairly on a non-discriminatory basis. The intention is that such a design would not encourage behaviour that gives individual generators an advantage at the cost to the system as a whole or be susceptible to gaming but would instead encourage new entrants, price stability and promote competition.

A.1.1.1 Derivation and calculation of capacity payments

The annual capacity payments sum (ACPS) is calculated as the product of the annual cost of a peaking plant established from the annualised fixed costs of a Best New Entrant, and the capacity requirement calculated as the sum of the installed capacity and deficit or surplus required to meet the all-island generation security standard.

The annual pot resulting from the product of these two variables is divided into monthly pots weighted by peak to trough demand with a larger sum going to months with higher levels of demand. Each monthly pot is in turn divided into three pots which are allocated to generators. These are:

- a fixed ex-ante component, consisting of 30% of the total;
- a variable ex-ante component consisting of 40% of the total; and
- an ex-post component consisting of 30% of the total.

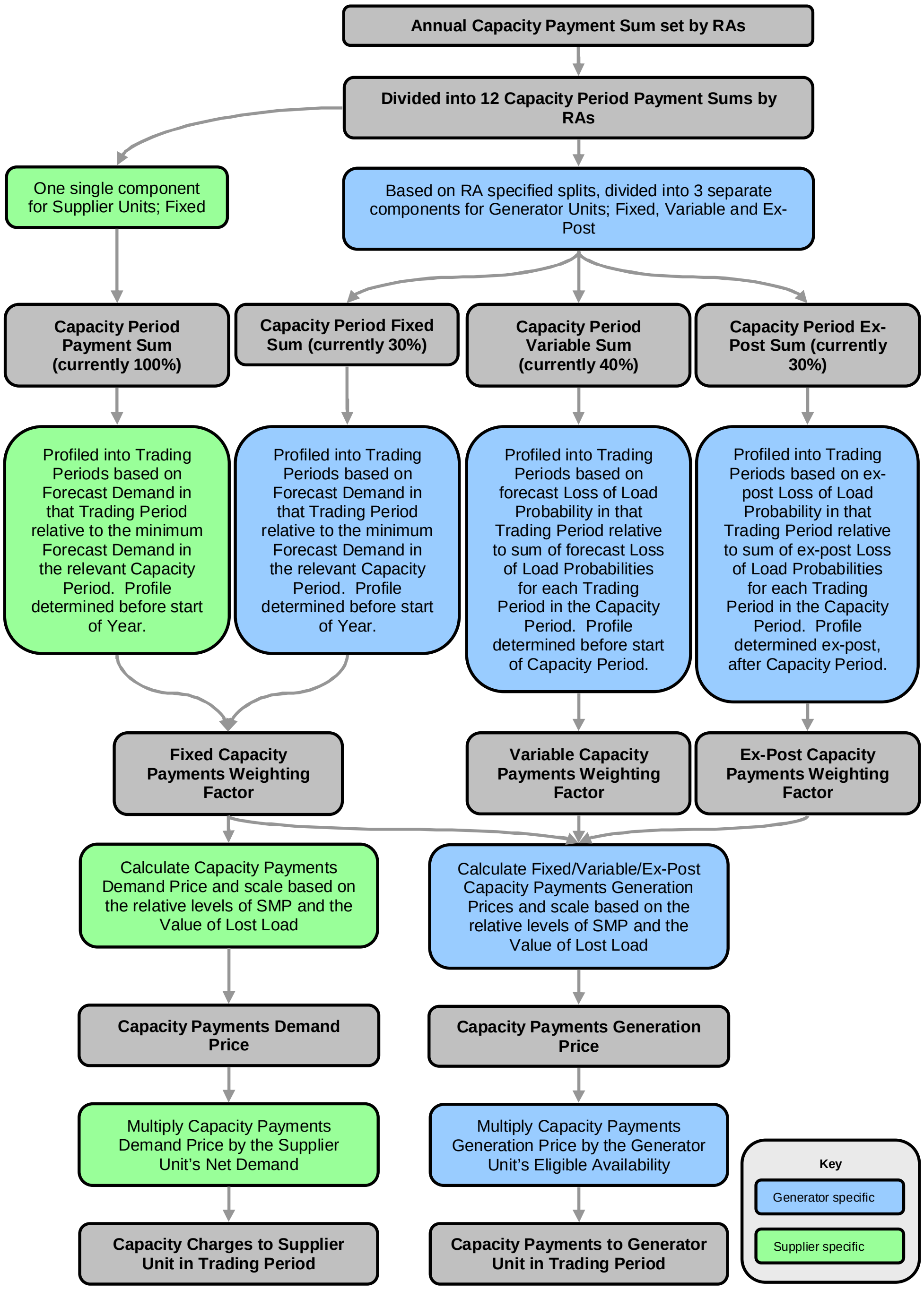
Of the monthly pot constituents, the fixed ex-ante payment is intended to provide certainty to generators; however it provides weak incentives to respond to shortages. The variable ex-ante constituent is calculated before each month and provides additional certainty for generators and improves forecast of likely shortages. However it too has limited response to forecast shortages which are not forecast. Finally the ex-post constituent provides a short term responsive incentive but the payment incidence is uncertain. Thus up to 70% of the payments are determined in advance as an ex-ante signal for capacity, with the remainder of capacity payments made to generators based on their outturn availability in each half hour (with adjustment for transmission losses).

The variable ex-ante and the ex-post capacity payments are linked to the system margin via a Loss of Load Probability (LOLP) curve. The system margin is the difference between eligible availability and demand in any one period and is a measure of security of supply. The LOLP curve is used as a proxy of the relationship between the margin and the security of the system and is used to weight capacity payments in each trading period. It is calculated annually. In the current design of the CPM, a Flattening Power Factor (FPF) is applied to the Loss of Load Probability curve. FPF shapes the LOLP curve to make it either 'steep' or 'flat'. Its purpose is to reduce volatility in the capacity payments mechanism. The FPF can be used to change the balance between retaining sufficient volatility to signal the need for availability in times of low margin and avoiding excessive volatility that would render the mechanism excessively unpredictable.

The application of a fixed annual capacity value rather than calculating a value in each trading period independently means that in any year there may be a divergence between the total payments for capacity and the economically 'efficient' level of payments in that year. This was a deliberate choice by the RAs to ensure year-on-year price stability. In addition, within the year, the distribution of capacity payments between periods is expected to diverge from the economically efficient level due to the application of the monthly totals and the fixed and ex-ante elements of price. This reduces the extent of price volatility between periods. However, to the extent that the volatility of capacity prices are damped compared with the true LOLP, then capacity prices will be too low at the times of tightest capacity margin, and too high outside these times.

The ACPS is paid for by capacity charges levied on suppliers based on their metered consumption in each half hour and reflect their proportion of total consumption. A summary of the methodology by which capacity payments are derived and funded is summarised in simplified form in Figure 40.

Figure 40 – Derivation of capacity payments and capacity charges in the SEM



A.2 Trading and Settlement Code CPM Algebra

Eligible availability for capacity payments

The values of Eligible Availability (EAuh) for use within the determination of Capacity Payments will be taken from the values of Availability Profile (APuh), which are calculated by the Market Operator from Availability data submitted by the relevant System Operator. The Market Operator shall calculate the values of Availability Profile (APuh) in relation to the Availability of the Generator Unit without consideration of access limitations. The Market Operator shall calculate the Eligible Availability (EAuh) for each Generator Unit u in Trading Period h as follows:

$$EAuh = APuh$$

Where

1. APuh is the Availability Profile for Generator Unit u in Trading Period h.

Parameters for the determination of Capacity Payments and Capacity Charges

No later than four months before the start of the first Capacity Period in each Year, the Regulatory Authorities shall consider and shall determine values, which will then be made available to the Market Operator, for the following parameters for the calculation of Capacity Payments and Capacity Charges for that Year:

2. Annual Capacity Payment Sum (ACPSy);
3. Capacity Period Payment Sum (CPPSc) for each Capacity Period, such that the total of Capacity Period Payment Sums over the Year is equal to the Annual Capacity Payment Sum (ACPSy);
4. Fixed Capacity Payments Proportion (FCPPy), such that 0 ≤ FCPPy ≤1;
5. Ex-Post Capacity Payments Proportion (ECPPy), such that 0 ≤ ECCPy ≤ (1-FCPPy); and
6. The Value of Lost Load (VOLL).

The Market Operator shall make a report to the Regulatory Authorities at least four months before the start of the Year and in advance of the first Capacity Period in each Year, proposing a value for the following parameter for that Year:

1. the Annual Capacity Exchange Rate (ACERy).

The Market Operator's report must set out any relevant research or analysis carried out by the Market Operator and any justification for the specific values proposed. Such a report may, and shall, if so requested by the Regulatory Authorities, include alternative values from those proposed and must set out the arguments for and against such alternatives.

The Market Operator shall publish the approved value(s) for each of the parameters set out in paragraphs 4.95 and 4.96 within 5 Working Days of receipt of the Regulatory Authorities' determination or two months before the start of the Year to which they shall apply whichever is the later.

Basis for Capacity Payments and Capacity Charges

The Market Operator shall procure that Capacity Payments shall be made in respect of each Generator Unit on the basis of its Loss-Adjusted Eligible Availability in each Trading Period as set out algebraically below.

The Market Operator shall procure that Capacity Charges shall be levied in respect of Loss-Adjusted Net Demand at each Supplier Unit in each Trading Period as set out algebraically below.

The System Operator shall calculate prior to the start of each Capacity Period the Loss of Load Probability (λh) in each Trading Period h of that Capacity Period. The calculation methodology is set out in Appendix M "Description of the Function for the Determination of Capacity Payments".

The Market Operator shall calculate the Ex-Post Loss of Load Probability (Φh) in each Trading Period h, in accordance with the Settlement Calendar. The relevant calculation methodology is set out in Appendix M "Description of the Function for the Determination of Capacity Payments".

The Market Operator shall calculate prior to the start of the first Capacity Period in each Year the Annual Combined Load Forecast (ACLFh) in each Trading Period h (based on the Annual Load Forecast Data) as set out in paragraph 4.32.

Calculation of Capacity Payments

The Capacity Period Payment Sum (CPPSc) shall be divided into the Capacity Period Fixed Sum (CPFSc), the Capacity Period Variable Sum (CPVSc) and the Capacity Period Ex-Post Sum (CPESc) within each Capacity Period c, using the Fixed Capacity Payments Proportion (FCPPy) and the Ex-Post Capacity Payments Proportion (ECPPy) as follows:

$$CPFSc = CPPSc \times FCPPy$$

$$CPESc = CPPSc \times ECPPy$$

$$CPVSc = CPPSc \times (1 - (FCPPy + ECPPy))$$

Where

1. CPPSc is the Capacity Period Payment Sum in Capacity Period c;
2. FCPPy is the Fixed Capacity Payments Proportion for Year y;
3. ECPPy is the Ex-Post Capacity Payments Proportion for Year y.

For each Trading Period h within Capacity Period c, the Market Operator shall calculate a Fixed Capacity Payments Weighting Factor (FCPWFh) prior to the start of the first Capacity Period in the Year based on the relative values of Annual Combined Load Forecast (ACLFh) as follows:

$$if \sum_{h\ in\ c} (ACLF_h - MinACLFc) > 0 \ \ then$$

$$FCPWFh = \frac{ACLF_h - MinACLFc}{\sum_{h\ in\ c}(ACLF_h - MinACLFc)}$$

$$else \ \ FCPWFh = \frac{1}{Number of\ Trading Periods\ in\ Capacity Period}$$

Where

1. ACLFh is the Annual Combined Load Forecast for Trading Period h determined by the Market Operator;
2. MinACLFc is the minimum value of ACLFh in any Trading Period h within Capacity Period c;

$\sum_{h\ in\ c}(ACLF_h - MinACLF_c)$ is a summation over all Trading Periods h in Capacity Period c.

For each Trading Period h within the Capacity Period, the Market Operator shall calculate a Variable Capacity Payments Weighting Factor (VCPWFh) prior to the start of the relevant Capacity Period based on the relative values of the Loss of Load Probability in Trading Period h (λh) as follows:

$$if \sum_{h\ in\ c} \lambda_h > 0\ \ then$$

$$VCPWFh = \frac{\lambda_h}{\sum_{h\ in\ c} \lambda_h},$$

$$else\ \ VCPWFh = \frac{1}{Number\ of\ Trading\ Periods\ in\ Capacity\ Period}$$

Where

1. λh is the Loss of Load Probability in Trading Period h determined as set out in Appendix M "Description of the Function for the Determination of Capacity Payments";
2. $\sum_{h\ in\ c}$ is a summation over all Trading Periods h in Capacity Period c.

For each Trading Period h within Capacity Period c, an Interim Ex-Post Capacity Payments Weighting Factor (IECPWFh) shall be calculated based on the relative values of the Interim Ex-Post Loss of Load Probability (IΦh) as follows:

$$if \sum_{h\ in\ c} I\phi_h > 0\ \ then$$

$$IECPWFh = \frac{I\phi_h}{\sum_{h\ in\ c} I\phi_h},$$

$$else\ \ IECPWFh = \frac{1}{Number\ of\ Trading\ Periods\ in\ Capacity\ Period}$$

Where

1. IΦh is the Interim Ex-Post Loss of Load Probability in Trading Period h determined as set out in Appendix M "Description of the Function for the Determination of Capacity Payments";
2. $\sum_{hinc}$ is a summation over all Trading Periods h in Capacity Period c.

For each Trading Period h within the Capacity Period c, the Market Operator shall calculate an Ex-Post Capacity Payments Weighting Factor (ECPWFh) based on the relative values of the Ex-Post Loss of Load Probability in Trading Period h (Φh) as follows:

$$if \sum_{h\,in\,c} \phi_h > 0 \;\; then$$

$$ECPWFh = \frac{\phi_h}{\sum_{h\,in\,c} \phi_h},$$

$$else \;\; ECPWFh = \frac{1}{Number\,of\;Trading\;Periods\;in\;Capacity\;Period}$$

Where

1. Φh is the Ex-Post Loss of Load Probability in Trading Period h determined as set out in Appendix M "Description of the Function for the Determination of Capacity Payments";
2. summation $\sum_{h\,in\,c}$ is over all Trading Periods h in Capacity Period c.

For each Trading Period h within the Capacity Period c, a Capacity Payments Price Factor (CPPFh) shall be calculated to scale Capacity Payments for Demand and scheduled generation based on the level of System Marginal Price (SMPh) and the Value of Lost Load (VOLL) as follows:

$$CPPFh = Max\left\{\left(\frac{(VOLL - SMPh)}{VOLL}\right), 0\right\}$$

Where

1. SMPh is the System Marginal Price in Trading Period h;
2. VOLL is the Value of Lost Load.

Capacity Payments in Respect of Generator Units

Capacity Payments shall be determined for each Generator Unit in each Trading Period as set out in this Section 4 and paid to the relevant Participant as a separate payment in each Capacity Period according to the procedures set out in Section 6.

The Loss-Adjusted Capacity Payments Eligible Availability (CPEALFuh) for each Generator Unit u in each Trading Period h shall be calculated as follows:

$$CPEALFuh = TPD \times EALFuh$$

Where

1. TPD is the Trading Period Duration;
2. EALFuh is the Loss-Adjusted Eligible Availability for Capacity Payments for Generator Unit u in Trading Period h.

Capacity Payments Generation Price Factor

Capacity Payments for Generator Units shall be calculated as set out below.

For Generator Units u in respect of which Participants submit Prices as part of their Commercial Offer Data, then for each Accepted Price Quantity Pair i which is applicable in Trading Period h, the Unscheduled Capacity Offer Quantity (UCOQuhi) and Unscheduled Capacity Offer Price (UCOPuhi) shall be calculated as follows:

$$UCOPuhi = Max\{SMPh, Puhi\}$$

$$UCOQuhi = Min\{EAuh, Max\{Quhi, MSQuh\}\} - Min\{EAuh, Max\{Quh(i-1), MSQuh\}\}$$

Where

1. SMPh is the System Marginal Price in Trading Period h;
2. Puhi is the ith Price for Generator Unit u which is applicable in Trading Period h;
3. Quhi is the ith Quantity for Generator Unit u which is applicable in Trading Period h;
4. Quh(0) is defined as the Minimum Output (MINOUTuh) for Generator Unit u in Trading Period h;
5. EAuh is the Eligible Availability for Generator Unit u in Trading Period h;
6. MSQuh is the Market Schedule Quantity for Generator Unit u in Trading Period h.

For any Generator Unit u for which the relevant Participant is not required to submit Prices as part of its Commercial Offer Data for any Trading Period h, all values of Unscheduled Capacity Offer Quantity (UCOQuhi) will be calculated by the Market Operator to be zero.

The Capacity Payments Generation Price Factor (CPGPFuh) shall be determined for each Generator Unit u in Trading Period h as follows:

$$if \ \left(MSQuh + \sum_i UCOQuhi\right) \neq 0, then$$

$$CPGPFuh = \frac{\left((MSQuh \times CPPFh) + \sum_i \left(UCOQuhi \times Max\left\{ \frac{VOLL - UCOPuhi}{VOLL}, 0 \right\} \right) \right)}{MSQuh + \sum_i UCOQuhi}$$

$$else \ CPGPFuh = 0$$

Where

1. MSQuh is the Market Schedule Quantity for Generator Unit u in Trading Period h;
2. CPPFh is the Capacity Payments Price Factor for Trading Period h in the Capacity Period c;
3. $\sum_i$ is a summation over all Accepted Price Quantity Pairs i for Generator Unit u which are applicable in Trading Period h;

4. UCOQuhi is the Unscheduled Capacity Offer Quantity for Generator Unit u, for Price Quantity Pair i which is applicable in Trading Period h;
5. UCOPuhi is the Unscheduled Capacity Offer Price for Generator Unit u, for Price Quantity Pair i which is applicable in Trading Period h;
6. VOLL is the Value of Lost Load.

Fixed Capacity Payments Generation Price Calculations

For each Capacity Period c, the Capacity Period Fixed Generation Scaling Price (CPFGSPc) shall be calculated by the Market Operator as follows:

$$if \sum_{u,h\,in\,c}(CPEALFuh \times FCPWFh \times CPGPFuh) > 0 \;\; then$$

$$CPFGSPc = \frac{CPFSc}{\sum_{u,h\,in\,c}(CPEALFuh \times FCPWFh \times CPGPFuh)}$$

$$else \quad CPFGSPc = 0$$

Where

1. CPFSc is the Capacity Period Fixed Sum in Capacity Period c;
2. CPEALFuh is the Loss-Adjusted Capacity Payments Eligible Availability for Generator Unit u in Trading Period h;
3. FCPWFh is the Fixed Capacity Payments Weighting Factor in Trading Period h;
4. CPGPFuh is the Capacity Payments Generation Price Factor for Generator Unit u in Trading Period h;
5. the summation $\sum_{u,h\,in\,c}$ is a summation over all Generator Units u, and across all Trading Periods h within Capacity Period c.

For each Trading Period h within Capacity Period c, the Fixed Capacity Payments Generation Price (FCGPh) shall be calculated by the Market Operator as follows:

$$FCGPh = FCPWFh \times CPFGSPc$$

Where

1. FCPWFh is the Fixed Capacity Payments Weighting Factor in Trading Period h;
2. CPFGSPc is the Capacity Period Fixed Generation Scaling Price in Capacity Period c.

Variable Capacity Payments Generation Price Calculations

For each Capacity Period c, the Capacity Period Variable Generation Scaling Price (CPVGSPc) shall be calculated by the Market Operator as follows:

$$if \sum_{u,h\,in\,c}(CPEALFuh \times CPGPFuh \times VCPWFh) > 0 \;\; then$$

$$CPVGSPc = \frac{CPVSc}{\sum_{u,h\ in\ c}(CPEALFuh \times VCPWFh \times CPGPFuh)}$$

$$else \quad CPVGSPc = 0$$

Where

1. CPVSc is the Capacity Period Variable Sum in Capacity Period c;
2. CPEALFuh is the Loss-Adjusted Capacity Payments Eligible Availability for Generator Unit u in Trading Period h;
3. VCPWFh is the Variable Capacity Payments Weighting Factor in Trading Period h;
4. CPGPFuh is the Capacity Payments Generation Price Factor for Generator Unit u in Trading Period h;
5. the summation $\sum_{u,h\,in\,c}$ is a summation over all Generator Units u, and across all Trading Periods h within Capacity Period c.

For each Trading Period h within Capacity Period c, the Variable Capacity Payments Generation Price (VCGPh) shall be calculated by the Market Operator as follows:

$$VCGPh = VCPWFh \times CPVGSPc$$

Where

1. VCPWFh is the Variable Capacity Payments Weighting Factor in Trading Period h;
2. CPVGSPc is the Capacity Period Variable Generation Scaling Price in Capacity Period c.

Ex-Post Capacity Payments Generation Price Calculations

For each Capacity Period c, the Capacity Period Ex-Post Generation Scaling Price (CPEGSPc) shall be calculated by the Market Operator as follows:

$$if \sum_{u,h\,in\,c}(CPEALFuh \times CPGPFuh \times ECPWFh) > 0 \;\; then$$

$$CPEGSPc = \frac{CPESc}{\sum_{u,h\ in\ c}(CPEALFuh \times ECPWFh \times CPGPFuh)}$$

$$else \quad CPEGSPc = 0$$

Where

1. CPESc is the Capacity Period Ex-Post Sum in Capacity Period c;
2. CPEALFuh is the Loss-Adjusted Capacity Payments Eligible Availability for Generator Unit u in Trading Period h;

3. ECPWFh is the Ex-Post Capacity Payments Weighting Factor in Trading Period h;
4. CPGPFuh is the Capacity Payments Generation Price Factor for Generator Unit u in Trading Period h;
5. the summation $\sum_{u,h\,in\,c}$ is a summation over all Generator Units u, and across all Trading Periods h within Capacity Period c.

For each Trading Period h within Capacity Period c, the Ex-Post Capacity Payments Generation Price (ECGPh) shall be calculated by the Market Operator as follows:

$$ECGPh = ECPWFh \times CPEGSPc$$

Where

1. ECPWFh is the Ex-Post Capacity Payments Weighting Factor in Trading Period h;
2. CPEGSPc is the Capacity Period Ex-Post Generation Scaling Price in Capacity Period c.

Capacity Payments Generation Price Calculations

The Capacity Payments Generation Price (CPGPh) shall be calculated by the Market Operator for each Trading Period h as follows:

$$CPGPh = (VCGPh + FCGPh + ECGPh) \times CPPFh$$

Where

1. VCGPh is the Variable Capacity Payments Generation Price in Trading Period h;
2. FCGPh is the Fixed Capacity Payments Generation Price in Trading Period h;
3. ECGPh is the Ex-Post Capacity Payments Generation Price in Trading Period h;
4. CPPFh is the Capacity Payments Price Factor in Trading Period h.

Capacity Payments Calculations

The Capacity Payment (CPuh) for each Generator Unit u in Trading Period h shall be calculated by the Market Operator as follows:

$$if\ CPPFh \neq 0\ \ then$$

$$CPuh = CPGPh \times CPEALFuh \times \left(\frac{CPGPFuh}{CPPFh}\right)$$

$$else \quad CPuh = CPGPFuh \times CPEALFuh \times (VCGPh + FCGPh + ECGPh)$$

Where

1. CPPFh is the Capacity Payments Price Factor in Trading Period h;
2. CPGPh is the Capacity Payments Generation Price in Trading Period h;

3. CPEALFuh is the Loss-Adjusted Capacity Payments Eligible Availability for Generator Unit u in Trading Period h;
4. CPGPFuh is the Capacity Payments Generation Price Factor for Generator Unit u in Trading Period h;
5. VCGPh is the Variable Capacity Payments Generation Price in Trading Period h;
6. FCGPh is the Fixed Capacity Payments Generation Price in Trading Period h;
7. ECGPh is the Ex-Post Capacity Payments Generation Price in Trading Period h.

The Capacity Period Payment (CPPuc) for each Generator Unit u in each Capacity Period c shall be calculated by the Market Operator as follows:

$$CPPuc = \sum_{h \text{ in } c} CPuh$$

Where

1. CPuh is the Capacity Payment for Generator Unit u in Trading Period h;
2. the summation $\sum_{h \text{ in } c}$ is over all Trading Periods h in Capacity Period c.

Capacity Charges

Capacity Charges shall be levied by the Market Operator on a Participant in respect of its Supplier Units in each Trading Period according to the procedures set out below.

For each Capacity Period c, the Capacity Period Demand Scaling Price (CPDSPc) shall be calculated by the Market Operator as follows:

$$if \sum_{v,h in c} (NDLFvh \times FCPWFh \times CPPFh) \neq 0 \;\; then$$

$$CPDSPc = \frac{CPPSc}{\sum_{v,h \text{ in } c} (NDLFvh \times FCPWFh \times CPPFh)}$$

$$else \; CPDSPc = 0$$

Where

1. CPPSc is the Capacity Period Payment Sum in Capacity Period c;
2. NDLFvh is the Loss-Adjusted Net Demand of Supplier Unit v in Trading Period h;
3. FCPWFh is the Fixed Capacity Payments Weighting Factor in Trading Period h;
4. CPPFh is the Capacity Payments Price Factor in Trading Period h;

5. the summation $\sum_{v,h\,in\,c}$ is over all Trading Periods h in Capacity Period c and over all Supplier Units v.

The Capacity Payments Demand Price (CPDPh) shall be calculated by the Market Operator for each Trading Period h as follows:

$$CPDPh = FCPWFh \times CPDSPc \times CPPFh$$

Where

1. FCPWFh is the Fixed Capacity Payments Weighting Factor in Trading Period h;
2. CPDSPc is the Capacity Period Demand Scaling Price in Capacity Period c;
3. CPPFh is the Capacity Payments Price Factor in Trading Period h.

Capacity Charge Calculations

The Capacity Charge (CCvh) for each Supplier Unit v in Trading Period h shall be calculated by the Market Operator as follows:

$$CCvh = CPDPh \times NDLFvh$$

Where

1. CPDPh is the Capacity Payments Demand Price in Trading Period h;
2. NDLFvh is the Loss-Adjusted Net Demand at Supplier Unit v in Trading Period h.

The Capacity Period Charge (CPCvc) for each Supplier Unit v in each Capacity Period c shall be calculated by the Market Operator as follows:

$$CPCvc = \sum_{h\ in\ c} CCvh$$

Where

1. CCvh is the Capacity Charge for Supplier Unit v in Trading Period h;
2. the summation $\sum_{h\ in\ c}$ is over all Trading Periods h in Capacity Period c.

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ANNEX B – PERFORMANCE INDICATORS

We have developed an assessment criteria, agreed with the RAs and used to compare the performance of the current CPM design against the benchmarks and against other alternative reform options. The criteria consists of metrics based on:

- Performance against the CPM objectives set forth in the SEM's Trading and Settlement Code (TSC), i.e. providing capacity adequacy or reliability of the system, price stability, simplicity, minimal susceptibility to gaming, fairness and efficient price signals for long term investments, and the impact on customers.
- Performance against the objectives of the regulatory agencies CER and NIAUR and the SEMC such as promoting continuity in regulatory decisions, limiting regulatory risks and ensuring the efficient workings of the market as a whole.

Table 33 provides a more detailed version of the assessment framework and highlights the main qualitative and quantitative metrics adopted to compare the selected reform options based on each of the policy objectives identified.

Table 33 – Detailed list of performance indicators

Assessment criteria	Qualitative / Quantitative metrics
Capacity adequacy/ reliability of the system	
▪ Ensuring there is enough capacity to meet consumer demand at reasonable cost; ▪ Ensuring that enough capacity is available to meet demand up to the necessary security standard calculated by the SOs; and ▪ Ensuring that that plants are available at times of system tightness.	▪ Evaluating the relationship between capacity payment and system margin and whether its appropriate. ▪ Metrics for assessment include the absolute levels of changes, trends in capacity adequacy such as (a) level of investment in new capacity since go-live; and/or attributable to the CPM (b) level /incidence of outages - scheduled, forced; (c) changes in capacity margins, de-ratings, and changes in plant retrials.
Price stability	
▪ Ensuring that prices have the necessary stability to minimise end-user risk ▪ Ensuring that prices are not so volatile that it becomes an overbearing risk to investment ▪ Ensuring that prices can be predicted to a reasonable level	▪ Ensuring capacity payments prices are not unduly volatile. Metrics include (a) range of annual maximum and minimum payments (b) range of payments within month (c) standard deviation of annual/monthly/daily capacity payments. ▪ Ensuring overall generator revenues are stable.

Simplicity	
▪ Ensuring transparency in methodology ▪ Ensuring that the payment structure is easy to understand ▪ Ensuring the design encourages new entrants and promotes competition	▪ Assessing whether a revised CPM methodology is more or less complex than the current methodology. ▪ Assessing whether CPM payments are easier to predict for generators. ▪ Assessing whether CPM payments are easier to predict for Suppliers.
Efficient price signals for long term investments	
▪ Ensuring that the capacity payment mechanism together with SMP prices and ancillary service payments provide the required level of income to encourage investment; and ▪ Ensuring that the market is stable enough for investment decisions.	▪ Assessing whether long-term capacity payments are easier to project. ▪ Evaluating whether long-term capacity payments provide the required price signals to facilitate efficient entry (and exit) in terms of efficient IRR. ▪ Evaluating whether the methodology gives longer term stability and assessing the aggregate efficiency of payment signals. ▪ Quantitative metrics include the volatility of capacity prices year on year or 'long term' (more than one year); Distribution of payments by generator type on an Annual/Monthly/Daily/Hourly basis (a) Average capacity payment in each half hour versus demand/ margin/ projected margin/wind availability (b) (i) Capacity payments to individual generators versus actual availability/'firmness (capacity credit); (ii) calculating the percentage of payments that are in 'peak/low margin' periods (iii) plotting capacity payment vs. margin (outturn or month-ahead eligible availability).
Susceptibility to gaming	
▪ Ensuring that the methodology is robust enough to withstand any attempts at gaming by generators; ▪ The CPM should not encourage behaviour that gives individual generators an advantage at the cost to the system as a whole.	▪ Assessing whether the revised approach improves/ worsens the alignment between generators' incentives and the CPM objectives, this includes evaluating (a) the potential to manipulate ex-ante/ex-post availability declarations (b) whether individual generators impact payments (c) whether portfolio players can shift the pattern of capacity payments to their benefit. ▪ Investigating the possibility of quantitative analysis of correlation of market power measures with position of peak cap price potential.
Fairness	
▪ Ensuring that all types of generators are rewarded fairly on a non-discriminatory basis.	▪ Assessing whether CPM payments to different plant types are non-discriminatory to all generators, given the capacity adequacy they provide to the market, thus firmness adjusted capacity payments should be the same to all generators.

Minimise regulatory risks	
▪ Promoting continuity in regulatory decisions; ▪ Ensuring that the whole market works efficiently to provide generators with the required level of remuneration; ▪ Ensuring that overpayments or underpayments does not count/subsidise across the different revenue areas.	

ANNEX C – IMPACT OF INTERMITTENCY

C.1 Impact of intermittency in future years

The Republic of Ireland faces a legally binding target of 16% renewable share of final energy demand, with the equivalent figure for the UK set at 15%. These targets were agreed as part of the EU's 2020 targets for 20% renewable energy. A large burden for meeting the targets is expected to fall on the electricity generation sector. The RoI national target for renewable generation by 2020 was set at 40% in 2008. Similarly, the Draft Strategic Energy Framework published by DETI in July 2009 committed Northern Ireland to a 40% renewable generation target by 2020.

Given the prominence of wind as the predominant renewable resource in RoI and NI that is commercially deployable, these ambitious targets suggest that wind is likely to be the primary driver in pricing and dispatch in the SEM and is likely to radically re-shape the electricity market in Ireland. A recent report by Pöyry among others, details the likely impact of wind in 2020.[16] These are reviewed here as context for the discussion of future years in Section 3.

In a system with significant volumes of intermittent generation, extreme days or trading periods when wind generation could be contributing all of generation or nothing will become much more normal. This is likely to result in regular frequency of price spikes, significant changes in generation patterns, or indeed significant overcapacity within the system.

Load factors of conventional thermal plant will likely be strongly impacted by high volumes of wind. The main reason for this is that higher penetration of wind reduces the 'space' for these plant to operate in. With increased volumes of low-cost intermittent generation, the running patterns of conventional plant by 2020 are increasingly the inverse of wind generation. Newer CCGTs face could likely face increasing number of starts and a reducing period when they are on the bars. However, for older CCGTs and coal plants the number of starts falls as the units are called upon to operate less and less in 2020. The existence of larger amounts of peaking plant in the SEM, however could lessen the impact of lower load factors.

Higher levels of intermittent generation are also likely to lead to an increasing frequency of trading periods of zero prices and falling average prices. The 2009 Pöyry intermittency study, assessing the impact of intermittency in the GB and SEM markets, found over 700 hours in 2020 when prices would be between £0 and £10 per MWh, and over 1000 hours when prices are below £20 per MWh. This study assumed that wind is modelled to bid at marginal costs (assumed in ROI to be zero, and in NI to be the negative value of one ROC), the frequency of negative prices would likely increase sharply. Subject to final agreement on dispatch and pricing principles, we expect price taker generators to interact with the SEM as if they were bidding at the market floor price rather than zero.

In a high wind build, average within-day price profiles are likely to remain broadly similar as wind generation increases, with the pattern of lower prices overnight and higher prices during the day. However, the variance around these prices becomes much greater.

Wind generation is highly variable and will change the profile of demand supplied by thermal plant. The demand which must be met by non-wind capacity is likely to become

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16 Pöyry Energy Consulting, Impact of Intermittency, How Wind Variability Could Change the Shape of the British and Irish Electricity Markets, July 2009, see http://www.poyry.com/linked/group/study

much more variable than the current demand profile. Additionally, the potential ramping required by the thermal system will increase. The ramping (hour-on-hour change) for demand net wind is greater than that for demand, and as the installed capacity of wind increases, the ramping will increase. According to the Pöyry intermittency study, in the SEM, hourly ramping of demand net of wind increases from 2.1GW in 2020 to 2.6GW in 2030, compared to 1.1GW with demand only.

Price volatility and spikes may increase as a result of the increase in extreme events becoming normal. This is exacerbated by interconnection with the GB market. Annual average prices will become increasingly driven by wind. Although prices will become more extreme than currently, they will not be as volatile as GB prices because of the SEM market rules which regulate bidding. However, there will be more zero or low priced periods than in GB due to the higher volumes of wind generation as a share of the market, though (due to our assumed bidding of wind in the SEM at zero) very few negative priced periods. The extremes of high prices that GB may experience will be tempered in the SEM due to the Capacity Payment Mechanism, although GB will maintain a strong influence on SEM prices exporting that market’s higher peakier prices.

Reserve requirements may also increase, as may requirements for warming. Response characteristics vary for different markets depending on their physical size. According to the Pöyry intermittency study, the requirement for four hour reserve in the SEM is likely to rise from 800 MW to almost 1200 MW by 2030. In the SEM, the four hour reserve is largely met from operating plant or peaking plant held in reserve. As a result, very little less responsive plant needs to be kept warm (so that it can synchronise within four hours). The amount of cold plant also rises because load factors of CCGTs fall, and they are off for longer periods of time due to being displaced by wind.

Increased wind penetration is also likely to affect investment signals. Due to the market design and an explicit capacity payment mechanism, peaking plant makes reasonable returns – in particular the lower efficiency but cheaper designs. The payments for capacity provision mean that peaking and low-merit plant makes a return on investment even if it only generates infrequently. Qualitatively, the existence of the CPM may therefore enable the SEM to achieve a better balance of investment to meet the needs of a high-wind environment than in other markets such as the GB market.

C.1.1 Dispatch principles workstream modelling assumptions

We have assessed the performance of the market in 2020 and capacity payments received in those years using data and assumptions from the modelling conducted by the dispatch principles workstream. Selected assumptions are detailed in this Annex.

Table 34 – Plant assumptions for future year analysis

Unit Name	2010	2015	2020	2025
AA1 - Ardnacrusha 1	21	21	21	21
AA2 - Ardnacrusha 2	22	22	22	22
AA3 - Ardnacrusha 3	19	19	19	19
AA4 - Ardnacrusha 4	24	24	24	24
AD1 - Aghada 1	258	258		
AT1 - Aghada 11	15	88	88	88
AT2 - Aghada 12	0	88	88	88
AT4 - Aghada 14	70	90	90	90
B10 - Ballylumford 10	103	103	103	103
B31 - Ballylumford 31	240	240	240	240
B32 - Ballylumford 32	240	240	240	240
B4 - Ballylumford 4	170	170	170	170
B5 - Ballylumford 5	170			
B6 - Ballylumford 6	170			
BGT1 - Ballylumford GT1	58	58	58	58
BGT2 - Ballylumford GT2	58	58	58	58
CGT8 - Coolkeeragh GT8	53	53	53	53
CPS CCGT - Coolkeeragh GT and ST	404	404	404	404
DBP - Dublin Bay Power	415	415	415	415
ED1 - Edenderry Power	118	118	118	118
ER1 - Erne Cliff 1	10	10	10	10
ER2 - Erne Cliff 2	10	10	10	10
ER3 - Erne Cathaleen's Fall 3	23	23	23	23
ER4 - Erne Cathaleen's Fall 4	23	23	23	23
GI1 - Great Island 1	54	54		
GI2 - Great Island 2	54	54		
GI3 - Great Island 3	108	108		
HN2 - Huntstown Phase 2	401	401	401	401
HNC - Huntstown	343	343	343	343
K1 - Kilroot 1	238	238	238	238
K2 - Kilroot 2	238	238	238	238
KGT1 - Kilroot auxiliary GT1	29	29	29	29
KGT2 - Kilroot auxiliary GT2	29	29	29	29
LE1 - Lee Inniscarra 1	15	15	15	15
LE2 - Lee Inniscarra 2	4	4	4	4
LE3 - Lee Carrigadrohid	8	8	8	8

Table 35 – Plant assumptions for future year analysis

Unit Name	2010	2015	2020	2025
LI1 - Liffey 1	15	15	15	15
LI2 - Liffey 2	15	15	15	15
LI4 - Liffey 4	4	4	4	4
LI5 - Liffey5	4	4	4	4
LR4 - Lough Ree Power	90	90	90	90
MP1 FCR - Moneypoint 1	283	283	283	283
MP2 FCR - Moneypoint 2	283	283	283	283
MP3 FCR - Moneypoint 3	283	283	283	283
MRT - Marina No ST	90	90		
NEW - Aghada CCGT	420	420	420	420
NEW - CCGT1		0	400	400
NEW - CCGT3			400	400
NEW - CCGT4				400
NEW - Edenderry		116	116	116
NEW - KGT3	40	40	40	40
NEW - KGT4	40	40	40	40
NEW - Kilroot CCGT		440	440	440
NEW - OCGT1		0	200	200
NEW - OCGT2			100	100
NEW - OCGT3			79	100
NEW - Quinn CCGT		430	430	430
NEW - Whitegate CCGT	445	445	445	445
NW4 - North Wall CC	163	163		
NW5 - North Wall	109	109		
PBC - Poolbeg CCGT	480	480	480	480
RP1 - Rhode 1	52	52	52	52
RP2 - Rhode 2	52	52	52	52
SK3 - Sealrock 3	83	83	83	83
SK4 - Sealrock 4	83	83	83	83
TB1 - Tarbert 1	54	54		
TB2 - Tarbert 2	54	54		
TB3 - Tarbert 3	241	241		
TB4- Tarbert 4	241	241		
TH - Turlough Hill	292	292	292	292
TP1 - Tawnaghmore Peaking	52	52	52	
TP2 - Tawnaghmore Peaking	52	52	52	52
TYC - Tynagh CT and ST	373	373	373	373
Wind	1,874	3,222	5,822	5,987
WO4 - West Offaly Power	136	136	136	136

ANNEX D – INTERNATIONAL EXPERIENCE

D.1 International experience in delivering adequate capacity

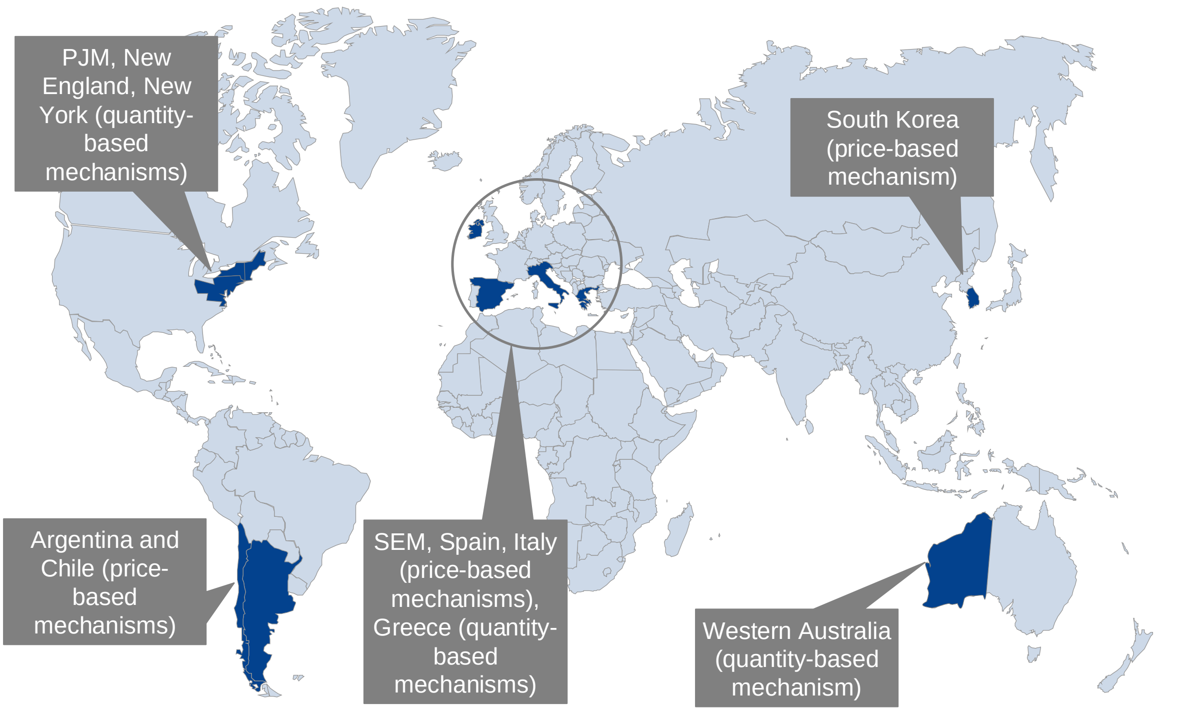
There are three possible electricity market design options for delivering adequate capacity and remunerating generation capacity provision. These include:

- energy only market: capacity is remunerated within the market price, with no explicit capacity mechanism;
- price-based capacity mechanism: a value is attached to capacity and this is paid to providers of capacity under an explicit capacity mechanism; and
- quantity-based capacity mechanism: the capacity mechanism places obligations on parties to provide adequate generation capacity.

We conducted a detailed analysis of international experience and have reviewed five quantity based capacity payment systems in New England, PJM, New York, Western Australia and Greece. We have also reviewed six price based capacity payment systems in Ireland, Spain, Argentina, Italy, South Korea and Chile. Figure 41 highlights all markets reviewed.

The objective of the comparisons is not to judge which is the better capacity payment mechanism, but to provide a factual review of the mechanics of the selected markets, in order to identify features of interest to SEM. In general there are a few valuable insights enumerated below which could be applied in the SEM context:

Figure 41 – International markets under review



D.1.1 Quantity-based capacity mechanisms

Quantity-based mechanisms identify a capacity requirement intended to provide the desired level of generation adequacy. This is translated into obligations to secure the desired level of capacity that are in turn mandated to suppliers or to the ISO.

Examples of quantity-based systems assessed and the main differences between them are described in the Table below.

Table 36 – Quantity-based capacity systems

Features	Key differences observed across markets
Centralized vs. non-centralised obligations	The systems in New York, Western Australia and Greece are non-centralised and the obligation to secure capacity is placed directly upon suppliers. Each supplier can fulfil its individual obligation through self-supply (i.e. effectively contracting with its own generation capacity) or by contracting with capacity providers. Where parties do not meet their own obligations, the ISO/IMO secures residual capacity requirements, with these costs allocated to those with a capacity obligation shortfall. The New England and PJM systems used to follow a similar approach. However, the New England and PJM mechanisms have been revised and are now based around centralised capacity mechanisms. In these mechanisms, the ISO secures capacity on behalf of the market. Consider commitment period greater than one year so that capacity providers have greater certainty as to remuneration for capacity provision.
Review time horizon	The different mechanisms vary in terms of their review horizon (i.e. the period for which capacity is to be secured). The New York and Greece models have a short-term focus, as they are concerned with capacity provision in the forthcoming season/year only. The New England, PJM and Western Australia markets have a longer-term focus. These mechanisms are centred upon the provision of capacity in a period three years-ahead (five years-ahead for new capacity in the case of New England).
Capacity price	The basis for capacity price formation varies across the models. In the New England model, prices are determined via a descending clock auction, within the confines of an administered cap and collar. In PJM, the capacity price is determined through an auction process, based upon a demand curve determined administratively to reflect the maximum price for a given level of capacity resource relative to reliability requirements. The auction clearing price determines the capacity price in the New York mechanism. In the Western Australian and Greek mechanisms, trade is conducted bilaterally and so the capacity price varies depending upon the bilateral trade price.

Compared with energy-only markets, the performance of quantity-based mechanisms suggests that they are better at delivering capacity although payments to generators are generally higher than energy-only markets. In theory, the advantage of quantity-based systems is that the obligations commit existing plant to remain on the system and encourages additional capacity to be developed. They also provide stable environment for delivery of efficient new generation.

D.1.2 Price-based capacity mechanisms

Price-based mechanisms establish a price for the provision of capacity. The price is intended to provide an appropriate financial incentive for generators (and demand side participants) to provide capacity necessary to meet the desired level of generation adequacy. Examples of price-based systems assessed and the main differences between them are described in the Table below

Table 37 – Price-based capacity systems

Features	Key differences observed across markets
Capacity price	In all cases assessed, the capacity price is determined via an administered process. In many cases the actual basis for the price is opaque. The basis upon which payments are made to capacity providers is generally non-dynamic to prevailing system conditions. In Argentina, Italy and Chile, payments are made at pre-defined times of anticipated tight system conditions, regardless of actual system conditions. The Spanish system, which makes a distinct separation between an investment incentive and an availability incentive, does take some account of system conditions but only to a limited extent. Payments under the investment incentive are dependent upon system conditions at the time of investment, but are not dynamic thereafter.
Mechanism review	The price-based mechanisms vary in terms of their review horizon. The mechanisms in Spain and Argentina have been implemented on a long-term basis and are effectively enduring. The other mechanisms have, in general, annual review periods which focus on the arrangements for the forthcoming year.

Compared with energy-only markets, the performance of price-based mechanisms suggests that they are better at delivering capacity, although at higher market prices than energy-only markets. In theory, the advantage of explicit capacity prices is that they signal the need for existing plant to remain on the system and/or for additional capacity to be developed. They also provide reasonable expectation of cost recovery for efficient new generation (to supplement infra-marginal rent earned from energy market) or demand side provision of capacity. This changes the risk profile for generators.

D.2 Summary findings

International experience provides valuable insight into options which could be applied in the SEM. Key lessons include differences in (a) time horizon of regulatory changes; (b) calculation and use of cost of new entry; (c) calculation and use of capacity requirement; and (d) differentiation of incentives for capacity and flexibility. These are discussed in detail in this section.

D.2.1.1 Time horizon

Under the current design of the CPM, the RAs are responsible for setting a new ACPS every year. The experiences of other markets suggest considering a review period which sets the ACPS for several years ahead rather than for the following year. Even if the review is on an annual basis, the fact that the payments take effect several years ahead would provide capacity providers, particularly new entrants, relatively greater certainty and ability to respond. The New England, PJM and Western Australia markets for instance are based on the provision of capacity in a period three years-ahead (five years-ahead for new capacity in the case of New England). Thus a new entrant commissioning a plant in

2013 is assured of the capacity payment at the time of commissioning compared to the SEM where the payment for 2013 is yet to be determined.

Secondly, it would be useful to consider a commitment period greater than one year so that capacity providers have greater certainty as to remuneration for capacity provision. This is similar to the indexation of the BNE highlighted in this section and would involve setting an ACPS or BNE price that is valid over a number of years.

D.2.1.2 Cost of New Entry

The Cost of New Entry or BNE price is another area for learning. In general, other markets reviewed follow SEM-type processes and assumptions in setting the BNE price. In Western Australia, the cost of a new peaking plant is taken as the basis for BNE/CONE on the assumption that it is considered an efficient entry point for new capacity. However, the calculated BNE/CONE is inflated marginally to provide a small amount of headroom. In the US markets, baseload gas-fired generation is considered to be the efficient point for new entry and so this capacity is taken as the basis for BNE/CONE calculations. Despite these similarities, there is scope for using BNE/CONE other than solely for setting the ACPS as currently used. This could include using BNE to set an upper or lower limits for capacity price although this would require a bidding process by capacity providers to set clearing price. There is also scope for exploring the potential for the value of the BNE to be influenced or determined by the market rather than set administratively.

D.2.1.3 Capacity Requirement

The markets reviewed use SEM-type inputs in setting capacity requirements. In the New York, PJM and Western Australia markets, the overall capacity requirement reflects forecast demand plus a reserve margin such that generation adequacy criteria are met. While there are differences in terms of the calculation inputs, the underlying approach is similar. Possible lessons could include resetting capacity requirement as a percentage margin rather than absolute surplus or deficit over and above the current installed capacity, as this may provide more flexibility and transparency to new entrants. A target reserve margin of 10% for instance allows generators all else equal to predict the likely capacity requirement used to set the ACPS. Finally, the emerging treatment of wind, capacity credits used, etc. are areas to constantly review the experiences of other markets.

D.2.1.4 Differentiation

There are precedents for incentivising capacity provision and flexibility services separately as the case in Spain highlights. There is also precedent for differentiation between types of capacity providers, differentiating between new entrants and existing generators. The Spanish capacity mechanism for example differentiates between the uses of capacity and the treatment of capacity providers, treating new capacity and existing capacity differently and rewarding thermal and renewable capacity differently.

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Pöyry Management Consulting

King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.ilexenergy.com
E-mail: consulting.energy.uk@poyry.com

PÖYRY

Pöyry Management Consulting (UK) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK

www.poyry.com