# SINGLE ELECTRICITY MARKET COMMITTEE

## Integrated Single Electricity Market (I-SEM)

## SEM Committee Decision on High Level Design

## Impact Assessment

**SEM-14-085b**

**17 September 2014**

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'The SEM Committee is established in Ireland and Northern Ireland by virtue of section 8A of the Electricity Regulation Act 1999 and Article 6 (1) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 respectively. The SEM Committee is a Committee of both CER and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CER or NIAUR in relation to an SEM matter.'

# 1 SUMMARY

## 1.1 INTRODUCTION

This paper forms part of the process for implementing a new High Level Design ('HLD') for the Integrated Single Electricity Market ('I-SEM') in Ireland and Northern Ireland by the end of 2016. This Impact Assessment (IA) informed the Decision of the SEM Committee on the HLD for the I-SEM, covering both energy trading arrangements ('ETA') and Capacity Remuneration Mechanisms ('CRMs'). Therefore, the IA document should be read alongside the Decision Document (SEM-14-085a), and the Summary of Responses to the draft HLD Decision (SEM-14-085c).

This IA includes:

- A cost-benefit analysis of the different options for the HLD of energy trading arrangements, and CRMs.
- Qualitative assessment of different HLD options against the nine assessment criteria set out for the I-SEM HLD, supported by quantitative assessment.

The cost benefit analysis includes the results of the modeling of two reference scenarios - Base Case A and Base Case B. In both Base Cases, the All-Island Market meets the 2020 renewable target of 40%. However, post-2020 growth in renewables is assumed to be much stronger in Base Case A (52% renewables by 2030) than in Base Case B (45% renewables by 2030). In addition, in Base Case A, low carbon prices and high gas prices mean that coal is relatively much more competitive than gas as a fuel for power generation.

Since the Initial Impact Assessment ('IIA') published alongside the Draft Decision Document (SEM-14-045), we have carried out further quantitative analysis, particularly on the distributional impact of different options. We have also reviewed the qualitative assessment in light of the responses received to the Draft Decision Document and the IIA.

## 1.2 OBJECTIVES OF INTERVENTION

In Ireland and Northern Ireland, the Department of Communications, Energy and Natural Resources (DCENR) and the Department of Enterprise Trade and Investment (DETI) respectively have charged the SEM Committee with responsibility for developing the set of trading arrangements that will be compliant with the EU Target Model. This set of arrangements will be called the I-SEM.

Furthermore, it is timely to review the design of the market as by the time the I-SEM is implemented, the SEM will have been in operation for nearly 10 years. Over that period, there have been many changes in the All-Island market, including:

- increased DC interconnection capacity with the GB electricity market;
- much higher contribution of variable renewables to the generation mix;
- the development of the EU Target Model which provides an opportunity for closer integration with other European electricity markets; and
- greater potential for more active involvement of the demand side.

The HLD of the I-SEM must be in line with the Principal Objective of the SEM Committee to protect the interests of electricity consumers in Ireland and Northern Ireland. This is supported by the nine assessment criteria for the I-SEM HLD, which have been categorized into primary and secondary criteria.

Primary assessment criteria are backed up by the SEM Committee objectives in primary legislation in Ireland and Northern Ireland. Furthermore, they reflect the three pillars of European energy policy of sustainability, competitiveness and security of supply and as such are requirements of European law. The primary assessment criteria are:

- Internal Energy Market;
- Security of Supply;
- Competition;
- Environmental; and
- Equity.

Secondary assessment criteria are implicit in the SEM Committee's objectives and standard principles of economic regulation but are not expressly set out in national or EU legislation. They remain important for the SEM Committee when reaching a decision on the I-SEM and are as follows:

- Adaptive;
- Stability;
- Efficiency; and
- Practicality.

## 1.3 ENERGY TRADING ARRANGEMENTS

Figure 1 presents a summary of the ETA that will form the HLD for the I-SEM. The Decision Document sets out more details on these arrangements.

***Figure 1 - I-SEM Energy Trading Arrangements[1]***

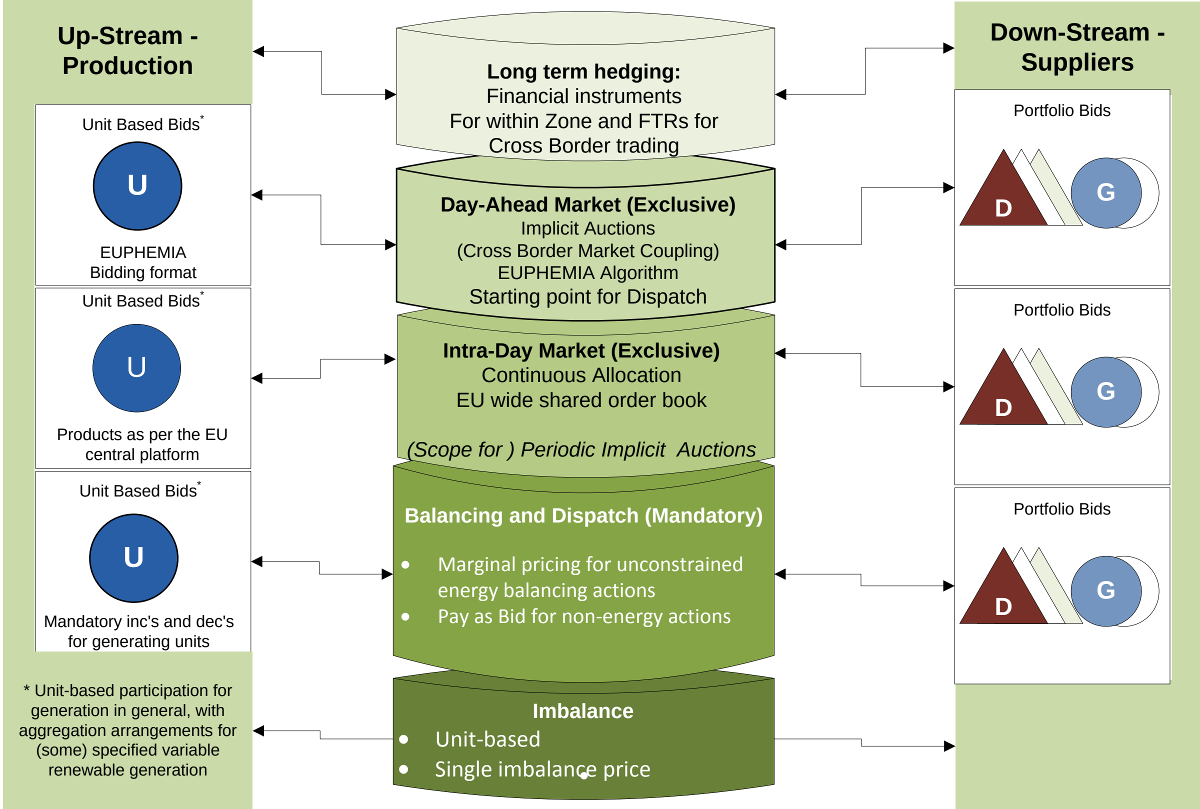



Table 1 summarises the qualitative rationale for the SEM Committee Decision on the HLD of the ETA. This is presented against the full set of assessment criteria for the HLD, set out in the February 2013 Next Steps Decision Paper. The SEM Committee has reached this decision after a detailed, lengthy and objective assessment process, informed by extensive engagement with a wide range of stakeholders.

One of the outcomes of this process has been to identify the major decision points in determining the overall decision on the ETA package.

These decision points are:

- Use of Balancing Market v use of ex-post pool (gross or net); and
- Whether or not to allow physical self-scheduling based on forward trades to offset

[1] Forward trading is financial in that any contracts struck between market participants in the forwards timeframe will not confer a right to physically schedule generation, demand or cross-zonal capacity in the All-Island Market. The use of forward financial trading in the I-SEM does not preclude intermediary or aggregation arrangements.

imbalance exposures caused by a difference between metered volumes and traded positions from the Day-Ahead market ('DAM'), Intraday market ('IDM') and Balancing Market ('BM').

***Table 1 – Summary of qualitative rationale for the SEM Committee Decision on the HLD of the ETA***

| | | **Rationale for the decision on the HLD of the ETA** |
|---|---|---|
| Primary Assessment Criteria | Internal Electricity Market | Supports most efficient implementation of the Target Model in the All-Island Market because of emphasis on centralised and transparent arrangements to concentrate physical trading in the DAM and IDM. |
| | Security of Supply | Delivers the DAM as both a strong reference market for forward trading, and a robust starting point for dispatch, This is supported by a liquid IDM and mandatory BM |
| | Competition | Facilitates strongest competitive pressures through focus on unit-based bidding by generation into liquid centralised market places with full integration of physical interconnector capacity in price-setting dynamics |
| | Environmental | Provides the best overall package in terms of delivering market signals to reduce curtailment, and facilitating greater ex-ante trading opportunities for variable renewables |
| | Equity | Imbalance arrangements delivering sharper targeting of cost and benefits associated with flexibility, with emphasis on centralised market places ensures market access for all participants, with |
| Secondary Assessment Criteria | Stability | Retains many strengths of the SEM whilst becoming more closely aligned with the prevailing design of European electricity markets |
| | Adaptive | Easier coordination of changes to trading arrangements because of emphasis on trading in centralised European markets |
| | Efficiency | Starting point for dispatch is based on a centralised unit commitment process that fully integrates the available physical interconnector capacity |
| | Practicality/Cost | Emphasis on low-cost routes to market for participants of all sizes and technologies |

It is widely recognised that it can be difficult to objectively model different forms of ETA. This is because the quantitative outcomes, e.g. wholesale market costs, will typically be driven by assumptions about the market dynamics under any set of ETA– e.g. such as the bidding behaviour and level of competitive pressure assumed for each option.

Therefore, we *quantified* the possible benefits from an efficient market design in three key areas that were susceptible to modeling:

- efficiency of DA allocation of interconnector capacity through the price coupling process;

- efficiency of ID trading to ensure scheduled interconnector flows respond appropriately to changes in the All-Island Market after the DA stage; and
- facilitation of renewables deployment.

Table 2 summarises the possible overall welfare benefits to the All-Island Market of efficient outcomes in each of these modelled areas.

***Table 2 – Possible wholesale market welfare gains from implementation of an efficient HLD of the ETA in the I-SEM[2]***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Base Case A (52% RES by 2030) | Base Case B (45% RES by 2030) |
|---|---|---|
| Efficient DA interconnector flows[3] | From +€8m to +€458m | From +€12m to +€200m |
| Efficient ID trading | +€441m | +€130m |
| Lower cost of capital for variable renewable generation | +€450m | +€419m |

We then reviewed the results of the *qualitative* assessment to see how closely each option might be expected to be to an efficient market design in each of these areas. This then informs an assessment of the possible scale of welfare benefits associated with each of the ETA HLD options.

The qualitative assessment identified that of the options, the proposed HLD would be the most likely to deliver the closest outcome to the efficient market outcomes in these three areas. This is the result of the following features of the proposed HLD:

- **Physical scheduling only resulting from unit-based trading, alongside allocation of full physical interconnector capacity, in centralised DA and ID markets that** provide a framework for effective competition, supported by routes to market for a range of different market participants.
- **A mandatory Balancing Market after the DA stage** to provide the TSO with access to a wide range of bids and offers to help it manage the system efficiently in real time.
- **Cost-reflective imbalance prices** to provide efficient short-term signals for market participants (including flexible resources) to reduce the need for the TSO to balance the system in real time.

Even if only a proportion of the benefits shown in Table 2 were realised through the implementation of the proposed HLD, then the benefits would be significant and far

[2] Table 2 shows the gains in welfare by moving from inefficient flows to efficient flows whereas the tables presented in Chapter 5 show the welfare changes as negative numbers, reflecting the general approach in the modelling for the CBA of the ETA where inefficiencies are modelled as welfare reductions from moving from the baseline perfectly functioning energy-only market.

[3] This shows the range of the welfare changes resulting from the four types of inefficient DA flows that were modelled as set out in Table 6

outweigh any estimated difference in implementation and operation costs.

In the IIA, the SEM Committee presented initial estimates of the estimated implementation and operating costs for different HLD. This identified that these costs were sensitive to the estimate of ongoing market participant costs, particularly in relation to trading in the IDM. These costs are driven by the requirements of the Target Model, rather than differences in the overall HLD of ETA that comply with the Target Model. In the HLD of the ETA, the SEM Committee has already identified that there will be ways for smaller market participants to manage these costs through aggregation and/or outsourcing. During the detailed design phase, the SEM Committee will ensure the implementation of the trading processes is focused on delivering value for money for customers in the All-Island Market.

We also carried out analysis of the distribution of these changes in welfare between consumers, producers and interconnector users and consumers who underwrite them. Efficient ID trading led to an increase in welfare for all 3 groups. However, for the other two cases, the distribution of welfare changes was particularly uncertain as it was sensitive to the underlying scenario, and the assumed cause of the inefficiency in interconnector flows.

**In summary, the SEM Committee has chosen to implement the HLD of energy trading arrangements, identified in the qualitative assessment as delivering the greatest long term benefits for consumers in the All-Island Market.**

**This choice is supported by the outcome of the quantitative element of the cost-benefit analysis, which illustrates that the potential welfare benefits of the proposed HLD in delivering more efficient outcomes are much higher than estimated differences in implementation and operating costs compared with other options.**

## 1.4 NEED FOR AN EXPLICIT CAPACITY REMUNERATION MECHANISM

We now present the findings of the quantitative and qualitative assessment of the need for an explicit CRM in the I-SEM.

EirGrid's most recent All-Island Generation Capacity Statement 2014-2023 (GCS) projected a generation surplus out to 2023 on an unconstrained All-Island Market basis. This is based on the notifications by generators of closure decisions, which are based on the fact that there is an explicit capacity mechanism currently in place in the All-Island Market.

Therefore, to provide the SEM Committee with a wider perspective on the state of generation adequacy beyond 2016, the Regulatory Authorities (RAs) asked EirGrid to carry out analysis of the outlook for generation capacity adequacy in the All-Island Market in the absence of an explicit capacity mechanism. EirGrid's Assessment of Generation Adequacy (SEM-14-048) was published in June 2014 alongside the Draft Decision Paper (SEM-14-045).

The EirGrid assessment considers some scenarios for closure of generation plant in addition to those notified by generators for the GCS (2014-2023). These closure scenarios are then tested for capacity adequacy against a reference case, and a number of sensitivities in relation to a tighter security standard, higher peak demand, and reduced interconnector availability.

Plants are assumed to close if based on their generation volumes from a market simulation, they require on average more than €3000/MWh from the energy-only market to recover their required costs on an annual basis. This also means that plants close if they have no running hours. €3000/MWh is used as the cut-off price as it is the price cap in place in the EUPHEMIA algorithm already being employed in the DA coupling of electricity markets in Western Europe.

The SEM Committee has not used the EirGrid assessment as a stand-alone prediction of generation adequacy in an energy-only market. Rather, it forms part of the package of quantitative analysis to inform the assessment of the possible challenges for generation adequacy under an energy-only market.

The main findings of the analysis are that projections of capacity adequacy are sensitive to assumptions about closure decisions – with the system not being capacity adequate in 2020 and 2023 in the higher closure scenarios. In addition, the availability of interconnector capacity in tight periods is particularly important in determining the extent of the shortfall in capacity adequacy in the higher closure scenarios.

As part of the modelling for the cost-benefit analysis presented in this Impact Assessment, we considered a perfectly-functioning energy-only market. It is assumed to be fully competitive, with perfect foresight of 'expected' future revenues. Although there is a price cap of €3000/MWh (to reflect the price cap in the DAM), there is no restriction on price spikes up to that level. However, any price spikes are assumed to encourage investment in demand-side response in the modelling. In reality, we would, however, expect price spikes in the energy market to deliver demand-side response.

Because the energy-only market is assumed to be perfectly-functioning, it delivers a level of security of supply that meets or exceeds the required security standard in the All-Island market. In addition, the assumption that the energy-only market is perfectly functioning means that it does give rise to a missing money problem in the modeling. This is contrary to the RAs' and market participants' expectations of what would happen in an energy-only market in practice.

Even with the energy-only market assumed to be perfectly functioning, the modelling highlights challenges for delivery of capacity adequacy in the energy-only market. These challenges have also been identified in the qualitative assessment, in particular relation to:

- **the importance of price spikes at times of system tightness -** these allow generation plants to recover their fixed costs when they only have a small number of hours of operation.

- **how non-renewable plants manage the possibly large variability from year to year in extent of fixed cost recovery -** i.e. a plant may have a very bad year or a very good year depending on the level of renewable generation, electricity demand, and availability of other plants.

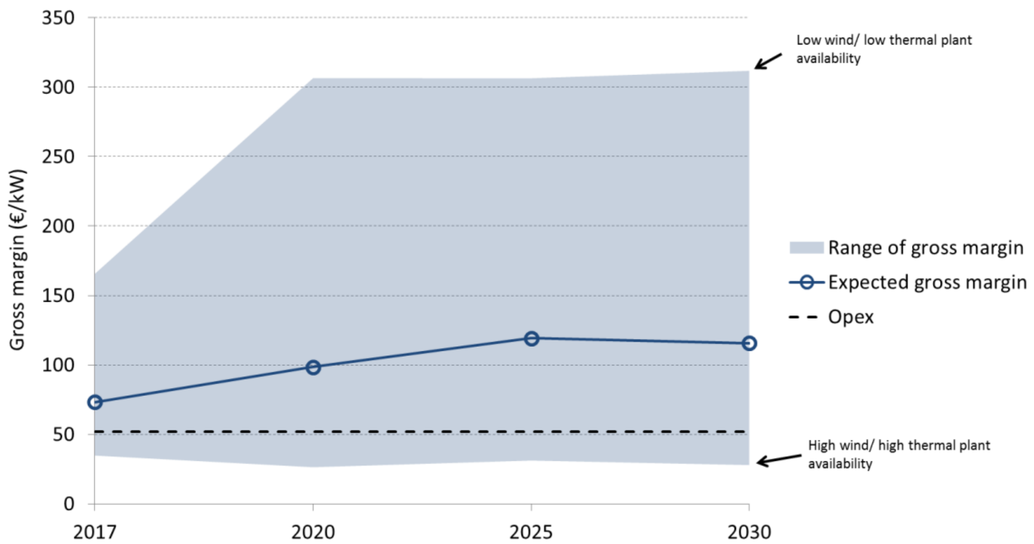
In the perfectly functioning energy-only market, the number and magnitude of price spikes increase over time. This is the result of further renewable deployment reducing the running hours for thermal plant, meaning that the fixed costs have to be recovered in fewer hours.

In years with low wind generation and low thermal availability, these price spikes are much more frequent than in the average year. This variability is illustrated in Figure 2, which shows the range of gross margins for each snapshot year for a 51% efficient (HHV) CCGT in the modelled perfectly-functioning energy-only market.

The gross margin, shown here, equals wholesale electricity revenues plus net system service revenues minus variable fuel and operating costs. Therefore, it would need to be sufficient to cover annual fixed operating costs at least in order for the plant to stay open.

In a year with relatively comfortable capacity margins, e.g. as a result of high renewable generation, the gross margin can be as low as around €25/kW. This would not be sufficient for the CCGT to cover its fixed annual operating costs.

***Figure 2 - Gross margin[4] for a 51% efficient (HHV) CCGT (Base Case A)***




The entry and exit decisions of thermal generators in the modelling of the perfectly competitive energy-only market assumes that plants are able to capture all of the high price periods without regulatory or political intervention. However, the qualitative assessment of an energy-only market has highlighted the scope for missing money whereby spot electricity market prices do not rise high enough during 'scarcity' hours to produce adequate net revenues to cover the capital costs of investment in an efficient level and mix of generating capacity.

4 Gross margin shown on this chart equals (wholesale electricity revenues + net DS3 revenue) minus variable fuel and operating costs

This is because the increased magnitude and frequency of the price spikes seen in the modelling may increase the risk of regulatory or political intervention. This is especially given a general concern amongst stakeholders about the ability of the market to correctly price scarcity in all circumstances (for example because of market power).

Even in the assumed absence of missing money, the potential variability in the modelled gross margins could then reduce the confidence of plants that they will be able to recover the costs of staying in the All-Island market – even where the average expected gross margin is sufficient to cover their fixed costs. By assuming perfect foresight, the entry and exit decisions in the modeling are not directly affected by the size of this range.

This is a particular risk for plants that run infrequently, even though they may be essential for security of supply.

This then raises the prospect of excess or disorderly exit, which is made worse by the relatively large unit sizes in the All-Island market and the current existence of an explicit CRM.

Excess or disorderly exit would be particularly challenging for the All-Island Market given the relative isolation of the market, placing a high burden on domestic actions to ensure security of supply. Over the long run, it could give rise to a boom and bust cycle of over- and then underinvestment in capacity.

By reducing variability in gross margin to manageable levels for capacity essential to maintaining security of supply for consumers in the All-Island Market, an explicit CRM would mitigate the impact of this uncertainty about future gross margins.

In addition, the assumption of a perfectly functioning energy-only market means that the modeling does not reflect other challenges identified in the qualitative assessment:

- **Public good nature of reliability** may prevent an energy-only market being able to deliver the efficient level of reliability in practice.
- **Uncertainty over the timing of the need for thermal generation** may make it harder to strike forward contracts if sufficiently granular products are not available.
- **Indivisibility and coordination failures** where unit sizes are relatively large compared with the overall market – this may be a particular problem for efficient exit in a set of energy-only trading arrangements in the I-SEM

Under national and European legislation, targeted contracting is available as a 'backstop' measure to address specific security of supply concerns on a case by case basis. Whilst this is a useful measure in specific circumstances, the SEM Committee does not believe that it would address the more general challenges that have been identified for capacity adequacy in the I-SEM.

**In conclusion, the qualitative and quantitative assessments support the retention of an explicit CRM in the HLD of the I-SEM in order to better meet the I-SEM primary objectives, compared with an energy-only market**

## 1.5 FORM OF EXPLICIT CAPACITY REMUNERATION MECHANISM

The consultation process has considered a number of different options for explicit CRMs. Based on stakeholder feedback and the assessment so far, these options have been narrowed down to the following types of CRM:

- Price-based:
  - long-term price-based;
  - short-term price-based;
- Quantity-based,
  - centralised capacity auctions;
  - centralised reliability options.

There is a range of different terminology that is used to describe CRMs in different contexts. Therefore, it is important to define the main points of distinction between a 'price-based' CRM versus a 'quantity-based' CRM, as defined in this Impact Assessment and related documents.

A 'price-based scheme' is defined as a scheme where:

- capacity remuneration depends on actual availability in a particular period (i.e. there is no advance commitment to deliver capacity); and
- the capacity payment is paid to all eligible generation – i.e. there is no process in allocating payments based on a merit order of the cheapest providers up to a centrally determined quantity.

In a price-based scheme, there is no direct competition between the providers to receive the payment in any period. Instead, the quantity of eligible capacity determines the price based on the administered pricing function. If more capacity is available, that will reduce the payment received by everybody.

A 'quantity-based' scheme is defined as one in which:

- providers receive an advance payment for capacity, in exchange for a commitment to deliver either capacity or energy in the certain required periods and face a penalty if unable to do so; and
- there is direct competition between providers to receive the payments, with payments allocated to a centrally determined quantity based on a merit order of bids. This does not exclude the use of a sloping demand curve in the capacity auction.

In a quantity-based scheme, there is scope for the total level of payments by consumers to be determined by the competitive auction process, within regulatory bounds.

Table 3 summarises the impact of different CRMs on overall welfare in the I-SEM under Base Case A, which was used as the reference scenario for this modelling. The changes are shown relative to the baseline of the long-term price-based CRM because that is closest to the status quo position of the current SEM arrangements. The net welfare changes shown in Table 3 are relatively small compared to the overall size of the I-SEM market over a 14 year period. In addition, the additional implementation and operating costs (i.e. negative welfare) for quantity-based CRMs compared to price-based CRMs are relatively small.

***Table 3 – Impact on I-SEM welfare of different CRMs relative to long-term price based CRM***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Short-term Price Based | Capacity Auctions | Reliability Options |
|---|---|---|---|
| Change in wholesale market welfare | +€129m | +€64m | -€47m |
| Change in welfare from market participants costs | +€0m | -€34m | -€34m |
| Change in welfare from institutional costs | +€0m | -€20m | -€20m |
| **Overall change in welfare** | **+€129m** | **+€10m** | **-€101m** |

Table 4 looks at the distribution of the change in the wholesale market welfare between consumers, producers and interconnector owners (this is the wholesale market welfare change shown in the second row of Table 3, which is by far the biggest element of the overall change in welfare). In line with standard practice, consumer and interconnector surplus have been reported separately. The arrangements around interconnector cost recovery in the All-Island market should though mean that changes in interconnector surplus (i.e. net profit) should be passed through to consumers.

The key findings of the distributional analysis of our modeling results are that:

- the gains to consumers from moving away from a long-term price-based CRM are proportionally much larger than the total change in overall welfare.
- ROs result in significant redistribution from producers (and to a much smaller extent interconnectors) to consumers.
- a move to a short-term price based scheme could result in a very large redistribution from producers to consumers with moderate reduction in interconnector congestion rent.
- capacity auctions result in redistribution from interconnector users (and ultimately the consumers who in Ireland and Northern Ireland underwrite the interconnectors) to overall consumers and producers, because of the dampening of peak prices in the I-SEM both reduces overall congestion rent and reduces the value of investment in new interconnection.

*Table 4 – Impact on I-SEM wholesale market welfare distribution of different CRMs relative to long-term price based CRM*

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Short-term Price Based | Capacity Auctions | Reliability Options |
|---|---|---|---|
| Change in consumer surplus | +€2743m | +€237m | +€527m |
| Change in producer surplus | -€2274m | +€208m | -€501m |
| Change in congestion rent | -€340m | -€380m | -€73m |
| **Change in wholesale market welfare** | **+€129m** | **+€64m** | **-€47m** |

In order to reflect the effect of changes in congestion rent on all island consumers it is also useful to show the aggregate change in consumer surplus (wholesale market consumer surplus + change in congestion rent) for the three CRMs shown in Table Four. These are:

- For the Short-term Priced Based mechanism an increase in net consumer surplus of **€2,403 million**
- For Capacity Auctions a decrease in net consumer surplus of **-€143 million**
- For Reliability Options an increase in net consumer surplus of **+€454 million**

The quantitative results from the modelling provide useful insight into the relative strengths and weaknesses of the different CRM options. However, in line with the SEM Committee decision in the February 2013 Next Steps Paper and international best practice in carrying out impact assessments, the modeling results should not be considered in isolation from the qualitative assessment.

This reflects the importance of hard to quantify factors, which provide the context for the interpretation of the modeling results. The combined impact of these hard to quantify factors would be to strengthen the performance of the centralised reliability options compared with the modelled outcomes used in the CBA.

These factors include:

- **Importance of hedging for capacity providers and energy retailers** – the quantity-based CRMs, and the long-term price-based CRM offer a hedge for market participants against short-term variability of energy prices and gross margins. However the short term price based CRM does not offer a similar long-term hedge. The modelling does not quantify the full benefits of a long term hedge for producers, which can reduce the risk of a boom and bust cycle as may be the case in a short-term price CRM.
- **Ability of quantity-based CRMs to differentiate between the duration of capacity**

**price certainty needed by different types of capacity providers** - Mechanisms can be put in place in the quantity-based CRMs that provide long-term capacity price certainty for new entrants (where large upfront investment is typically required) over a number of years whilst not paying that long-term price to existing plants in years when new entry is not required. This would still provide firm signals for efficient entry and exit whilst reducing the total costs to consumers under the quantity-based schemes.

- **Impact of retaining efficient short-term price signals on incentives to invest in flexible resources** – the modelling does not include any scope for additional investment in flexible resources, such as demand-side response, that could be delivered by efficient short-term price signals. The qualitative assessment identified that reliability options and short term price based CRMs are able to deliver efficient short-term price signals.

Table 5 summarises the outcome of the qualitative assessment which identified the centralised reliability options as the best option for the CRM HLD in the I-SEM.

*Table 5 – Summary of qualitative assessment of CRMs against each assessment criteria*

| | | Relative strength of centralised reliability options |
|---|---|---|
| Primary Assessment Criteria | Internal Electricity Market | Compatible with general European drive towards quantity-based CRMs; with reliability options more consistent with efficient short-term energy price signals needed for efficient market coupling |
| | Security of Supply | Transparent and flexible mechanism for providing efficient entry and exit signals, and more compatible than other CRM designs with efficient short-term energy price signals. Also it can provide longer term price certainty for new investment |
| | Competition | Provide transparent centralised platform for competition that facilitates efficient and coordinated entry and exit signals, whilst introducing competitive pressures (supported by regulatory oversight) to ensure that consumers don't overpay for adequacy. Market power is a particular concern for quantity based capacity markets and the centralised design allows for the application of various market power mitigation measures in the capacity auction in line with international best practice. Centralised reliability options also fit well with possible market power mitigation measures in the energy market |
| | Environmental | Most compatible CRM with efficient short-term energy price signals that should encourage the flexible resources that can help to reduce curtailment (e.g. interconnection, storage, demand-side response) |
| | Equity | Repayments by providers at times of high energy prices is a market-based mechanism to address double payments from capacity and energy markets. Centralised platform supports access for new entrants through a transparent market mechanism, with consumers all effectively paying the same price for the same level of generation adequacy. Equity across capacity providers is ensured by providing that technologies are treated equally according to their ability to contribute to system reliability. |
| Secondary Assessment Criteria | Stability | Offers good stability going forward, as fits well with the philosophy of the I-SEM design for energy trading arrangements, and with direction of travel on CRMs in Europe. This means that it is a timely change from the current scheme – the review of which has been signaled for a number of years. |
| | Adaptive | To be determined by the detailed design phase |
| | Efficiency | Most compatible with efficient short-term energy price signals that support a more efficient overall dispatch |
| | Practicality/Cost | Slightly higher implementation costs in changing to quantity-based scheme, but relatively small compared to potential value of other benefits |

**In summary, the qualitative assessment and CBA have both highlighted the relative merits of the centralised reliability options compared with the other CRMs in delivering sustainable benefits for all-island consumers. the modeling does show the short-term price-based CRM is delivering much greater redistribution from producers to consumers, although net welfare gains are small. However, the qualitative assessment has identified a number of concerns about its suitability to be the explicit CRM in the I-SEM.**

**The centralised reliability options also fit well with the I-SEM philosophy for energy trading arrangements of market participants having responsibility for trading in centralised, public and transparent marketplaces.**

**Therefore, the overall conclusion of the impact assessment is that the centralised reliability options would be the best HLD for the explicit CRM in the I-SEM.**

**Together, the proposed ETA and CRM designs for the I-SEM together provide the most coherent end-to-end package for the HLD that best meets the stated objectives of the SEM Committee.**

# 2 PURPOSE OF THIS DOCUMENT

## 2.1 OVERVIEW

In September 2014, the SEM Committee published its Decision on the new High Level Design (HLD) for the Integrated Single Electricity Market (I-SEM) in Ireland and Northern Ireland (SEM-14-085a). The SEM Committee Decision is informed by this comprehensive Impact Assessment, which should be read alongside the Decision Paper. The SEM Committee has also published the Summary of Responses to the draft HLD Decision (SEM-14-085c)., which contains some discussion of the responses provided by stakeholders to the Initial Impact Assessment.

The Impact Assessment includes a Cost-Benefit Analysis (CBA) and qualitative evaluation against the assessment criteria for the I-SEM HLD set out in the Next Steps Decision Paper (SEM-13-009). The CBA considers the impact of different options on wholesale market costs, and on implementation and operating costs.

## 2.2 STRUCTURE OF THIS DOCUMENT

The rest of this IA is structured as follows:

- **Objectives of intervention (Section 3)** – to meet the requirement for the HLD of the All-Island Market to fully comply with the EU Target Model in accordance with the CACM Guideline, as judged by the prioritised set of nine assessment criteria confirmed in the SEM Committee's Next Steps Decision on Implementing the EU Target Model.
- **Approach to assessment (Section 4)** – a description of the balance between qualitative and quantitative assessment, including CBA, and brief summary of approach to wholesale market modelling, and estimation of the implementation and operating costs.
- **Evaluation of options for energy trading arrangements (Section 5)**– a cost-benefit analysis (CBA) alongside a qualitative assessment of the proposed HLD and the main alternatives**.**
- **Evaluation of the need for an explicit CRM (Section 6)** – qualitative and quantitative assessment, including additional generation adequacy analysis by the TSO.
- **Evaluation of the options for the form of explicit CRM (Section 7)** – a CBA alongside a qualitative assessment of the different options for an explicit CRM.
- **Supporting appendices (Annexes 1 to 5)** – more detail on the SEM Committee objectives, the sources of the values used in the cost-benefit analysis, and changes in reported modelling results since the Initial Impact Assessment.

## 2.3 DEVELOPMENTS SINCE THE INITIAL IMPACT ASSESSMENT

This Impact Assessment has been updated since the Initial Impact Assessment (SEM-14-046) published alongside the Draft Decision Paper on the SEM HLD (SEM -140-045).

A separate paper summarises the responses received to the Draft Decision Paper and to the Initial IA. The Summary of Responses document sets out our position on the issues raised by responses in relation to the Draft Decision Paper, and the IIA. In updating this IA, we have taken account of these responses but do not directly refer to the responses in this document. Respondents did not provide any quantitative information that could be used in updating the cost-benefit analysis, either in relation to wholesale market modeling, or in the estimation of implementation and operation.

As well as carefully considering the points raised by stakeholders and further technical analysis, we have carried out further quantitative analysis. This includes:

- quantitative assessment of the distributional impact of different ETA and CRM options, in support of the overall welfare impacts shown in the Initial IA;
- further quantitative assessment of the challenges for generation adequacy in an energy-only market focusing on the issues around the impact of large unit sizes in a small market; and
- further review of the modelling outputs reported in the initial IA[5], including refined assumptions about the structure of renewable support payments and correction of calculation errors.

In the IIA, most results for the change in monetary values over the whole modelled period were presented on a total NPV basis. Some results in the Initial Impact Assessment were also presented on an annual equivalent basis[6]. Those annual equivalent figures were simply calculated by dividing the NPV by the number of years in the modelled timeframe (i.e. 14 years) rather than as fully annuitising by dividing the NPV by the present value of an annuity factor (which have resulted in larger annual values). In this Impact Assessment, all results for the change in monetary values over the whole modelled period are presented on a total NPV basis. This is in line with international custom for impact assessments, and to aid cross-referencing of results between the Executive Summary and the rest of the document. For the avoidance of doubt, this has not affected the values shown for snapshot years, which are still shown on an undiscounted basis.

In order to calculate the NPV over the 14 year assessment period (2017-2030), we use an assumed discount rate of 3.5% in line with the discount rate recommended in the UK Treasury's Green Book[7] for Appraisal and Evaluation in Central Government

5 Changes from the results reported in the Initial IA are listed in Annex 5. The overall messages from the modelling results though remain unchanged though from the Initial IA.

6 Tables 2 and 5 in the Executive Summary, and Tables 8, 21, 33, 35, 37, 39, 41, 43 on the implementation and operating costs.

7 https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

In this Impact Assessment, we have used the following baselines for reporting the quantitative results:

- **Energy Trading Arrangements (ETA): modelling:** a theoretically efficient HLD is used as the baseline for reporting the modelling results for the Energy Trading Arrangements (ETA)[8]. This reflects the challenges of modelling different sets of energy trading arrangements as discussed in Section 5.3.
- **Energy Trading Arrangements (ETA): implementation and operating costs:** the preferred option is used as the baseline for reporting the differences between options in terms of implementation and operating costs. This reflects the fact that there is no appropriate 'do nothing' or 'do minimum' option that is compliant with the requirements of the EU Target Model, and that the 'theoretically efficient market outcome' could be not be used as a baseline for reporting practical implementation costs.
- **Explicit Capacity Remuneration Mechanism (CRM): modelling, and implementation and operating costs.** The long-term price-based CRM is the baseline for reporting the differences between different explicit CRMs in terms of modelling costs, and implementation and operation costs. That form of CRM most closely reflects the current scheme in operation in the SEM.

[8] The qualitative assessment identified that of the options, the proposed HLD would be most likely to deliver the closest outcome to the efficient market in the three aspects quantified in the modelling. That proposed HLD is used as the baseline for reporting the results of the analysis of implementation and operating costs for the ETA.

# 3 OBJECTIVES FOR INTERVENTION

## 3.1 REASON FOR INTERVENTION

The European Union (EU) is building an internal market for electricity and gas, to help deliver energy supplies that are affordable, secure and sustainable. The process of European electricity market integration was given fresh impetus by the EU's Third Energy Package. This set in place provisions for the implementation of the European Electricity Target Model (EU Target Model). The EU Target Model is a set of harmonised arrangements for the cross-border trading of wholesale energy and balancing services across Europe.

EU Member States have the responsibility to comply with the requirements of the EU Target Model. In Ireland and Northern Ireland, the Department of Communications, Energy and Natural Resources (DCENR) and the Department of Enterprise Trade and Investment (DETI) respectively have charged the SEM Committee with responsibility for developing a new set of wholesale electricity market arrangements to that are in line with the EU Target Model.

The new all-island wholesale electricity market will be known as the Integrated Single Electricity Market (I-SEM). As well as efficiently meeting the requirements of the EU Target Model, the I-SEM represents a timely opportunity to learn from the experience of the current market, and take account of major changes in generation, demand and interconnection.

It is timely to review the design of the All-Island Market for electricity given the changes seen since the creation of the SEM, which will have been in operation for over nine years by the time the I-SEM comes into operation. This will help to ensure that, as far as possible, the HLD for the I-SEM will deliver the greatest benefits for consumers on the island of Ireland, in line with the overall objective of the SEM Committee.

## 3.2 ASSESSMENT CRITERIA

In its Next Steps Decision Paper, the SEM Committee set out a set of criteria for use in its assessment of the options for HLD for the I-SEM. These provide an agreed framework for the qualitative assessment process, and were consulted upon with stakeholders before the commencement of the HLD phase of the Market Integration Project. All but one of these criteria were used in the assessment of the original SEM design, and therefore are familiar to stakeholders.

As explained in the Initial IA, primary assessment criteria are backed up by the SEM Committee objectives in primary legislation in Ireland and Northern Ireland. Furthermore, they reflect the three pillars of European energy policy of sustainability, competitiveness and security of supply and as such are requirements of European law.

Secondary assessment criteria are not expressly set out in national or EU legislation (though they are implicit in the SEM Committee's objectives and standard principles of economic regulation). They remain important for the SEM Committee when reaching a decision on the I-SEM.

When making a trade-off between competing objectives in relation to the decision on the I-SEM HLD, the primary assessment criteria take precedence over the secondary assessment criteria.

The primary criteria are:

- **Internal Energy Market[9]:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade
(Source: EU Electricity Regulation 714/2009, European Electricity Network Codes).
- **Security of Supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards (Source: SEM Committee Objective on ensuring reasonable demand for electricity is met and that participants are able to finance their activities; Security of Supply Directive (Directive 2005/89/EC)).
- **Competition:** the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner (Source: SEM Committee Primary Objective, SEM Committee Objective on transparent pricing; Electricity Regulation (EC) 714/2009 and the EU Treaties).
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables. (Source: SEM Committee Objective on the environment and promotion of RES; EU Renewables Directive (Directive 2009/28/EC)).
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner (Source: SEM Committee Objective to avoid unfair discrimination).

Secondary assessment criteria are as follows:

- **Adaptive**: The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **Stability**: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- **Efficiency**: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.
- **Practicality:** the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

[9] The Internal Energy Market criterion was also an important filter during the initial option development process, so that only compliant options were taken forward. The second stage of the assessment against this criterion then considers the efficiency of implementation of the Target Model.

# 4 APPROACH TO ASSESSMENT

## 4.1 OVERVIEW

Undertaking an Impact Assessment is good regulatory practice and is designed to help to inform the development of policy decisions. The SEM Committee has made a commitment to evidence-based decision making. Accordingly, in its Next Steps Decision Paper, the SEM Committee stated that:

- "The High Level Design shall be subject to an impact statement that is in line with best practice."
- "There will be a cost benefit analysis, carried out at an appropriate stage, which takes into account the key energy policy objectives which are materially affected by the wholesale electricity market high level design."

The SEM Committee noted in this case it would expect to rely more on qualitative analysis where there are wide ranges of uncertainty associated with costs and benefits, as is the case here. A monetised Cost-Benefit Analysis (CBA) is only one part of an IA, which will always consist of a mixture of qualitative and quantitative evaluation. Quantitative evidence, including a CBA, provides insights that aid decision making, but cannot support a purely mechanistic approach to determining those decisions.

The CBA of the possible differences between HLD options includes estimates of wholesale market costs and benefits, and costs of implementation and operation of different arrangements. It quantifies separately the options for Energy Trading Arrangements (ETAs) and for CRMs. This is appropriate given the difficulty of objectively modeling differences between different sets of energy trading arrangements, as discussed further in Section 5.3.

The CBA is supported by a qualitative assessment of hard-to-quantify factors. This is presented separately for the ETA and for the CRM. Where appropriate, the qualitative assessment, particular for the form of the explicit CRM, does consider the interactions between the proposed ETA and the proposed CRM – e.g. in terms of DA liquidity.

## 4.2 ESTIMATING WHOLESALE MARKET COSTS AND BENEFITS

We have modelled the All-Island and GB wholesale electricity market to estimate the quantitative impact of different HLD options. Annex 2 contains more information on the approach and input assumptions for the modelling. This includes our approach to calculation of the different elements of overall welfare.

### 4.2.1 MODELLING TIMEFRAME

We have modelled four snapshot years (2017, 2020, 2025 and 2030) using Pöyry Management Consulting's power market model, BID3. We have used linear interpolation between these snapshot years to calculate the Net Present Value (NPV) for use in the cost-benefit analysis (CBA).

### 4.2.2 MODELLING APPROACH

The wholesale market modeling has been carried out using Pöyry's wholesale electricity market model. It should be noted that this is a model extensively used for market analysis in Ireland, GB and in Europe more widely.

For each snapshot year, we have modelled 15 different combinations of weather, demand and availability profiles. In this IA, we report the average outcome for each snapshot year, unless otherwise stated.

In all cases, market players are assumed to have perfect foresight of their expected level of future energy and capacity revenue in each snapshot year, i.e. the average across the 15 different combinations of weather, demand and availability.

In the modeling for the CBA of the ETA, the reference cases assume a perfectly-functioning (ideal) energy-only market. There is a price cap of €3000/MWh, which reflects the price cap currently in place in the NWE DAM. There is assumed to be no free-riding problem and investment is coordinated, which reduces the risk of a boom and bust cycle in wholesale prices. Once new entry is needed, the annual level of scarcity rent in the energy price is then assumed to remain at new entry levels for the rest of the modelled period.

### 4.2.3 REFERENCE SCENARIOS

We have used two reference scenarios, Base Case A and Base Case B, to inform the estimates of the wholesale market costs of different options. In both cases, we have assumed that renewable deployment in the All-Island and GB markets is sufficient to meet the relevant 2020 targets. This is in line with stated policy objectives in Ireland and Northern Ireland.

For the purposes of this Impact Assessment, it is reasonable to assume that policies and tools will be in place to support continued growth in renewables beyond 2020.
The main differences between the input assumptions for each Base Case are:

- the rate of renewable growth in the all-island market post 2020; and
- the cost competitiveness of coal-fired generation against gas-fired generation.

In the Base Case A scenario, renewable penetration in the I-SEM continues to grow quickly after 2020, reaching 52% by 2030, before curtailment. High gas prices and depressed carbon prices mean that coal-fired generation remains more competitive compared to gas-fired generation for the entire modelled timeframe.

Base Case B is a scenario where renewable penetration in the All-Island Market slows down after 2020, although it still grows to reach 45% by 2030 (before any curtailment). Stronger carbon prices mean that the relative cost of gas and coal reverses in the long term, with gas-fired generation becoming more competitive after 2025.

### 4.2.4 MODELLED OUTPUTS

The quantitative modeling outputs presented in this Impact Assessment include:

- monetised impacts;
  - wholesale market welfare[10], as proxied by changes in wholesale market costs (whereby an increase in costs results in an equivalent decrease in welfare);
  - distribution of the overall change in wholesale market welfare, i.e. between consumer surplus, producer surplus, congestion rent; and
  - consumer bills;
- non-monetised impacts related to key energy policies, in particular;
  - curtailment of variable renewable generation, and
  - security of supply, as measured by the Loss of Load Expectation (LOLE).

## 4.3 ESTIMATING IMPLEMENTATION AND OPERATING COSTS

In the Initial IA, we presented a set of estimated implementation and operating costs for the ETA options, and for the CRM options. Some respondents provided a qualitative comment on these estimates but no alternative values. In this IA, we have focused the presentation on the cost differences between options. For the ETA, the overall implementation costs are likely to be dominated by the common costs required to comply with the EU Target Model, e.g. a move to DA and ID ('ID') trading, rather than the differences between different HLD options.

For the ETA, we have reviewed international best practice to identify the costs associated with the introduction of a new energy market design. This review included first hand evidence gathered from recent system procurement processes, such as those in Turkey and Romania, alongside desk based research. This desk based research focused on the 2006 Cost-Benefit Study of the Single Electricity Market[11]; the Intra Day Proposed Costs and Estimated Benefits report[12] and the Assessment of the Costs and Cost Savings of NETA compared with the England and Wales Pool[13].

The assessment of CRM costs is primarily informed by published figures from DECC (as part of their CRM Cost Benefit Analysis process[14]) and Ofgem (as part of the Gas Significant Code Review[15], which looked at the costs of introducing a demand-side auction).

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10 The concepts associated with the measurement of changes in the level and distribution of welfare are further detailed in Annex 2.

11 http://www.detini.gov.uk/year_cost_benefit_study_of_the_single_electricity_market_-_a_final_report_for_niaer_and_cer__december_2006_.pdf

12 http://www.allislandproject.org/en/TS_Decision_Documents.aspx?article=7bc8db07-0493-4ba6-aa04-c885a2826c23

13 http://www.nao.org.uk/wp-content/uploads/2003/05/0203624.pdf

14 https://www.gov.uk/government/uploads/system/uploads/yearttachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

15 https://www.ofgem.gov.uk/ofgem-publications/85990/poyrygasscrdsrcbafinalreportv20.pdf

# 5 ENERGY TRADING ARRANGEMENTS

## 5.1 OVERVIEW

This chapter describes the updated assessment of different options for the HLD of the Energy Trading Arrangements (ETA). This includes updated qualitative and quantitative assessment since the Initial Impact Assessment.

In the In the quantitative assessment, we have used the following baselines for reporting the quantitative results for the different ETA options:

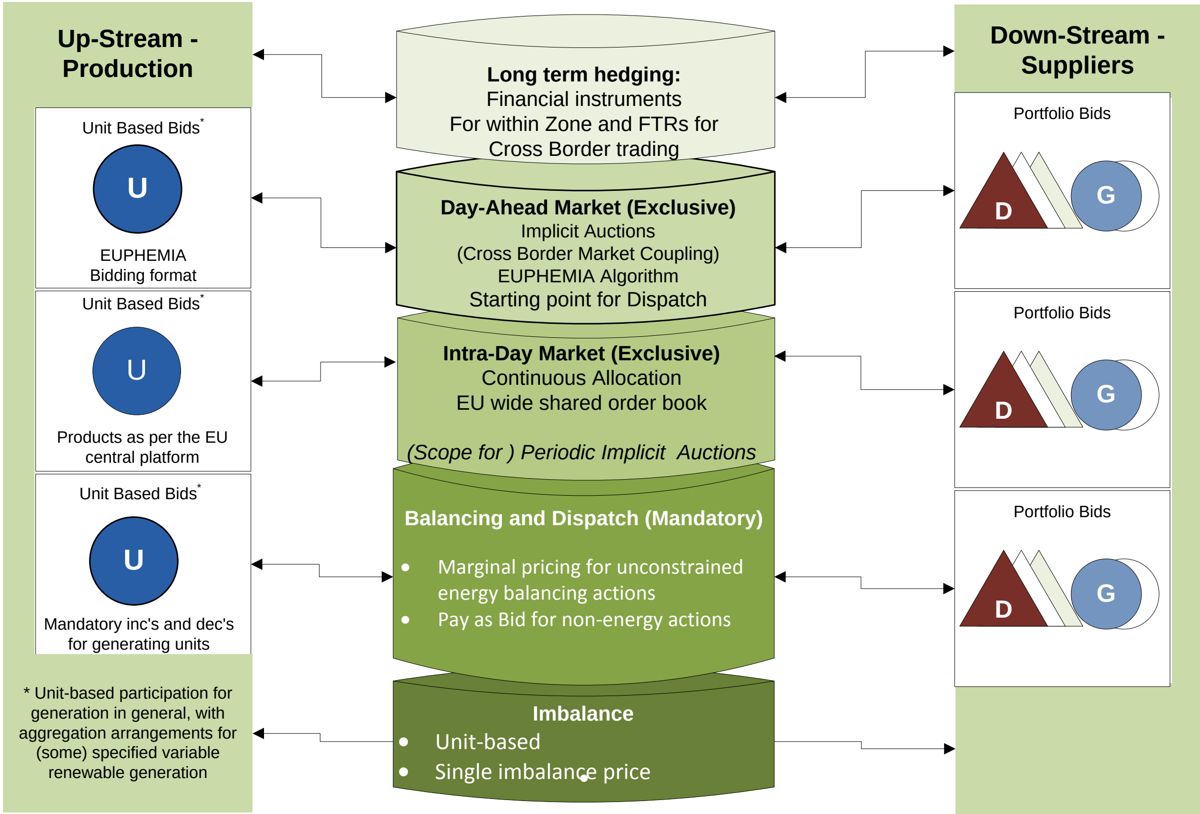
- **Modelling:** a theoretically efficient HLD is used as the baseline for reporting the modelling results for the Energy Trading Arrangements (ETA)[16]. This reflects the challenges of modelling different sets of energy trading arrangements as discussed in Section 5.3.
- **ETA: implementation and operating costs:** the preferred option is used as the baseline for reporting the differences between options in terms of implementation and operating costs. This reflects the fact that there is no appropriate 'do nothing' or 'do minimum' option that is compliant with the requirements of the EU Target Model, and that the 'theoretically efficient market outcome' could be not be used as a baseline for reporting practical implementation costs.

[16] The qualitative assessment identified that of the options, the proposed HLD would be most likely to deliver the closest outcome to the efficient market in the three aspects quantified in the modelling. That proposed HLD is used as the baseline for reporting the results of the analysis of implementation and operating costs for the ETA.

## 5.2 OPTIONS

Figure 3 below presents the key features of the Energy Trading Arrangements that formed the proposed Decision on the HLD for the I-SEM.

***Figure 3 - Proposed I-SEM Energy Trading Arrangements[17]***




The preferred option represents significant change from the SEM in particular with the move to a Balancing Market, compared to the current design of a pool-based approach to dispatch and calculation of ex-post prices with only financial trading ex-ante.

The Integrated Single Electricity Market (I-SEM) HLD Consultation Paper (SEM-14-008) set out some detailed choices for alternative ETA designs, with the main choices being whether or not to allow:

- physical scheduling for generation and load based on firm ex-ante trades with a Balancing Market for dispatch and determination of ex-post prices (rather than an ex-post pool);
- portfolio bidding for all generation in the DAM and the IDM;
- whether or not to allow physical self-scheduling based on forward trades to offset

17 Forward trading is financial in that any contracts struck between market participants in the forwards timeframe will not confer a right to physically schedule generation, demand or cross-zonal capacity in the All-Island Market. The use of forward financial trading in the I-SEM does not preclude intermediary or aggregation arrangements.

imbalance exposures caused by a difference between metered volumes and traded positions from the Day-Ahead market ('DAM'), Intraday market ('IDM') and Balancing Market ('BM'); and
- participation in the BM to be on a voluntary basis only.

One of the outcomes of the consultation process has been to identify some main decision points in determining the overall decision on the ETA package:

- Use of Balancing Market v use of ex-post pool (gross or net); and
- Whether or not to allow physical self-scheduling based on forward trades to offset imbalance exposures caused by a difference between metered volumes and traded positions from the Day-Ahead market ('DAM'), Intraday market ('IDM') and Balancing Market ('BM').

Therefore, the assessment presented in this Impact Assessment focuses on differences between the proposed HLD and alternative approaches in these two areas, which are summarised in Figure 4, Figure 5 and Figure 6.

***Figure 4 - Energy Trading Arrangements with Balancing Mechanism and physical self-scheduling based on forward trades ('self-scheduling')***

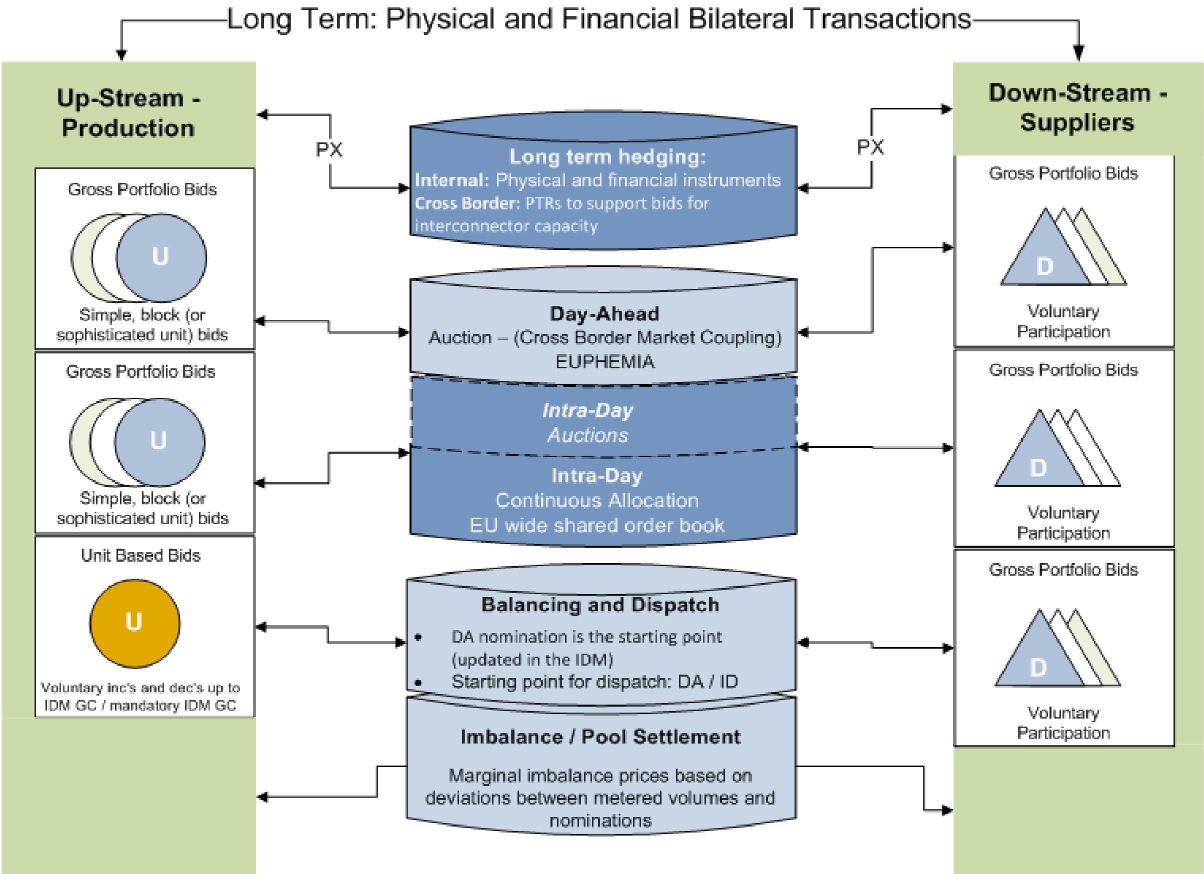


*Figure 5 – Energy Trading Arrangements with gross ex-post pool*

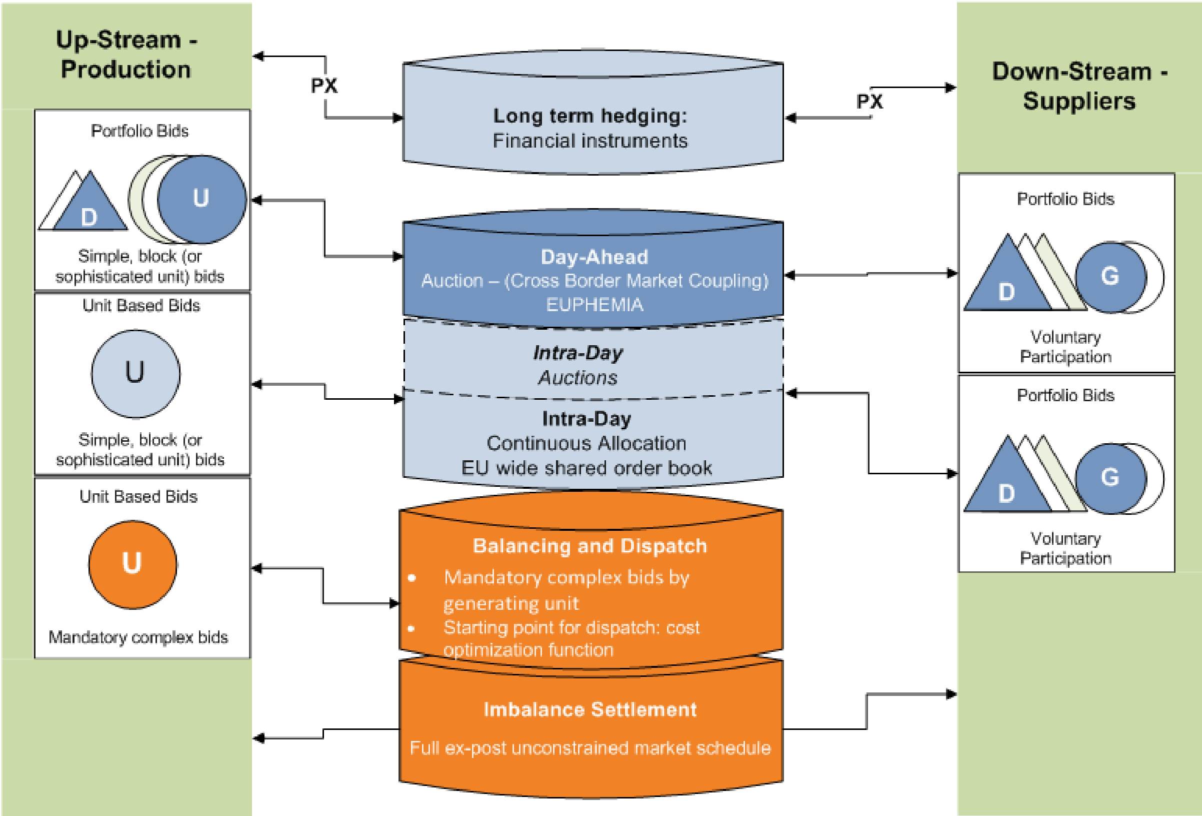
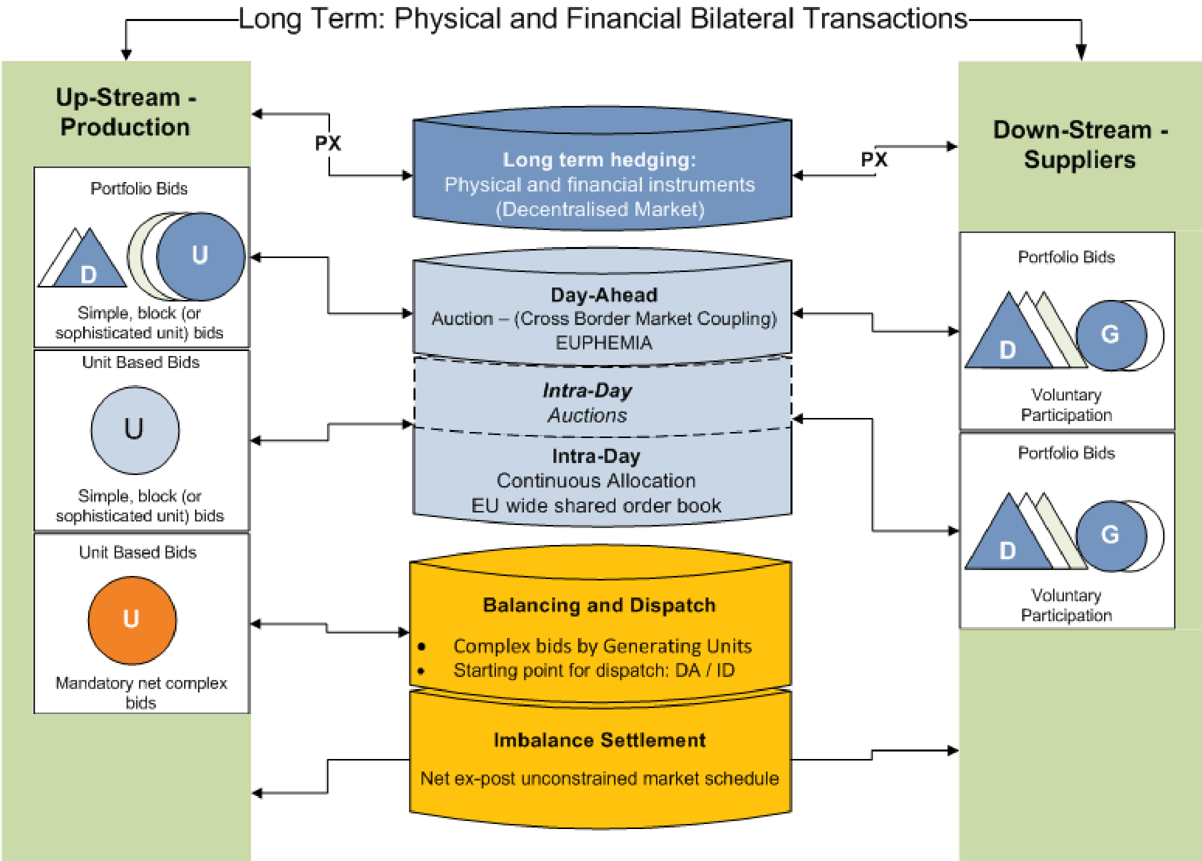



*Figure 6 – Energy Trading Arrangements with net ex-post pool*



## 5.3 WHOLESALE MARKET COSTS AND BENEFITS

This section reports the findings of our modelling of the potential wholesale market impacts of different HLD outcomes for the Energy Trading Arrangements. This provides insight into the outcomes associated with different ETA outcomes in terms of:

- **non-monetary factors,** primarily curtailment; and
- **monetary factors,** in terms of the level and distribution of wholesale market welfare and consumer bills.

It is widely recognised that it can be difficult to objectively model different forms of energy trading arrangements. This is because the quantitative outcomes, e.g. wholesale market costs, will typically be driven by assumptions about the market dynamics under any set of HLD ETA– e.g. such as the bidding behaviour and level of competitive pressure assumed for each option.

Therefore, we *quantified* the possible benefits from an efficient market design in three key areas that were susceptible to modeling through a number of sensitivities on the two reference scenarios, A and B:

- efficiency of DA allocation of interconnector capacity through the price coupling process;
- efficiency of ID trading to ensure scheduled interconnector flows respond appropriately to changes in the All-Island Market after the DA stage; and
- facilitation of renewables deployment.

We then reviewed the results of the *qualitative* assessment to see how closely each option might be expected to be to an efficient market design in each of these areas. This then informs an assessment of the possible scale of welfare benefits associated with each of the ETA HLD options, and how this compares to the magnitude of any estimated differences between the implementation and operating costs of different options.

Each sensitivity necessarily looks at one aspect of the wholesale market arrangements in isolation –- for example, the impact on the efficiency of the DA schedule produced or the efficiency of intraday trading across the interconnector.

This is not intended to suggest that these three aspects covered by the sensitivities are the sole areas on which a decision should be made between different packages of ETA. The qualitative assessment is clear that the ETA should be considered as a package for delivering overall efficient dispatch of generation and interconnection.

The EU Target Model is built around the coupling of the DA and ID markets, where unused cross border capacity is required to be allocated in a non-discriminatory manner initially at the day ahead stage through public auctions run by power exchanges. It is through the pooling of trading in these power exchanges combined with the implicit use of cross zonal capacity that the competitive benefits of being part of a large single market can accrue to end consumers. It is precisely the lack of firm day-ahead contracts in the SEM that has limited the benefits of market integration for SEM consumers and therefore achieving integration with the rest of the EU internal market at the day ahead timeframe is naturally a core component of the I-SEM project.

Potential differences between the ETA options in other timeframes (that is, other than the DAM and IDM) are hard to objectively quantify and are therefore covered in the qualitative assessment.

Delivery of an efficient outcome in a near-term market such as the DAM (through efficient trading and cross-border arbitrage) should facilitate the more efficient dispatch of generation and interconnection in the short-term and the long-term. However, an efficient DAM cannot on its own deliver efficient dispatch, as that will also depend on the effective operation of arrangements in other timeframes. For example, forward timescales are important for efficient investment decisions. Robust intraday markets and balancing tools are key mechanisms for adjusting dispatch to reflect updated information and system constraints. Ultimately, the I-SEM must operate coherently across all timeframes.

## 5.4 EFFICIENCY OF DA INTERCONNECTOR FLOWS

### 5.4.1 CONTEXT

In an efficient market, energy flows would be from the high price zone to the low price zone. This has not always been the case in the SEM (with respect to flows to/from GB) for a number of reasons, including:

- long gate closures in the SEM;
- the specific mechanisms for recovering start-up and no-load costs in the SEM (i.e., the uplift component of prices; and
- participants' trading strategies.

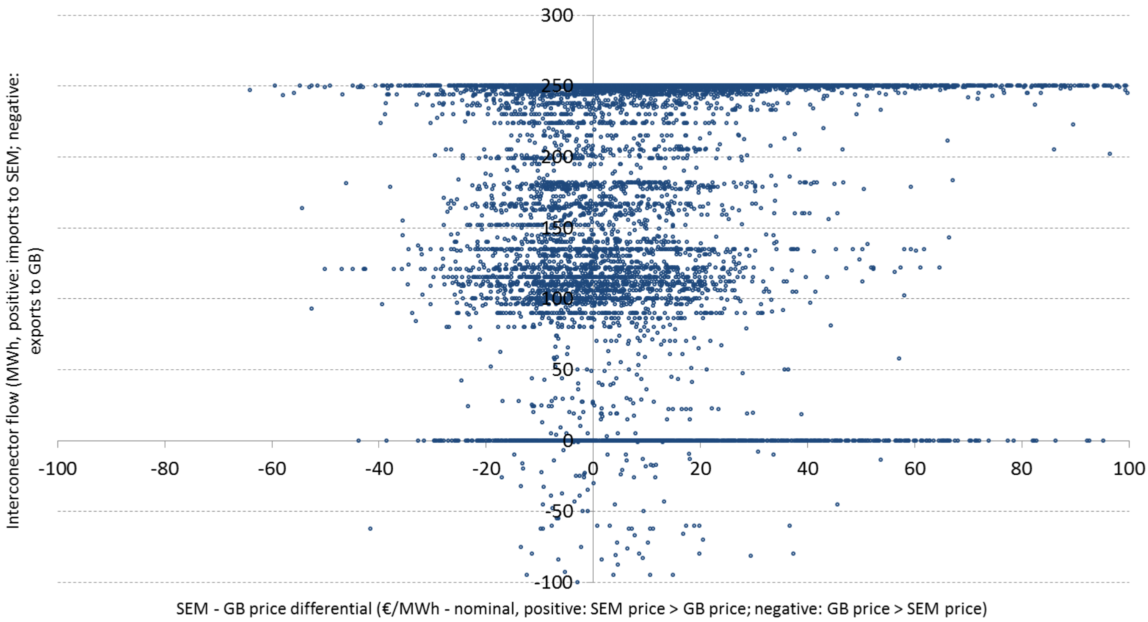
This presents an area for improvement for the new I-SEM arrangements, and one of the main goals of the new market design of the I-SEM is achieving efficient interconnector flows with GB at the day ahead and intra day timeframes[18].

Historically, interconnector flows to and from the SEM have not fully responded to DA price differentials between the SEM and GB in each individual delivery period. Figure 7 shows flows across the Moyle interconnector in each trading period against the price differential (SEM-GB) for 2013[19].

[18] And other markets if further interconnection is built.

[19] We have chosen to focus on flows with GB in 2013 to avoid factoring in the impact of charges from the GB side (BSUoS and TNUoS), which were no longer faced by interconnection in 2013.

*Figure 7 –Flows across Moyle in each trading period and the SEM-GB price differential (2013[20])*




Efficiency requires that flows are always in the same directions as prices and that all available capacity on the interconnectors is used when there is a non-zero price differential. If flows are efficient, the points in Figure 7 should be concentrated around straight horizontal lines in the top right quarter and in the bottom left quarter of the diagram, with these horizontal lines joined by a vertical line.

Points in the top right quarter of Figure 7 represent flows from GB to the SEM when the price in GB is lower than the price in the SEM. Similarly, points in the bottom left quarter represent flows from the SEM to GB when the SEM price is lower than the GB price.

Points in the other two quarters (bottom right and top left) represent flows in the opposite direction of the price differential for that individual pricing period.

In theory, whenever a price differential between the two markets exists (allowing for losses on the interconnector), the interconnector should be fully used. When the price in GB is lower than in the SEM (allowing for losses), Moyle should have been fully congested in the direction GB to the SEM. When the price in the SEM is lower than in GB (allowing for losses), Moyle should have been congested in the direction SEM to GB.

Figure 7 shows that flows appear to not be fully responsive to price differences with market participants trading electricity primarily from GB to the SEM irrespective of the actual price differential in individual delivery periods.

There are two types of inefficient flow observed in Figure 7:

20 The chart shows the difference between the N2EX DA prices for GB, and the sum of the DA SMP and the ex-post capacity payments (as a proxy for DA SEM wholesale price). Flows are based on the DA scheduled flows across Moyle

- flows in the opposite direction to prices (in 33% of periods) – this is shown by points appearing in the top left quarter or bottom right quarter of the chart; and
- less than full utilisation of the interconnector capacity when a non-zero price differential exists.

These inefficiencies may happen as a result of differences and perceived risks in the nature and timing of price formation in the two markets, and/or the mechanics and strategies of trading across the interconnector.

### 5.4.2 APPROACH

Our two reference scenarios (Base Case A and Base Case B) both assume the efficient scheduling and use of interconnection on an unconstrained basis. This is defined in terms of flows being consistent with the modelled price differential between the I-SEM and GB in each individual delivery period, taking account of the physical losses on the interconnector. This reflects the assumption that implicit market coupling should deliver optimal scheduling of interconnection. This leads to lower production costs and higher social welfare across the interconnected markets. This is based on the assumption that prices on either side of the interconnector are determined efficiently.

We have used two types of modeling sensitivity to capture the impact of potential inefficiencies in the scheduling of interconnector flows[21]:

- **A unilateral 'shift' whereby** the interconnector only flows from the All-Island Market to GB once the GB price is significantly higher than the price in the All-Island Market.
    - o This reflects barriers to trade (for example due to market design misalignments) leading to uneconomic cross border trades, i.e. trades in the wrong direction, in some half hour periods. This can be seen as equivalent to a risk premium being added onto bids into the DAM in the I-SEM, reflecting a number of factors, such as perceived riskiness of participation (e.g. in terms of mitigating exposure to ex-post prices) and/or excessive exercise of market power.
    - o We have modelled two 'shift' values of €10/MWh and €20/MWh.

- **A 'deadband',** whereby the interconnector only flows in either direction when the price differential exceeds a certain absolute value (where this value is in excess of the cost of physical losses).
    - o We have modelled two deadband values of €5/MWh and €10/MWh.

Figure 8 shows flows across the Moyle in 2013 (in the same format as Figure 7), alongside the stylised impact of a €20/MWh 'shift'. Similarly, a €10/MWh premium would result in a similar line with the vertical part of the curve crossing the x-axis at -€10/MWh.

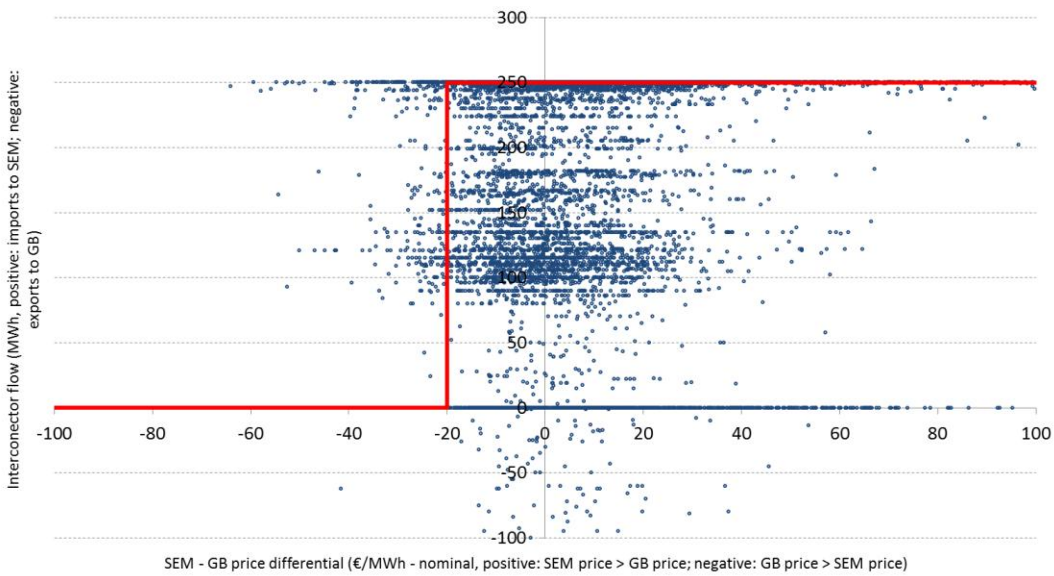
In 2013, GB wholesale prices were on average lower than the SEM wholesale prices. There

21 Historically, there are irregular patterns in the inefficiencies in the use of the interconnector. To capture this 'irregularity' we would have to take (and apply) a random pattern that may overstate future trading patterns on the interconnector

was a flow from the SEM to GB in only 2% of periods. In 33% of periods, when the flow was from GB to the SEM, the SEM price was lower than the GB price. Therefore, in the majority of periods when the SEM price was lower than the GB price, flows were from GB to SEM (i.e. in the 'wrong' direction).

For the periods when the flow was in the direction from GB to the SEM despite the SEM price being lower, the SEM price was on average €10/MWh lower (on a straight-line average) and €5/MWh lower (when weighted by flows). Therefore, the two premium levels we have used (€20/MWh and €10/MWh) represent a reasonable range around these average values.

***Figure 8 – Flows across the Moyle in 2013[22] and 'shift' of 20€/MWh***




### 5.4.3 NON-MONETARY RESULTS

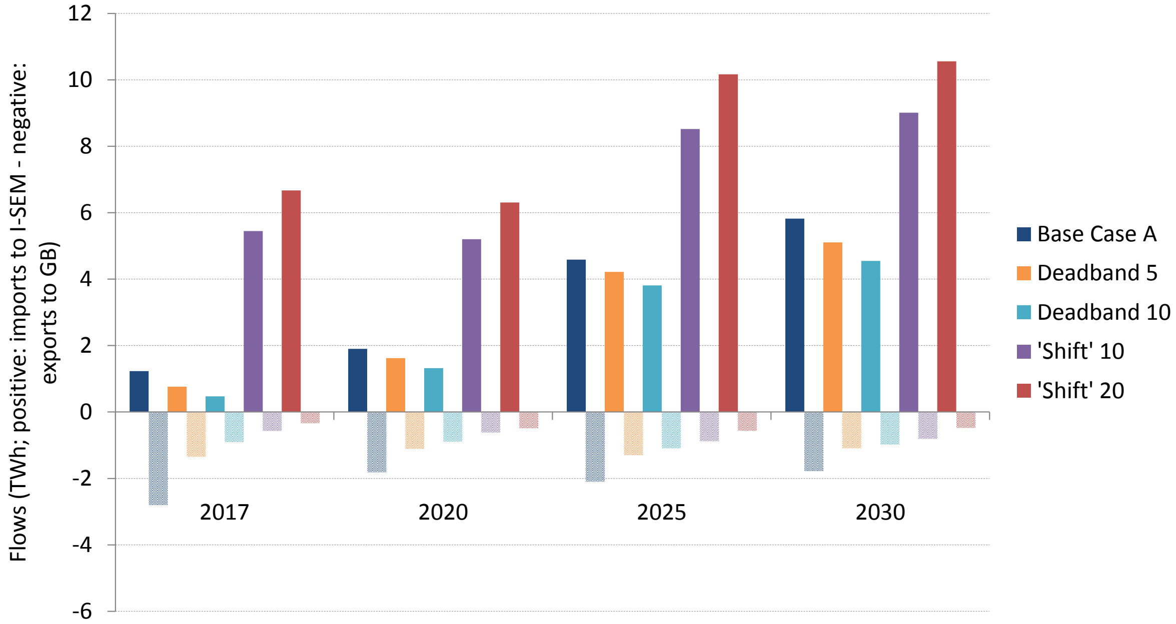
Figure 9 shows the impact of the modeling sensitivities on interconnector flows. In both types of sensitivity, there is increased barrier to export from I-SEM. This reduces the exports from I-SEM in all years in all scenarios.

The 'deadband' reduces flows in both directions between the two markets because it effectively introduces a two-way barrier to trade. Therefore, it also reduces imports into the I-SEM, as well as reducing exports from it.

The 'shift' has the impact of increasing flows from GB to I-SEM compared to the Base Case. This is because generation in the I-SEM becomes relatively more expensive than in the Base Case. This effectively distorts the merit order in favour of GB generation, but at the expense of generation located in the I-SEM.

22 We have used the N2EX DA prices for GB, the ex-ante SMP and the ex-post capacity payments to create an ex-ante SEM wholesale price. Under current rules, interconnector flows are based on the x-ante scheduled quantities (i.e. the modified interconnector unit nominations).

*Figure 9 – Annual imports to and exports from the I-SEM in Base Case A*[23]




We would expect greater barriers to export from the I-SEM to result in higher wind curtailment.

This is confirmed in Figure 10. In this graph, the blue line represents wind curtailment in Base Case A. The blue and orange lines in Figure 10 represent the wind curtailment when a 'deadband' is applied to Base Case A and the red and purple lines represent the wind curtailment when 'risk premiums' are applied to Base Case B.

Figure 10 shows that curtailment increases from 2020 to 2030 in all scenarios due to increasing levels of absolute wind.

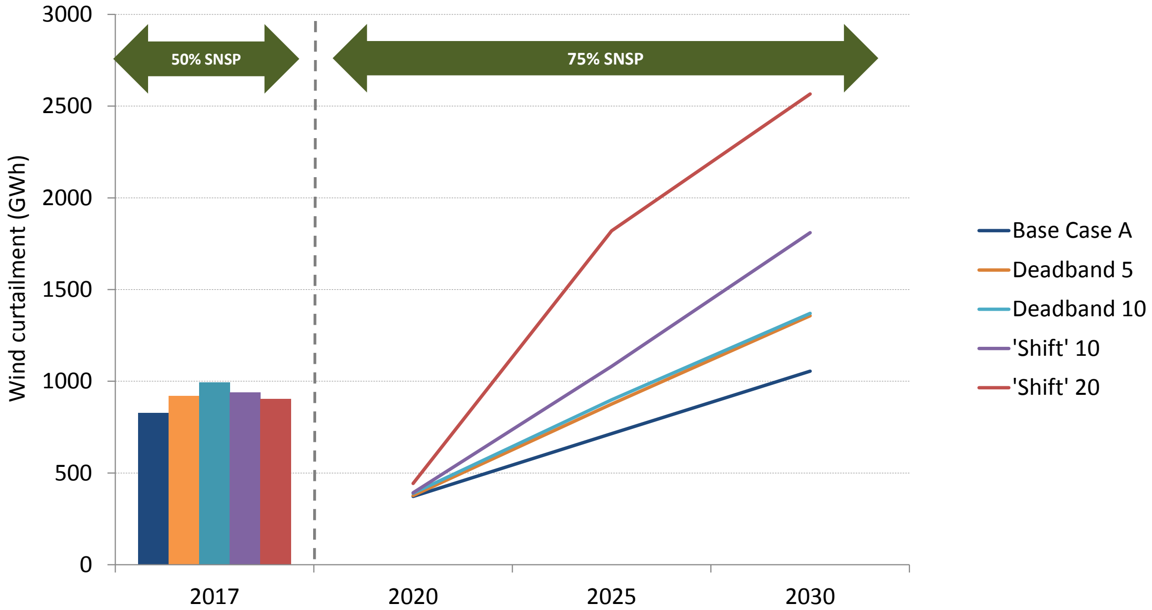
These outcomes are based on the scheduling of the DA interconnector flows. For the modeling purposes, it assumes that there are no subsequent changes in wind, demand, generation availability and interconnection flows. Notably, the curtailment levels shown in this chart do not take account of potential TSO countertrading to reduce curtailment. This reflects the principle that market driven cross border flows should provide a more reliable and efficient means of minimising curtailment in the long run than reliance on curative actions by the TSOs.

In these circumstances, the DA schedule provides the efficient dispatch on an unconstrained basis[24]. As described earlier, this is done intentionally to isolate the impact of one aspect of the market arrangements. It does not suggest that the efficiency of the DA schedule should be the sole area on which a decision should be made between different packages of ETA.

23 Exports in Base Case A fall between 2017 and 2020 as a result of changing fuel and carbon prices in GB and the All-Island Market, as well as the pattern of low marginal cost build in the two markets.

24 The modelling is carried out on a unconstrained basis, which is consistent with the definition of the market schedule.

*Figure 10 – Wind curtailment in Base Case A[25] for reference case and with inefficient scheduling of DA interconnector flows*




### 5.4.4 OVERALL WELFARE

The main finding from the modelling is that inefficient scheduling of interconnector flows at the DA stage leads to a loss in economic welfare for I-SEM in all sensitivities, for both Case A and Case B. This is illustrated by the reduced welfare shown in Table 6. This shows the NPV of the I-SEM welfare reduction for the two 'shift' cases and the two 'deadband' cases (compared with the two Base Cases).

Table 7 and Table 8 present the breakdown of the NPV of the change in wholesale market costs under each cost element. Since we have assumed that any inefficiency in the scheduling of interconnection would not result in differences in new build or plant retirement, there is no difference in terms of annual fixed costs and annualised capex. The value of total change in wholesale market costs, as shown in the last row of Table 7 and Table 8, is the exact opposite of the change in welfare presented in Table 6.

The welfare losses from inefficient scheduling of interconnector flows are in line with the expected impact of the introduction of a barrier to efficient cross-border trade.

For the 'shift', there would always be a reduction in production in the I-SEM because of reduced exports and increased imports. In the market coupling process that schedules the interconnector flows, the shift effectively increases the variable costs of domestic generation relative to GB generation as shown in Table 7 and Table 8. For the I-SEM, there is an increase in the cost of net imports, because more expensive imports are displacing cheaper domestic generation, and because there are lower export earnings. The reduction in domestic variable costs is outweighed by the increase in net import costs, and there is an

[25] Curtailment based on limit of 50% non-synchronous generation in 2017, and limit of 75% non-synchronous generation from 2020 onwards)

overall reduction in welfare from the inefficient use of interconnectors.

Similarly, for the case of the 'deadband', there is always a welfare loss for I-SEM from the inefficient use of the interconnectors as shown in Table 6 – this is because of missed opportunities for efficient arbitrage in setting the DA schedule. However, the direction of change in variable production costs and net imports depend under the balance between exports and imports in the underlying scenario because the deadband is a two way barrier to trade.

Overall, the two 'deadband' cases result in a much smaller loss of welfare than the 'shift'– this is because the deadband still has flows in the correct direction but only when prices are sufficiently different[26]. The risk premium actually leads to flows being scheduled in the wrong direction – i.e. against the direction suggested by the 'underlying' prices.

For Base Case A (Table 7), the reduction in the value of exports is greater than the value of the reduced imports, and hence the cost of net imports increases. The opposite is true for Base Case B (Table 8), where the overall effect of the 'deadband' is to increase production s in I-SEM, but reduce net import costs.

***Table 6 – Change in I-SEM wholesale market welfare compared with the reference cases***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Base Case A | Base Case B |
|---|---|---|
| 'Shift' €10/MWh | -€391m | -€135m |
| 'Shift' €20/MWh | -€458m | -€200m |
| Deadband €5/MWh | -€8m | -€12m |
| Deadband €10/MWh | -€22m | -€37m |

***Table 7 – Change in I-SEM wholesale market costs compared with the reference case for Base Case A***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | 'Shift' €10/MWh | 'Shift' €20/MWh | Deadband €5/MWh | Deadband €10/MWh |
|---|---|---|---|---|
| Annualised capex | 0 | 0 | 0 | 0 |
| Annual fixed costs | 0 | 0 | 0 | 0 |
| Variable production costs | -€3679m | -€4447m | -€248m | -€112m |
| Cost of EEU[27] | 0 | 0 | 0 | 0 |
| Cost of net imports | +€4070m | +€4905m | +€256m | +€134m |
| Total change in wholesale market costs | +€391m | +€458m | +€8m | +€22m |

[26] It does not capture partial flows (which have been historically observed) even in the case of greater price differences. This sensitivity presents a small degree of inefficiency and may underestimate the overall impact.

[27] Expected Energy Unserved (EEU), which is monetised using the VOLL of €10898/MWh that has been set for the All-Island Market)

*Table 8 – Change in I-SEM wholesale market costs compared with the reference case for Base Case B*

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | 'Shift' €10/MWh | 'Shift' €20/MWh | Deadband €5/MWh | Deadband €10/MWh |
|---|---|---|---|---|
| Annualised capex | 0 | 0 | 0 | 0 |
| Annual fixed costs | 0 | 0 | 0 | 0 |
| Variable production costs | -€2800m | -€3381m | +€236m | +€390m |
| Cost of EEU | 0 | 0 | 0 | 0 |
| Cost of net imports | +€2935m | +€3581m | -€224m | -€353m |
| Total change in wholesale market costs | +€135m | +€200m | +€12m | +€37m |

Table 9 and

Table 10 shows the changes in annual welfare for each of the snapshot years we have modeled. It presents the annual wholesale market costs for the I-SEM under Base Case A and Base Case B respectively, alongside the increase in wholesale costs for each of the modeled sensitivities.

It illustrates the welfare loss from the 'deadband' is stable over time, but the impact of the 'shift' is highest in 2017, and lowest in 2030.

*Table 9 – Annual I-SEM wholesale market costs for Base Case A, and the impact of each of the modelled sensitivities for inefficient interconnection*

| €m, real 2012 money | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Base Case A with efficient interconnector flows | €2407m | €2697m | €3088m | €3533m |
| 'Shift' €10/MWh | +€50m | +€34m | +€37m | +€23m |
| 'Shift' €20/MWh | +€69m | +€42m | +€35m | +€28m |
| Deadband €5/MWh | +€3m | +€1m | +€0m | -€1m |
| Deadband €10/MWh | +€6m | +€3m | +€1m | -€1m |

*Table 10 – Annual I-SEM wholesale market costs for Base Case B, and the impact of each of the modelled sensitivities for inefficient interconnection*

| €m, real 2012 money | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Base Case B with efficient interconnector flows | €2490m | €2804m | €3415m | €3946m |
| 'Shift' €10/MWh | +€22m | +€14m | +€9m | +€6m |
| 'Shift' €20/MWh | +€28m | +€20m | +€16m | +€10m |
| Deadband €5/MWh | +€1m | +€0m | +€1m | +€4m |
| Deadband €10/MWh | +€3m | +€2m | +€4m | +€6m |

#### 5.4.5 DISTRIBUTIONAL EFFECTS

Table 11 and Table 12 show the impact of less efficient flows on the surplus accruing to I-SEM producers, I-SEM consumers (in the wholesale market) and interconnection owners under Base A and Base Case B respectively.

*Table 11 – Change in distribution of I-SEM wholesale market welfare between Base Case A and the modelled sensitivities for inefficient interconnector use*

| €m, real 2012 money<br>NPV over 2017-2030 with a 3.5% discount rate | Change in consumer surplus | Change in producer surplus | Change in congestion rent | **Change in wholesale market welfare** |
|---|---|---|---|---|
| 'Shift' €10/MWh | +€600m | -€1012m | +€20m | **-€391m** |
| 'Shift' €20/MWh | +€1038m | -€1605m | +€109m | **-€458m** |
| Deadband €5/MWh | -€158m | +€95m | +€55m | **-€8m** |
| Deadband €10/MWh | -€435m | +€314m | +€99m | **-€22m** |

*Table 12 – Change in distribution of I-SEM wholesale market welfare between Base Case B and the modelled sensitivities for inefficient interconnector use*

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Change in consumer surplus | Change in producer surplus | Change in congestion rent | **Change in wholesale market welfare** |
|---|---|---|---|---|
| 'Shift' €10/MWh | +€448m | -€624m | +€41m | **-€135m** |
| 'Shift' €20/MWh | +€719m | -€1016m | +€97m | **-€200m** |
| Deadband €5/MWh | -€145m | +€119m | +€14m | **-€12m** |
| Deadband €10/MWh | -€270m | +€239m | -€6m | **-€37m** |

In the presence of a 'deadband', I-SEM consumers face higher prices in periods where imports from GB are reduced – this is because the imports are replaced by more expensive I-SEM generation. In periods where exports are reduced by the 'deadband', this lowers effective demand in the I-SEM. This reduces the I-SEM price which is a benefit to I-SEM consumers, but is a loss for I-SEM producers. Congestion rent from the interconnectors, which ultimately feeds back to customers in Ireland and Northern Ireland through reduced TUoS charges, also increases in most cases as a result of increased price differential between the I-SEM and GB over some periods (when the underlying prices in the two markets are actually relatively close in the reference case) which offsets the partial reduction in flows in those periods.

In the 'shift' sensitivities, there is actually an increase in I-SEM consumer surplus, and a reduction in producer surplus compared to the situation with efficient scheduling of interconnector flows. The reduction in producer surplus is because part of domestic generation is displaced by imports from GB and even domestic generators at the lower end of the merit order realise lower revenues from the energy market.

This is the result of assuming that the 'shift' acts as an artificial subsidy for imports into the I-SEM. In line with the economic principles of international trade, the removal of this effective 'import subsidy', which is a one-way barrier to trade from I-SEM to GB, would lead to times of higher demand (including exports) and hence price in the I-SEM. This would reduce I-SEM consumer surplus and increase I-SEM producer surplus. There would be a concomitant reduction in GB price, with higher GB consumer surplus and lower GB producer surplus.

However, it must be remembered that the 'import subsidy' effectively distorts the merit order against I-SEM generation and in favour of GB generation. A more efficient pattern of flows would reflect greater opportunities for I-SEM producers to access demand in the GB market. This is one of the intentions of the removal of barriers to trade and harmonisation of cross border trading rules under the Target Model.

The distribution of welfare changes depends on how this 'shift' is assumed to arise. If it reflects higher bid prices from I-SEM generators, then this would raise prices in the I-SEM and reduce I-SEM consumer surplus. The impact on producer surplus would depend on whether the higher bid prices reflected an increase in costs, e.g. the perceived risk of participation in the DAM, or an exercise of market power. In the latter case, there would definitely be an increase in I-SEM producer surplus at the expense of consumers.

Furthermore, the impact on consumers in the I-SEM would be offset by the increased competitive pressure in the I-SEM coming from efficient coupling with the GB market and any savings to consumers from any changes to the CRM.

For reference, Figure 11 compares the annual consumer bills[28] under efficient use of interconnection to the costs for each of the sensitivities with different degrees and types of inefficiencies.

For the 'deadband', consumer bills increase with inefficient interconnector flows by an average of €11m/a for a deadband of €5/MWh, and €31m/a for a deadband of €10/MWh.

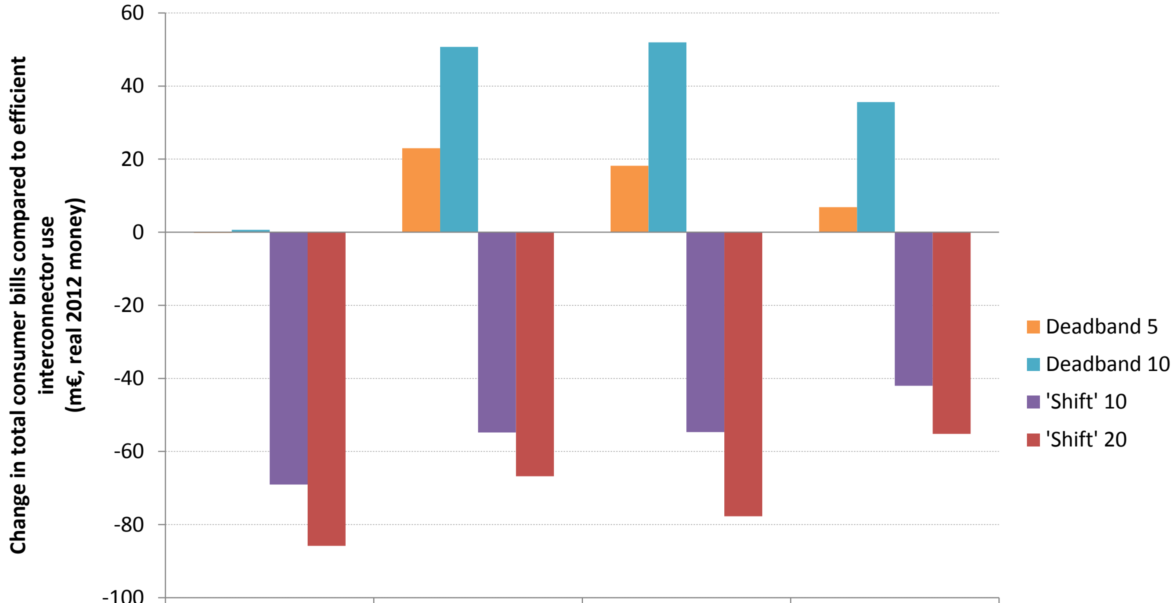
Under the 'shift', the bias in flows from GB to the I-SEM results in an annual average of €69m and €53m total savings in consumer bills in Base Case A under the €20/MWh and the €10/MWh shift respectively. These reflect the changes in wholesale bill elements and therefore do not capture any additional costs that appear in retail bills as an indirect result of the effective import subsidy.

The changes in bills are in line with the consumer surplus impacts, and again the results are sensitive to the assumptions of how the 'shift' is assumed to arise.

In summary, the analysis confirms that the impact of consumers of inefficient interconnector flows depends on what gives rise to the inefficiency and the underlying pattern of flows – which will be affected by fuel costs, relative generation and load mix in the two markets, RES penetration in the two markets etc. In all of our modelled cases for inefficient interconnector flows, there is a net reduction in I-SEM welfare overall from the reduction in the efficiency of cross border flows.

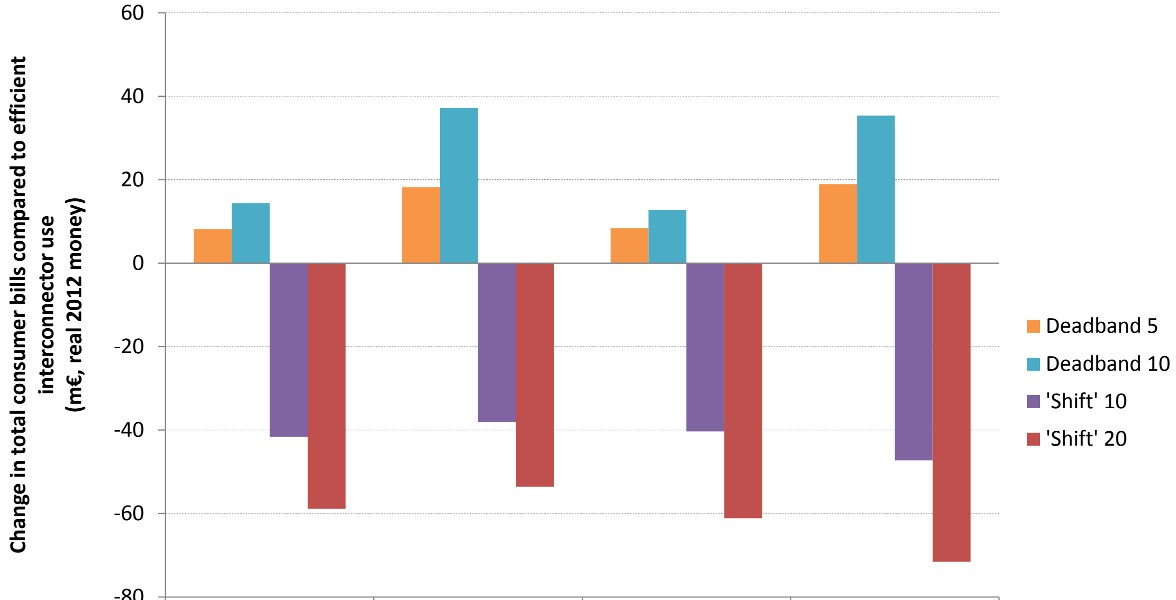
[28] The consumer bill differences shown in this section are based on changes in wholesale market outcomes. They do not include the small differences in the implementation and operation costs, which are covered in a separate section.

*Figure 11 – Differences in annual consumer bills between efficient use of interconnection and alternative inefficient use of interconnection sensitivities in Base Case A*




| | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Deadband 5 | 0 | 23 | 18 | 7 |
| Deadband 10 | 1 | 51 | 52 | 36 |
| 'Shift' 10 | -69 | -55 | -55 | -42 |
| 'Shift' 20 | -86 | -67 | -78 | -55 |

*Figure 12 – Differences in annual consumer bills between efficient use of interconnection and alternative inefficient use of interconnection sensitivities under Base Case B*




| | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Deadband 5 | 8 | 18 | 8 | 19 |
| Deadband 10 | 14 | 37 | 13 | 35 |
| 'Shift' 10 | -42 | -38 | -40 | -47 |
| 'Shift' 20 | -59 | -54 | -61 | -72 |

### 5.4.6 IMPLICATIONS FOR HLD

There is an inherent difficulty in representing different market designs in economic models since all designs are based on a set of input assumptions, including whether the wholesale electricity market is perfectly competitive or oligopolistic. For example, oligopolistic behaviour can be modelled assuming Bertrand and Cournot behaviour on the part of firms in the sector. However, we do not consider that there is any meaningful way of distinguishing between the options for energy trading arrangements using these techniques. Therefore, we believe that it is more transparent to quantify the impacts of possible inefficiencies in the DA scheduling of interconnector flows. We then qualitatively explore the extent which this inefficiencies may be more likely to occur under the different HLD options.

The proposed HLD for the ETA strongly integrates the interconnector into the DA scheduling arrangements, supported by the use of FTRs to maximise the availability of physical interconnection capacity for the DAM. Exclusive participation in the DAM, along with measures to facilitate participation by variable generation, means that the full competitive pressure of the interconnector is brought to bear on the main spot market in the I-SEM, increasing overall efficiency across both markets.

High levels of participation in the DAM and IDM by variable renewable generation will deliver more efficient scheduling of the interconnectors based on ex-ante market trading. This should facilitate more efficient use of the interconnector at the day ahead stage thus minimizing the likely changes to interconnector flows during real time dispatch. The proposed HLD of the ETA as the I-SEM High Level Design incentivises high participation in the short term markets through balance responsibility, supporting routes to market, and exclusive physical trading in the centralised, public and coupled market places.

In the qualitative assessment, we describe the features that may reduce the efficiency of the DA market outcomes , such as:

- **Physical Transmission Rights being allocated on the interconnectors in forward timeframes,** reducing the capacity available for implicit auctions of interconnector capacity and energy in the DAM, which can then reduce competitive pressures in the DAM (particularly where PTRs are nominated in the economically correct direction);
- Not having the central market places as collectively exclusive routes to physical nominations.
- **Competition for liquidity between the DAM and an ex-post pool**, which could be gross or net**.** Price-setting generation is likely to be drawn to the European DAM and IDM both to access the interconnectors and to gain the highest price possible. Variable renewable generation on the other hand, if it is conservative in forecasting DA volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. Low levels of participation in the DAM and IDM would likely see inefficient patterns of scheduled imports and exports, and higher levels of scheduled curtailment.

For these reasons the SEM Committee considers that the proposed ETA HLD is the superior option for delivering the most efficient cross border scheduling of flows and the least curtailment of variable renewable generation based on DAM schedules. The modeling provides quantitative evidence of the reduced social welfare that could result from the implementation of a market design that results in less efficient DA scheduling of the interconnectors.

The SEM Committee recognises that efficient DA scheduling does not in itself guarantee efficient actual flows on the interconnectors. Conversely, an efficient DA schedule should not reduce the chance of efficient flow, for example in the case of the proposed HLD option which allows for adjustment in the IDM and by the TSO.

## 5.5 INTRADAY ADJUSTMENT OF INTERCONNECTOR FLOWS

### 5.5.1 CONTEXT

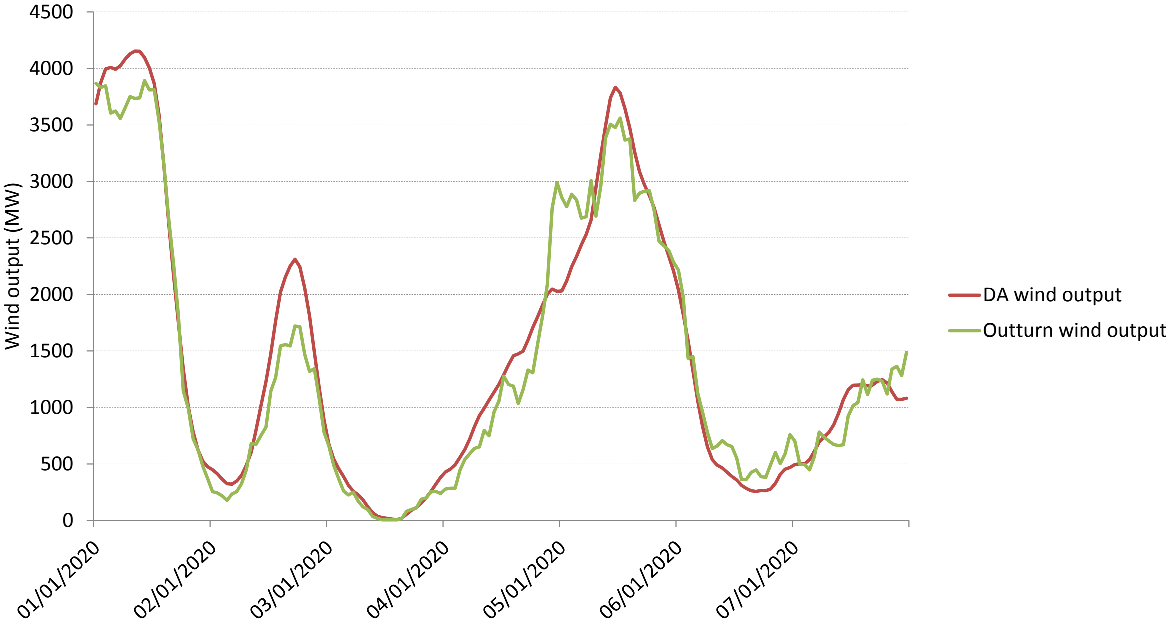
An effective IDM can be used to refine market participants' positions closer to real time as conditions change. This is of particular importance to variable renewable generators.

Trading on a common ID platform and allowing for interconnector flows to respond to changes in plant availability and wind output can lead to a benefit in terms of:

- lower wholesale market costs, as the most efficient resources can be utilised; and
- reduced wind curtailment, with less reliance on TSO countertrading.

For a sample week (based on January 2006 historical data), Figure 13 presents DA expectation for wind output alongside the outturn for the whole island of Ireland.

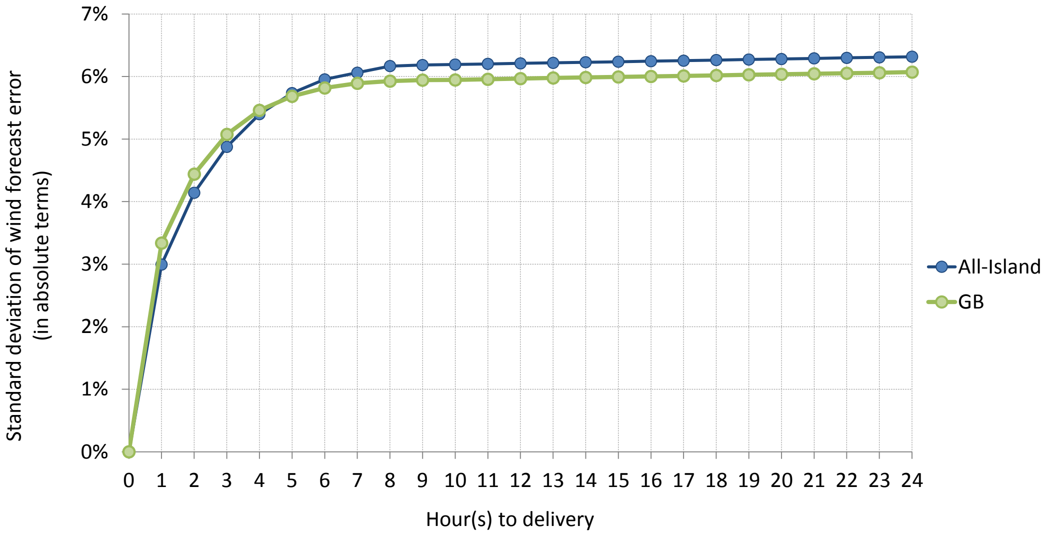
***Figure 13 – Outturn and expected DA wind output for the whole island of Ireland for a sample week in January 2020 (weather year 2006)***



Based on historical data, in both the All-Island system and GB the average DA forecast error in the absolute wind load factor is around 6% (in absolute terms). In terms of improvement, as we approach closer to real-time, the magnitude of forecast error does not decrease significantly up to 8 hours ahead of real-time. Significant improvement in forecasting takes place around 4 hours ahead of delivery.

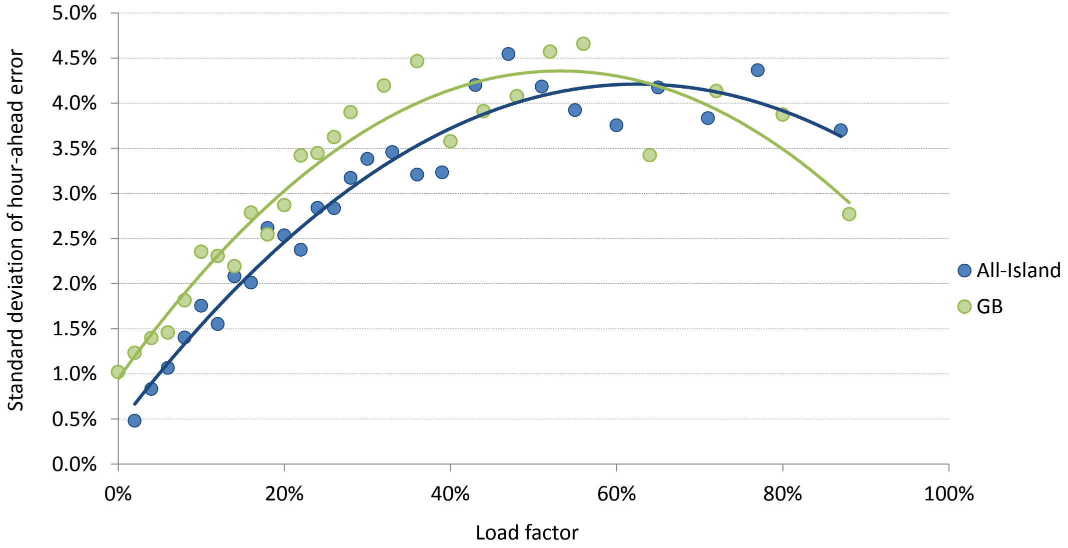
Figure 14 presents the evolution of the average absolute wind forecast error from 24 hours ahead of real-time up to real-time. It can be read as follows: the error in the wind load factor 1 hour ahead of real-time in the All-Island system is on average +/-3%, 2 hours ahead of real-time +/-4% and so on and so forth. The wind load factor forecast error is presented in absolute terms and not relative to the actual wind load factor.

*Figure 14 – Evolution of estimated wind forecast error in the SEM and GB*




Apart from proximity to real-time, the wind forecast error is also dependent on the level of the expected (and actual) wind load factor. The standard deviation is highest when the outturn load factor is in the mid-range of the expected wind load factors. It is, however, significantly lower at low load factors. This is illustrated in Figure 15.

*Figure 15 – Standard deviation of 1 hour-ahead error as a function of outturn load factor for wind (for GB and the SEM)*[29]




### 5.5.2 APPROACH

We have modelled the benefit of using interconnection ID efficiently when compared to less responsive flows. We assume that the original runs of the two cases, Base Case A and Base Case B, represent the outcome of the DAM. We then update demand and wind based on historical analysis of forecast errors.

Initially, we assume that flows across the interconnector are based on expected DA wind output (as shown by the red line in the illustrative Figure 13). We then model the market with updated wind and demand assuming that the flows across the interconnector cannot respond to those changes. In this case, there will be an inefficient use of the interconnection as the changes in both wind and demand patterns cannot be reflected in the flows.

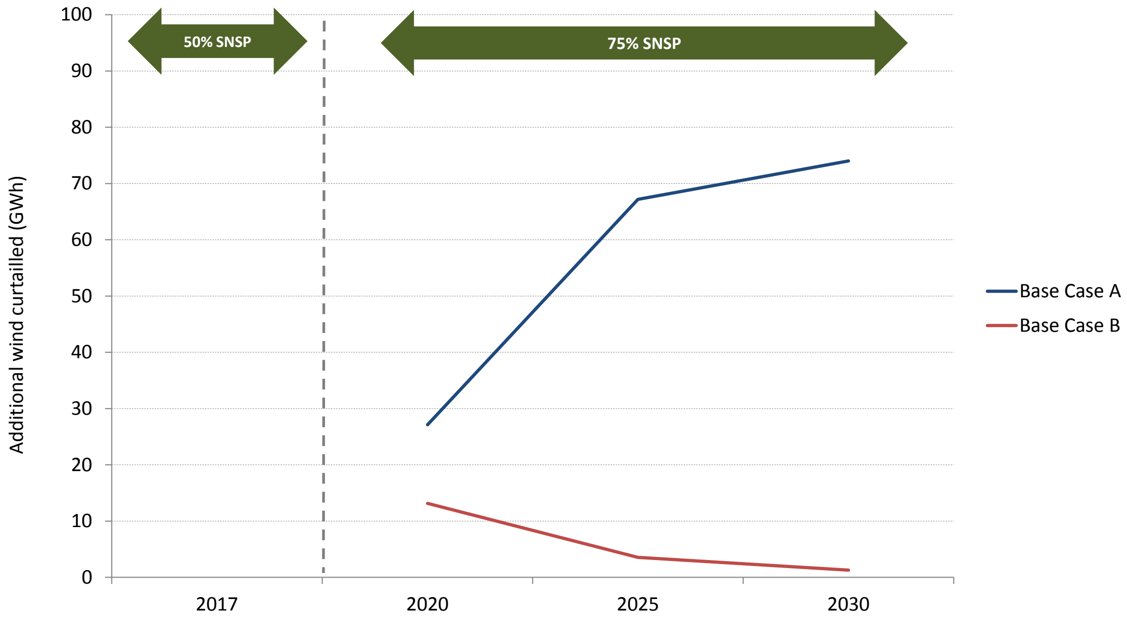
For example, if the outturn wind output is lower than expected and the interconnector cannot respond, it may be that a more expensive thermal unit in the I-SEM has to replace the shortfall. If the interconnector could however respond to that change, a potentially cheaper unit in GB could have been utilised.

### 5.5.3 NON-MONETARY RESULTS

The efficient use of the interconnector ID should also further reduce wind curtailment, as shown in Figure 16 below. When there is additional wind output when compared to the DA forecast volumes, allowing the interconnector to respond to such changes closer to real-time, means more opportunities for market participants to trade additional wind output. This also limits the need of further curative actions by the TSO.

29 It has to be noted that the distribution of expected wind does not necessarily follow a normal distribution. This means that even at low load factor, close to zero, there can still be a positive standard deviation.

*Figure 16 – Additional wind curtailment with no ID cross-border trading*[30]




### 5.5.4 WELFARE IMPACT

Table 13 shows the increase in welfare as result of allowing trading cross-border ID. The benefit arises from allowing interconnector flows to respond to changes in demand and wind after the close of the DAM.

The benefits would have been even greater if outages were included, and the modelling quantified the additional costs of changes that happened closer to real time[31]. This would have led to a reliance on more flexible (and expensive) capacity to respond in the absence of a change in interconnector flows.

*Table 13 –Change in I-SEM wholesale market welfare from efficient ID cross border trading*

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Base Case A | Base Case B |
|---|---|---|
| Change in wholesale market welfare | +€441m | +€130m |

Table 14 presents the annual increase in wholesale market welfare arising from ID trading in the modelled snapshots years. This shows that for Base Case A, the benefits of ID trading are much higher in 2025 and in 2030 than in the initial years of the modeling. This reflects the increased wind penetration in these years, which means that there are larger ID changes in the direction of the efficient flow.

Table 15 shows the breakdown of the NPV reduction into the different elements of

30 Curtailment based on limit of 50% non-synchronous generation in 2017, and limit of 75% non-synchronous generation from 2020 onwards)

31 In this analysis we assume that there is foresight of changes in wind and demand well in advance of the event

wholesale market costs. Since we have assumed that any inefficiency would not result in differences in new build or plant retirement, there is no difference in terms of annual fixed costs and annualised capex.

***Table 14 – Annual change in I-SEM wholesale market welfare from efficient ID cross border trading***

| €m, real 2012 money | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Base Case A | +€5m | +€1m | +€64m | +€99m |
| Base Case B | +€1m | +€19m | +€8m | +€14m |

***Table 15 –Change in I-SEM wholesale market costs resulting from efficient ID cross border trading***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Base Case A | Base Case B |
|---|---|---|
| Annualised capex | +€0m | +€0m |
| Annual fixed costs | +€0m | +€0m |
| Variable production costs | -€175m | -€113m |
| Cost of EEU | -€45m | +€17m |
| Cost of net imports | -€221m | -€34m |
| Total change in wholesale market costs | -€441m | -€130m |

### 5.5.5 DISTRIBUTIONAL IMPACTS

Table 16 shows how efficient ID trading increases the surplus accruing to I-SEM producers, I-SEM consumers and interconnector owners for Base Case A and Base Case B respectively.

***Table 16 – Change in distribution of I-SEM wholesale market welfare as a result of more efficient cross-border ID trading for both Base Case A and Base Case B***

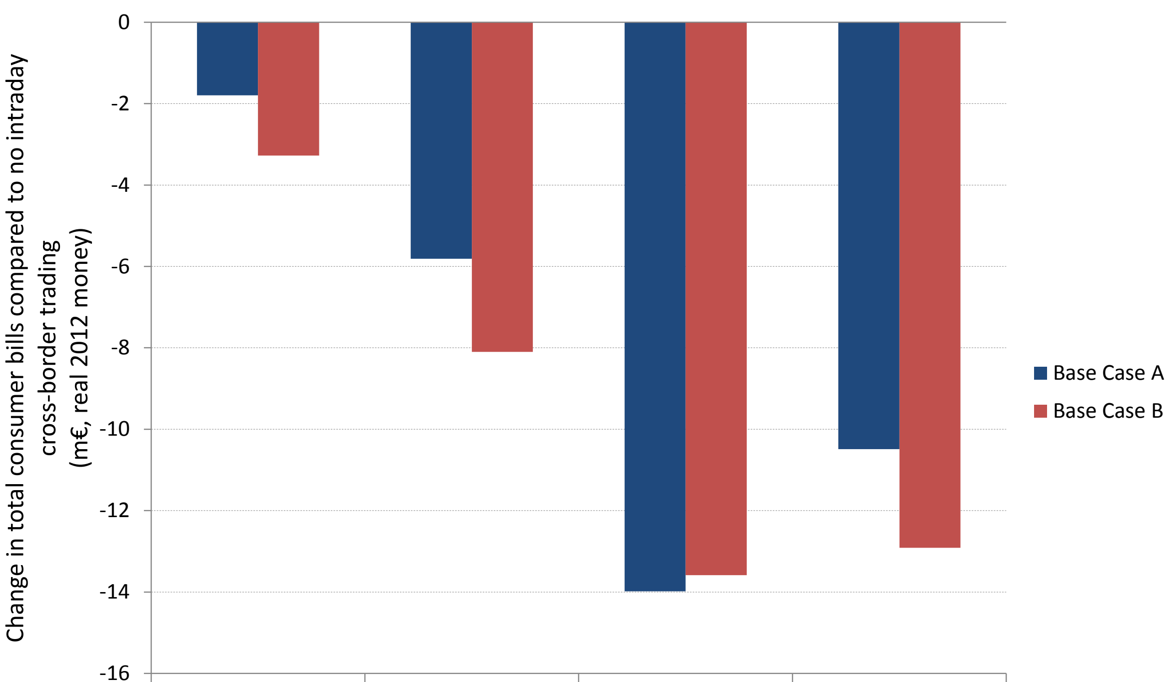
| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Change in consumer surplus | Change in producer surplus | Change in congestion rent | **Change in wholesale market welfare** |
|---|---|---|---|---|
| Base Case A | +€140m | +€170m | +€130m | **+€441m** |
| Base Case B | +€92m | +6m | +€32m | **+€130m** |

Over the whole modelled period, more efficient trading ID delivers a benefit for all parties across each of our two base cases. Over some periods, domestic producers benefit from additional surplus through trading across border when there is a need for additional generation in the GB market. Over other periods, where additional generation is needed to meet domestic demand in the I-SEM, demand benefits from having access to cheaper resources across border.

When it comes to interconnection, the ID timeframe has effectively been modelled assuming a series of auctions throughout the intraday period. This is a simplification for modeling purposes and is a reasonable for the assumption of a theoretically efficient outcome. This also means that a single price (like in the DA auction) is revealed for each trading period for each market (the I-SEM and GB). As a result, interconnection can capture the value of the trades in the form of (additional) congestion rent, as further cross-border trading takes place ID. This pricing of the interconnector capacity affects the welfare distribution rather than the overall level of welfare (in the short-term at least).

Figure 17 shows the annual reduction in consumer bills under both Base Case A and Base Case B, which are broadly in line with the change in consumer surplus.

***Figure 17 – Change in annual consumer bills[32] as a result of more efficient ID cross-border trading for both Base Case A and Base Case B***




| | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Base Case A | -2 | -6 | -14 | -10 |
| Base Case B | -3 | -8 | -14 | -13 |

### 5.5.6 IMPLICATIONS FOR HLD

ID trading benefits arise from allowing interconnector flows to change in response to changes in demand, wind and generator availability. An effective IDM can be used by market participants to change their market positions closer to real time as more information comes to light on generator availability and as demand and wind forecasts become more accurate. This allows scheduled interconnector flows to respond to these changes and leads to benefits both in terms of lower overall wholesale market costs (as the most efficient resources can be utilised across Europe) and in terms of reduced curtailment of variable renewable generation.

[32] This covers costs of wholesale energy, capacity payments, additional renewable support payments, and DS3 payments. The figures shown in this chart do not include the impact of costs of operation and implementation.

While the assumed design of the IDM is the same under all options evaluated, the incentives to participate in it will vary between them. The assessment in this section equates efficient intraday market with efficient (unconstrained) dispatch. This reflects the fact that we are considering the possible welfare impact of inefficiencies in one aspect of the market design (intraday trading), and does not mean that it is the only important aspect of the trading arrangements, which through efficient trading outcomes should ultimately facilitate efficient dispatch (in the short-term and long-term)

In the proposed HLD, the presence of a Balancing Mechanism with cost-reflective and suitably marginal imbalance prices should provide incentives for generation and demand to enter the IDM to avoid or mitigate exposure to imbalance prices. The use of an exclusive and centralised IDM in the proposed HLD means that it should support a liquid IDM and result in a greater likelihood of reduced wholesale market costs and reduced curtailment quantified in Tables 15 and 16 and shown in Figure 16 respectively.

If generators are allowed to schedule their own physical positions without trading in the centralised market places, this could reduce the use of the IDM by these generators (or their bilateral counterparties) to manage changes close to real-time. The option for portfolio players to balance deviations between their day ahead contractual position and metered generation within their portfolio reduces liquidity in the IDM and hence the efficiency of cross border trade through IDM coupling.

Under a pool-based approach, whether gross or net, the risk is that there are insufficient incentives for ex-ante physical trading, which could greatly reduce the effectiveness of the IDM. Variable renewable generation and demand, if it is conservative in forecasting DA volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. The resulting reduced incentive for market participants to trade ID would reduce the efficiency of cross border flows and hence increase wholesale market costs based on inefficient ID scheduling.

In summary, the SEM Committee consider the proposed HLD ETA option contains the combination of features to best deliver the benefits to consumers in the form of efficient ID trading. This is both in terms of optimal scheduling of flexible resources in both markets and the reduction in the curtailment of variable renewable generation.

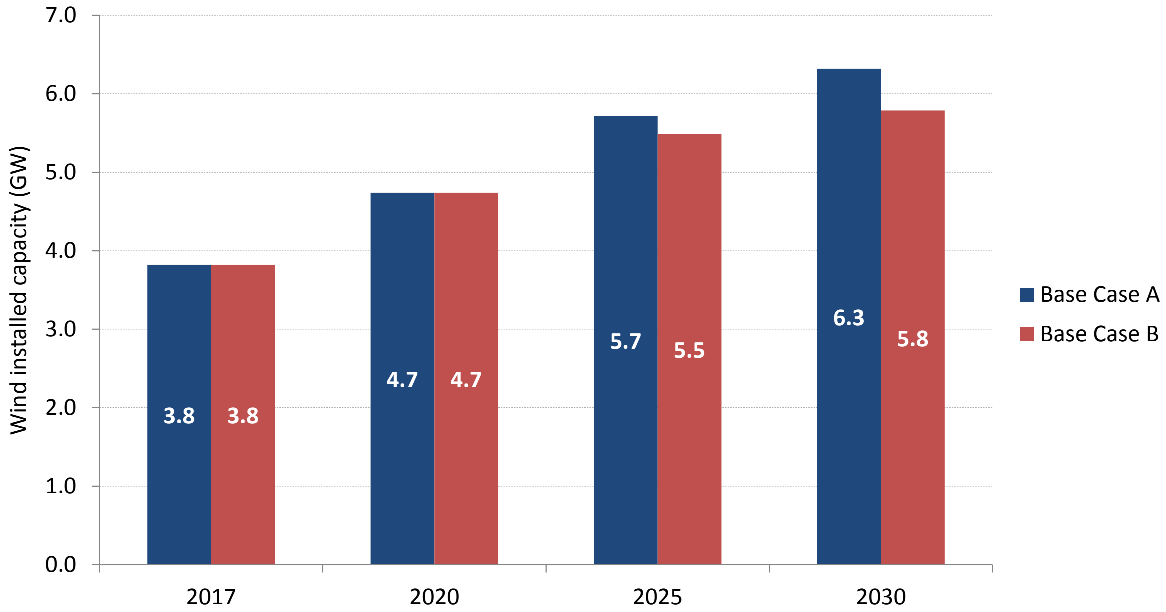
The modelling supports more efficient cross border trade and more integrated markets as a means of promoting renewable energy sources and meeting national an EU Targets for renewable energy. It also highlights the potential welfare losses from reduced efficiency of ID trading in terms of incorrect scheduling of the interconnector.

## 5.6 COST OF CAPITAL FOR WIND

### 5.6.1 CONTEXT

Wind generation accounts for a significant proportion of the projected wholesale market costs. Figure 18 presents the installed wind capacity in both reference scenarios.

*Figure 18 – Installed wind capacity in the I-SEM in Base Case A and Base B*




Both Base Cases assume that 2020 RES targets are met. Further decarbonisation is primarily led by stronger renewables penetration under Base Case A in the years after 2020. In both Base Cases, installed wind capacity accounts for more than 45% of the total installed capacity by 2020. This means that the cost of building wind is one of the most important wholesale market cost elements.

In our two Base Cases we have assumed a WACC of 7.9% for onshore wind. In a market where there is increased risk for wind generators we would expect the weighted average cost of capital (WACC) to increase and that this would result in higher overall wholesale market costs.

### 5.6.2 APPROACH

We assume a 1% increase in the WACC for wind. For reference, this is comparable to the change in WACC assumed by DECC when modelling the difference between moving from the Renewables Obligation (8.3%) to the CfD (7.1%) support scheme under EMR. We have then calculated the impact on total wholesale market costs for delivering the same amount of wind capacity.

### 5.6.3 NON-MONETARY RESULTS

A higher cost of capital may also lead to lower investment in wind generation with an impact on decarbonisation efforts. We have not explored the effect of lower wind capacity being installed – this will depend on any resulting change in the renewable support schemes.

### 5.6.4 OVERALL WELFARE

Table 17 presents the NPV of wholesale market costs for the I-SEM in both Base Case A and Base Case B alongside the wholesale market cost increase assuming a 1% increase in the WACC for wind (from the reference value of 7.9%).

***Table 17 – Impact of higher cost of capital for wind on I-SEM wholesale market costs***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Base Case A | Base Case B |
|---|---|---|
| Reference case with WACC of 7.9% | €31965m | €34494m |
| Change in wholesale market costs with WACC of 8.9% | +€450m | +€419m |

Table 18 shows the annual increase in wholesale market costs for the two cases.

***Table 18 – Impact of higher cost of capital for wind on annual wholesale market costs for I-SEM***

| €m, real 2012 money | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Base Case A with WACC of 7.9% | €2407m | €2697m | €3088m | €3533m |
| Change in wholesale market costs with WACC of 8.9% | +€17m | +€30m | +€49m | +€68m |
| Base Case B with WACC of 7.9% | €2490m | €2804m | €3415m | €3946m |
| Change in wholesale market costs with WACC of 8.9% | +€17m | +€30m | +€46m | +€62m |

### 5.6.5 DISTRIBUTIONAL EFFECTS

The change in welfare is equal to the change of wholesale market costs, as presented above in Table 17. The distribution of the lost welfare (between producers and consumers) is dependent on the renewables support mechanisms.

If the renewables support mechanisms are not amended to reflect the increase WACC for wind, the lost welfare will take the form of a reduction in producer surplus with consumers remaining unaffected. If, on the other hand, the renewables support mechanisms are re-based, then the lost welfare will be shared between consumers and renewable producers.

### 5.6.6 IMPLICATIONS FOR HLD

Increases in the cost of capital for new variable renewable generation projects could be driven by increases in price risk, volume risk or a combination of the two.

In the proposed HLD option for the HLD ETA, the interconnector capacity is fully integrated into the energy trading arrangements and the use of FTRs maximises the availability of physical interconnection capacity for the DAM and IDM. The exclusive nature of trading through the DAM and IDM and the commitment to provide an aggregator of last resort should provide greater comfort to independent variable renewable generation that they will have access to competitive and efficiently priced markets for off-take. The exclusive nature of trading through the DAM and IDM will also provide variable renewable generation with greater opportunity to manage their exposure to imbalance prices, compared with other options that allow trading outside centralised market places

Use of self-scheduling could reduce the access to the DAM and IDM for smaller players and particularly for variable renewable generation. In those circumstances, variable renewable generation could be forced into the Balancing Market where it would likely receive a lower price.

An ex-post gross pool could discourage voluntary financial trading in the DAM and IDM (as the results of the DAM and IDM do not provide generation with a physical schedule) Low levels of participation in the DAM and IDM would likely see inefficient patterns of scheduled imports and exports. Although efficient traded outcomes (including cross-border arbitrage) are not guarantees of efficient dispatch, they should help to facilitate it.

Variable renewable generation could be tempted to enter only the ex-post pool. Interconnector flows would not be fully integrated into the pool process for dispatch. This would reduce the efficiency of flows on the interconnectors and lead to higher levels of scheduled curtailment, with increased reliance on TSO intervention.

Under a net pool, there are effectively two distinct markets competing for liquidity, the European DAM and the ex-post pool. Price-setting generation is likely to be drawn to the European DAM and IDM in order both to access the interconnectors and to gain the highest price possible. Variable renewable generation, on the other hand, if it is conservative in forecasting DA volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. However the flows on the interconnectors will be set by the DAM and IDM so this would reduce the efficiency of flows on the interconnectors and lead to higher levels of curtailment.

As argued earlier, price-setting generation in a net pool is likely to be drawn to the European DAM and IDM. Variable renewable generation, on the other hand, if it is conservative in forecasting day ahead volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. Therefore the ex-post pool will deliver lower prices to variable renewable generation as it will be saturated with low cost generation.

As discussed further in the Summary of Responses document, the SEM Committee has noted that it is important the proposed HLD also provides all market participants, including small independent players, with suitable access to the tools to discharge this responsibility through their activities, including forecasting and trading. Therefore, the move to an imbalance pricing regime should be considered as part of a holistic solution, rather than as a stand-alone measure.

In addition, the SEM Committee notes that many of the concerns expressed by variable renewable generation relate to the detailed definition of a marginal imbalance price. The detailed design and implementation phase will determine the methodology for setting an imbalance price that accurately reflects the costs to the TSO of taking energy balancing actions, whilst providing robust signals for market participants to take actions that would support the maintenance of the balance between energy supply and demand.

For these reasons the SEM Committee considers that the proposed option for the HLD ETA will best mitigate the overall risks facing variable renewable generation in the energy market. This will help to deliver a lower possible cost of capital for new investment in variable renewable generation compared to the other options. As demonstrated by the quantitative modeling, this would provide significant welfare gains in the All-Island Market.

## 5.7 IMPLEMENTATION AND OPERATING COSTS

In this section, we estimate the impact of different choices for the energy trading arrangements on the implementation and operating costs for the I-SEM HLD. Annex 3 details the estimated costs of the implementation and operation of different energy trading arrangements.

For the avoidance of doubt, these cost estimates cover the cost that will be incurred to set up, run and participate in the Energy Trading Arrangements. They do not include costs of delivering energy, which are described in Sections 5.4 to 5.6

The preferred HLD option is used as the baseline for reporting the differences between options in terms of implementation and operating costs. This reflects the fact that there is no appropriate ‘do nothing’ or ‘do minimum’ option that is compliant with the requirements of the EU Target Model, and that the ‘theoretically efficient market outcome’ could be not be used as a baseline for reporting practical implementation costs.

We then estimate the changes in costs for three stakeholder groups of moving to other sets of trading arrangements. These stakeholder groups are:

- market participants, covering systems, staff and external advice;
- the TSO and MO; and
- the RAs.

The analysis presented in the Initial Impact Assessment illustrated that the estimate of implementation and operating costs for different sets of energy trading arrangements were sensitive to the estimate of ongoing market participant costs, particularly in relation to trading in the IDM. These costs are driven by the requirements of the Target Model, rather than differences in the overall HLD of ETA that comply with the Target Model.

In the HLD of the ETA, the SEM Committee has already identified that there will be ways for smaller market participants to manage these costs through aggregation and/or outsourcing. During the detailed design phase, the SEM Committee will ensure the implementation of the trading processes is focused on delivering value for money for customers in the All-Island Market.

Therefore, as detailed in Annex .the main difference between the implementation and operating costs of the different options is the cost of the arrangements for dispatch and ex-post prices – i.e. an ex-post Balancing Mechanism versus gross pool versus net pool. Therefore, Table 19 summarises the estimated change in costs faced by the three stakeholder groups in in choosing to continue with a pool rather than move to a Balancing Market (which is included in the baseline option). The central cost impact shown in Table 19 is the same as presented in the Initial Impact Assessment. Table 19 highlights that there is relatively little difference between the central estimates for different arrangements, with the main difference being the additional cost of the more complex net pool arrangements

***Table 19 – Change in implementation and recurrent non-market costs in not implementing a Balancing Market***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Market Participant | Central Agency | Regulatory Authorities | Total |
|---|---|---|---|---|
| Retention of gross pool | +€0m | +€4m | €0m/a | **+€4m** |
| Move to net pool | +€0m | +€21m | €0m/a | **+€21m** |

We do not differentiate between the implementation and operating costs in respect to other possible differences between different HLD:

- Physical scheduling on the basis of trading in the forward timeframe, within-zone and across-zone;
- Portfolio bidding being allowed for all generation in the DAM and the IDM;
- The ability to physically self-schedule without making a trade in the centralised market places; and
- Voluntary participation in the Balancing Mechanism.

These factors are hard to quantify and are covered in the qualitative assessment.

This partly reflects the fact there are a number of common costs that we would expect to be incurred irrespective of the design of the energy trading arrangements – particularly in relation to costs of systems and staff required for trading in the DAM and IDM.

One potential source of difference in implementation and operation costs between the option chosen for the HLD of the I-SEM ETA and other options was the relative cost of moving to a Balancing Market compared to retaining an ex-post pool arrangements, albeit modified to comply with the Target Model. In practice though, there was little difference in the central estimate of the implementation and operation cost of these two mechanisms, particularly given the uncertainty around the central estimates.

We have not quantified the possible change in costs related to credit cover and collateral related to participation in different market timeframes (with different settlement practices).

This will vary for the different options, but for an ex-post gross pool, the savings will not be as substantial. This is because the physical market settlement will be based on the pool settlement that would be expected to follow the settlement timeframe of the current market.

## 5.8 QUALITATIVE ASSESSMENT AGAINST PRIMARY ASSESSMENT CRITERIA

This section assesses different choices for the energy trading arrangements against the primary assessment criteria set out in Section 3.2. In particular, this highlights the difference between these options on hard to quantify factors.

We use as our reference point the proposed HLD option set out in the draft decision document, particularly with comparison to a pool-based approach which would be closest to the status quo. Where relevant, we also highlight the impact of the choices around:

- physical scheduling for generation and load based on firm ex-ante trades with a Balancing Market for dispatch and determination of ex-post prices (rather than an ex-post pool);
- portfolio bidding for all generation in the DAM and the IDM;
- whether or not to allow physical self-scheduling based on forward trades to offset imbalance exposures caused by a difference between metered volumes and traded positions from the Day-Ahead market ('DAM'), Intraday market ('IDM') and Balancing Market ('BM'); and;
- participation in the BM to be on a voluntary basis only.

### 5.8.1 INTERNAL ELECTRICITY MARKET

By definition, any feasible option for the HLD of the Energy Trading Arrangements must comply with the high-level requirements of the five pillars of the EU Target Model:

- Capacity Calculation and Zones Delimitation;
- Cross Border Forward Hedging and Harmonisation of Capacity Allocation Rules;
- Day Ahead Market Coupling;
- Intra Day Continuous Trading; and
- Cross Border Balancing.

Therefore, the qualitative assessment considers only how the options differ in relation to how efficiently and easily compliance may be achieved within the EU timelines for Target Model implementation, particularly in relation to DA, ID and balancing. This is clearly in line with the definition of this criteria in the Next Steps Decision Paper (as confirmed in Section 3.2), where it refers to implementation of the EU Target Model, and efficient cross-border trade. In this respect, it is important to consider cross-border trade over a range of timeframes, including forward, Day Ahead, Intraday, and balancing. Therefore, this criterion cannot simply be interpreted as only judging strict compliance with the Target Model, which is an absolute requirement for a compliant I-SEM HLD.

The requirement for collective exclusivity of the DAM, IDM and BM in the proposed option for the ETA HLD reflects that the core centralised European markets for delivering the effective cross-border integration of spot markets that is at the heart of the Target Model. The assessment process has identified the importance of centralised scheduling and dispatch processes in the I-SEM. The focus on using the European markets for the centralised scheduling process should ensure the full benefits of integration with neighbouring markets are seen in the All-Island Market .

This is supported by the use of Financial Transmission Rights (FTRs) in the forwards timeframe. FTRs will ensure that the full capacity of the interconnectors is available for DA coupling. This is an advantage of over the use of Physical Transmission Rights (PTRs) which would likely reduce liquidity in the DAM, and hence competitive pressures from cross-border trade. This is not the result of inefficient PTR nominations as they can be superpositioned by the DAM – rather it is the result of PTR nominations being in the economically correct direction, i.e. in line with prices. This reduces the amount of capacity available to the DAM in the valuable direction (i.e. in line with prevailing price differentials), which could reduce the efficiency of price formation in that key reference market.

The use of a separate Balancing Market in the proposed HLD option should facilitate compliance with the EU Target Model requirements for cross-border integration of electricity balancing. This is because many EU markets, including GB, has a dedicated balancing market.

By comparison, the retention of an ex-post pool would raise challenges for:

- The efficiency of the DAM and IDM, given the incentives for many market participants, particularly variable renewable generation to trade only in the pool;
    - Under the EU Target model, trading in the DAM and IDM will set the flows on the interconnectors. Therefore the drawbacks of less efficient DAM and IDM participation are particularly acute in terms of overall costs and benefits to consumers.
- Less familiar arrangements for the DAM and IDM in a European context.
    - It is our understanding that using 'financial' instruments to determine cross-border flows would be unique in Europe as market splitting/coupling has historically been carried out by spot exchanges or spot market operators (Nord Pool Spot first, then EPEX Spot, Belpex, APX, OMIE, GME, which are all physical exchanges proposing physical contracts)[33]. This would also create a discussion if the price coupling are done on the same product if the trading on one side is physically firm and on the other side would be just financially firm.
- Accommodating the requirements emerging under the Target Model for balancing, as well as increasing the complexity of achieving all the benefits from efficient cross border balancing, because it would be harder to achieve cross-border integration (based around a shared merit order list) between an ex-post pool and a Balancing Market – for example, with different gate closures. ,

The net pool option considers combining physical ex-ante trading with a net ex-post pool.

[33] Other financial instruments are allowed under the EU Target Model in relation to cross-border risk hedging – e.g. FTRs and CfDs – but these do not determine the physical flow on the interconnectors.

However, the major challenge is that that there are effectively two markets competing for primacy in the trading of physical quantities: the centralised European DAM (and IDM) and the ex-post pool. If measures are put in place to ensure that sufficient price-making generation is committed through the pool, then this could restrict participation in, and ultimately the efficiency of, the European centralised markets. Such measures would also create barriers to trade between Member States which would be contrary to EU single market rules.

In addition, the move to a net ex-post pool would require major changes to existing SEM systems would be needed. For example, this includes the introduction of physical nominations and net complex bids into the pool, possible changes to the recovery of start and no-load costs and changes to the timing of bid resubmissions. This would be challenging under the required timelines for implementation, especially given that there is little international experience to draw upon.

**In the All-Island Market, there is a high emphasis on centralised and transparent trading arrangements for spot physical markets. The arrangements set out in the proposed HLD will concentrate physical liquidity into the European spot markets – with FTRs ensuring that interconnectors are fully integrated into the price-making process in these markets, and balancing arrangements more closely aligned with neighbouring countries. Therefore, on balance, the proposed HLD is assessed as representing the most efficient implementation of the EU Target Model in terms of delivering the benefits of market integration whilst respecting the particular circumstances of the All-Island Market.**

### 5.8.2 SECURITY OF SUPPLY

There are two dimensions to security of supply: short-term issues and long-term issues. Short term issues generally refer to the ability of the TSO to deliver a secure system in dispatch. The TSO has highlighted the afternoon/early evening of D- 1 (after the DAM results) as being an important point for receiving these physical nominations. In addition, the management of changes in interconnector flows may be easier for the TSO if the physical contract nominations are as close to final as possible after the DA stage as this should reduce the likelihood of large swings in the scheduled interconnector flows close to real-time.

In the longer term, the issues are around having sufficient installed capacity on the system and the strength of forward contracting as a price signal to incentivise efficient entry and exit. In the proposed HLD, the strong emphasis on very liquid trading at the DAM is key for informing the physical nominations at that stage. Very high levels of unit-based bidding, albeit on a "best endeavours" basis, into a welfare-optimising algorithm should give a good-quality and efficient (unconstrained) initial schedule to the TSOs which is based on competitive outcomes from the DAM. This will again support the efficiency of the market.

In options with significant levels of physical bilateral trading in the forwards timeframe, this would reduce the levels of demand unserved at the DAM stage. This could foreclose the market for non-vertically integrated participants, including variable renewable generation. Given priority dispatch for renewables in subsequent timeframes, there is a potential for higher levels of redispatch in such options.

A Balancing Mechanism with mandatory participation before the IDM gate closure will increase the scope and tools available to the TSO to manage the system. If the BM only becomes mandatory after the IDM, this would likely mean that there are fewer bids and offers available to the TSO in the BM until close to real time. We would judge such an option as performing quite low on short term security of supply in I-SEM.

Under a gross ex-post pool, the TSO dispatch processes to deliver a secure and safe system are likely to be broadly similar to the current arrangements. The biggest differences are likely to relate to the scheduling of plant closer to real time. The interconnectors will be scheduled based on the DAM and IDM.

If effective incentives are in place for participation in these markets, cross border flows could change ID based on new information such as increased or reduced wind. The ability to update bids by generators in the ex-post pool will also mean the TSO expected or actual dispatch could be changed closer to real-time. This will depend on the extent to which the bids of domestic generation changes ID.

This means that one of the relative disadvantages of a gross ex-post pool is that the interconnector flows would not be fully integrated into the pool process for dispatch as they are inputs into the process rather than being determined within the pool itself. This could reduce the coordination and efficiency of overall dispatch and could increase reliance on TSO countertrading.

In terms of longer term security of supply, the liquidity of the DAM is seen as important in determining the incentives from the energy market for new entry (or exit) – for example, by providing strong and robust reference prices to support forward trading and a route to market for uncontracted generation. The proposed HLD for the ETA performs well on this as it is designed specifically to deliver a very high level of liquidity in the DAM. This is a strength over pool-based approaches, where we expect greater challenges in delivering a liquid DAM.

**In summary, the proposed HLD has a number of features that should be particularly helpful in delivering a secure system. Its strong emphasis on the DAM will give a robust starting point for dispatch. The interconnectors are fully integrated into the physical spot markets, which inform the detailed, feasible physical nominations from the market participants. The release of the contractual schedule from a liquid DAM should help to deliver a good-quality set of nominations for the TSO as the starting point for dispatch. The liquid and transparent DAM will be a strong reference market to support the development of liquid forward financial trading, which should support long-term security of supply.**

**The operation of a mandatory balancing mechanism after the DA stage will provide the TSO with access to a wide range of bids and offers to help it manage the system, primarily for energy balancing, but also to support its wider set of arrangements for procuring system services, thereby ensuring short term security of supply**

**Other approaches could deliver security of supply but the potential for inconsistencies between timeframes may make a less robust starting point for dispatch or less efficient interconnector scheduling, increasing the requirement for TSO intervention. The key point is that the market design should provide incentives to follow dispatch instructions to ensure short term security of supply.**

### 5.8.3 COMPETITION

No set of market arrangements can guarantee a fully competitive outcome in the long-term and short-term. Hence market power mitigation measures will need to be considered in any set of trading arrangements.

The issue for the assessment against this criterion is the extent to which the set of trading arrangements include structures and arrangements that are designed to support features that typically enhance competitive pressures, such as:

- reduced barriers to entry for market players of all sizes and technologies;
- the encouragement of trading in liquid and transparent market places[34]; and
- support for efficient cross-border trading in all timeframes.

The proposed HLD focuses competition for physical volumes in the centralised European DAM and IDM. This means that the interconnector capacity is fully integrated into the market arrangements, which should ensure that the full benefits of competition from neighbouring markets are brought to bear on the All-Island Market. In addition, a reliable DA price should encourage the participation of the demand side, as highlighted in the RAs paper on the 2020 Demand Side Vision. Interconnection and the demand-side are both alternative constraints on the possible exercise of market power in the I-SEM. The emphasis on liquid centralised market places is a key attribute of the proposed HLD. It provides competitive but equal routes to market for all players including independent and small generators or suppliers.

[34] This can give rise to a virtuous circle effect whereby confidence of market players in the competiveness of the arrangements can itself support a competitive outcome.

High levels of participation, in particular in the DAM, will provide a competitive method of price formation in the I-SEM, given the requirement for unit based bidding. Unit based bidding has many positive attributes which are accentuated in a market like I-SEM, where market power is a concern, and transparency has a premium. Unit based bids provide significant transparency in the behaviour of individual participants and promote understanding and ultimately confidence in the price formation in the market. This, combined with the scope for different bidding approaches catered for in Euphemia, sees a reliance on unit-based bidding as the basis for physical schedules be seen as helping to facilitate effective competition in the I-SEM.

The exclusive nature of the IDM in the proposed HLD is another significant feature in relation to competition. This exclusivity means that all players must settle any imbalance on an open marketplace rather than within a portfolio. This creates non-discriminatory access for independent and smaller participants, as well as those that are not vertically integrated.

Other options have considered the ability to allow physical scheduling without a requirement for trading through the centralised spot markets – for example, through forward bilateral trades. This could include, for example, different approaches to trading demand or wind generation in the face of forecast error and asymmetric imbalance prices. In theory, this could provide benefits to consumers either in terms of lower costs and/or more attractive products and services.

In addition, if it functions efficiently, the ability to choose a trading strategy could also act as a constraint on the exercise of market power; e.g. if there is gaming in a particular market, then participation may decline which mitigates the negative impact of the gaming.

However, the potential downside is that this innovation would have little transparency, could benefit the individual participant to the detriment to the market as a whole, and might only be required because of design inefficiencies in other aspects of the market. This could be particularly the case in I-SEM where there are a number of players that are not vertically integrated and who rely on an open competitive and centralised market place. Therefore the success of options without collective exclusivity of the spot markets relies heavily on the adaptations, such as liquidity promoting measures that would be required.

The levels of competition within the industry structure will determine the success of this type of physical forward contracting in delivering benefits for consumers. If there are high levels of physical contracts within vertically integrated players, there could be increased transactions costs and greater barriers for smaller players. Furthermore, any of the purported benefits to consumers from physical forward trading can equally be delivered through financial forward contracting, which has the benefit of being referenced against reliable reference prices in the short term centralised market places. The important point in terms of benefits to consumers is that there is liquid forward contracting market to allow market participants to tailor products to their consumers' needs.

An approach based around a gross ex-post pool would concentrate competition for physical quantities in the ex-post pool. This would provide a route to market, with a strong reference price, for independent and small generators or suppliers, similar to the arrangements in the current SEM. The requirement for complex (unit-based) bids and mandatory participation in the pool means that there would be transparent bidding in this option, which would facilitate ex-post market monitoring.

However, the issue for an approach with an ex-post gross pool is the extent to which the there will be sufficient participation in the DAM and IDM to support effective competition in those markets. Participation in these cross border markets will set interconnector flows and so their success is key to achieving competitive outcomes in the I-SEM as a result of greater integration with other European electricity markets. Low levels of participation in the DAM and IDM would likely see inefficient patterns of scheduled imports and exports.

One approach to alleviate concerns about the impact of physical forward trading is to use an ex-post net pool to create a route to market for small players especially since there is an optimisation of physically contracted capacity in the pool algorithm. This should provide a strong reference price for independent and small generators or suppliers, similar to the arrangements in the SEM.

One key potential downside of the net pool approach would be where the majority of physical trading concentrates in the pool at the expense of the earlier markets and in particular the DAM and IDM. This could reduce cross border competition where a high level of I-SEM demand is met by internal generation.

**In summary, it is important that stakeholders have confidence that the conditions are in place for effective competition, i.e., transparency of trading behaviour and outcomes. Features that are seen as positive for transparency are the use of unit-based bidding and reliance on centralised market places, which are at the core of the proposed HLD for the ETA. If trading is concentrated in the European markets, then the power exchanges operating these markets can also support the regulators' market monitoring activities, as market surveillance is typically a key activity of the European power exchanges.**

**Overall, the proposed HLD for the ETA best meets the competition criterion, in the I-SEM context, given its focus on liquid centralised exclusive market places and unit based bidding.**

### 5.8.4 ENVIRONMENTAL

Assessment of performance under this criterion considers the direct impact of the market arrangements on renewables, in terms of possible routes to market and compatibility with renewable support schemes. It also considers the extent to which the option facilitates flexible resources that could help the system to accommodate the output patterns of variable renewables, which typically act as price-takers in the SEM today.

The focus in the proposed HLD for ETA is on liquid centralised market places for all market participants with full integration of the interconnectors into the market. This sets a level playing field for all participants to trade and to trade out positions in centralised market places. This provides an assurance to smaller players that the balance responsibility they assume can be managed in a fair and efficient manner whilst at the same time aligning with the drive at European level of integrating renewables more into the market.

The use of a dedicated Balancing Mechanism with cost-reflective marginal imbalance prices should provide appropriate incentives for the development of flexible resources that offer its services for energy balancing close to real time, within market timescales. Valuing flexibility appropriately in the energy market should reduce the cost of separate mechanisms which incentivise the delivery of the flexibility required to help the system accommodate higher levels of variable generation.

Exposure to cost-reflective imbalance prices naturally poses challenges for all market participants and so it is important to have a liquid IDM to trade out positions. Variable generation is particularly reliant on liquid trading places given that it is less predictable closer to real time. This is a strength of the proposed HLD for the ETA with its requirement for collective exclusivity for physical scheduling of the centralised spot markets with a default of unit-based bidding for generation. If this is relaxed, e.g. to allow scheduling outside the market and/or portfolio bidding, then the ability of independent variable generation to manage imbalance risk through trading close to real time will depend on the success of any adaptions designed to promote liquidity in these markets.

In the proposed HLD for the ETA, the existence of and focus on liquid centralised market places should allow for the establishing of reliable reference prices and revenue transparency for renewables support schemes, recognising that the Government Departments have competence and responsibility for the design of these schemes. Therefore, any reduction in liquidity in these markets would weaken performance against this criterion.

Using an ex post gross pool rather than a Balancing Mechanism to determine the ex-post prices would likely reduce the exposure of variable generation to the impact of it being less predictable closer to real time. This is because in the gross pool where the algorithm effectively assumes that out-turn values of demand, variable renewable generation were known at the day-ahead stage (in order to calculate the ex-post price and schedule) All generation and load, whether predictable or unpredictable, faces the same ex-post price established through the ex-post unconstrained schedule. This is a positive attribute for variable renewable generation when looking at the market in one particular timeframe.

However, it is possible that overall market efficiency for renewables could be sub-optimal under an ex-post gross pool. This reflects the risk that the incentives for participation in earlier markets by particular types of market participants could be lower in pool-based options with a Balancing Market. If as a consequence there are significant concentration of volumes in the ex-post pool there could be less than efficient scheduling of the interconnectors in the pool based on the firm scheduling of the interconnection flows from the DAM and IDM.

Another potential weakness of an ex-post gross pool based approach is that flexible resources required to help manage variable renewable output do not receive the full value of this flexibility in the pool. This is the corollary of paying the same price to predictable and unpredictable generation. This means that flexible resources responding close to real-time do not access a premium market price for providing that valuable service.

The scope for flexible resources to benefit from ID prices will depend on the extent to which variable renewable generation will be sufficiently encouraged to trade in the IDM, given the relative attractiveness of the ex-post pool price for variable renewable generation.

Similarly for net ex-post pool, overall market efficiency, including for renewables, could be reduced if there was significant concentration of volumes in the ex-post pool. This concentration could be influenced by many factors including liquidity issues in earlier timeframes, and could reduce the efficiency of the use of the interconnectors. The efficient use of interconnectors is a key issue for the renewables industry and inefficient scheduling, particularly in the IDM, could increase curtailment of wind (absent of increased intervention by the TSO).

In summary, the proposed HLD for the ETA provides the best package in terms of facilitating renewable deployment in the I-SEM. The greater reliance on market-based signals for flexibility and strong integration of interconnectors into the physical spot markets should help better manage changes in renewable generation in the All-Island market.

The emphasis on liquid, centralised DAM and IDM will provide independent renewable generators with more opportunities to manage their exposure to imbalance prices, as well as providing robust reference prices for renewable support schemes.

### 5.8.5 EQUITY

There are two main aspects to the assessment of equity. The first is about the equality of access to different markets for a range of market participants, such that for a market to be equitable it should present the same set of challenges and opportunities to all participants. In reality the market model on its own is unlikely to be the only factor in determining equity. The characteristics of the participant will also have a significant bearing. However to the degree that the market model has some bearing on equity, one of the key features of market design is market access.

The second aspect is the delivery of an allocatively efficient outcome where prices reflect marginal costs (including an appropriate allowance for risk). Prices that are cost-reflective can in turn be perceived as 'fair' and non-discriminatory. In practice, cost-reflective pricing is closely associated with the competition criterion, since competitive markets will generally be allocatively efficient.

The focus on exclusive liquid centralised markets in the proposed HLD for the ETA is key in terms of providing an equitable route to market for market participants. In particular, the proposed HLD relies on the DAM and IDM as exclusive routes to physical contract nominations before the balancing mechanism. In addition it uses FTRs on the interconnectors to maximise the availability of physical interconnection capacity for the DAM and IDM. This means that access to physical interconnector capacity is to the same for both larger players and smaller independent market participants.

The requirement for unit-based bidding into the DAM and IDM will also level the playing field between portfolio and non-portfolio players in terms of optimising internally between thermal generation. However, portfolio wind players may benefit compared with individual wind farms from a more diversified imbalance risk. The Aggregator of Last Resort is designed to bring this diversification of benefits to all renewable resources.

The existence of a highly liquid DAM should provide a robust reference price for forward trading and other financial contracting. This combined with the suite of products available in European market timeframes should support confidence in forward trading for entities with and without a physical presence in the market.

A relaxation of collective exclusivity of the centralised spot markets with a well-functioning set of trading arrangements may still be able to deliver equitable outcomes. However, it places the greatest reliance on competitive market structures underlying the market. In the absence of such a competitive structure, it places much greater reliance on specific adaptations to achieve competitive outcomes. The exercise of market power would be more difficult to detect under this design which would have a negative impact on consumers.

The combination of forward physical contracting, a voluntary DAM, portfolio bidding and a non-exclusive IDM may favour vertically integrated market participants in the first instance. There would likely be higher transactions costs and greater barriers to market participation for non-portfolio players thereby reducing competitive pressure on portfolio players and incentivizing to vertical integration.

While competitive pressures, such as cheaper generation being available to meet demand, should drive competitive outcomes, such an outcome is not always certain. For example, if a portfolio player can meet its demand from an independent generator for marginally less than running their own plant, they may still choose to run their own plant, especially if this means the marginally cheaper plant does not run.

In the proposed HLD, the imbalance price is intended to reflect the marginal cost to the TSO of balancing the residual difference between energy supply and demand (i.e. the physical volumes neither settled in an ex-ante market nor on the basis of a trade with the TSO to manage a system constraint). The second aspect of equity - of cost-reflective pricing - would therefore be met by arrangements based around cost-reflective imbalance prices. Furthermore, the proposed HLD includes a single energy imbalance price which can be considered more equitable than a dual pricing regime which would risk favouring larger market participants, who are better about to manage the risks of imbalances, at the expense of smaller participants.

A gross mandatory ex-post pool should provide an equitable route to market for participants in I-SEM. This combined with a robust reference price should give confidence in the market.

Similarly, a net pool should provide a route to market for smaller players, although there is a reliance on certain levels of liquidity. In particular, with a net pool, the existence of physical trading in the forwards timeframe may however, favour portfolio players and may pose difficulties for smaller participants trading in earlier timeframes. This would be particularity the case for smaller suppliers looking for forward liquidity.

Under an ex-post pool, the costs of the TSO's energy balancing actions are socialised in the ex-post price, and in dispatch balancing costs. Whether this is equitable will be determined by the extent to which it is judged that the recovery of these balancing costs should be targeted at the market participants who are deemed to have caused them. This, in particular raises questions as to whether those providing flexibility to the system are being appropriately rewarded for it in the energy market.

**In summary, a highly liquid DAM and IDM in the proposed HLD provides all market participants with access to ex-ante markets including the full integration of interconnector capacity into the market. These markets also provide tools for market participants to manage exposure to cost-reflective imbalance prices that target the recovery of energy balancing costs. Robust reference prices and the suite of order structures in Euphemia should provide forward liquid opportunities for different types of market participants.**

## 5.9 QUALITATIVE ASSESSMENT AGAINST SECONDARY ASSESSMENT CRITERIA

This section assesses different choices for the energy trading arrangements against the secondary assessment criteria set out in Section 3.2. In particular, this highlights the difference between these options of hard to quantify factors.

We use as our reference point the proposed HLD option set out in the draft decision document, particularly with comparison to a gross ex post pool-based approach which would be closest to the status quo. Where relevant, we also highlight the impact of the choices around:

- Physical trading in the forward timeframe, within-zone and across-zone;
- Portfolio bidding allowed for all generation in the DAM and the IDM;
- The ability to self-schedule without making a trade in the centralised market places;
- Voluntary participation in the Balancing Mechanism; and
- Physical ex-ante trading with a net ex-post pool for dispatch.

### 5.9.1 STABILITY

The assessment of this HLD criterion considers how robust the set of energy trading arrangements may be to any future changes in circumstances without major disruption.

Like the current SEM, the proposed HLD for the I-SEM is focused on trading in centralised market places with transparent bidding. However, this is done through centralised European markets rather than an all-island ex post pool as under current arrangements. This means that there will be significant changes required to the SEM. However, once established, this will provide a stable set of arrangements looking forward which will build confidence, deliver efficiency and encourage investment.

If on top of the introduction of a Balancing Mechanism, bilateral physical contracting was allowed with a move away from any mandatory markets or requirement for collective exclusivity, that would represent the most radical change from the current SEM, certainly in terms of philosophy. However, it would also represent a market design which likely most closely aligns with the designs of many markets across Europe. Therefore, it would be robust to future changes in direction at EU level

An approach using an ex-post gross pool would be the closest to the current SEM. However, it could still represent significant change in the energy trading arrangements. In those circumstances, the risk for forward-looking stability would be that an I-SEM design based around an ex-post gross pool would still be different to the other markets across Europe with which I-SEM will integrate. This could pose challenges for future changes in the direction of the EU Target Model.

There could be significant changes from the current market arrangements in a move to a net pool, even it retained some elements of a pool-based approach for dispatch with complex bids and ex-post pricing. However, the consultation process has highlighted major concerns about the stability of the arrangements, given the competition for liquidity between the two physical markets of the DAM and the net pool.

In summary, compliance with the EU Target Model will require a change to the current SEM. An approach based around an ex-post gross pool could, in theory, require the least change, but change could still be substantial. A move to any option based around a Balancing Mechanism would require similar levels of change from the current SEM arrangements. A move to a net ex-post pool would probably require the most change and represent the biggest challenge for the stability of the arrangements.

Overall, the proposed HLD strikes a good balance in terms of stability. It retains an emphasis on physical trading in centralised, transparent marketplaces, whilst facilitating much closer integration with other European electricity markets.

### 5.9.2 ADAPTIVE

The proposed HLD for the ETA has a high reliance on physical trading through the European DAM and IDM. This could make it hard to make all-island specific alterations to the trading arrangements based on changing circumstances within the SEM, which was a concern for a number of respondents.

The governance arrangements for the European DAM and IDM will allow for changes to be made to the DAM and IDM arrangements in the future, with representatives of the I-SEM having a role in these governance arrangements. As the proposed HLD is strongly in line with thrust of the current market coupling arrangements in the NWE region, it is expected that the governance arrangements should more easily to be able to accommodate any changes required for an I-SEM based around this design.

If a gross ex-post pool was used, it may be easier to all-island specific changes to the local arrangements governing the pool. However, it may be harder to coordinate these changes with developments across Europe, which is important for compliance with the requirements of the Electricity Balancing Regulation. This will depend on the provisions put in place for arrangements for integrated scheduling and dispatch arrangements that are allowed under the Electricity Balancing Regulation.

If a hybrid approach with a net pool is used, the adaptability issues will depend on whether the physical trading is concentrated inside the pool (or bilateral arrangements), or whether it is concentrated in the centralised European markets.

A reasonable concern is that an approach based around a net pool will suffer from the worst of both worlds; i.e. vulnerability to external change (as there may be few if any markets in Europe with a similar design); but also high costs of change since the systems will all be bespoke.

The detailed design and most critically the systems implementation are important in ensuring that any set of energy trading arrangements are suitably adaptive. For example any future changes agreed to the rules or mechanisms for energy trading need to be implemented without excessive delays or costs of introducing change resulting from system issues. Therefore, adaptability in systems should be designed in from the start, under any HLD for energy trading arrangements. The EUPHEMIA algorithm currently has a change control process and generally has two releases per year. It is expected that the NEMO for I-SEM will become a partner of PCR to be able to participate and influence the process going forward.

### 5.9.3 EFFICIENCY

In the proposed HLD for the ETA, the emphasis is on centralisation of the commitment and dispatch process in a liquid DAM, with a mandatory BM from the DA Stage onwards. The physical nominations from generators are linked to trades made in the centralised market places (DAM, IDM and/or BM), which are on a unit basis.

This centralised commitment process will use the different bid formats that have been developed in other markets to allow market participants to manage the risk of start-up costs (in the optimisation by EUPHEMIA across a whole trading day), without requiring the full (three part) complex bids currently used in the SEM. Given the importance of EUPHEMIA in the I-SEM, and in the Target Model as a whole, it is important to complete a detailed testing programme with clearly specified goals. SEMO is engaging with the Price Coupling of Regions (PCR) Group as an associate member to put forward test cases for testing by the algorithm working group. The bid formats that may be best suited to the circumstances of the all-island market will be explored further during this testing phase.

The implications for participants of reliance on the Euphemia algorithm will also be dependent on the process through which the market schedule (MWh per trading period) for generation (including demand-side units) is converted into more granular and feasible planned physical nominations for use in dispatch. This will be determined as part of the detailed design phase.

An alternative option is to relax the requirements for collective exclusivity, unit-based bidding by most generation, and mandatory participation in the BM before the IDM gate closure. This could result in a decentralised unit commitment process if unit-based physical nominations are driven by direct bilateral trades, management of a vertically integrated portfolio that does not go through the DAM, or the conversion of portfolio-level results from the DAM and IDM.

In those circumstances, centralisation of the commitment process will depend primarily on the liquidity of the DAM and the voluntary use of unit-based bidding in the DAM[35] . It will also be affected by the degree of participation in the balancing mechanism which only becomes mandatory after ID gate closure.

With a net ex-post pool, there would be mandatory participation for generating units based on complex bids submitted after the DA stage and updated throughout the day. The full (three part) complex commercial bids currently used in the SEM could be used for unit commitment within the pool. However plants can provide contractual nominations to provide a starting point above zero into the pool.

Therefore, the degree to which initial unit commitment (in the form of detailed physical nominations of generation profile) is centralised will depend on the form of trading outside the pool, including the nature of bids (both in terms of format and whether unit or portfolio) into the market.

In any of these approaches based on ex-ante physical nominations from market participants, the scope for physical nominations to reflect non-energy factors (e.g. reserve) will depend on the rules governing the bidding of market participants, and the arrangements put in place for the procurement of system services (which will be determined under the DS3 work programme[36]. Any bidding rules and the interaction with

[35] The February 2013 Next Steps Decision Paper described the European DAM as essentially being a centralised market.

system services procurement will be determined by the detailed design of the energy trading arrangements.

In an approach based around an ex-post gross pool, there are no physical nominations from participants (other than interconnectors) based on an unconstrained energy market schedule. Instead, the starting point for unit commitment and dispatch are complex bids submitted into a mandatory pool at the DA stage, with subsequent update windows for bids.

Even under an ex-post gross pool, scheduled interconnector flows would be held firm from the results of the financial trading on the European DAM and IDM. One possible issue for an ex-post gross pool is the efficiency of the DAM based on voluntary trading (given a strong ex post Pool), and the extent to which that provides an effective signal for demand side response (and interconnection flows) in the ex-ante markets.

**In summary, previous reports for the RAs have noted that in theory, an efficient dispatch outcome should be achievable under different dispatch arrangements, including central or self-dispatch[37].**

**In the context of the all-island market, the proposed HLD for the ETA has a number of practical advantages in facilitating efficient dispatch. The starting point for dispatch is based on a centralised unit commitment process that fully integrates the available physical interconnector capacity. There is then emphasis on centralised IDM and BM to enable adjustments in response to changing forecasts and system constraints (in the BM).**

**The detailed design phase will determine how and when non-energy factors are taken into account in the dispatch process – e.g. how non-energy factors may be reflected in the physical nominations that provide the starting point for dispatch.**

### 5.9.4 PRACTICALITY/COST

In the proposed HLD, participation in the European DAM and IDM is the only route to physical contract nomination (outside of the Balancing Mechanism). This would allow smaller market participants to benefit from cost advantages of centralised trading mechanisms.

However, if generation trading is only allowed on a unit basis, then all generators would need to have direct access to systems and resources to individually manage their position throughout the trading day (e.g. in response to changes in forecasts of generation availability). Facilitating some form of intermediary and/or aggregation arrangements in the proposed HLD will help to mitigate this cost, as it would allow smaller generators to benefit from economies of scale in trading resources.

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[36] Further information on the DS3 project is available at http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=06c22cd8-a936-426b-ac21-ed28b5292566, or at http://www.eirgrid.com/operations/ds3/

[37] For example, see page 26 of the September 2012 Easter Bay Report.

In the proposed HLD, the European ID solution is the only route to ID physical contract nominations. During the consultation process, respondents have raised issues around the practicality of relying on European ID solution that is not yet in place as the only route to ID physical contract nomination. This should not raise issues for the ID trading within the All-Island Market but possible fallback measures for the allocation of ID interconnector capacity to allow ID trading with GB. These may need to be considered as part of the detailed design phase in case of further delays in the NWE ID project. In practice, fallback measures would need to be considered for all options to address a range of possible contingencies – e.g. IT outage with Europe.

It would be possible to allow a number of different possible routes to market for physical electricity, including optimisation within portfolios, bilateral trading, aggregation (with aggregated volumes traded in the centralised markets), and the centralised European market places. The practicality and cost of accessing these various routes may differ significantly by type and size of market participant (e.g. in terms of collateral arrangements), with the risk that the costs are much higher for smaller market participants.

The proposed HLD is based around a Balancing Mechanism rather than an ex-post gross pool. As Balancing Mechanisms already exist in different forms in a number of other European markets, this should help to reduce the cost of implementation of any approach based around a balancing mechanism. Ultimately, though the cost of implementation will be dependent upon the customisation that is required for the all-island market. This would be established at the detailed design phase.

If an ex-post pool was retained instead of moving to a Balancing Mechanism, then the data flows and pricing algorithm involved in the pool may be able to build on the system and processes currently in place. Some change will definitely be required, e.g. more frequent rebidding, more data to be provided by market participants to facilitate the net settlement process, and the net settlement process itself. Therefore, the cost of implementation will be determined by the extent of these changes, which would be defined at the detailed design phase.

A move to a net rather than gross pool would poses particular challenges with respect to practicality and cost of implementation. The data flows and pricing algorithm involved in the pool may require a substantial change from that of today to allow for the net pool concept and are likely to be unique worldwide in terms of computational requirements.

In addition, the costs of participation in the European markets may be higher for generating units because of the need to maintain parallel systems for IDM and for the pool (mandatory after the DA stage) with quite different bid structures.

**In summary, the quantification of the implementation and operation costs for any of the ETAs (see Annex 3) has identified significant implementation and operation costs that are common to any option that is compliant with the requirements of the EU Target Model. For example, central systems will need to be developed and/or procured to allow All-Island market participants to access the European DAM and IDM under any of the options.**

**Similarly, market participants are likely to require some new systems or interfaces (or to participate through an intermediary if this is permitted) in any of the four options if they wish to participate in the European DAM and/or IDM. For effective participation in a continuous IDM, the ability to trade 24 hours a day is likely to be a requirement (which could be delivered by an intermediary). This is already a feature of other European markets including GB, and the necessary trading infrastructure will already be in place for some market participants.**

## 5.10 SUMMARY OF QUALITATIVE ASSESSMENT

As described in the February 2013 Next Steps Decision Paper, the view of the SEM Committee is that it is essential to have a centralised and transparent set of energy trading arrangements in place in I-SEM. This reflects the particular context of the all-island market, as described in detail in that paper and in the consultation paper on the draft HLD.

The SEM Committee notes that the proposed HLD for the ETA performs strongest overall against the assessment criteria. It concentrates physical liquidity in the European DAM and IDM, which act as the centralised market places. This integrates the interconnector into the market arrangements. There is also an emphasis in this set of arrangements on unit-based bidding by generators in the physical spot markets, which will support transparency and help to promote competition.

The actions of the TSO to deliver a secure system are supported by the operation of a mandatory balancing mechanism from the DA stage onwards. The imbalance prices the proposed HLD will appropriately reflect the costs of actually balancing the system with balance responsibility for all parties. This supports the principles of equity and efficiency.

The exclusive nature of trading through centralised DAM and IDM will also help to provide assurance to market participants, in particular suppliers and smaller variable renewable generators, that they will have access to the risk management tools needed to accompany the introduction of greater balance responsibility. The emphasis on trading in the DAM and the IDM is also compatible with the renewable support arrangements in terms of REFIT and CfDs, which rely on transparency of revenue and/or clear reference prices.

While a well-functioning implementation set of arrangements that would allow physical self-scheduling has the potential to do well against a number of the criteria, it would impose high transaction costs on small participants and represent a move away from the centralised trading arrangements that the SEM Committee placed at the heart of the I-SEM in the February 2013 Next Steps Decision Paper.

Retention of a gross ex-post pool would be the option closest to the current SEM. However, it could still represent significant change from the current SEM arrangements in a number of areas. The key reasons that any option based on a gross ex-post pool fares less well in the qualitative assessment is the potential for less than efficient integration of the interconnectors into the market. This would mean that the full benefits of market integration would not be seen in the All-Island Market.

The introduction of a net pool is seen as untested and riskier and costlier to implement than any of the other options, particularly within the tight timescales for the I-SEM. The assessment has also not identified additional benefits against the primary assessment principles that could justify the additional risk and/or cost. One of the biggest challenges for this option is that there are effectively two markets competing for primacy in the trading of physical quantities - the European DAM, and the ex-post pool. This is not comparable to the spreading of liquidity between the DAM and IDM in the proposed option as that reflects differences in trading based on updated information.

# 6 REQUIREMENT FOR EXPLICIT CRM IN THE I-SEM

## 6.1 OVERVIEW

In this section, we present the analysis that has informed the Decision of the SEM Committee with respect to the need for an explicit CRM in the I-SEM HLD, including:

- **Quantitative evidence in relation to risks for generation adequacy from the Generation Adequacy reports published by EirGrid.**
- **Assessment of the market failures associated with energy only markets,** particularly with reference to a small island system with limited interconnection and high levels of variable generation. The qualitative assessment is supported by Pöyry modelling analysis on the impact of the changing system dynamics on the running patterns and hours of conventional generation as a result of the increased penetration of low carbon renewable technologies.

## 6.2 TSO ASSESSMENT OF GENERATION ADEQUACY IN AN ENERGY-ONLY MARKET

### 6.2.1 PURPOSE

The most recent annual All-Island Generation Capacity Statement 2014-2023 (GCS) projected a generation surplus out to 2023 on an unconstrained All-Island Market basis[38]. This is partly as a result of increased wind generation capacity and the continuing impact of the financial crisis in 2008 on load. The capacity margin is, however, expected to tighten in the period to 2023 as demand growth erodes excess capacity currently on the system, whilst some plant retirement is expected as a result of environmental restrictions.

The GCS is broadly consistent with the general approach to generation adequacy assessments that is currently used across Europe. It is nationally focused and based on notifications provided by generators, which are underpinned by the assumption that the existing capacity regime will remain in force.

Based on these assumptions, the GCS assessment would suggest that in the first few years of the operation of the I-SEM, there should be no shortage of capacity in the overall system. However, as a result of local constraints on the transmission system, SONI is now putting in place supplementary measures to ensure sufficient generation capacity is available in Northern Ireland to address a potential risk to security of supply.

This means that as it stands, the most recent GCS assessment does not answer the question of whether or not an explicit CRM is required. This can only be answered by analysing scenarios for the evolution of the capacity margin if generators were to rely solely on revenues from the energy market to recover their avoidable fixed costs.

[38] http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf

Given this, the Regulatory Authorities asked EirGrid to carry out analysis of theoutlook for for generation capacity adequacy in the absence of an explicit capacity mechanism. EirGrid's Assessment of Generation Adequacy in an Energy-only Market (SEM-14-048) was published in June 2014 alongside the Draft Decision Paper (SEM-14-045)., That report includes more details on the approach and findings of the study. This report provided the SEM Committee with a wider perspective on the state of generation adequacy beyond 2016 in reaching its Decision on the requirement for an explicit CRM in the I-SEM HLD.

EirGrid's assessment of generation adequacy in an energy-only market is subject to a number of caveats and should not be relied on as a standalone assessment of future generation adequacy for the All-Island system. Rather, it is an important element of the overall assessment underpinning the SEM Committee Decision on the retention of an explicit CRM. Other aspects of the assessment include the most recent GCS (covering the period 2014-2023), assessment of the market failures associated with energy-only markets, and Pöyry modelling undertaken as part of this Impact Assessment.

The European Commission, ACER and national regulatory authorities see generation adequacy assessments as an important input into the discussion of the need for CRMs in different European markets. Therefore, ENTSO-E has been asked to consider possible improvements to existing adequacy assessment methodologies[39]. This is in the context of increasing shares of variable generation across Europe and greater cross-border integration of Day Ahead and Intraday markets.

It is to be expected that the way in which generation adequacy is assessed across Europe will develop over time, with more coordination and harmonisation at regional and European level. In the future, there will also be consideration of the scope for incorporating an assessment of generation economics (e.g., in response to policy changes rather than relying purely on notifications from market participants). Through involvement in ACER and ENTSO-E, the SEM RAs and the TSOs will contribute to the development of the adequacy assessment methodology.

### 6.2.2 APPROACH

The EirGrid assessment considers some scenarios for closure of generation plant in addition to those notified by generators for the GCS (2014-2023). These closure scenarios are then tested for capacity adequacy against a reference case, and a number of sensitivities in relation to a tighter security standard, higher peak demand, and reduced interconnector availability.

The EirGrid assessment consists of two steps, which are carried out for each of the study years – 2017, 2020 and 2023. It first calculated which generators would not be able to recover their annualised costs from energy payments in a theoretical energy only market. Plants are assumed to close if based on their generation volumes from a market simulation, they require on average more than €3000/MWh from the energy-only market to recover their required costs on an annual basis. This also means that plants close if they have no

[39] 'ENTSO-E Target Methodology for Adequacy Assessment. Consultation material', ENTSO-E, July 2014.

running hours. €3000/MWh is used as the cut-off price as it is the price cap in place in the EUPHEMIA algorithm already being employed in the day-ahead coupling of electricity markets in Western Europe. These generators are then assumed to shut down and hence are removed from the generation portfolio used to recalculate the generation adequacy position. EirGrid's study is subject to a number of important caveats in relation to the modelling of the closure decision:

- The cost recovery methodology uses Plexos to estimate generation running hours for a median year. It is not used to model any of the I-SEM HLD options nor produce energy prices based on those options.
- The study assumes that generators get no revenue from the sale of ancillary (or system) services.
- This study looks at security of supply in the context of revenues only from the sale of energy. However, in cases where revenue shortfalls leading to a capacity shortage have been identified, it cannot be inferred that an explicit CRM is necessarily required to meet this shortfall.
- The cost recovery methodology looks only at a likely set of conditions to determine the dispatch of units on the system. In reality the processes used by generation companies to decide which units should be withdrawn or kept in the market are likely to be more complex.
- The study assumes that generators receive revenue only from energy payments, and that average revenues of at least €3,000 /MWh are achievable across all running hours. It may not be possible for generators to achieve such revenues in practice.

### 6.2.3 SCENARIOS

EirGrid used a Reference Case which had the following assumptions:

- median demand forecast;
- full reliance on interconnector imports; and
- an adequacy standard of a LOLE of 8 hours a year.

EirGrid described the Reference Case as the set of "most lenient assumptions". Therefore, the EirGrid study considered a number of further scenarios, to test the robustness of the findings on generation adequacy in the base case.

These further scenarios include:

- Tightening the adequacy standard from 8 hours loss of load expectation (LOLE) a year to 3 hours LOLE/year[40].
- Reducing the reliance on interconnectors to half of the available import capacity.
- Reducing the reliance on interconnectors to zero.
- Using a high demand forecast, representing a particularly cold (1-in-10 year) winter.
- No price cap scenario where only plants that did not run in the initial energy only model runs are removed from the generation portfolio.

40 LOLE represents the number of hours a year in which, over the long-term, it is statistically expected that supply will not meet demand

These scenarios are intended partially to give a wider picture of future generation adequacy for the All-Island System and partially to test the impact of using assumptions that are more consistent with the approach taken by neighbouring Member States.

For example, in its assessment of generation adequacy in Great Britain, Ofgem assume in all scenarios that the Moyle and East West Interconnectors flow in the direction from GB into Ireland[41]. By contrast, in their reference scenarios, Ofgem assume no net flows of energy from GB to mainland Europe.

From one perspective, the EirGrid GCS is consistent with this assumption in that it assumes that the GB-Ireland interconnectors are always available for import to the SEM. However, it is prudent, and consistent with Ofgem's approach to its larger connecting market of continental Europe, to consider scenarios where the interconnectors may not be available for full import, for example due to periods of concomitant peak demands in GB and Ireland.

A further area of potential consistency with Ofgem's generation adequacy assessment for GB is the security standard. The All-Island GCS uses a security standard of loss of load expectation of 8 hours a year. Ofgem uses a tighter LOLE of 3 hours a year[42]. The security standards in the other countries interconnected with GB are 3 hours a year in France and 4 hours a year in the Netherlands.

### 6.2.4 MAIN FINDINGS

Table 20 summarises the results of the scenarios considered in the EirGrid study, alongside a summary of the main differences in input assumptions between the scenarios.

***Table 20 – Summary of results from EirGrid study on generation adequacy (closure of plants needing to recover more than €3000/MWh to recover annual fixed costs)***

| Capacity Adequacy (MW) | 2017 | 2020 | 2023 | Load Forecast | LOLE (hrs/yr) | IC reliance |
|---|---|---|---|---|---|---|
| 'Reference case' | 208 | -109 | -13 | Median | 8 | 690 |
| 3 hr LOLE | 9 | -313 | -216 | Median | 3 | 690 |
| High demand | 4 | -339 | -253 | High | 8 | 690 |
| Half IC | -69 | -378 | -287 | Median | 8 | 375 |
| No IC | -417 | -738 | -638 | Median | 8 | 0 |

Source: 'Assessment of Generation Adequacy in an Energy-only Market, SEM-14-048', Eirgrid, June 2014

In summary, EirGrid's study finds that in the reference case, there is no shortage of supply in 2017 but capacity is in short supply in 2020 and 2023 – as demonstrated by failure to meet the required adequacy standard.

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[41] See Ofgem, Electricity Capacity Assessment Report, July 2013https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013.pdf

[42] The GB standard of 3 hours LOLE a year was determined by dividing the cost of new entry (estimated at £47/kWh) by the value of lost load (estimated to be £17/kWh) and rounding up to 1 significant figure.

These results are broadly replicated under the various additional scenarios around interconnector availability, higher demand and the tighter security standard (of an LOLE of 3 hours a year).

The results shown in Table 20 are based on the assumption of a €3000/MWh price cap, in line with the current value of the price cap in the NWE DA coupling arrangements. For each scenario, EirGrid also considered the impact of assuming no price cap exists in the initial modelling to determine whether plants were able to recover their fixed costs in the energy-only market. The adequacy modelling only shows a surplus of generation capacity in the majority of scenarios to 2023 when there is that assumption of no price cap.

## 6.3 CHALLENGES FOR GENERATION ADEQUACY IN AN ENERGY-ONLY MARKET

The real-time nature of electricity, the lack of storage possibilities and the high value users place on its reliability means that its economics differ from most other goods and services. An efficient electricity system would have an excess of usable capacity at almost all times, other than a few hours each year (on average) in line with the security standard.

Consequently, there has been a longstanding international debate about whether or not energy-only markets can provide sufficient incentives to ensure sustained generation adequacy in the long-term.

The following sections discuss the challenges for delivering generation adequacy in an energy-only market. We start by considering the general points in relation to missing money, and the public good nature of reliability. We then consider the particular issues for the operation of an energy-only market in the all-island market, which is a small island market with increasing levels of variable renewable generation.

### 6.3.1 MISSING MONEY

For an operational plant to stay in the market, it needs to recover its avoidable fixed costs on top of its variable costs of production. In order to enter a market, a plant needs to expect to also be able to recover its investment costs, on top of its variable and fixed costs. In the energy-only market, the net revenue required to cover for investment costs and avoidable fixed costs come from two sources:

- **infra-marginal rent (IMR),** which is captured by operating at greater cost efficiency than the price-setting (marginal) plant, which is relatively predictable;
- **'scarcity rent'**, which is captured through price spikes at times of relative system scarcity, which may be relatively unpredictable.

This means that in an energy-only market, energy prices need to be allowed to rise at times to levels that allow for sufficient amounts of scarcity rent to be recovered to ensure that enough plants are on the system to deliver the required level of reliability. These price levels will be significantly above the short run marginal cost of the least efficient plant on the system at the time, and arguably can go as high as the value of lost load (in the absence of a price cap).

The ‘missing money’ problem describes the inability - for whatever reason - of an energy-only market to fully remunerate the amount of capacity required to deliver the efficient level of reliability. In these circumstances, spot electricity market prices do not, or are expected not to, rise high enough at times of ‘scarcity’ to produce adequate net revenues to cover the fixed and capital costs of the efficient level and mix of generating capacity.

The existence of explicit price caps or bidding restrictions is one of the most common reasons cited for ‘missing money’.
Explicit price caps include the PCAP in the SEM or the €3000/MWh limit that currently applies in the Euphemia algorithm that is used for the DAM coupling in North West Europe.

Implicit price caps may be the result of actual or expected intervention in response to prices spikes by regulators or governments. These implicit price caps can also results from the operating practices of the system operator, for example in the actions in the Balancing Market.

There are some circumstances that would increase the likelihood of regulatory intervention (whether actual or perceived). In particular, these are increased concern about the ability of the market to price scarcity correctly, and the lack of a sufficiently active demand-side.

Times of scarcity inevitably create a perceived opportunity to abuse a position of market power. Distinguishing between ‘correct’ scarcity pricing and abuse of market power will be a particular challenge for any energy-only market, regardless of its market structure. Sooner or later either energy prices will be capped, or, more importantly, market participants will expect prices to be capped. This thereby dulls the incentives to build new capacity.

Furthermore, the (perceived) risk of regulatory intervention in response to price spikes will be increased by the importance that has been placed on the need for market power mitigation in the All-Island Market.

This risk may be reduced by the use of long-term hedging products that would reduce the gains from the exercise of market power in the spot market. For example, these products could take the form of directed contracts or one way CfDs, including reliability options. These products would also mitigate the impact of price spikes on other market participants, such as small suppliers and end consumers. These hedging products could form part of the market power mitigation tools set in place as part of the energy trading arrangements.

In most electricity markets, energy prices under scarcity conditions depend critically on decisions made by the system operator. For example, before implementing rolling blackouts, system operators often reduce system voltage to stabilise the system. This has the effect of reducing demand, thereby reducing wholesale prices relative to what they otherwise would be at times of scarcity.

However, voltage reductions are not free. If they were free the system could simply be run at a lower voltage. Voltage reductions lead lights to dim, equipment to run less efficiently and on-site generators to turn themselves on, etc. These are costs that are widely dispersed among electricity consumers and are not reflected in market prices. Thus, the aggregate marginal social cost of voltage reductions is not reflected in market prices. This means that there is a downward bias in market price signals at times when generation capacity is in short supply. This would typically lead to underinvestment in reliability over time.

An active demand-side would reduce the scope for market prices to rise at the times of scarcity, as demand would reduce at high prices. Therefore, the lack of a sufficiently active demand side means that market prices are more likely to rise to higher levels at times of scarcity. This would make the energy-only market more prone to regulatory/political intervention.

87 MW of capacity was registered with demand side units (DSUs) in the SEM at the start of 2014, compared with 41MW in 2012. There are also a number of measures that should facilitate increased demand-side participation in the future. This includes the introduction of a firm DA schedule and price under I-SEM[43], efficient short-term price signals, and the roll-out of smart metering in Ireland and in Northern Ireland. In the medium term, the responsiveness of the demand-side may increase, though the pace and scale of this increase will depend on technological and behavioural changes.

### 6.3.2 PUBLIC GOOD NATURE OF RELIABILITY

Reliability has all the characteristics of a public good in that it is both:

- **non-excludable** in the sense that individual consumers of electricity cannot be effectively excluded from the supply of system-wide reliability.
- **non-rivalrous** in the sense that consumption of reliability by one individual consumer does not reduce the reliability enjoyed by others.

This is one of the principal market failures associated with an energy only market, as it dampens the market signal for the delivery of reliability.

This is because consumers cannot choose their individual preferred level of reliability during rolling blackouts, except by installing their own generating equipment. Their lights go out along with their neighbours' lights, since the system operator cannot selectively disconnect any but the largest consumers. This means that, even if other market or regulatory imperfections are resolved, an energy-only market alone cannot be relied upon to provide the efficient level of reliability.

### 6.3.3 OPERATING PATTERN OF THERMAL PLANT WITH HIGH WIND PENETRATION

The Governments in both Ireland and Northern Ireland have set a policy target of 40% renewable generation by 2020. This target is expected to be largely delivered predominantly by wind generation. This would represent the highest level of penetration by wind for any synchronous system in Europe.

[43] The May 2011 Demand Side Vision for 2020 Decision Paper (SEM/11/022) D identified the creation of a visible and firm DA schedule (and price) for the All-Island Market as being a high value measure to support demand side participation.

Large scale deployment of variable renewables has some important consequences for conventional thermal generation in the market:

- total energy requirements from thermal generation (TWh) fall relative to requirements for capacity (GW); and
- thermal generation faces major changes in operating patterns, with increased emphasis on flexibility to respond to weather variation and, forecast error at short notice.

As installed wind capacity increases, capacity margins become wider for the majority of the periods across a year. This is illustrated in
Figure 19 below, which shows the hourly capacity margins for Base Case A from our quantitative assessment of an assumed perfectly-functioning energy-only market. The line represents the percentage of hours in a year in which the capacity margin is below the level on the y-axis.

***Figure 19 – Hourly capacity margins[44] for I-SEM in 2020 and 2030 in the energy-only market (Base Case A)***

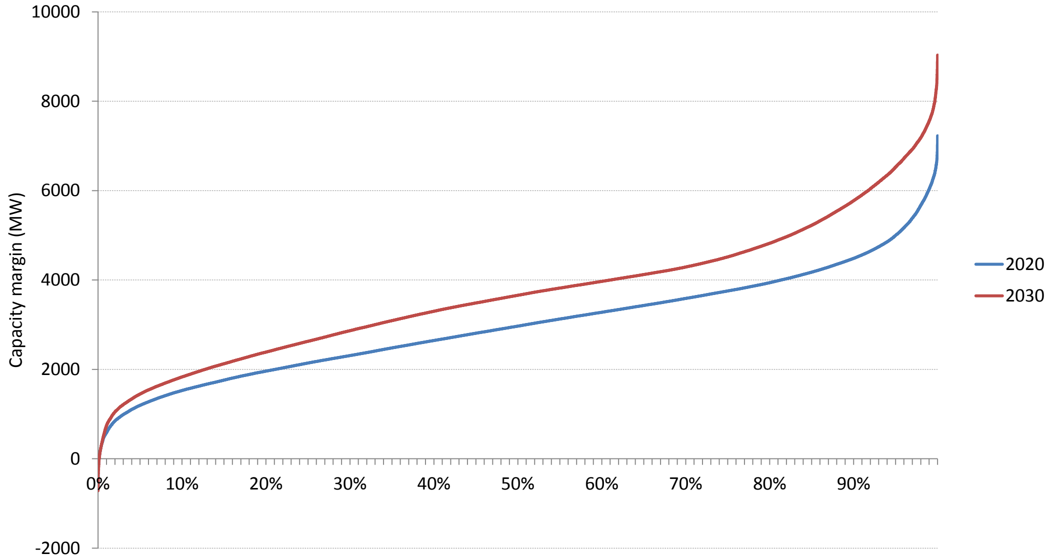


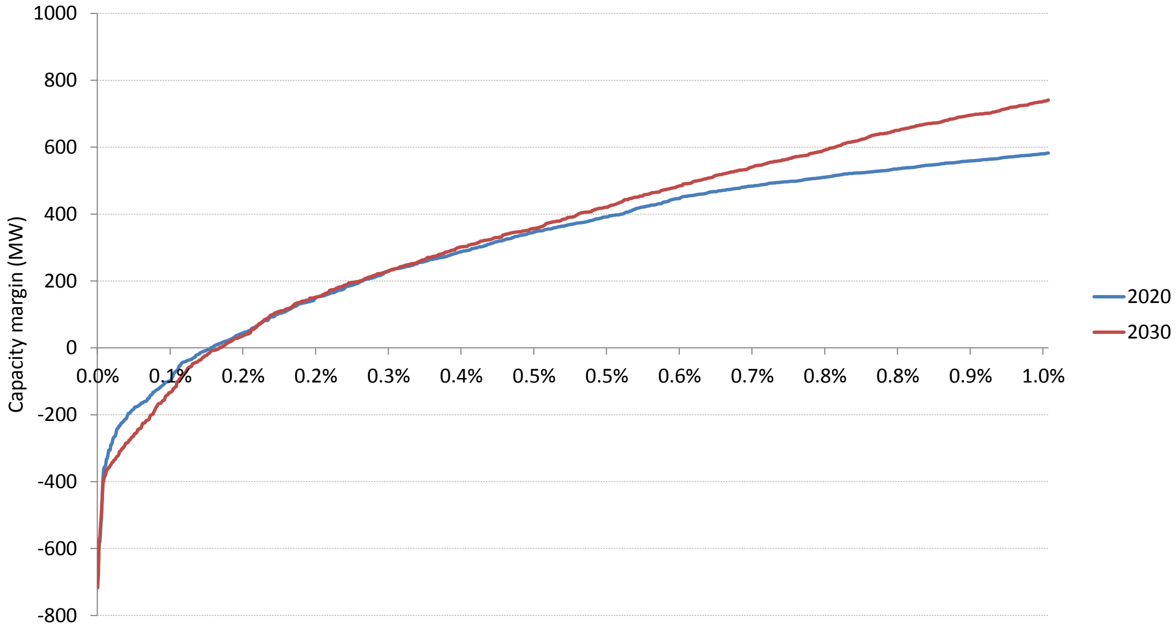

Figure 19 illustrates that as installed wind capacity increases there is reduced need for conventional thermal capacity across the whole year. However, conventional thermal capacity is required on the system to cover for low wind output coupled with high demand, albeit over a limited number of periods. This is because the increased wind capacity has little impact, if any, on the capacity margin in the tightest periods.

This is illustrated in Figure 20, which focuses in on the capacity margin in the top 1% of periods shown in

44 The capacity margin for each period of the year is calculated as demand net of all available capacity and net of net interconnector flows in that period

Figure 19. In these tightest periods, the capacity margin in 2030 is similar to that in 2020, despite the fact that in 2030 capacity margins are greater for most of the year, as shown in Figure 19.

***Figure 20 – Hourly capacity margins[45] for I-SEM in 2020 and 2030 in the tightest 1% of periods in the energy-only market (Base Case A)***

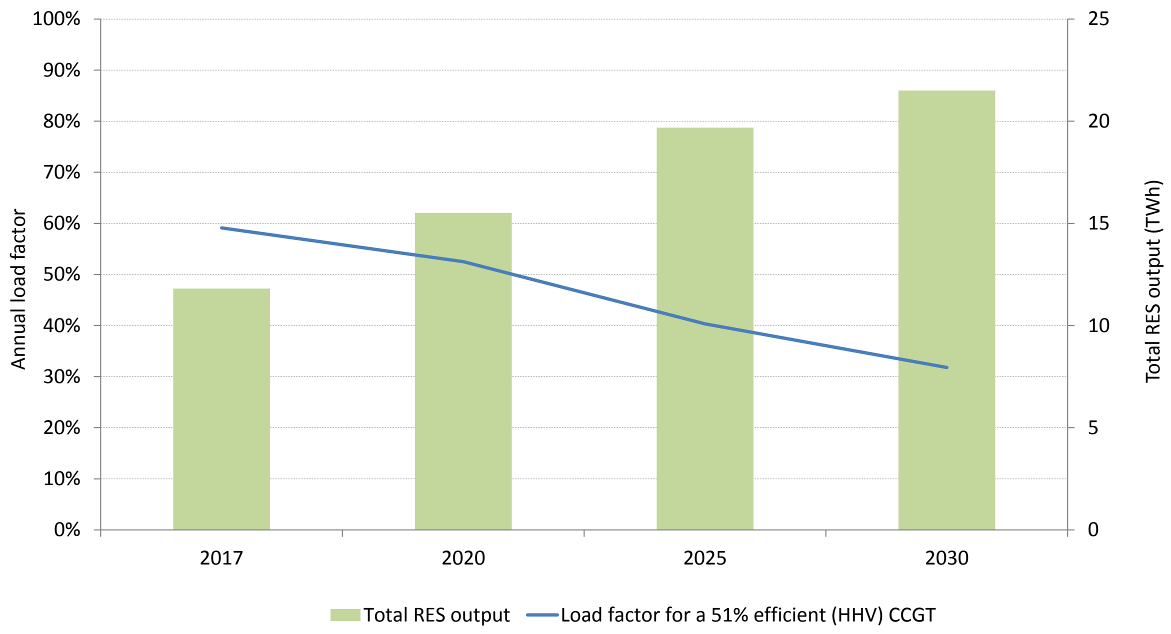



Consequently, the high penetration of renewables means that even new-build thermal generation may now expect to run in mid-merit (at best) rather than at baseload. For both mid-merit and peaking plants, there is increased reliance on the more unpredictable scarcity rent element which can increase the perceived risk of entering (or continuing to operate) in the energy-only market.

Figure 21 shows how the load factor of a 51% efficient (HHV) CCGT changes over time in Base Case A. In 2017, the plant has an annual load factor of around 60%. By 2030, the annual load factor of the plant has dropped to about 30%, meaning that the plant is much closer to running like a peaking plant. The drop in load factor is not the result of new entry by more efficient plants between 2017 and 2030, but rather by the increased output of renewable generation (as denoted by the green bars in Figure 21).

45 The capacity margin for each period of the year is calculated as demand net of all available capacity and net of net interconnector flows in that period

*Figure 21 – Annual load factor for a 51% efficient (HHV) CCGT in the I-SEM (Base Case A)*




### 6.3.4 RISKS FOR THERMAL PLANT WITH HIGH WIND PENETRATION

This change in operating patterns can make it much harder for energy-only markets alone to deliver investment with a "reasonable" risk profile, even in the absence of market features such as bidding restrictions and price caps.

On average, there will be reduced number of hours of scarcity, assuming a system with adequate generation capacity. This is because there will be variable renewable output for some but not all of the peak demand hours. So the volatility of scarcity rent will increase as it is recovered in fewer hours. As a result, higher price spikes may increase the actual or perceived threat of political and/or regulatory intervention.

Table 21 and Table 22 report the number of hours of high prices in an assumed perfectly-functioning energy-only market in Base Case A. In the modelling of the perfectly-functioning energy-only market, the entry and exit decisions of thermal generators assume that plants are able to capture all of these high price periods without regulatory or political intervention.

Table 21 shows the average expected number of hours of high prices in each snapshot year, with the number and magnitude of price spikes increasing over time. This is the result of further renewable deployment reducing the running hours for thermal plant, meaning that the fixed costs have to be recovered in fewer hours.

Table 22 reports the number of high price periods in the most extreme year (of low wind generation and low thermal plant availability). It shows that in these circumstances, the price spikes are much more frequent than in the average year.

Historically in the SEM, spikes in wholesale prices (SMP plus capacity payments) have been more infrequent and much lower than reported in Table 21 and Table 22. Over the last six years (2008-2013), wholesale prices in the SEM have been above €500/MWh over around 10 periods on average each year. This reflects the presence of a price cap for the SMP set at €1000/MWh, which is in excess of the SRMC of the most expensive unit, combined with the BCoP restrictions on bidding. In addition, there has generally been sufficient capacity on the system above the security standard resulting in 'damper' capacity payments. In comparison, our modeled scenarios deliver a significant increase in number price spikes. That also reflects the much tighter capacity margins (close to the desired standard) in our modelled scenarios when compared to historical values.

***Table 21 – Number of high price hours in average year in 'perfectly-functioning' energy-only market (Base Case A)***

| Number of hours | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| I-SEM price > €2500/MWh | 3 | 7 | 10 | 12 |
| I-SEM price > €2000/MWh | 3 | 7 | 14 | 14 |
| I-SEM price > €1000/MWh | 5 | 16 | 33 | 35 |
| I-SEM price > €500/MWh | 19 | 43 | 69 | 71 |

***Table 22 – Number of high price hours in extreme year in perfectly-functioning 'perfect functioning' energy-only market (Case A)***

| Number of hours | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| I-SEM price > €2500/MWh | 14 | 33 | 44 | 55 |
| I-SEM price > €2000/MWh | 14 | 33 | 63 | 63 |
| I-SEM price > €1000/MWh | 28 | 72 | 115 | 116 |
| I-SEM price > €500/MWh | 79 | 140 | 215 | 216 |

Figure 22 and Figure 23 show the average, or expected, gross margin for each snapshot year for two example plants from the modelling of a perfectly-functioning energy-only market. They also show the range of gross margins across the 15 different combinations of weather, demand and availability profiles.

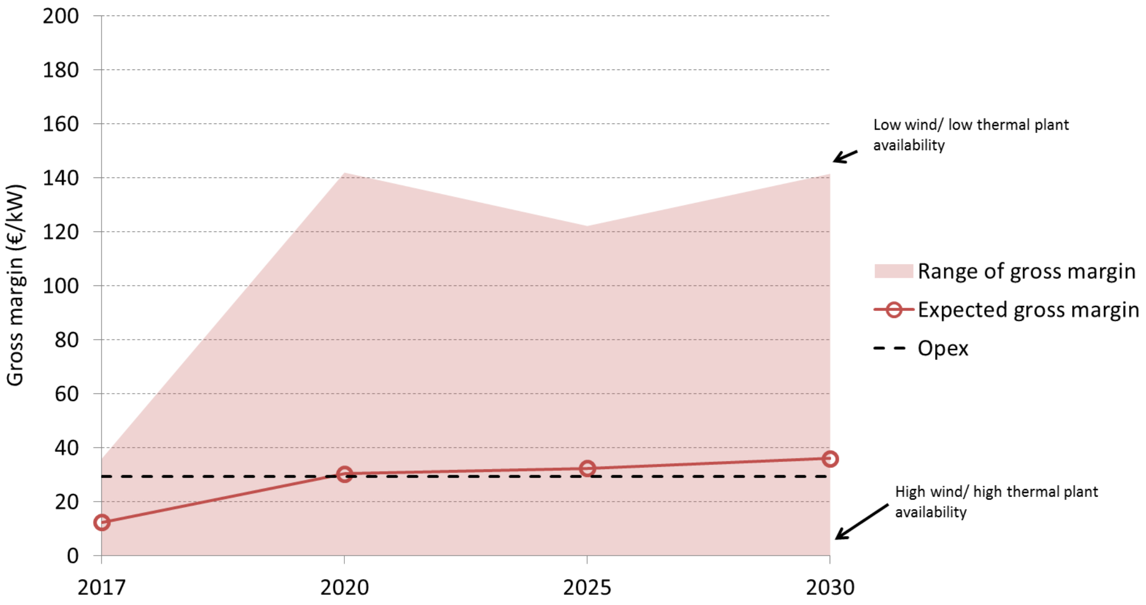
The gross margin shown in these charts equals:

- wholesale electricity revenues
- **plus** net system services revenue
- **minus** variable fuel and operating costs.

For the plant to remain viable, the gross margin would need to be sufficient to cover annual fixed and capital costs.

Figure 22 shows the expected range of the gross margin for a 29% efficient (HHV) OCGT. It shows that the expected gross margin is sufficient to cover the fixed operating costs from 2020 onwards[46]. However, the range illustrates that the gross margin realised in any year is highly sensitive to the level of demand, renewable generation and availability of thermal plant. In a high wind year, the OCGT might realise virtually no gross margin from the energy market. In contrast, in a year in which there is a significant number of periods with low wind coinciding with relatively high demand, the gross margin of the OCGT could be over €120/kW in 2020, 2025 and 2030.

*Figure 22 –Gross margin[47] for a 29% efficient (HHV) OCGT (Base Case A)*




46 The opex requirement shown on the chart is an average requirement across OCGTs, which means that there are some OCGTs with lower fixed costs (and hence remain viable at lower expected gross margins).

47 Gross margin shown on this chart equals (wholesale electricity revenues + net DS3 revenue) minus variable fuel and operating costs

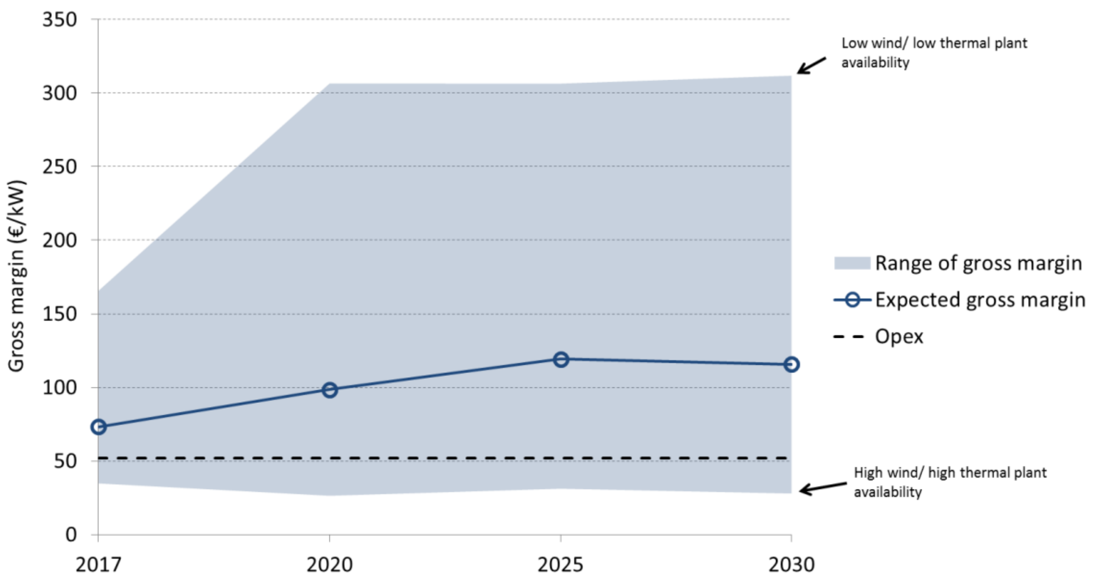
Figure 23 shows the expected and range of gross margins for each snapshot year for a 51% efficient (HHV) CCGT in the modelled energy-only market. In a year with relatively comfortable capacity margin, e.g. as a result of high renewable generation, the gross margin can be as low as around €20/kW. This would not be sufficient for a plant to cover its fixed annual operating costs. However, the gross margin could be as high as €300/kW in a year with low renewable generation, high demand and low generation availability. Achieving this level of gross margin relies on the level and frequency of price spikes shown in Table 22.

In the modelling of this perfectly-functioning energy-only market, the assumption of perfect foresight of expected gross margins, and no dampening of price spikes (below the €3000/MWh cap) means that a wide range of gross margins has no impact on the entry/exit decision of plants.

In practice, the potential variability in gross margins could then reduce the confidence of plants that they will be able to recover the costs of staying in the all-island market by capturing price spikes (without regulatory intervention) – even where the average expected gross margin is sufficient to cover their fixed costs.

This will particularly be the case where plants run infrequently, even though they may be essential for security of supply. This then raises the prospect of excess or disorderly exit, which is made worse by the relatively large unit sizes in the All-Island Market and the current existence of a CRM. Excess or disorderly exit would be particularly challenging for the All-Island Market given the relative isolation of the market, placing a high burden on domestic actions to ensure security of supply.

***Figure 23 - Gross margin[48] for a 51% efficient (HHV) CCGT (Base Case A)***




In summary, thermal plants will be increasingly reliant on high prices in a small number of periods to cover their fixed and capital costs. For a peaking plant in particular, all of its gross

48 Gross margin shown on this chart equals (wholesale electricity revenues + net DS3 revenue) minus variable fuel and operating costs

margin is recovered in these few periods of scarcity. Uncertainty about demand and supply means that the number of these hours will not be uniform from year to year but can vary significantly between years.

Accordingly, investors will be concerned about actions by regulators or discretionary behaviour by system operators that might have the effect of constraining prices in exactly those few hours with very high prices when investors expect to earn most of the net revenues required to cover their capital investment costs.

#### 6.3.5 CHALLENGES FOR FORWARD CONTRACTING

Credible long-term contracts can be an efficient institutional response to the some of the spot market uncertainty discussed in the previous section. Long term power supply contracts with credit worthy buyers can allow for investing in generating plant to shift this risk to consumers. However, these long-term contracts will not replace (expected) missing money in the spot market, and their effectiveness will ultimately be limited by the public good nature of reliability.

In the circumstances of the All-Island Market, a particular challenge is that traditional traded hedging instruments for firm quantities such as forward energy contracts are not well-suited to managing the combination of price and volume risk faced by some plants in a high-RES world. Volume risk reflects the fact that the operating profile for low-merit thermal plants is not known in advance. So there may be no way to trade profitably, e.g. through a positive forward spread, as there is not a sufficiently granular forward product available.

For example, suppose a super-peak product covers 100 hours. There may be a negative spread for the low-merit plant over the whole 100 hours, but there are 20 hours in which its operation is profitable. However, those 20 hours are not known in advance and hence cannot be captured in a forward product with a positive spread.

Insufficient forward contracting opportunities have been highlighted as an issue for delivering sufficient generation adequacy through any possible set of energy-only trading arrangements in the I-SEM. The design of the energy trading arrangements in the I-SEM will emphasise the importance of measures to promote forward market liquidity and this will rely on sufficient spreads and/or sufficiently granular forward products.

#### 6.3.6 INDIVISIBILITY AND FORWARD CONTRACTING FAILURE

The indivisibility issue arises when generating unit sizes are relatively large relative to total market size. This means that the entry or exit decision of an individual plant can have a significant impact on the security of supply position and on prices. For example, new entry by one plant reduces prices below the sustainable new entry level for a number of years – this therefore delays or even discourages new entry even when required by the system.

The indivisibility issue can apply to additions to or retirements of installed capacity. It is linked to another possible market failure, that of co-ordination failure. In a perfectly functioning market, decisions to build new capacity are made independently. This induces strategic uncertainty: the profitability of one's own investment in new plant will depend on the decision of others whether also to invest or not. This may result in a new entrant delaying its decision until the prospective capacity margin is tight enough to support more than one new entrant; or alternatively in entering early to discourage entry by potential competitors. The optimal strategy implies a random element and so the outcome is likely to be inefficient; and these concerns would apply with more weight to a small market where a new entrant will have a significant effect on prices.

Indivisibility was highlighted as a key challenge for the All-Island Market in the development of the arrangements for the SEM. Since the creation of the SEM, some proposed new generation projects are around 100MW and the Best New Entrant is defined as 200MW. This should have somewhat reduce the impact of the indivisibility issue for new entry.

However, the All-Island system remains a relatively small system. Peak demand currently is around 6.2GW and is expected to be 7.8GW by 2030. Over the last decade the majority of new entry consisted of CCGTs with a typical size of around 400MW. New entry (or exit) of a generating unit of that size can result in a significant change in the capacity margin of the All-Island system. Smaller-sized CCGT configurations are available, but come at a higher cost and with a sacrifice in efficiency.

The perfectly-functioning energy-only market has been modelled assuming coordination between market participants. This means that there is exit on an economic basis up to the point where the security standard is met. When additional capacity is required, there is again sufficient new entry to ensure the security standard, and the costs of this investment are recovered through wholesale prices. In reality, investment decisions are taken independently by different market players. There is a risk of capacity being delivered in excess of the target capacity or not sufficient capacity being delivered when needed.

Figure 24 shows the impact on security of supply beyond the required capacity for ensuring the security standard is met and no new entry when needed. In our reference case, Base Case A, there was 400MW of new entry between 2020 and 2025 in order to meet the required security standard.

We have explored two additional sensitivities where there is lack of coordination. In one case (Entry of 400MW of 'excess' capacity), we test the impact of an additional 400MW of capacity being delivered between 2020 and 2025 (beyond the capacity required to meet the security standard) when compared to the reference scenario (coordinated). In the other case (No new entry), there is assumed to be no new entry between 2020 and 2025 (even though it is required in the Reference scenario) – alternatively, this case could be seen as one with the exit of an additional 400MW CCGT between 2020 and 2025. Either way, the important thing is that there is a net reduction of 400MW in CCGT capacity between 2020 and 2025 in this 'no entry' case compared to the reference scenario.

There are a number of existing CCGTs around 400MW in the all-island market. The analysis shown illustrates the sensitivity of the generation adequacy assessment to the exit decision of a relatively small number of CCGTs.

In the case where there is entry of an additional 400MW on the system between 2020 and 2025, the LOLE drops below 6 hours in 2025 and is around 4 hours in 2030. This 'enhanced' security standard will however come alongside reduced profits for generating units. This can be seen in Figure 25, which shows the impact on wholesale prices, assuming an energy-only market As the capacity margin is 'looser' there are less opportunities for generating units to capture scarcity rent in the market. In reality, however, reduced profitability may mean further exit (in subsequent years), assuming there is a signal for efficient exit (which is not necessarily the case for price-based CRMs).

In the other case, where there is no entry of a 400MW CCGT between 2020 and 2025, there is a significant increase in LOLE with more than 15 hours in both 2025 and 2030, as shown in Figure 24. This increase in LOLE comes alongside an increase in profitability for generating units, which effectively delivers a signal for new entry. Therefore, in practice, we would expect new entry to take place in subsequent years, thus decreasing LOLE.

***Figure 24 – Impact on security of supply of uncoordinated entry in 2023 compared to Base Case A***

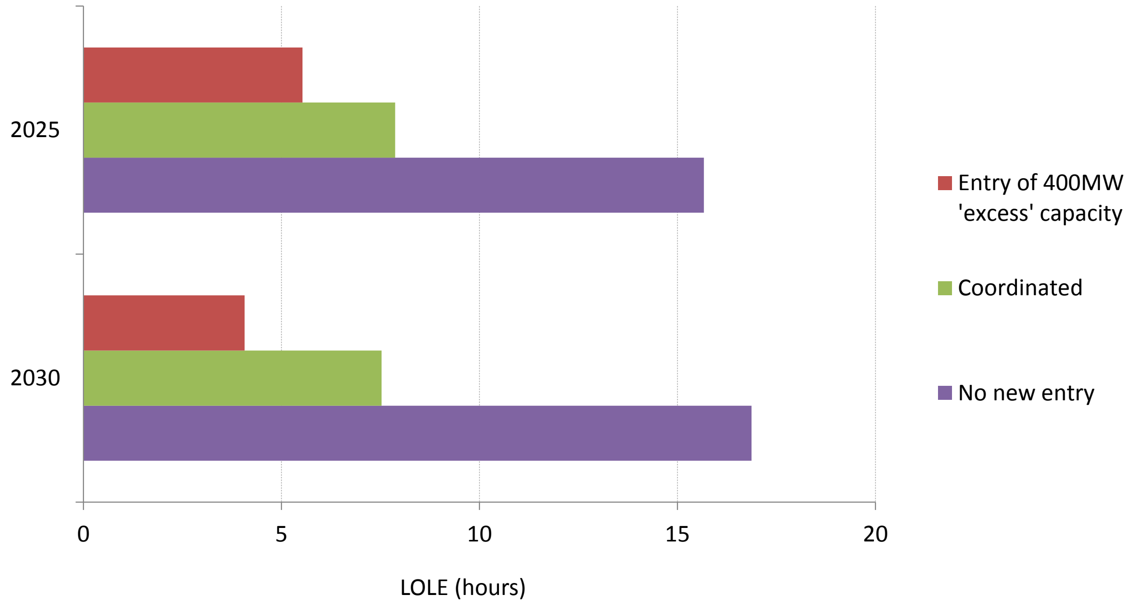
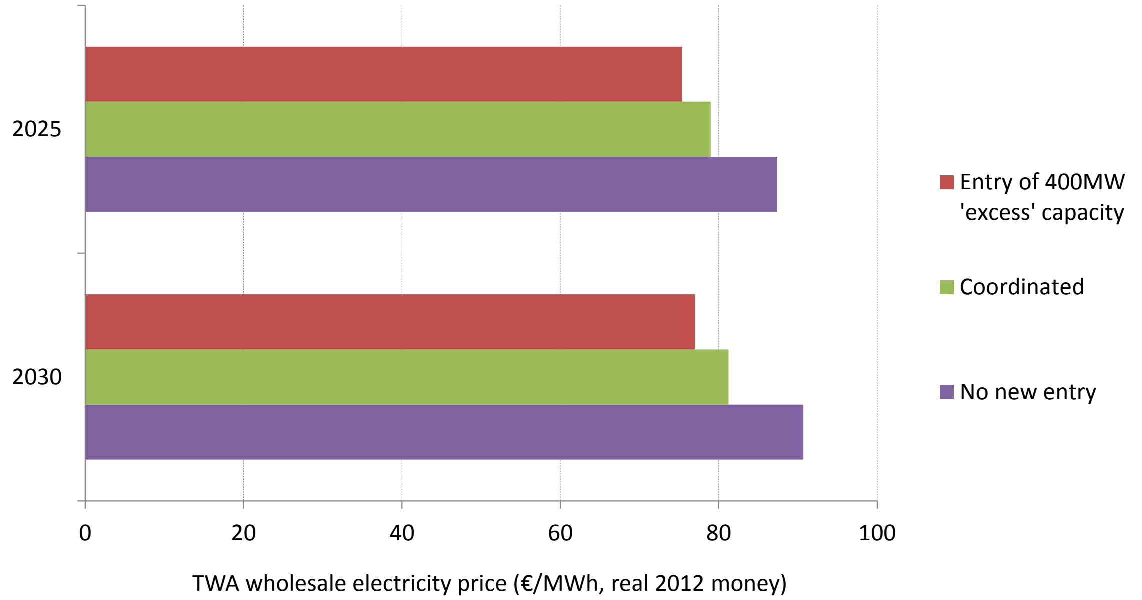


*Figure 25 – Impact on TWA wholesale price of uncoordinated entry in 2023 compared to Base Case A*




## 6.4 TARGETED CONTRACTING

In line with National Legislation in Ireland and Northern Ireland and the Security of Supply Directive (Directive 2005/89/EC), targeted contracting will continue to be available as a 'backstop' measure to address specific security of supply concerns on a case by case basis.

The SEM Committee recognises the benefits of targeted contracting to address specific circumstances that provide risks to security of supply.

However, targeted contracting would not be an appropriate response to the fact that energy prices may be dampened at times of scarcity in an energy-only market, and that reliance on fixed cost recovery through gross margins, with increased uncertainty about the timing and magnitude of these gross margins (as illustrated in Section 6.3.4).

Therefore, the SEM Committee is of the view though that targeted contracting would not be sufficient to address the wider challenges for generation adequacy that have been identified for the I-SEM.

# 7 FORM OF EXPLICIT CRM

## 7.1 OVERVIEW

This chapter describes the updated assessment of different options for the HLD of the explicit Capacity Remuneration Mechanism (CRM). This includes updated qualitative and quantitative assessment since the Initial Impact Assessment, particularly in relation to distributional impacts.

In the quantitative assessments, we use the long-term price-based CRM as the baseline for reporting the results because that effectively represents the status quo position in terms of the current CRM in the SEM. We then consider the costs and benefits of a number of different options for changes to the form of explicit CRM.

## 7.2 OPTIONS FOR EXPLICIT CRM

This IA considers the following types of CRM:

- Price-based:
  - long-term price-based;
  - short-term price-based;
- quantity-based:
  - centralised capacity auctions; or
  - centralised reliability options.

### 7.2.1 DIFFERENCES BETWEEN PRICE-BASED AND QUANTITY-BASED CRMs

There is a range of different terminology that is used to describe CRMs in different contexts. Therefore, it is important to define the main points of distinction between a 'price-based' CRM versus a 'quantity-based' CRM, as defined in this Impact Assessment and related documents.

A 'price-based scheme' is defined as a scheme where:

- capacity remuneration depends on availability in a particular period (i.e. there is no advance commitment to deliver capacity); and
- the capacity payment is paid to all eligible generation – i.e. there is no process in allocating payments based on a merit order of the cheapest providers up to a centrally determined quantity.

In this sense, 'price-based' does not mean that the central body necessarily fixes the level of payment received by each capacity provider. Instead, the central body can fix the relationship between quantity of capacity provided, and the price received. For example, this can be done by fixing a total pot for capacity payments, with the price then determined by the amount of capacity provided. However, the key point remains that the central body effectively fixes the price, or pricing function that determines the price based purely on the quantity that provided.

In this context, a 'quantity-based' scheme is defined as one in which:

- providers receive an advance payment for capacity, in exchange for a commitment to deliver either capacity or energy in the certain required periods and face a penalty if unable to do so; and
- there is direct competition between providers to receive the payments, with payments allocated to a centrally determined quantity based on a merit order of bids. This does not exclude the use of a sloping demand curve in the capacity auction.

A central body determines the amount of generating or demand reduction capacity to be procured and uses a market mechanism, typically an auction to discover a price for this capacity[49]. The procurement would generally be open to all resource types that can meet the required performance criteria[50].

It is likely that with a quantity-based scheme, in a situation of overcapacity relative to system needs, not all generators in the market would get a contract to receive capacity payments; or that the capacity price in the auction would be driven to low levels. On the other hand, it is possible that some providers might not want a contract for all their eligible capacity (given an exposure to penalties for unavailability/non-delivery).

In all of the quantity-based mechanisms, there is a requirement for a re-trading mechanism to allow providers of capacity contracts to manage their risk of non-availability closer to real time. This is of particular importance where there is a multiyear gap between commitment and delivery.

An alternative way of thinking about this is to equate 'price-based' with capacity payments, and 'quantity-based' with capacity markets. In either case, there can be some form of price-quantity trade-off included in the procurement process

In a price-based scheme, there is no direct competition between the providers to receive the payment in any period. Instead, the quantity of eligible capacity determines the price based on the administered pricing function. If more capacity is available, that will reduce received by everybody, and capacity will be willing to provide as long as the costs are below the price.

In a quantity-based scheme, there is scope for the total level of payments to be determined by the competitive auction process, within regulatory bounds.

### 7.2.2 DIFFERENT FORMS OF PRICE-BASED CRMS

The status quo represented by the **long-term price-based CRM** is one in which a central body fixes the total pot for capacity payments with some certainty for several years into the future. Even if the value of the total pot is updated every few years, the principles used to

49 This differs from a long-term price-based scheme, where the capacity pot is determined centrally (e.g. by the RA) and is then spread across the available capacity.

50 These criteria may be more explicit in the capacity auctions/obligations than in the reliability options where it will be driven more by the choice of reference market for example.

fix the pot are designed to be stable over the very long-term. The size of pot will be based on the amount of the capacity required to meet the security standard, and the cost of new entry. As this option is designed to give long-term signals, the size of the pot is assumed to be weakly influenced (if at all) by the projected capacity margin for the given period – this means that the pricing function has a weak relationship between quantity and price.

In this design of the long-term price-based CRM, the annual capacity pot is then converted into a string of spot capacity prices (e.g. differing by each half hour), with the spot capacity price in particular periods set to reflect the tightness of the capacity margin[51].

In a long-term price-based CRM with a fixed total value, there needs to be some mechanism to reconcile the actual money paid out with the pot set at the start of the year. In the current SEM this is done through a monthly ex-post capacity price calculation.

In a **short-term price-based CRM**, the capacity price for each settlement period (e.g. half hour) is determined by the system tightness in that settlement period through an explicit pricing function. There is no fixed annual pot to be recovered under a short-term price scheme and therefore the amount to be given out has no upper or lower bounds.

### 7.2.3 DIFFERENT FORMS OF QUANTITY-BASED CRMs

The main distinctions between the quantity-based options considered in this Impact Assessment are the determination of when delivery (or availability) is required and the penalty for non-delivery (or unavailability).

Under **capacity auctions,** an administrative process is used to determine when delivery is required, and the methodology for the penalty for non-delivery is determined centrally.

In the **reliability options**, the seller of the option is giving up the chance to earn additional income above the strike price in exchange for an advance option fee – i.e. swapping a volatile income for a more stable one. Similarly the 'buyer' of the option is paying an advance option fee to avoid exposure to prices above the strike price in the reference market.

This is because the principle is that the providers of reliability options are exposed to making a net payment equal to the difference between the reference price and the strike price if they do not deliver in a period where the reference price is above the strike price.

This net payment results from the following set of cashflows. Generators holding a reliability option would have to make a gross payment of the difference between the reference price and strike price. However, generators delivering energy over that period into the reference market would have received the difference between the reference price and the strike price. Therefore, overall they would have made no net payment.

51 There is typically some intermediate steps of profiling the pot into intermediate periods (such as months or weeks).

This incentivises delivery in the time frames in which the option is called as failure to deliver energy at these times leads to possible financial exposure. This means that the signal for energy delivery by option holders and the penalty for non-delivery are market-based (with the potential for an additional administrative penalty if required, even under a reliability option scheme

A reference market must be defined for the reliability options. The choice would be between the coupled day ahead market price and an ex-post price, particularly if it takes the form of a single imbalance price. An ID price could be used to settle financial reliability options if ID auctions were developed under the provisions in the Capacity Allocation and Congestion Management (CACM) Framework Guidelines.

## 7.3 QUANTITATIVE ASSESSMENT OF WHOLESALE MARKET COSTS

This section reports the findings of our modelling of the wholesale market impacts of different CRM options under Base Case A. This provides insight into the outcomes associated with different CRMs in terms of:

- **non-monetary factors,** primarily security of supply as this is the prime driver identified for the retention of an explicit CRM; and
- **monetary factors,** in terms of the level and distribution of wholesale market welfare and consumer bills.

We use the long-term price-based CRM as a baseline for reporting the differences between different explicit CRMs in terms of modelling costs. That form of CRM most closely reflects the current scheme in operation in the SEM. We also model a short-term price-based CRM, and two quantity-based CRMS - capacity obligations, and reliability options.

### 7.3.1 APPROACH TO MODELLING DIFFERENT CRMS

In the long-term price-based CRM ('LT price-based'), the CRM has the same high level design as the current capacity payment scheme in place in the SEM. The capacity payment is set at a level that provides a long-run signal through a regulated Best New Entrant price. The BNE is assumed to be an OCGT running on distillate. We assume a change in the distribution of the pot when compared with the current arrangements with a greater fraction of the overall pot being distributed based on the capacity margin to rebalance more of the pot to generation that has a greater contribution to system security.

In the short-term price-based CRM ('ST price-based'), the spot capacity price is paid to all available capacity in the particular hour. The spot capacity price is based on a scarcity function that reflects capacity margin tightness and also depends on the value of lost load. This function is assumed to persist throughout the whole modelled period. The annual total level of capacity payments responds to the capacity margins throughout the year, rather than being set ex-ante

In the capacity auction/obligation ('capacity auction'), an annual auction is held with the demand for capacity being set at a level that ensures the required security standard is met

(8 hours a year LOLE). Both new entry and existing capacity can participate in the annual auctions, but there is no provision in the modelling for mothballing: closure is an irreversible decision. New entry is assumed not to 'lock in' a capacity payment for an extended contract length, because we are modelling snapshot years. However, as with the scarcity rent assumption in the energy-only market, the capacity price remains at new entry level once new entry is required[52]. Interconnected capacity is not eligible to participate, although the capacity requirement is reduced by a capacity contribution for interconnection.

Reliability options are intended to help deliver the short-term price signals of a perfectly-functioning energy-only market by addressing some of the recognised market failures of a pure energy-only market. For example, reliability options reduce the likelihood of regulatory intervention in response to price spikes and are expected to have a positive impact on financing costs by providing greater revenue certainty. This can then mitigate the perceived riskiness of the energy-only market. Therefore, the results for reliability options are based on the modeling of a perfectly-functioning energy-only market. In line with the other CRMs, the energy market is assumed to be fully competitive, with perfect foresight of 'expected' future revenues. Although there is a price cap of €3000/MWh (to reflect the price cap in the NWE DAM), there is no restriction on price spikes up to that level[53].

The modelling results should be interpreted in light of the modelling assumptions including:

- competitive markets for energy and capacity;
- no portfolio behaviour – i.e. all bidding into energy and capacity markets are designed to be optimal from the perspective of each individual unit;
- no quantification of any differences in the cost of capital under different CRMs;
- no allowance for cross-border participation in the quantity-based CRMs;
- plants have perfect foresight of expected energy and capacity revenues;
- fixed system service payments per technology, as set out in Appendix 2.1.5; and
- no additional deployment of demand-side response.

### 7.3.2 MODELLED RESULTS FOR SECURITY OF SUPPLY

Figure 26 shows the projected LOLE for the modelled CRMs. The security standard of a LOLE of 8 hours a year is met in all years for all of the CRMs.

In the two price-based schemes, the LOLE stays below 2 hours for the whole period to 2030. This this means that more plants stay on the system than are needed to meet the security standard. The overshooting of the security standard in a price-based CRM reflects the absence of a strong exit signal in those types of arrangements. The LOLE would be expected to rise towards 8 hours once new entry is needed.

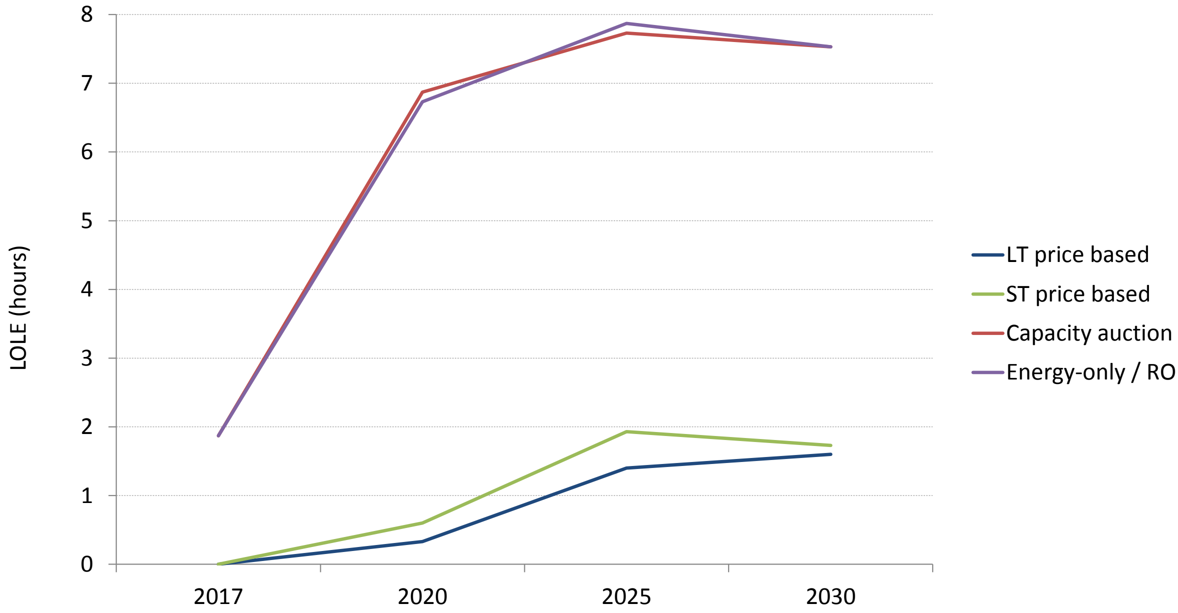
The amount of the capacity procured in the quantity-based CRMs means that the security standard of a LOLE of 8 hours a year is met almost exactly from 2020 onwards. The quantity-based CRMs actually deliver lower LOLE than the security standard in 2017 because of the assumption of perfect foresight of expected revenues. This means that some plants

52 This may result in an overestimate of consumer costs, compared with a situation where only the new entry receives the new entry cost for more than its year of entry.

53 Although no investment in demand-side response happens in response to these short-run price signals.

stay on the system even though they may make insufficient revenue in 2017 alone, because they are expecting to recover any losses in later years.

***Figure 26 – LOLE for  the different options for an explicit CRM in the I-SEM***




One of the benefits of a CRM is to provide a longer-term hedge for capacity providers (and for energy retailers), which could become more valuable in a world of high deployment of variable renewable generation

Figure 27 shows the range in gross margins for each snapshot year for a 51% efficient (HHV) CCGT under each of the CRMs.

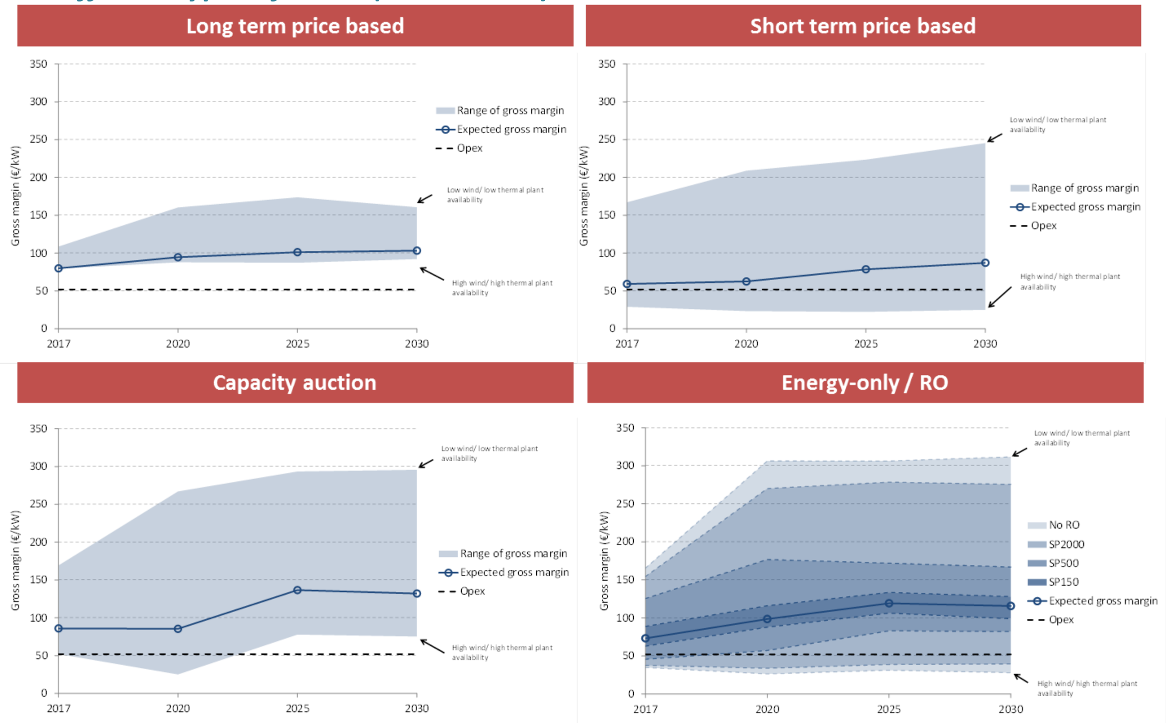
The pattern of gross margins in the long-term price-based CRM (top left chart) shows how the commitment to capacity payments based on new entry costs in all years reduces significantly the downside risk for plant.  This also discourages exit even when it is efficient.

The short-term price-based CRM (top right chart) has relatively little impact on the downside for the gross margin for the CCGT.  This means that it provides virtually no long-term hedge for the generator.  For the purposes of the modelling, this is not assumed to affect the plant exit or entry decision, although it is likely to do in practice.

In the capacity auction in 2017 and 2020 (bottom left chart), the capacity payment is low, reflecting the relatively comfortable supply-demand balance.  The level of capacity payment increases (and stays high) once new entry is required in 2025. The higher capacity payment then significantly reduces the range of gross margins, compared with the energy-only market.

As described earlier, the reliability options have been modelled effectively as a perfectly-functioning energy-only market.  In practice, the reliability options would offer a long-term hedge (as illustrated in bottom right chart).  The impact of the reliability options on the range of the gross margin depends on the level of strike price assumed. The range of gross margins will decrease with a reduction in the strike price (SP). However, in the modeling, the expected gross margin does not change with different strike prices.

*Figure 27 –Gross margin[54] for a 51% efficient (HHV) CCGT under the energy-only market and different types of CRMs (Base Case A)*




The modelling has also illustrated the difficulties of incentivising efficient levels of exit under a long-term price-based CRM. The current installed capacity in the SEM is around 2GW above the required capacity for meeting the existing security standard. Part of that capacity surplus (around 900MW) is expected to come offline by 2017 as a result of environmental restrictions. Of the remaining capacity, there is a combination of around 1GW GT , 600MW of steam and 1GW of CCGT capacity, which is likely to capture limited rents from the energy market and may present similar levels of 'missing money'. Of that 2.6GW of capacity, around 1.1GW of capacity could exit without breaching the overall system security standard.

In a long-term price-based CRM, where the price is set at the BNE level, there is little likelihood of plant exit, given that the price will be significantly higher than the annual avoidable fixed costs of the above capacity. If, the price was set at a lower level when more comfortable capacity margins are expected for a number of years, this would more closely reflect the prevailing capacity margin situation. There would then be a stronger signal for efficient exit. However, similarities in the technical and operational characteristics of the generating units that might be expected to exit the market means that it would be very hard to set a price that would deliver exactly the efficient amount of exit – this is because the supply curve is effectively horizontal or close to it around the efficient amount of exit (e.g. in the case described above, the efficient level of exit is around 1GW but there is around

54 Gross margin shown on this chart equals (wholesale electricity revenues + net system services revenue) minus variable fuel and operating costs

2.6GW of plants with similar requirements in terms of level of capacity payment). In these circumstances, there is a risk of delivering plant exit in excess of the target if the price signal is too sharp, or incentivising insufficient exit maintaining all (or most) of the capacity well above the target capacity

### 7.3.3 OVERALL WELFARE

Compared with the LT price-based CRM, all of the other CRM designs show a welfare improvement across the I-SEM and GB (in total).

Table 23 shows the change in overall welfare for the I-SEM alone (i.e. excluding GB) of moving from a long-term price-based scheme. Welfare is again higher for the capacity auction and short-term price based CRM than for the long-term price-based CRM. However, the level of welfare decreases slightly for I-SEM alone when moving to the perfectly-functioning energy-only market/reliability options. The differences, however, are very small by comparison with the total costs of the I-SEM over the modelled 14 year period, which suggests that these differences are unlikely to be not statistically significant given the uncertainties in any modeling exercise.

***Table 23 – Change in I-SEM wholesale market welfare between a long-term price-based CRM and alternative CRMs (Base Case A)***

| €m, real 2012 money<br>NPV over 2017-2030 with a 3.5% discount rate | Change in I-SEM welfare<br>(compared with LT price-based CRM) |
|---|---|
| ST price-based | +€129m |
| Capacity auction | +€64m |
| Energy-only/RO | -€47m |

Table 24 shows the changes in the different wholesale market cost elements between the explicit CRMs This table shows costs rather than welfare – an increase in costs in this table is equivalent to a reduction in the wholesale market welfare which was reported in Table 23 and Figure 28. Therefore, the total change in costs shown in the bottom row of Table 24 is equivalent to the total change in welfare in Table 23, but with the opposite sign.

A capacity auction delivers higher annualised capital expenditure but lower annual fixed costs as a result of different plant new entry in terms of technology type. As there is more generation in the I-SEM under the capacity auction than the long-term price-based CRM, there is a corresponding increase in variable production costs in the I-SEM and a similar decrease in the cost of net imports. However, as peak prices remain damped in both markets, there is a reduced signal for new interconnection to be built, assuming that interconnection does not receive capacity payments.

When compared with the LT price based CRM all alternative CRM schemes deliver a reduction in the cost of net imports and an increase in domestic variable production costs. This comes as result of higher imports from GB as the profiling of the capacity payments in the LT price based CRM supports flows from GB even when the capacity margin is 'loose' at the expense of domestic generation.

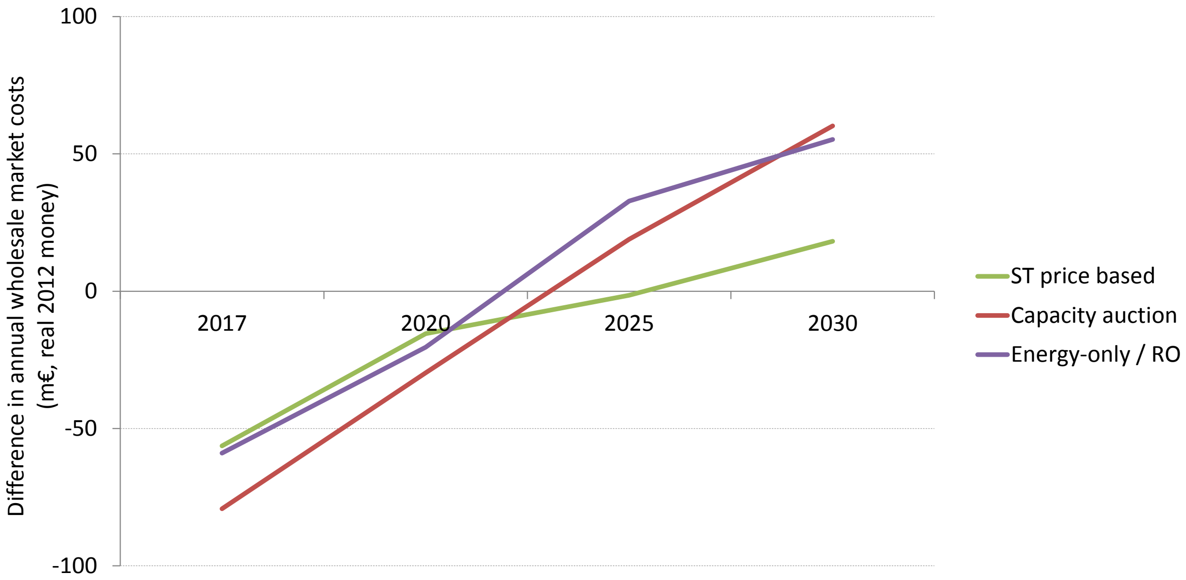
***Table 24 – Change in I-SEM wholesale market costs compared with the long-term price-based CRM***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | ST price-based | Capacity auction | Energy-only/reliability options |
|---|---|---|---|
| Annualised capex | -€14m | +€203m | +€108m |
| Annual fixed costs | -€77m | -€547m | -€659m |
| Variable production costs | +€2419m | +€2536m | +€1958m |
| Cost of EEU | +€9m | +€277m | +€401m |
| Cost of net imports | -€2466m | -€2533m | -€1762m |
| **Total change in wholesale market costs** | **-€129m** | **-€64m** | **+€47m** |

Figure 28 compares the annual I-SEM wholesale market costs under the long-term price-based CRM to the costs for each of the alternative CRMs. This shows that the long-term price-based CRM presents a much lower welfare in 2017 than the other CRMs. In 2020, it still has the lowest total welfare of any of the CRMs. However, in 2025, it has a higher total welfare than the quantity-based CRMs, and by 2030, it has the highest total welfare of all the CRMs.

This pattern of results is because a long-term price-based CRM encourages existing capacity to stay on the system[55]. Therefore, the higher wholesale market costs in 2017 and 2020 are driven by higher total fixed costs under the long-term price-based CRM as more plant stays on the system. By 2025, total fixed costs under the long-term price-based CRM start to fall as capacity retires because it reaches the end of its technical lifetime. At the same time, new entry in the perfectly-functioning quantity-based CRMs pushes up capital expenditure (and hence wholesale market costs) compared with the long-term price-based CRM. Lower levels of EEU in the price-based CRMs also help reduce wholesale market costs compared with the quantity-based CRMs.

*Figure 28 – Difference in annual I-SEM wholesale market costs between a long-term price-based CRM and alternative CRMs (Base Case A)*




### 7.3.4 DISTRIBUTIONAL ANALYSIS

Table 25 presents the change in wholesale market welfare (equal to change in the opposite direction in wholesale market costs) for the alternative explicit CRM options compared to the baseline of the long-term price-based CRM, alongside the change in distribution of welfare. In line with standard practice, consumer and interconnector surplus have been reported separately. The arrangements around interconnector cost recovery in the all-island market should though mean that changes in interconnector surplus (i.e. net profit) should be symmetrically passed through to consumers. Consumer surplus significantly increases under a short-term price-based CRM with an estimated increase in consumer surplus of €2.5bn (on a net present value basis). This increase is offset by a reduction in producer surplus (estimated around €2bn) and significantly lower congestion rent for interconnector transmission rights holders and ultimately TUoS customers in Ireland and Northern Ireland who underwrite the East West and Moyle Interconnectors.

55 A short-term price-based CRM also supports the retention of existing capacity, even though annual payments are low in 2017 and 2020 because of the high capacity margin.

A short-term price based CRM provides incentives for existing capacity to remain on the system. The capacity payments are set at a level, which is sufficient to achieve that, but much lower than a level that would support new entry (compared to the methodology for setting the pot in the long-term price-based CRM). This was also illustrated in Figure 27, where it can be seen that CCGT gross margins in the short-term price based CRM are much lower than alternative CRMs. This then translates in a transfer of surplus from producers to consumers, as shown in **Error! Reference source not found.**.

Under a capacity auction scheme, both consumer and producer surplus increase by around €0.2bn when compared with a long-term price-based CRM. Congestion rent, on the other hand, drops. Distribution of welfare in a capacity auction scheme changes across time. A capacity auction increases consumer surplus when there is more capacity on the system with a corresponding reduction in producer surplus, unlike the long term price-based CRM. This is the case for 2017 and 2020, when there is capacity in excess of that required for the targeted security standard. In the later years, there is a transfer of surplus from consumers to producers. These benefits for consumers would be larger if the modeling had assumed a differentiation of contract length for plants depending on whether they are new entrants or existing plant.

In a perfectly-functioning energy-only market or market with reliability options there is a transfer of around €0.5bn in terms of surplus from producers to consumers when compared with the long-term price based CRM. There is also a small reduction in congestion rent, significantly smaller than that under the short term priced based or capacity auction, which is relatively beneficial to TUoS consumers in Ireland and Northern Ireland who underwrite the interconnectors and therefore benefit from higher congestion revenue.

Similarly to a capacity auction when there is excess capacity on the system consumer surplus increases in a perfectly-functioning energy-only / reliability options scheme when compared to the long-term price based CRM. This comes alongside a reduction in producer surplus in such years. However, in the later years, when new entry is required, the perfectly-functioning energy-only / reliability options scheme delivers similar welfare distribution as the long-term price based CRM. This is because in the perfectly-functioning energy-only / reliability options scheme, revenues for generators rise to a level sufficient to support new entry and consumers face that cost.

***Table 25 – Change in I-SEM wholesale market welfare (and its breakdown) between a long-term price-based CRM and alternative CRMs***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Change in consumer surplus | Change in producer surplus | Change in congestion rent | **Change in wholesale market welfare** |
|---|---|---|---|---|
| ST price based | +€2743m | -€2274m | -€340m | **+€129m** |
| Capacity Auction | +€237m | +€208m | -€380m | **+€64m** |
| Energy-only / RO | +€527m | -€501m | -€73m | **-€47m** |

CONSUMER BILLS

Figure 29 presents the change in consumer bills and its breakdown[56] between a long-term price-based CRM and alternative CRMs. There is a significant reduction in consumer bills when moving away from a long-term CRM in the short-term. For example, under a perfectly-functioning energy-only / reliability options market a €270m and a €116m reduction in consumer bills is expected in 2017 and 2020 respectively. This equates to electricity bills that are 8% and 3% lower when compared to the long-term price based CRM in those two years.

In the quantity-based CRMs there is a transfer of cost in the form capacity payments to cost in the form of energy payments. In 2017 and 2020, however, the reduction in capacity payments is higher than the increase in energy payments in absolute terms. In 2025 and 2030 this transfer is more balanced.

In the short-term price based CRM there is only a small increase in energy payments when compared with the long-term price based CRM in all years. However, there is a significant reduction in capacity payments in all years as these become more targeted.

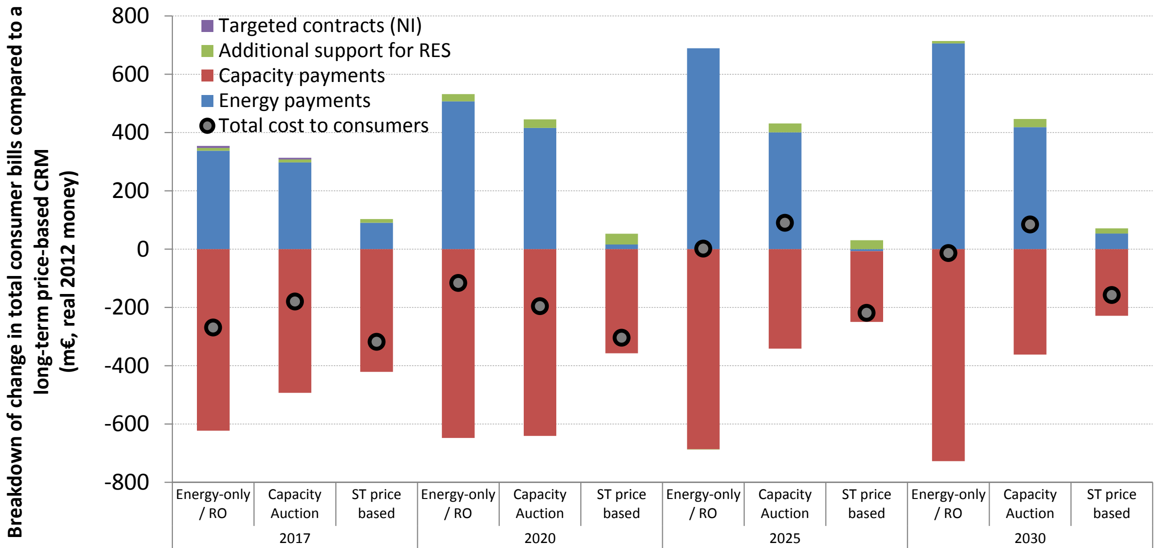
Across all alternatives there is a need for increased payments for supporting renewables. This is a result of reduced capacity payments in all alternative options (if any) towards wind with additional revenue coming in the form of top-up payments under REFIT II.

The breakdown for a perfectly-functioning energy-only / reliability options market is presented assuming that upfront payments (in the form of option fees) is zero and all revenues arise from the energy market. Effectively, any increase in capacity payments (under the reliability option scheme) would result in a corresponding drop in energy costs. The split between cost of energy and cost of capacity payments depends on parameters of the reliability option scheme, and in particular the strike price of the options.

In the two quantity-based CRMs it is estimated that there is a need in 2017 for a form of additional side payments for supporting plants in N. Ireland as market revenues on their own appear to be insufficient to keep capacity on the system. The impact of those side payments on consumer bills is however minimal.

56 The consumer bill differences shown in this section are based on changes in wholesale market outcomes. They do not include small differences in the implementation and operation costs, which are covered in a separate section.

*Figure 29 – Breakdown of difference in annual consumer bills[57] between a long-term price-based CRM and alternative CRMs (Base Case A)*

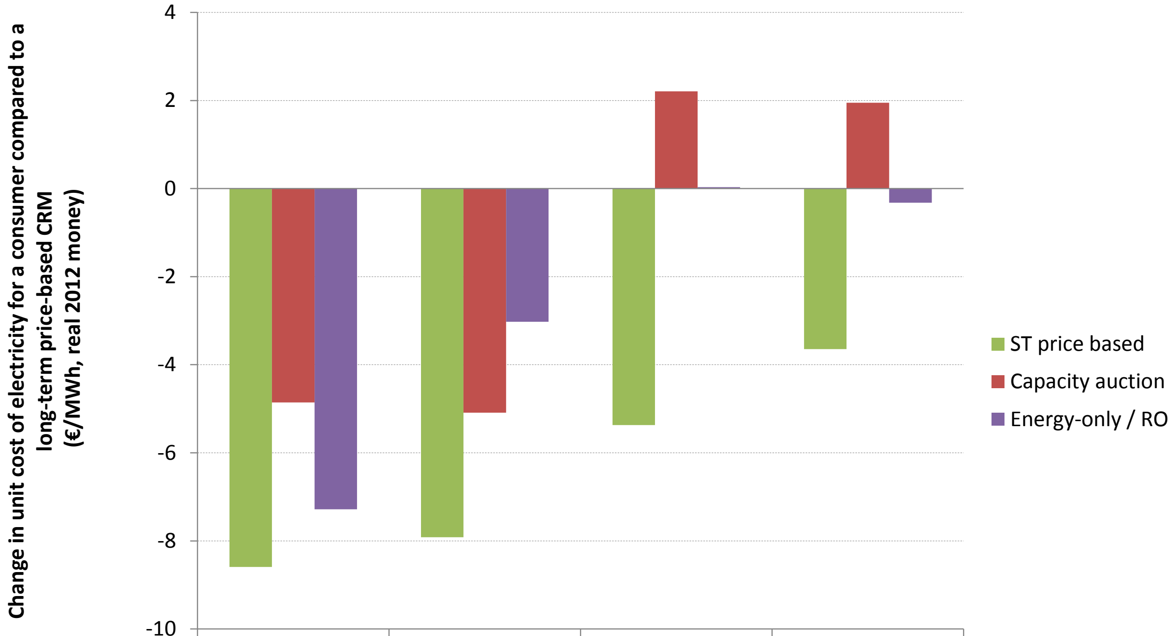



| | 2017 Energy-only / RO | 2017 Capacity Auction | 2017 ST price based | 2020 Energy-only / RO | 2020 Capacity Auction | 2020 ST price based | 2025 Energy-only / RO | 2025 Capacity Auction | 2025 ST price based | 2030 Energy-only / RO | 2030 Capacity Auction | 2030 ST price based |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Targeted contracts (NI) | 7 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Additional support for RES | 10 | 11 | 13 | 24 | 29 | 37 | -1 | 31 | 31 | 8 | 28 | 18 |
| Capacity payments | -623 | -493 | -421 | -648 | -641 | -357 | -687 | -341 | -243 | -728 | -362 | -229 |
| Energy payments | 337 | 297 | 90 | 507 | 416 | 16 | 689 | 401 | -7 | 706 | 418 | 54 |
| Total cost to consumers | -270 | -180 | -318 | -116 | -196 | -305 | 1 | 90 | -219 | -14 | 84 | -158 |

The change in the unit cost of electricity for a typical consumer with a demand profile similar to the I-SEM total demand follows the same pattern as the change in total consumer bills when moving from a long-term price-based CRM to an alternative CRM. The change in the unit cost for such a consumer is presented in Figure 30.

57 This covers costs of wholesale energy, capacity payments, additional renewable support payments, and system services payments. The figures shown in this chart do not include the impact of costs of operation and implementation.

*Figure 30 – Change in unit cost of electricity for a typical consumer with a demand profile similar to the overall I-SEM profile (demand-weighted average cost of electricity)*

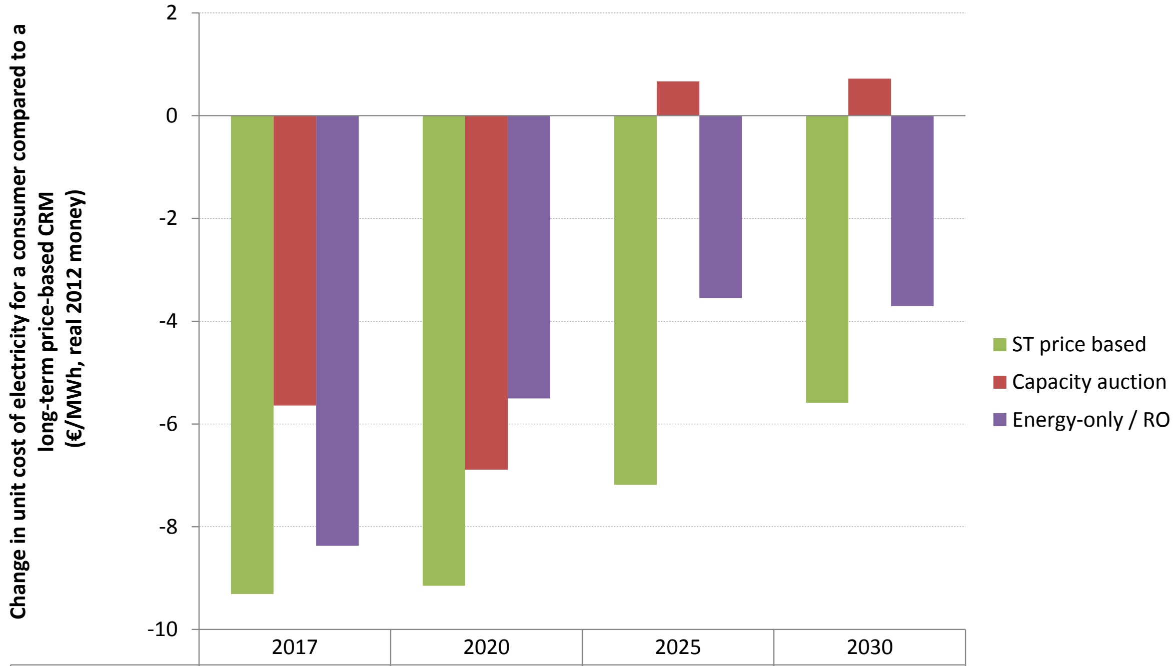



| | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| ST price based | -8.6 | -7.9 | -5.4 | -3.6 |
| Capacity auction | -4.9 | -5.1 | 2.2 | 1.9 |
| Energy-only / RO | -7.3 | -3.0 | 0.0 | -0.3 |

Moving away from a long-term price-based CRM presents greater benefits for consumer types with a baseload demand profile. This comes, primarily, as a result of more ‘targeted’ capacity payments (and/or scarcity rent in the energy market) over periods with a tighter capacity margin.

In the energy-only / reliability options market the unit cost of electricity is lower for such a consumer type throughout the whole period, even though the average unit cost of electricity is higher than the long-term price-based scheme in the long-term (2025 and 2030).

*Figure 31 – Change in unit cost of electricity for a consumer with a uniform demand profile (time-weighted average cost of electricity)*




| | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| ST price based | -9.3 | -9.1 | -7.2 | -5.6 |
| Capacity auction | -5.6 | -6.9 | 0.7 | 0.7 |
| Energy-only / RO | -8.4 | -5.5 | -3.6 | -3.7 |

### 7.3.5 IMPLICATIONS FOR HLD

When interpreting the results of the cost-benefit analysis, it should be noted that it does not include the impact of unquantified factors covered by the qualitative assessment. The combined impact of these factors would be to strengthen the performance of the centralised reliability options compared with the modelled outcomes shown in the cost-benefit analysis.

These factors include:

- **Importance of hedging for capacity providers and energy retailers:** the quantity-based CRMs, and the long-term price-based CRM offer a hedge for market participants against short-term variability of energy prices and gross margins – the need for this hedge was identified as one of the main challenges for an energy-only market which supported the retention of a CRM. However, the benefits of the long-term hedge are not fully quantified in the modelling. In the modelling of the short-term price-based CRM, thermal plants stay in the market even if there are a number of years where gross margins are not sufficient to cover annual fixed costs (e.g. as a result of high renewable generation, and high plant availability). In practice, the impact of this could be greater exit from the market (if plants cannot sustain the losses) and/or increased financing costs – which would both be expected to push up costs to consumers in the short-term price-based CRM (and a pure energy-only market) compared with the modelled outcome.
- **Ability of quantity-based CRMs to differentiate between the duration of capacity**

**price certainty needed by different types of capacity providers** - The modelling of the quantity-based CRMs (and the energy-only market) assumes that once new entry is required in one year, the combined capacity and energy price will then stay at new entry levels in all subsequent years. This assumption is driven by the modelling of snapshot years (at 5 yearly intervals). In practice, mechanisms can be put in place in the quantity-based CRMs that provide long-term capacity price certainty for new entrants (where large upfront investment is typically required) over a number of years whilst not paying that long-term price to existing plants in years when new entry is not required. This would still provide firm signals for efficient entry and exit whilst reducing the total payments by consumers under the quantity-based schemes, compared with the modelled estimate used in the cost-benefit analysis. For example, the quantity-based CRM being implemented in GB has this type of mechanism with 15 year contracts with a fixed capacity price for new entrants, and annual contracts with variable capacity prices for existing plant.

- **Competitive markets for energy and for capacity**: the modelling assumes competitive outcomes for energy and capacity, with no portfolio aspects to bidding behaviour. The qualitative assessment has identified particular concerns about the scope for gaming in the short-term price based CRM as the spot capacity price will be sensitive to the withdrawal of capacity on the day (particularly given the importance of the peakiness of the capacity price function to the overall reduction in consumer bills). Any such gaming could push up consumer bills compared with the modelled outcome. Effective market power mitigation measures may be needed in the quantity-based CRMs in the quantity-based CRMs to ensure that consumers benefit appropriately from the introduction of competition. These measures would be developed at the detailed design stage.
- **Impact of retaining efficient short-term price signals on incentives to invest in flexible resources**: the modelling does not include any scope for additional investment in flexible resources, such demand-side response, that could be delivered by efficient short-term price signals. The qualitative assessment identified that reliability options and short term price based CRMs are the CRM best able to deliver efficient short-term price signals.

## 7.4 IMPLEMENTATION AND OPERATING COSTS

In this section, we estimate the impact of different explicit CRMs on the implementation and operating costs for the I-SEM HLD. For the avoidance of doubt, these cost estimates covers the cost that will be incurred to set up, run and participate in the CRM. These costs quoted in this section do not include costs of providing capacity, or delivering energy, which are described in Section 7.3.

We use the long-term price-based CRM as the reference case as it represents the status quo. We then estimate the changes in costs for three stakeholder groups of moving to a quantity-based CRM:

- market participants, covering systems, staff and external advice;
- central agency; and
- the RAs.

We do not differentiate between the implementation and operating costs for:

- long-term and short-term price-based CRM, as any difference in costs are expected to be relatively minor as many, if not all, of the same processes are required;
- different quantity-based CRMs, as many, if not all, of the same high-level processes are required, and cost differences would be more strongly driven by detailed design choices.

This is consistent with the outcome of the estimates presented in the Initial Impact Assessment. Respondents to the Draft Decision and the Initial Impact Assessment did not provide any specific comments on the estimates of implementation and operating costs.

Table 26 summarises the estimated change in costs faced by the three stakeholder groups in in moving from a price-based CRM to a quantity-based CRM. Further details of these cost estimates are available in Appendix 4.

We estimate the additional upfront and ongoing costs that could be incurred by market participants, the Market Operator and the TSO, and the Regulatory Authorities during the implementation and operation of the CRM.

The central cost impact shown in Table 26 is the same as presented in the Initial Impact Assessment. We have included a range of costs in the table this time to test the sensitivities of the overall cost figure to different cost elements.

The High cost estimate is based on:

- 48 market participants compared to 30 in the central case;
- a 50% uplift on costs for the Central Agency and RAs compared to the central case.

The Low cost estimate is based on:

- 17 market participants compared to 30 in the central case;
- a 50% reduction in costs for the Central Agency and RAs compared to the central case.

***Table 26 – Change in NPV of implementation and recurrent non-market costs in moving from price-based CRM to quantity-based CRM[58]***

| €m, real 2012 money NPV over 2017-2030 with a 3.5% discount rate | Market Participant | Central Agency | Regulatory Authorities | Total |
|---|---|---|---|---|
| High | +€54m | +€26m | +€4m | +€83m |
| Central | +€34m | +€17m | +€3m | +€53m |
| Low | +€19m | +€9m | +€1m | +€29m |

Table 26 reflects that there will be additional implementation and operating costs in moving

58 Note that the figures in this table have been rounded.

to a quantity-based CRM, with a central estimate of €53m increase in the NPV of the implementation and operating costs (over the whole 14 year assessment period). This will need to be weighed against any estimated net benefit in terms of wholesale costs. The increased costs reflect:

- More active participation by market parties in quantity-based CRMs, e.g. in submitting bids, and managing any re-trading required; and
- A need for new central systems.

## 7.5 QUALITATIVE ASSESSMENT AGAINST PRIMARY ASSESSMENT CRITERIA

This section assesses different CRM options against the primary assessment criteria set out in Section 3.2. In particular, this highlights the difference between these options on hard to quantify factors.

### 7.5.1 INTERNAL ELECTRICITY MARKET

We focus here on the impact of the CRMs on cross-border trading and on cross-border investment decisions. Participation by out-of-zone resources is a major issue for the design of proposed CRMs in Europe.

In addition, any CRM should be compatible with the requirements of the relevant EU State Aid Guidelines. As this is not a formal assessment of the CRM against the State Aid Guidelines, we do not explicitly test each scheme design against the full set of criteria. However, many of the State Aid criteria relate to good scheme design and overlap with our primary assessment principles – for example, the assessment principles of the internal energy market[59] and competition (including entry and exit)[60].

The price-based CRM schemes, including the current SEM design, create a real time scarcity price in each settlement period. This would help to provide efficient short-term signals, provided that market prices reflect the true value of scarcity and are known (with reasonable certainty) at the time of trading. For cross-border flows, the expiry of long-term transmission rights at the DA stage means that the capacity price needs to be effectively known (or predictable) at the DA stage to support efficient cross-border flows and participation. This conflicts with the need for prices to reflect actual scarcity conditions.

The short-term price-based CRM is expected to give stronger short-term signals than the long-term price based CRM. The tendency is for longer-term designs to smooth the stream of scarcity prices, which may not provide the appropriate signals for cross-border flows particularly at times of system stress. This feature of the current long-term price-based CRM in the SEM was identified as part of the CPM medium term review undertaken by the SEM Committee.

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[59] The State Aid Guidelines refer to avoiding negative effects on the internal market and the CRM being open to participation from other Member States where physically possible.

[60] The State Aid Guidelines refer to a 'competitive bidding process', the fact that any CRM should be open to all with the same technical performance; the selection of beneficiaries should address the scheme objectives in most cost-effective manner; and that the CRM should not unduly strengthen market dominance.

A move to quantity-based CRM would be more compatible with the quantity-based CRMs being introduced in other European countries, such as GB, France and Italy.

The capacity auctions effectively carve out some of the scarcity rent into more stable upfront capacity payments. Therefore, this may dampen peak prices below the economic level. This risks distorting cross-border energy trades compared to other CRMs if they can achieve the economic level of peak pricing.

Capacity auctions and obligations pose challenges to cross zonal participation. This is because of the requirement for physical availability or energy delivery into the system[61]. However, proposals for participation by out-of-zone generation are now being developed for the capacity auction/obligations being introduced in GB and France.

For the centralised capacity auction, the high-level similarities with the GB design may be seen as possibly mitigating some of the possible distortions to cross border flows. This would in theory make it easier to possibly move to a common scheme in the future. However, this would rely on the detailed design of the auctions and the behavioural response in energy and capacity pricing also being similar. If that were not the case, the residual scarcity rent in the energy price could be quite different in the GB market and in the All-Island market, potentially distorting trade between the two markets, despite their similar CRM designs.
The reliability options are designed explicitly to support efficient short-term energy price signals. This should help to deliver more efficient cross-border trading over a range of timescales, including ID.

In addition, where the options are referenced to the DAM, out-of-zone generation can participate if they also purchase long-term transmission rights, preferably with the same lead time and duration as the reliability option. This is supported by the European Commission working paper on generation adequacy in the internal electricity market[62]. This recommended that Member States should allow the participation of cross border capacity based on holding of (financial or physical) interconnection capacity rights, or alternatively implement reliability options which ensure that participants are incentivised to hold capacity rights.

**In summary, reliability options allow greater reliance on competitive pressures in the capacity market <u>and</u> in the energy market. Of the explicit CRMs under consideration, it should hence minimise long and short term distortions in cross border investment and trade. This is consistent with the objectives of the European Internal Market.**

### 7.5.2 SECURITY OF SUPPLY

The assessment of the need for an explicit CRM in Section 6 highlighted a number of challenges for long-term generation adequacy that need to be addressed by the explicit

[61] With physical delivery, this is difficult because the rules governing cross border access do not easily allow capacity to be withdrawn from the market through all timeframes to hold for physical delivery.
[62] See http://ec.europa.eu/energy/gas_electricity/doc/com_2013_public_intervention_swd01_en.pdf

CRM. At the same time, the CRM design should as far as possible be consistent with short-term price signals for the delivery of capacity.

In price-based schemes, the payments available for capacity are determined by the regulator, based usually on an estimate of the cost of new entry. Estimating the cost of new entry is not without its difficulties: it requires the choice of a technology, a series of hypotheticals about the costs of constructing new capacity, the net energy revenues that each type of new capacity would earn, and the rates of return required to encourage investors to sink capital into long-lived assets.

Capacity providers decide how much capacity to offer, with the possibility of a trade-off between the quantity provided and the per unit price received. Even if the cost of new entry can be estimated perfectly, price-based schemes run the risk of attracting either too much or too little capacity, given uncertainty about how much capacity will be forthcoming at the estimated cost of new entry.

The price-based schemes offer a mechanistic spot price for capacity, with the short-term price-based potentially offering the sharpest spot price signal. As discussed earlier, this spot price for capacity may need to be calculated at the DA stage to be compatible with the current market coupling arrangements in order to minimise distortions of flows, and facilitate cross-border participation. This could reduce the ability of these schemes to incentivise delivery of more flexible resources. The ability to move the capacity price signal closer to real-time will depend on how the ID trading arrangements develop in the future.

In terms of delivering a target level of capacity, quantity-based schemes have an advantage over price-base schemes in that the target, i.e. a required quantity of capacity, is directly under the control of the regulator, while the price of capacity is set by the market. As Cramton and Stoft put it:

> *'the regulator controls the level of capacity, but the market controls the price of capacity and the type and quality of capacity built. Hence the regulatory intervention has been strictly limited to the determination of the one factor about which the market has little information—the adequate level of capacity'* [63]

Under the capacity auctions/obligations, the response time for eligibility can be defined closer to real time. For example, the proposed GB scheme will have an administered signal of system stress 4 hours ahead of real time. This alone can provide additional incentives for flexible resources on top of the ID and balancing energy markets. And, given the penalty regime, there are clear risks associated with selling firm capacity which cannot respond in 4 hours.

However, it is difficult to derive a capacity price for individual trading periods, even through secondary trading. This might adversely affect short term signals for flexibility and dynamic demand response, by comparison with the other options.

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[63] Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency, Cramton, P. and Stoft, S., Utilities Policy, 16, pp 194-201, 2008.

One of the attractions of a CRM based on reliability options is that its design is more compatible with retaining short-term energy price signals, whilst providing a long-term hedging instrument. This would allow energy market volatility to govern cross-zonal trading (through market coupling in the various timeframes) and should also deliver efficient short-term prices to producers and consumers.

Making the day ahead price the reference market for the reliability options helps with cross-border participation (and supports a liquid day ahead market). If there is a requirement for capacity to respond closer to real-time, then alternatives with delivery times falling at points ID would need to be considered. Alternatively, since some market participants are sufficiently flexible to operate in the balancing market, and if there is a single balancing price, then this price could be used as a reference price for reliability options. However, even in a high wind world not all generation needs to be that flexible and setting the reference price on a real time price would place greater risks on less flexible capacity providers.

There is a perception that price-based mechanisms, and capacity auctions/obligations are better suited to address the 'missing money' problem than the reliability options. This perception, raised in consultation responses, is based on the logic that the advance option fee payment under a reliability option represents a 'risk-adjusted' estimate of the expected value of the payments (when the reference price is above the strike price), and any missing money in the energy market will translate into low option prices.

This is based on the assumption of no physical backing being required for the RO. In light of the views raised by respondents, the SEM Committee acknowledges the role of physical backing to the RO in helping it to address the missing money issue.

**In summary, there is a significant and growing body of evidence and international best practice (particularly in North and South America) showing that long-term auctions in the form of centralised reliability options have proved to be effective instruments to guarantee generation adequacy[64]. Reliability options provide a transparent and versatile mechanism for encouraging required new entry and sending efficient exit signals, whilst minimising interference with short term spot energy prices.**

### 7.5.3 COMPETITION

The consideration of competition with respect to CRMs has three dimensions:

- the scope for competition in the capacity market itself;
- the efficiency of entry and exit signals; and
- the impact on ability to exercise market power in the related markets (such as for energy).

[64] See: Cramton and Stoft, ibid; Batlle, Michel Rivier, Ignacio J Perez-Arriaga *Security of Supply in the Dutch Electricity Market: the Role of Reliability Options;* Carlos Vazquez, Carlos; 2003 and Batlle, C., Rodilla, P., 2010. *A critical assessment of the different approaches aimed to secure* electricity generation supply. Energy Policy 38, 7169–7179.

The incentivisation of efficient levels of efficiency of market entry and exit of a CRM was an issue highlighted in the Proposed HLD for SEM[65].

An administered short-term price signal in a price-based CRM could help to alleviate concerns about the exercise of market power in energy trading arrangements. This could then reduce the risk of regulatory/political intervention on short-term signals[66]. In addition, if the payments in the price-based mechanisms are linked to participation in the day ahead market, then this will help to support liquidity in that market. This is one of the market power mitigation measures proposed for energy trading arrangements.

For the long-term price-based scheme, the ability of market participants to game the short-term price signal will depend on the responsiveness of the spot price signal. However, the existence of a fixed pot means that capacity providers compete between themselves in the short term (in terms of reducing the payment received by each provider) but without the ability to increase or decrease the size of the pot and hence the cost to consumers. There are concerns about the efficiency of the exit-signal under a price-based mechanism, particularly a long-term scheme and in the absence of significant performance penalties. Excess quantity of plants staying on the system can depress the capacity price received per unit, and thereby deter new entry and/or refurbishment even when that may be efficient on performance grounds.

The ability of capacity providers are able to affect the spot capacity price, e.g., by withdrawing capacity from the market, will be a bigger issue for a purely short-term price-based scheme. This is because the capacity price is very responsive to the short-term supply and demand conditions. Where interconnection can influence the short-term price signal, then this would help to reduce the ability of market participants to game the spot capacity price in a short-term price-based scheme.

The evidence suggests that quantity based schemes can be tailored better to address issues such as flexibility more easily than price based schemes. This is evidenced by the CPM in the current SEM in that many potential investors in new flexible plants have argued that the current uniform distribution of the capacity pot makes investment decision difficult and can keep older plants on the system which they believe should have retired.

Quantity-based mechanisms provide strong entry and exit signals by coordinating new entry though a single and transparent auction. They simultaneously send efficient exit signals to inefficient generation by introducing a competitive element in the determination of the allocation of and price for capacity payments.

For quantity-based CRMs, the key area of competition is for the contract award in the form of the initial auction. Given the potential in a small market for anti-competitive behaviour,

65 SEM – Proposed High Level Design (2005), The Single Electricity Market – Proposed High Level Design, SEM Committee, AIP/SEM/06/05, 31 March 2005, page 24.

66 Ofgem is proposing to introduce an administered short-term scarcity pricing signal in the GB balancing arrangements, because the market is not expected to deliver an appropriate profile of prices at times of scarcity (because of the impact of strategic reserve procurement on offer prices into the Balancing Mechanism).

the SEM Committee recognises the importance of market power mitigation measures as part of the detailed auction design.

Just like in energy markets, market power mitigation measures are part of quantity-based CRMs in other markets, e.g. in the US and in the proposed GB scheme[67]. This can include bidding rules, which can relate to minimum offer prices to deter inefficient exit or maximum bids (e.g., for existing plant). These rules could also be targeted at a subset of the market where market power has been identified as a concern.

With respect to efficient entry signals, the capacity/energy value split under the capacity auction/obligations is to some extent arbitrary and hence uncertain. This means that entrants run the risk of committing for long term capacity with a market expectation of low-priced capacity and high priced energy, with the risk that during the contract term the market switches to high priced capacity (which is not available to those with long term contracts) and low priced energy[68].

By providing a long-term hedging instrument for generators and suppliers, reliability options can be part of a strategy for market power mitigation and promotion of liquidity in the energy trading arrangements. This is because they support liquidity in the reference market. By reducing the value of price spikes to the sellers of the options, it mitigates market power in the energy trading arrangements directly[69]. They may also provide a risk-hedging mechanism that is particularly attractive to new entrant suppliers with uncertain quantity requirements, thereby enhancing competition at the retail level.

Centralised reliability options offer a transparent public auction that is held on behalf of all demand in the market so as to exploit economies of scale (though the concentration of liquidity) with the objective of increasing competition, and creating a level playing field for market participants. International best practice and experience strongly argues for a centralised auction process on competition promotion and market power mitigation grounds[70].

**In summary, centralised reliability options perform well against the competition criterion. They promote competition between licence holders that delivers appropriate investment**

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67 In New England, neither existing units nor new units have the freedom to bid whatever they want. Existing units, unless they wish to retire, have constraints on how high a price they can demand to withdraw from the capacity market. New units (which include any upgrades of existing units) have their bids screened by the market monitor to ensure that they are not, in effect, proxy bids placed by buyers to reduce the market price. In addition, there are caps and floors in the auction process to avoid rapid price changes.

68 This concern may be overstated but it reflects the risk of separating total payments into different streams. The impact on consumers will depend on the extent to which it increases the risk (and hence financing) cost of participating in the capacity auctions/obligations.

69 At least over the duration of the options and for prices above the strike prices for the options. There might still be incentives for gaming over longer periods, to increase the price of the next round of options.

70 ‘ The international learning process has led to the conclusion that it is desirable to use centralised auctions for different reasons, among others, to benefit from economies of scale increasing competition, to avoid vertical integrated companies taking advantage of obscure agreements’ (Batlle, C., Rodilla, P., 2010)

**in a transparent manner. Through providing transparent centralised auctions that are held on behalf of all demand they exploit economies of scale in the market with the objective of increasing competition, concentrating liquidity and creating a level playing field for market participants.**

**Regarding efficient entry and exit, quantity based mechanisms in general and centralised reliability options in particular provide strong entry and exit signals by coordinating new entry though a single and transparent auction and simultaneously sending efficient exit signals to inefficient generation. This should avoid the boom and bust problem that may emerge in an energy only market whilst also ensuring that consumers do not overpay for generation adequacy.**

Reliability options based on a centralised auction (run by the TSO) also perform well in terms of their ability to reinforce market power mitigation measures in the energy market. They support cross-border participation more naturally than any of the other options, which helps to facilitate more competitive capacity price formation.

Market power mitigation measures will likely be required in the auction of reliability options, but that is a natural consequence of introducing some competitive elements into the CRM. It does not mean that the CRM is not market-based. Market power mitigation mechanisms have been a key part of the SEM but this has not been used as evidence that the SEM wholesale price is equivalent to an administered price. .

#### 7.5.4 ENVIRONMENTAL

Any CRM should allow the full participation of all technologies (including variable generation), to the extent that they can meet the required performance requirements. Moreover, the CRM should not be intended to address any (perceived or actual) failings in the renewable support schemes.

The challenges for generation adequacy discussed under the security of supply principles may present barriers to increasing levels of renewable deployment. Therefore, the extent to which the CRM design performs well in relation to security of supply may also determine its ability to facilitate higher levels of variable renewable deployment.

Within the I-SEM, the short-term price signals will also be important for helping to mitigate the risk of wind curtailment through the encouragement of flexible resources. However, the CRM design will have relatively little direct impact on this as the curtailment should only occur at times of low prices (and high capacity margins). Indeed, reduction of curtailment is not the concern of the CRM (compared with, say, the impact on wind curtailment of ID energy trading and the DS3 programme).

In this respect, the most relevant impact of the CRM on wind curtailment will be the extent to which it encourages investment in resources that can increase demand at times of high wind, e.g. interconnection (therefore the cross-border participation element is important), storage and demand-side response (where this involves shifting demand from high-price to low-price periods).

Price-based mechanisms should be designed to allow cross-border participation which could facilitate increased investment in interconnection through increased demand for long-term transmission. They could also help the development of the demand-side (to the extent that short-term price signals are sufficiently sharp).

The signals for investment in interconnection under the capacity auctions / obligations depends on the ability to facilitate cross-border participation. This has proved difficult so far, particularly where the delivery requirements are determined close to real-time and after the expiry of explicit cross-zonal transmission rights. The detailed rules will determine the attractiveness of the scheme to DSR, particularly load-shifting DSR, which will be relevant for reducing curtailment[71].

The reliability options offer greater scope for cross-border participation. This should support demand for long-term transmission rights which in turn should support increased investment in interconnection and hence allow for increased penetration of variable renewable energy sources (for more on this see ESRI research has suggested that high penetration of wind should be accompanied by increased interconnection to neighbouring systems [72]). Where the reliability options are referenced to the day ahead market, this should provide a good signal for DSM with load-shifting (in addition to the encouragement provided by the retention of the short-term energy price signals).

The facilitation of renewables by a CRM will depend mainly on the ability of the CRM to mitigate the risk of wind curtailment. It is unlikely to be able to do this directly through the encouragement of flexible resources, since curtailment should occur only at times of high capacity margins and low energy prices. A CRM might, however, indirectly reduce the need for curtailment by encouraging investment in resources that can increase demand at times of high wind, e.g. interconnection, storage and demand-side response.

Reliability options perform well in this respect because they offer greater scope for cross-border participation and, through their direct connection with the day ahead market, the provision of good signals for demand side response and storage, thereby encouraging demand to shift from high priced to low priced periods.

#### 7.5.5 EQUITY

One equity issue is the scope for double payments to providers. A revised CRM in Ireland and Northern Ireland must be closely interlinked with changes to the energy market and the ancillary services framework in order to reward flexibility and maintain an effective long term adequate capacity balance, while avoiding double payments for the provision of capacity.

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[71] e.g., the duration of the requirement to deliver capacity in a stress event.

[72] See: DIFFNEY, S., J. FITZ GERALD, S. LYONS and L. MALAGUZZI VALERI, 2009. Investment in Electricity Infrastructure in a Small Isolated Market: the Case of Ireland, Oxford Review of Economic Policy, Vol. 25, No. 3, pp. 469-487. This study finds that for a small and relatively isolated market such as Ireland, a high penetration of wind is economically sound only if it is accompanied by an increase in interconnection to Great Britain

For a price-based mechanism, with an administratively set total pot, there may need to be an administrative correction mechanism to account for revenues from different sources (which may differ by generation technology), thereby increasing the complexity of the market arrangements. The administrative correction mechanism could apply to any of the different revenue streams (e.g. capacity or system services).

For the quantity-based CRMs in general, including reliability options, competitive award of the capacity payments should encourage market participants to reduce the bids to reflect revenue from other sources (e.g. from system services). In addition, reliability options are effectively a one-way CfD that should directly address the risk of double payment between energy and capacity, at least for energy prices above the option strike price.

In terms of the degree of centralisation with quantity based mechanisms, centralised reliability options, where a centralised auction is run of the whole of system demand, ensures that all consumers pay the same price for generation adequacy which is consistent with public good attributes of reliability.

Furthermore, in terms of quantity-based mechanisms, a centralised auction for the entire system demand would ensure transparency and a level playing field for new entrants as well as ensuring that all consumers effectively pay the same price for generation adequacy.

**In conclusion, quantity-based mechanisms, including reliability options, ensure that distributional and equity concerns are met by avoiding the potential double payments to producers at the expense of consumers, which are associated with price-based mechanisms. Reliability options also provide a level playing field (insofar as is possible) between consumers and producers in different price zones.**

## 7.6 QUALITATIVE ASSESSMENT AGAINST SECONDARY ASSESSMENT CRITERIA

This section assesses different CRM options against the secondary assessment criteria set out in Section 3.2. In particular, this highlights the difference between these options on hard to quantify factors. This assessment does not include the performance against the adaptability criteria as this will be determined by the detailed design phase.

### 7.6.1 STABILITY

There are two aspects to stability of the HLD of the CRM: the need for continuing regulatory intervention; and the scope for pressure for major change in the future, whether this pressure is from external or internal sources.

Some degree of regulatory involvement is needed in any explicit CRM, with decisions having to be made about the key parameters of the scheme, including for example, the demand curve.

The major decisions in the long-term price-based scheme are the fixing of the total pot and the distribution between settlement periods. The distribution of payments between participants in a long-term price-based CRM can be sensitive to the detailed parameters of the scheme. This illustrates the scope for regulatory decisions on the details to lead to major changes in allocation of payments between participants, which could be seen as increasing the potential instability of the scheme.

In the short-term price-based CRM, the major decisions are around the values determining the VOLL/LOLP calculation.

In any quantity-based scheme, there will be a need to determine the quantity of capacity to be procured.

The use of a market-based penalty under the reliability options could reduce the perception of regulatory risk compared with complete reliance on an administratively determined penalty, including the setting of VOLL.

The CRMs currently being developed elsewhere in Europe are all quantity-based schemes of differing varieties, e.g. in France, Italy (reliability options), GB, with quantity-based alternatives also under consideration in Germany. So a quantity-based approach in the All-Island market would be more consistent with the high-level direction of travel amongst other European countries, why may reduce the risk of major changes in the future to meet a drive for greater harmonization at a European level.

Furthermore, reliability options are directly referenced in the European Commission's guidance on Capacity Remuneration[73]. They also do better than other quantity-based schemes on facilitating the inclusion of demand-side response, and interconnection capacity. These are expected to become increasingly important in a high-RES system.

**In summary, the proposed I-SEM design is predicated on a liquid short term physical markets coupled and integrated with the European Internal Market with financial forward intra- and cross-zonal hedging instruments. This fits naturally with reliability options, which are financial in nature and dependent upon liquid short term reference markets. For this reason, reliability options offer the best choice for SEM consumers in terms of stability over the lifetime of the ISEM and beyond.**

### 7.6.2 EFFICIENCY

This assessment criteria is linked to the impact of the CRM on short-term wholesale market price signals and dispatch decisions.

The price-based mechanisms have the scope to dampen short term energy price signals by comparison with what might otherwise have been the case. This is because, with a non-targeted CRM, less scarcity rent would need to be recovered from the wholesale price with the CRM than in the energy-only market. This is because the CRM payment would cover a portion of each eligible generator's costs.

Whether directly or indirectly, this would then dampen wholesale price signals – both

73 http://ec.europa.eu/energy/gas_electricity/internal_market_en.htm

average prices and the variation around the average. This would reduce the efficiency of scarcity spot prices, with implications for demand side response and interconnector flows[74].

This could change the dispatch for any plant not eligible for the CRM. In consequence, it is important that interconnector flows are exposed to the spot capacity price under the price-based mechanisms.

The capacity auctions raise similar challenges around dampening the wholesale price signals, without the possible partial mitigation of a spot capacity price.

**Under the reliability options, the short-term energy price signals could be retained to a much larger extent than under the other options. This should help to deliver a more efficient dispatch outcome.**

#### 7.6.3 PRACTICALITY/COST

The use of market-based mechanisms to allocate capacity contracts in the quantity-based approach will also typically lead to higher participation costs for market participants who will need to define a bidding strategy, participate in the auction and maintain continuing mechanisms for managing risk of exposure to penalty payments.

Our initial estimates of the total implementation and operation costs of different broad-based CRMs suggest that these costs would be higher by about €4m/year under a quantity-based scheme rather than a price-based scheme. However, this difference is small in the context of the likely level of payments under a CRM.

For the quantity-based approaches, there is a need to determine the rules for allocating the capacity contracts, and for allocating the responsibility for paying for these contracts, as well as some means of facilitating secondary contract trading. This is because, if providers are asked to take on a physical commitment in advance with availability/non-delivery penalties, then they have to have a way of managing these risks closer to real time (e.g., to manage an unscheduled outage).

For the All-Island market, there are fewer of the implementation issues seen in other markets with respect to reliability options. For example, there are no legacy physical bilateral contracts, providing the right to physically nominate, which would affect the ability of possible providers to access a reference market.

The process of contract renegotiation for introducing Reliability Options in GB was estimated by DECC to be comparable to the costs of replacing the English and Welsh pool by NETA (for the CRM, this equated to over a cost of over £1 billion in NPV terms for a 20 year period). Given that there is not a similar legacy of legacy physical contracts in the All-Island Market, these changeover costs would not be faced by the I-SEM.

Also, the fact that the CRM design is happening in parallel with the energy trading

[74] Through the market expectations of scarcity energy prices, or through actual or the perceived threat of caps on spot prices when a separate CPM was in place.

arrangements (including for example the Balancing Mechanism) should help to ensure a consistent approach. For example, the uncertainty of the outcome of Ofgem's cash-out review was another one of the reasons DECC gave for not proceeding with reliability options. Their Impact Assessment noted that there could be a possible future move to reliability options if the imbalance pricing regime delivered sharper short-term price signals.

## 7.7 SUMMARY

In conclusion, the quantitative modelling backed by assessment against the I-SEM Objectives and international best practice provide strong evidence for the decision to implement a quantity based CRM based on centralised reliability options issued by a central party in the I-SEM. These RO are strengthened by the SEM Committee decision to include a requirement for physical backing, which will help them to better address the issues around missing money.

# 1 ANNEX: OBJECTIVES OF THE SEM COMMITTEE

The Principal Objective of the SEM Committee is:

- 'to protect the interests of consumers of electricity in Ireland and Northern Ireland supplied by authorised persons, where appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity though the Single Electricity market'.

The SEM Committee is required to have regard to a number of ancillary objectives in furthering its principal objective to protect the interests of consumers. These are:

- the need to secure that all reasonable demands for electricity in Ireland and Northern Ireland are met,
- the need to secure that authorised persons are able to finance their activities,
- the need to secure that the functions of the Minister(s), the Commission, the Authority, and the Department(s) in relation to the Single Electricity Market are exercised in a coordinated manner,
- the need to ensure transparent pricing in the Single Electricity Market,
- the need to avoid unfair discrimination between consumers in Ireland and consumers in Northern Ireland,
- the need to promote efficiency and economy on the part of authorised persons,
- the need to secure a diverse, viable and environmentally sustainable long-term energy supply in the Ireland and Northern Ireland,
- the need to promote research into, and the development and use of—
- new techniques by or on behalf of authorised persons, and
- methods of increasing efficiency in the use and generation of electricity.
- the need to secure a diverse, viable and environmentally sustainable long-term supply in Ireland and Northern Ireland,
- the need to consider the effect on the environment in Ireland and Northern Ireland of the activities of authorised persons; and
- the need to promote the use of energy from renewable energy sources.

Further, in carrying out its functions the SEM Committee shall:

- not discriminate unfairly as regards terms and conditions—
- between authorised persons, or
- between persons who are applying to become authorised persons.
- ensure that decisions are transparent, accountable, proportionate, consistent and targeted only at cases where action is needed.

# 2 ANNEX MODELLING APPROACH AND ASSUMPTIONS

## 7.8 APPROACH

We have modelled I-SEM as an energy-only market under two reference cases (Base Case A and Base Case B). Both reference cases assume a security standard of 8 hours of LOLE for the All-Island system from 2020 onwards[75].

In the energy-only market, generators try to recover their capital expenditure ('Capex') and their annual avoidable fixed costs ('Opex') over 'tight' periods in the form of scarcity rent. When the capacity margin is 'wider', generators bid their SRMC in the market. We have assumed that investors have perfect foresight of the evolution of (average) future conditions (and hence expected future revenues and costs).

### 2.1.1 MODELLING APPROACH

The electricity market modelling has been carried out with Poyry Management Consulting's power market model, BID3. This is capable of modelling the dispatch of all generation on the European network. BID3 simulates 8760 hours per year with multiple historical weather and/or availability patterns. It generates hourly prices and dispatch patterns for each pant in the modelled region(s).

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. At a high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour. However, the model does take into account for costs associated with start-up and part-loading as well as other technical limitations, such as minimum on and off times and minimum stable generation.

Each future year is modelled under a combination of historical weather (and demand) patterns and thermal plant availability profiles. Each future year is therefore modelled under 15 different 'paths' that are the combination of weather years 2006-2010 and three thermal plant availability profiles (High, Central and Low). This provides 15 different market outcomes for each snapshot year.

This enables us to capture extreme conditions (for example a low wind period coupled with low thermal plant availability) ensuring that our scenarios are capacity adequate. This approach can be considered as pseudo-stochastic. In particular, such an approach allows us to:

- capture the expected plant gross margin under a suite of future conditions
- ensure sufficient capacity on the system to meet the security standard on average[76].

[75] For 2017 we assume that the North-South tie constraint is still in place and the security standard is different in Ireland and N. Ireland. The LOLE for Ireland and N. Ireland is 8 and 4.9 hours respectively.

[76] This means that under a combination of system conditions there can be a higher LOLE. On average, however, the LOLE is equal or less than 8 hours

### 2.1.2 ESTIMATING WELFARE IMPACTS

The results include an estimate of wholesale market costs, which are defined as:

- annualised capital expenditure on generation and interconnection;
- fixed operating costs for generation and interconnection;
- variable production costs, primarily fuel and carbon;
- Expected Energy Unserved (EEU), which is monetised using the VOLL of €10898/MWh that has been set for the All-Island Market);and
- cost of net imports (i.e. the total payments for imports minus the revenue received for exports)

The welfare calculations presented in this IA are focused on wholesale market costs, and so for example do not include costs of investing in and operating the transmission and distribution network

Welfare, also referred to as social welfare, consists of the producer surplus and the consumer surplus when considering one market in isolation.

A simple definition of a consumer's surplus is the maximum sum of money a consumer would be willing to pay for a given amount of a good or service, less the amount the consumer actually pays, which is measured by the area under the demand curve. A producer's surplus is simply economic rent, which is the difference between the price a producer gets for the good or service supplied and the economic cost of the inputs required to produce it, which is measured by the area above the supply curve

If, however, we estimate the welfare in a set of interconnected markets, part of the welfare is realised by interconnection in the form of congestion rent.

The welfare is, therefore, defined as:

$$\boldsymbol{Welfare = Consumer\ surplus + Producer\ surplus + Congestion\ rent}$$

Consumer surplus is the gain obtained by consumers when they can purchase a product at a price that is lower than the highest price they are willing to pay.

Producer surplus is the gain obtained by producers when they can sell a product at a price that is higher than the lowest price at which they are willing to sell.

For estimating the consumer surplus we use the following definition:

$$\begin{aligned}&\boldsymbol{Consumer\ surplus =}\\&\boldsymbol{\textstyle\sum_i\ VoLL \times Demand_i - \sum_i\ P_i \times Demand_i} \qquad -\\&\boldsymbol{-\ renewable\ support\ payments - CRM\ payments - Side\ payments\ -}\\&\boldsymbol{Cost\ of\ unserved\ energy}\end{aligned}$$

The first term of the above equation represents the total consumer willingness to pay for electricity given a predefined demand over each period across an entire year. All other terms (excluding the last one) represent the costs accrued by consumers for purchasing electricity in the form of payments for energy, capacity, PSO and side payments (for supporting plants in N. Ireland). The last term of the equation is the sum of unserved energy (when load is lost) multiplied by VoLL.

For estimating the producer surplus we use the following definition:

$$\begin{aligned}\boldsymbol{Producer\ surplus} &= \boldsymbol{Energy\ market\ revenue + renewable\ support\ revenue} \\ &+ \boldsymbol{CRM\ revenue + Side\ payment\ revenue} \\ &- \boldsymbol{Variable\ production\ costs - Opex - Annuatised\ Capex}\end{aligned}$$

The first four terms of the above equation represents the payments producers receive for supplying electricity through the energy market, the capacity market, renewable support payments and side payments. The side payments are targeted to plants in Northern Ireland to address local security of supply concerns in 2017 before the completion of the North-South tie-line.

The final three terms are the different costs faced by producers, namely variable production costs, opex and capex.

## 7.9 COMMON ASSUMPTIONS

### 2.1.3 ELECTRICITY DEMAND

Table 27 presents projected total annual demand for Ireland, N. Ireland and GB, whereas Table 28 shows the peak demand for both the All-Island system and GB.

We use the EirGrid Generation Capacity Statement 2014-2023 for projections of total annual demand for Ireland and Northern Ireland out to 202377. After that, the annual demand grows in line with Poyry's own assumptions. GB demand projections come from the National Grid Gone Green scenario78.

We model each future year under 5 different historical weather and demand patters (2006-2010). Peak demand is therefore based on the historical demand profiles.

***Table 27 – Total annual demand***

| TWh | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Ireland | 27.7 | 28.9 | 30.9 | 33.0 |
| N. Ireland | 9.3 | 9.5 | 9.9 | 10.2 |
| All-Island | 37.0 | 38.5 | 40.8 | 43.2 |
| GB | 344.8 | 342.6 | 346.3 | 357.1 |

77 All-Island Generation Capacity Adequacy Statement 2014-2023, Eirgrid&SONI

78 UK Future Energy Scenarios, National Grid; We have however included CHP generation as part of the total electricity demand.

*Table 28 – Annual peak demand*

| GW | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| All-Island | 6.7 | 7.0 | 7.4 | 7.8 |
| GB | 60.5 | 60.0 | 60.7 | 62.6 |

### 2.1.4 GENERATION COSTS

Table 29 shows the assumed generation costs (capital expenditure and operating expenditure), as well as other economic parameters for the main technologies, used in modeling the two scenarios and estimating related costs

*Table 29 – Generation costs and economic parameters for main technologies*

| | | CCGT (Ireland) | CCGT (N.Ireland) | OCGT (Ireland) | OCGT (N.Ireland) | Coal | Onshore | Offshore | Biomass |
|---|---|---|---|---|---|---|---|---|---|
| 2017 | Opex (€/kW) | 58 | 46 | 32 | 27 | 63 | 37 | 145 | 105 |
| | Capex (€/kW) | 840 | 840 | 629 | 647 | 1700 | 1324 | 2495 | 2539 |
| | Construction years | 2.5 | 2.5 | 2 | 2 | 4 | 2 | 3 | 3 |
| | Economic lifetime | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| | WACC | 9.0% | 9.0% | 8.5% | 8.5% | 9.5% | 7.9% | 9.6% | 12.5% |
| 2020 -2030 | Opex (€/kW) | 58 | 46 | 32 | 27 | 63 | 37 | 129 | 105 |
| | Capex (€/kW) | 840 | 840 | 629 | 647 | 1700 | 1305 | 2179 | 2474 |
| | Construction years | 2.5 | 2.5 | 2 | 2 | 4 | 2 | 3 | 3 |
| | Economic lifetime | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| | WACC | 9.0% | 9.0% | 8.5% | 8.5% | 9.5% | 7.9% | 9.6% | 12.5% |

### 2.1.5 SYSTEM SERVICES REVENUE

Other revenue streams (outside of the energy market) have an impact on investment decisions, the type of new technologies deployed and bidding in the energy market. It is still unclear what the level of payments will be for system services under the DS3 programme. The exact level of the revenue realised by market participants may (and most likely will) have an impact on the energy market.

The potential revenues for different types of technologies from the DS3 programme are indicative and may differ from the ones presented here. We have based the (net) revenues for different technologies on the payments from Scenario E (as described in the TSO recommendations paper) and the costs from the KEMA DNV study. For OCGTs, we use the current value of €4.5/kW assumed for ancillary services payments for the BNE for the entire modelled period.

System services revenues are treated as a fixed annual payment towards all generators. Table 30 presents our assumed system services revenues.

*Table 30 – System services revenue*

| Technology type | Equivalent annual payment (€/kW) |
|---|---|
| CCGT | 7.3 |
| OCGT | 4.5 |
| Other thermal | 12.1 |
| CHP | 25.6 |
| Hydro | 28.7 |
| Interconnector | 47.9 |

The ‘Economic Appraisal of DS3 System Services’ paper by IPA suggests that enhancement costs as reported in the original DNV KEMA study are reasonable with the exception of new OCGTs. In this case, the paper suggests that enhancement costs are 25% higher than expected. Below we have used an enhancement cost for OCGTs running on distillate, which is lower by 25% compared to the DNV KEMA study and the value used for modelling the market benefits of the I-SEM.

Based on the analysis carried out by Eirgrid and SONI, we have estimated the net revenue for existing CCGTs, OCGTs (distillate) and themal (coal) plants. The net revenues are comparable to the values used for modelling the market benefits of the I-SEM in the IA of the draft decision paper.

The net revenues for existing OCGTs still appear to be lower than the current levels of AS payments (around 4.5€/kW). If this is the case under DS3 (net system services revenues for existing OCGTs being below 4.5€/kW), then the profitability of GTs would be affected. Under a quantity-based CRM (reliability options and capacity auction), when OCGTs are the marginal technology, lower system services revenues would mean a corresponding increase in the capacity payment level. A decrease in expected net revenues for CCGTs means a corresponding increase in capacity payments in years where those are the marginal technology (for setting the price in the capacity market).

Table 31 shows the difference between the assumed system services net revenues for modelling market benefits for the I-SEM and the values from the DS3 consultation.

*Table 31 – Comparison of system services net revenues used for IA of I-SEM and DS3 consultation*

| Technology type | Initial Impact Assessment | | | DS3 consultation | | |
|---|---|---|---|---|---|---|
| | Revenue (€/kW) | Enhancement cost (€/kW) | Net revenue (€/kW) | Revenue (€/kW) | Enhancement cost (€/kW) | Net revenue (€/kW) |
| CCGT | 25.6 | 18.3 | 7.3 | 22.5 | 18.3 | 4.2 |
| OCGT (distillate) | 23.1 | 21.5 | 1.7[79] | 18.0 | 16.1 | 1.9 |
| Thermal (coal) | 24.5 | 12.5 | 12.1 | 22.5 | 12.5 | 10.1 |

[79] In the draft IA we have assumed a remuneration of 4.5€/kW for OCGTs.

### 2.1.6 DAM PRICE CAP

Euphemia, the DAM coupling algorithm, currently has a €3000/MWh price cap. We assume that this price remains in place throughout the entirety of the modelled period. Therefore, our electricity modelling assumes that generating units cannot bid above this price cap.

### 2.1.7 GB CRM

Under all scenarios and sensitivities we assume the introduction of a CRM in GB from 2018 onwards. This takes the form of a capacity auction. The auction format is PAC where each generating unit[80] is paid the clearing price of the auction. New entrants are assumed to lock in the price from the first auction in which they participate in for 10 years upon commissioning. From then on they are treated as existing plants receiving the annual level of the capacity payment. Existing plants act as price takers being allowed to bid in a low price in the auctions. Modelling of the GB CRM is in line with the modelling methodology adopted by DECC in its latest impact assessment.

## 7.10 SCENARIOS

We have developed two scenarios for quantifying the I-SEM wholesale market benefits and costs. These two scenarios do not cover the full range of all possible outcomes when it comes to fuel and carbon prices as well as evolution of demand and renewables deployment, but capture a plausible range to use in the cost-benefit analysis (CBA) and supporting quantitative analysis.

### 2.1.8 BASE CASE A

In the Base Case A scenario, current energy policies are assumed to persist globally. It uses the fuel and carbon price assumptions from the 'Current Policies' scenario (IEA WEO 2013[81]). Therefore, commodity prices (oil, gas and coal) increase over time in line with increased demand for conventional fuels on a global scale. Coal-fired generation remains more competitive compared with gas-fired generation for the entire modelled timeframe. This comes as a result of relatively higher gas prices, rising up to around 38 €/MWh in 2030, and depressed carbon prices.

Under this scenario, decarbonisation is delivered with an emphasis on the electricity sector and, in particular, through continuing support towards renewable and other low carbon generation. Decarbonisation is based primarily on RES with national schemes continuing to support RES throughout the entirety of the modelled period.

In both markets (I-SEM and GB), 2020 renewables targets are met. In the I-SEM, wind is the major renewable deployed technology with renewable penetration reaching 52% by 2030 before any curtailment.

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80 Excluding units that receive other forms of support, such as ROCs or CfDs.
81 World Energy Outlook 2013, International Energy Agency

GB continues with a policy of supporting the EU ETS price through imposing a floor on the carbon price and the carbon reduction target by 2030 is achieved through the rollout of a combination of nuclear, CCS coal, wind and solar. Assumptions for low carbon technologies in GB come from the National Grid 'Gone Green' scenario[82].

Table 32 compares the variable (full load) cost of a typical CCGT and a typical coal plant. Coal plants run ahead of CCGTs throughout the entirety of the modelled period.

***Table 32 – Variable cost of gas and coal generation in Base Case A***

| real 2012 money | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Gas variable cost (€/MWh, 2012 money) | 67.0 | 70.5 | 74.6 | 81.9 |
| Coal variable cost (€/MWh, 2012 money) | 40.9 | 45.9 | 50.8 | 55.1 |

### 2.1.9 BASE CASE B

Base Case B is a scenario where new policies drive a more concerted transition to alternative forms of energy. This scenario uses the fuel and carbon price assumptions from the 450 scenario (IEA WEO 2013). Weaker global demand for conventional fuels (due to higher carbon prices) results in gas and coal prices decreasing over time. In this word, the gas to coal relativity reverses in the long term with gas-fired generation becoming more competitive after 2025.

Decarbonisation is delivered through a stronger EU ETS price and is not based solely on explicit RES support. Carbon prices rise throughout the period, reaching €76/tonne CO2 in 2030 (in real terms). In this world, decarbonisation is not delivered primarily from emissions reduction in the electricity sector, but from other energy segments. Renewable support is assumed to be weaker and further renewable generation (in the long term) is delivered only on the basis of market revenues. GB maintains a carbon price floor in excess of the EU ETS price, however lower when compared with that assumed in Base Case A.

There is lower penetration of renewables (and other zero carbon generation) in both markets. Nonetheless, 2020 targets are met in both markets. Renewable growth in the All-Island Market slows down post 2020, although renewable penetration in the All-Island Market still reaches 45% by 2030 (before any curtailment).

Assumptions for low carbon technologies in GB come from the National Grid Gone Green scenario out 2020 and from then on follow the Slow Progression scenario out to 2030[83].
Table 33 compares the variable (full load) cost of a typical CCGT and a typical coal plant.

***Table 33 – Variable cost of a gas and coal in Base Case B***

| real 2012 money | 2017 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| Gas variable cost (€/MWh, 2012 money) | 67.2 | 71.4 | 77.3 | 81.6 |
| Coal variable cost (€/MWh, 2012 money) | 47.2 | 57.2 | 77.4 | 96.7 |

82 http://www2.nationalgrid.com/uk/industry-information/future-of-energy/fes/Documents/
83 http://www2.nationalgrid.com/uk/industry-information/future-of-energy/fes/Documents/

# 3 ANNEX: IMPLEMENTATION AND OPERATING COSTS FOR ENERGY TRADING ARRANGEMENTS

In this section, we present more detail on the estimated impact of different energy trading arrangements on the implementation and operating costs for the I-SEM HLD. This supports the summary presented in Section 5.7. For the avoidance of doubt, these cost estimates covers the cost that will be incurred to set up, run and participate in the energy market. These costs quoted in this section do not include costs of delivering energy, which are described in Sections 5.4 and 5.6.

We have reviewed international best practice to identify the costs associated with the introduction of a new energy market design. This review included first hand evidence gathered from recent system procurement processes, such as those in Turkey and Romania, alongside desk based research. This desk based research focused on the 2006 Cost-Benefit Study of the Single Electricity Market[84]; the Intra Day Proposed Costs and Estimated Benefits report[85] and the Assessment of the Costs and Cost Savings of NETA compared with the England and Wales Pool[86].

We then estimate the implementation and operating costs for three stakeholder groups:

- market participants, covering systems, staff and external advice;
- the TSO and MO; and
- the RAs.

The main difference between the options is the cost of the arrangements for dispatch and ex-post prices – i.e. an ex-post gross pool versus Balancing Mechanism versus ex-post net pool. This is consistent with the outcome of the estimates presented in the Initial Impact Assessment.

We do not differentiate between the implementation and operating costs in respect to other possible differences between different HLD:

- Physical scheduling on the basis of trading in the forward timeframe, within-zone and across-zone;
- Portfolio bidding being allowed for all generation in the DAM and the IDM;
- The ability to physically self-schedule without making a trade in the centralised market places; and
- Voluntary participation in the Balancing Mechanism.

All staff costs are based on an average salary of €35k /year[87] for each market participant plus an estimate of the additional costs faced by employers such as superannuation and national insurance contributions etc. We estimate these contributions to be in the region of

84 http://www.detini.gov.uk/year_cost_benefit_study_of_the_single_electricity_market_-_a_final_report_for_niaer_and_cer__december_2006_.pdf

85 http://www.allislandproject.org/en/TS_Decision_Documents.aspx?article=7bc8db07-0493-4ba6-aa04-c885a2826c23

86 http://www.nao.org.uk/wp-content/uploads/2003/05/0203624.pdf

87 Source: The Earnings and Labour Cost Statistics published by the Central Statistics Office.

20% of the salary[88]. This gives a total staff cost of €42k per member of staff.

### 3.1.1 COSTS TO MARKET PARTICIPANTS

Market participants will face a number of costs relating to the implementation of new Energy Trading Arrangements.

We have assumed the current back-office IT systems for invoicing etc. required by market participants are adequate for the all the options. As a result there will be no additional costs, even though there will be new products that will be invoiced. As a result we assume no additional cost.

All the central market systems for Forward trading (Financial and Physical), DAM, IDM and Balancing will be delivered with a standard user interface (typically through a web interface) to manage participation in the various markets. As a basic requirement, this means that there will be no additional costs for this.

However, for a market participant to be able to participate in all market timeframes and keep track of its trading and open positions, there will be a need for additional back-office functions.

The sophistication of system required will depend on the complexity of the portfolio of assets a market participant has. Some participants might operate more conservatively in the various markets and be able to manage this manually without any additional IT costs. Alternatively, some of the bigger market participants would like to have a more sophisticated system. The estimate of the range of costs based on examples from these systems is from €5k for a simplified Excel-solution to €150k for a full-fledged energy risk management system[89].

Our central estimate for the upfront cost of a standard solution tool is €15k per market participant, which would be common across any set of trading arrangements. Our central estimate for the ongoing maintenance costs is €12k/a per market participant.

There will also be additional Staff Costs incurred by companies participating in the IDM. This is due to the nature of the continuous trading in this market. Our estimate is that all market participants would require an additional 5 full-time members of staff to ensure that the trading desk is continually manned on 24/7 basis. This is linked to whether the market participants already have resources available to act on their behalf on a 24/7 basis– for instance if you have 24-hour shifts in a local “control center”, they might have the potential

88 This percentage estimate is based on the current national insurance contribution of 13.8% (http://www.hmrc.gov.uk/rates/nic.htm) in the UK, with an equivalent figure of 11% in Ireland e.g. PRSI Class A employers (http://www.welfare.ie/en/Pages/1896_Pay-Related-Social-Insurance.aspx ). In addition we have included an average pension contribution of 5%. This is based on UK statistics (http://www.ons.gov.uk/ons/rel/fi/occupational-pension-schemes-survey/2012/stb-opss-2012.html). We do not have a figure for the All-Island market but expect it to be in a similar range. We have then rounded the contribution to 20% to account for any additional costs.

89 This is based on quotes and examples from commercial international vendors supplying similar systems to other European markets participants

to perform this role. At the same time, smaller market participants might decide to participate in some hours of the day, but not 24 hours. In the central estimate of market participant costs, we have assumed that all of the relevant market participants seek to employ an additional 5 full-time members of staff. As a result this estimate can be seen as the upper end of our forecast.

Other costs incurred by Market participants will include additional consultancy support to help prepare their risk and bidding strategies for participation in the new markets. As any HLD that implements the EU Target Model will have provision for participation in the Forward, DA and ID timeframes, the cost will be similar for all options. We have estimated this to an average one off cost of €30k per market participan) for the first year of operation, and no further costs in the following years.

In summary, the central estimates for the average level of the common costs per market participant in each option are as follows:

- €15k: **upfront investment** in standard risk management tool for trading;
- €30k:**upfront procurement** of consultancy support to prepare new risk management and bidding strategies;
- €12k/a: **ongoing maintenance** of standard risk management tool for trading;
- €200k/a: **ongoing staff costs** for trading function.

For any pool-based option, there will be an additional complexity to administer quite different bidding formats for both the Pool, as well as the other markets. This is estimated to be an additional €10k per market participant in the pool-based option. This is both to cover for the additional complexity and also the fact that this will be a specialised solution for I-SEM that cannot be procured from a standard solution. Therefore, this represents a saving in moving away from a pool-based approach.

One of the biggest uncertainties is the number of market participants that would need to actively participate in the market, and hence incur these costs. This will be determined by both the liquidity of the ex-ante markets, and the use of aggregation and/or intermediary services that can allow smaller players to benefit from economies of scale. The impact of market design on incentives and opportunities to participate in the ex-ante markets should therefore be an important consideration in detailed design process. For the central estimates provided in this assessment we have assumed 40 market participants. However, there may be a range between 17 and 64, based on the number of registered units currently participating in the SEM[90]. The lower value of 17 takes account of the registered parties who own the major thermal generation, while the 64 includes parties with no thermal generation e.g. individual wind generation, and suppliers with no generation.

We have not quantified the possible change in costs related to credit cover and collateral related to participation in different market timeframes (with different settlement practices). The trading undertaken in the DA, IDM and Balancing market will be based on firm trades that can be settled the day after the trade. This means the Billing Period for the settlement of physical power (not including potential capacity payments) can be moved to become

[90] For these estimates of market participants, we have grouped the registered units by party ownership.

daily rather than weekly. In addition, the settlement can be done on the Trading day (i.e. there is no need to wait for metered values).

Where physical trading is in the organized ex-ante markets, such as in the proposed HLD, this will give savings on credit cover from today´s position. In summary, market participants could benefit from a reduction in the Credit Cover periods from seven Working Days (moving from weekly to daily settlement) and being able to settle at the Trading Day, (not when metered values are available).

### 3.1.2 COSTS TO TSO AND MARKET OPERATOR

In this section we present an assessment of the implementation costs associated with the Market Operator (MO) and the Transmission system operator (TSO) delivering the required trading systems in the various options.

Importantly we assume that the Market Operator will not purchase additional systems to facilitate trading the forwards market. The cost of setting up a Clearing House to run a forward market is prohibitively expensive, with an estimate of upwards of €1 billion. As a result we assume the Market Operator will sign up with an existing Clearing House to facilitate the forward market.

For all options, systems for the DAM and IDM will need to be procured. The cost for these will be the same for all of the options. There are some various options for how this can be procured. There are essentially three potential solutions that could be implemented:

- Procure all systems and services as part of SEMO;
- Procure IT services from others, but maintain the SEMO as the market operator;
- Outsource all market operations to another market operator.

As these costs will not vary between the various options, the estimates are based on the first option; i.e. that SEMO will be maintained as the operator of the All-Island market (the NEMO). This decision is assumed to be the same across the not be different between the various energy trading options. The choice of the NEMO is strictly not part of the HLD, but will have an effect on the detailed design and implementation phase.

The cost for the DAM and IDM systems is estimated to be€2.5m based on the results of two similar procurement processes in Turkey and Romania.

The cost for becoming part of the PCR project and therefore being part of the European DAM is set to a cost of €1m (based on current estimate of participation costs). A second major one-off cost impacting across all options relates to the contractual and consulting costs associated with setting up cost pre go-live. We estimate these costs to be in region of €10m.

Ongoing system costs include an estimated €500k per annum to maintain and operate the DAM and IDM for all energy trading options. The forward market is assumed to be operated by an existing market operator and therefore be of no cost for the markets.

The TSO/MO will also incur additional Opex costs associated with Payroll, facilities and insurance, professional fees, general and administration and corporate services. These costs (which are currently around €8m/year[91]) are assumed to be identical across all the four energy trading options.

The MO will require, on average, three operators on a 24/7 basis employed specifically in relation to the IDM. This means they will have a requirement for 15 new member of staff, on the assumption that 5 additional staff members are required to ensure one operator on a 24/7 basis.

Finally the 'Other' ongoing costs incurred by the Market Operator are estimated to be €12k per year. These costs cover a range of miscellaneous items such as additional consultancy costs. These costs are consistent across all energy trading options.

In summary, the central estimates for the average level of the common costs for the TSO and MO in any compliant HLD option are as follows:

- **€2.5m: upfront investment** in DAM and IDM systems;
- **€1m:upfront cost** of participation in the PCR;
- **€10m: upfront** contracting and contractual costs;
- **€0.5m/a: ongoing** maintenance and operation of DAM and IDM;
- **€8m/a: ongoing** opex requirements based on current expenditure;
- **€0.6m/a for ongoing** staff costs to cover the IDM
- **€0.01ma for other ongoing costs**, including consultancy support.

The cost of the ex-post arrangements will be the major difference between different options for a compliant HLD. The implementation cost of a Balancing Market, as in the proposed HLD, is estimated at a cost of €13m based on the cost of upgrade of the central EMS and balancing systems at energinet.dk (the Danish TSO). These are indicative estimates for the cost of the balancing systems[92] and the real costs will be discovered as part of the procurement process as part of the implementation project and are highly dependent on the level of customisation that is required.

There are several other international examples of other European TSOs that has procured balancing market systems (with supporting tools). These include the above-mentioned energinet.dk (Denmark), National Grid (GB), TenneT (Netherlands) and Statnett (Norway). The budget and content of these projects has informed our estimate of the cost for I-SEM.

However, one of the issues of reusing the budgets from the international experiences is the fact that these are not covering exactly the same scope. In all the international examples above, the systems procured includes other "bundled" modules as part of a bigger procurement. As we have had access to some of the detailed specifications for the

91 As per the SEM price control, ref SEM-13-054

92 The reason for highlighting that these are estimates is due to the fact that all reference procurement processes for a balancing market in the relevant cases are part of a"bundled" procurement where the balancing market is part of a bigger solution that for instance in Denmark also included an upgrade of their EMS system; in Norway it included all market systems including the ancillary services procurement, settlement and other functions.

procurement, we have a view of the portion that would be similar to the required procurement for I-SEM and this has been used for this comparison.

Annual ongoing maintenance and operation costs for the balancing market are assumed to be €1.2m/a.

Where an ex-post pool arrangement is retained, the costs will be the required adaptations to the current market systems. The cost of this is uncertain as it is highly dependent upon the amount of customisation required.

For a gross pool, the central cost estimate of changes to the current arrangements is €8m, mainly to cover for the Net Settlement process and the change in the management of interconnectors – this estimate is based on the estimated cost of implementing the ID modification in the current SEM systems[93] - however, it is uncertain how many rebidding windows would be needed, which could have a significant impact on the cost.
Similarly, the ongoing maintenance and operation costs for the pool are assumed to be in line with current system costs of €2m/a[94].

If there was a move to a net pool, then substantial changes would be required, as essentially it will require changing the systems from being a Gross Pool to a Net Pool. These implementation costs are estimated to be in the order of two times greater than the cost of developing the balancing market. This cost forms part of the 'All systems' cost for the Mandatory ex-post Pool for Net Volumes and is estimated to be €26m.

The ongoing maintenance and operation costs for the net pool are assumed to be in line with current system costs of €2m/a.

Table 34 summarises the differences in the central estimates of these costs of the ex-post arrangements.

*Table 34 –Non Market costs to the TSO and MO*

| | Balancing Market | Gross Pool | Net pool |
|---|---|---|---|
| Upfront system costs | €13m | €8m | €26m |
| Ongoing systems | €1.2m/a | €2m/a | €2m/a |

### 3.1.3 REGULATORY DESIGN AND ADMINSTRATION COST

The final set of costs relate to the regulatory design and administration costs incurred by the Regulatory Authorities (RAs). The design costs include any consultancy support used in the design of the project, while the administration costs include any additional costs of market monitoring and staffing. We have assumed these costs will be consistent across all four energy trading options.

93 This estimate is based on the SEMO functional costs (€3.4m) plus the SEMO Hardware and Software Costs (€4.6m) as set out in the Proposed Costs and Estimation of Benefits of the Introduction of additional Intra Day Gate Closures in the SEM.

94 As per the SEM price control, ref SEM-13-054

Upfront design costs include the costs incurred by the RAs in obtaining consultancy in the design of I-SEM prior to go live. This includes the costs of the HLD process and the estimated costs off the detailed design phase. The costs are based on actual costs incurred during the development of the SEM. We estimate these costs to be €5m for each of options.

Ongoing external support will include the costs incurred by the RAs in obtaining consultancy advice from lawyers, economists, IT specialists etc., and including the costs of undertaking industry consultation. These costs will be incurred following go-live of I-SEM.

The estimate for the ongoing external support for all options is equivalent to €200k per annum. These also cover the cost incurred to cover participation in the European forums to represent the I-SEM.

Administrative costs relate to the cost of market monitoring and surveillance of the energy trading in the new markets. We have estimated that the costs will be €96k per annum (e.g. 2 members of staff at €42k and €12k a year ongoing costs related to systems, legal, licensing and legislation).

In summary, the central estimates for the average level of the common costs per market participant in each option are as follows:

- **€5m: upfront** design cost
- **€0.2m/a: ongoing** external support costs; and ;
- **€0.1m/a: ongoing** administrative costs.

# 4 ANNEX: IMPLEMENTATION AND OPERATING COSTS FOR CRM

In this section, we present more detail on the estimated impact of different explicit CRMs on the implementation and operating costs for the I-SEM HLD. This supports the summary presented in Section 7.4. For the avoidance of doubt, these cost estimates covers the cost that will be incurred to set up, run and participate in the CRM.

This assessment is primarily informed by published figures from:

- DECC, as part of their CRM Cost Benefit Analysis process[95]; and
- Ofgem, as part of the Gas Significant Code Review[96], which looked at the costs of introducing a demand-side auction.

We use the long-term price-based CRM as the reference case as it represents the status quo. We then estimate the changes in costs for three stakeholder groups of moving to a quantity-based CRM:

- market participants, covering systems, staff and external advice;
- central agency; and
- the RAs.

We do not differentiate between the implementation and operating costs for:

- long-term and short-term price-based CRM, as any difference in costs are expected to be relatively minor as many, if not all, of the same processes are required;
- different quantity-based CRMs, a(os many, if not all, of the same high-level processes are required, and cost differences would be more strongly driven by detailed design choices.

This is consistent with the outcome of the estimates presented in the Initial Impact Assessment.

All staff costs are based on an average salary of €35k /year[97] for each market participant plus an estimate of the additional costs faced by employers such as superannuation and national insurance contributions etc. We estimate these contributions to be in the region of 20% of the salary[98]. This gives a total staff cost of €42k per member of staff.

### 4.1.1 COSTS TO MARKET PARTICIPANTS

95 https://www.gov.uk/government/uploads/system/uploads/yearttachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

96 https://www.ofgem.gov.uk/ofgem-publications/85990/poyrygasscrdsrcbafinalreportv20.pdf

97 Source: The Earnings and Labour Cost Statistics published by the Central Statistics Office.

98 This percentage estimate is based on the current national insurance contribution of 13.8% (http://www.hmrc.gov.uk/rates/nic.htm) in the UK, with an equivalent figure of 11% in Ireland e.g. PRSI Class A employers (http://www.welfare.ie/en/Pages/1896_Pay-Related-Social-Insurance.aspx ). In addition we have included an average pension contribution of 5%. This is based on UK statistics (http://www.ons.gov.uk/ons/rel/fi/occupational-pension-schemes-survey/2012/stb-opss-2012.html). We do not have a figure for the All-Island market but expect it to be in a similar range. We have then rounded the contribution to 20% to account for any additional costs.

It is expected that a move to a quantity-based CRM would lead to additional costs for market participants, in terms of upfront and ongoing costs.

The upfront costs include:

- **Investment in new systems to manage the processes involved in a quantity-based CRM** – e.g. submission of bids, retrading of capacity rights etc. Our central cost estimate is based on the annual transaction costs of participating in an auction, calculated as being around £10k as part of the Ofgem Gas SCR Assessment. In the first year we have assumed this cost will be doubled to take account of the one off implementation costs. This approach reflects the methodology outlines by DECC in its calculation of the administrative costs to business in its October 2013 impact assessment of the CRM proposals under EMR.
- **Building the internal capability to participate in the quantity-based CRMs (e.g. staff training, external advice etc.).** Our central cost estimate is based on the external support element of the transaction costs estimated in the Ofgem Gas SCR Assessment.

The ongoing costs include:

- **Maintenance of new systems to manage the processes involved in a quantity-based auction.** Our central cost estimate is based on the average annual transaction costs of participating in an auction calculated as part of the Ofgem Gas SCR Assessment.
- **Increased staffing requirements** because of more active involvement in the bidding process for the allocation of capacity payments, and managing subsequent commitments. The central cost estimate is based on market participants requiring on average one additional member of full time staff across the year.
- **Additional external advice** on preparation of bids, and on contractual and legal arrangements. Our central cost estimate is based on the average annual transaction costs of participating in an auction calculated as part of the Ofgem Gas SCR Assessment.

Table 35 presents the central estimate of changes in the upfront implementation and ongoing operating costs faced by market participants in moving from a price-based to a quantity-based CRM. We show the central cost estimate for market participants on average, and in total.

One of the main areas of uncertainty is the number of market participants. We have assumed 30 market participants for the central case for total costs for market participants shown in Table 35. This is broadly the midpoint of the number of registered parties in the SEM[99]. This is as presented in the Initial Impact Assessment.

In producing the low and high cost estimates shown in Section 7.4, we have assumed:

[99] Using registered units as a starting position, we first grouped the units by party ownership and secondly removed all the supplier units.

- 17 market participants in the low cost estimate, which reflects the number of registered parties with sizeable thermal generation assets in the SEM[100]; and
- 48 market participants in the high cost estimate, which is the number of registered generation parties in the SEM[101].

This range reflects the uncertainty around degree of active market participation by small parties, particularly windfarms. The impact on the costs of participation by individual parties should therefore be an important consideration in detailed design process.

Varying the number of market participants is also a proxy for uncertainty in the estimated additional costs to market participants of participating in the quantity-based CRM, including any subsequent re-trading required. The range of market participant costs is effectively equal to +/- 50% on costs per market participants, assuming no change in number.

***Table 35 – Change in implementation and recurrent non-market costs for market participants in moving from price-based CRM to quantity-based CRM (2017-2030, €, real 2012 money)***

| €, real 2012 money | Central case for average cost per market participant | Central case for total cost across market participants (30 market participants) |
|---|---|---|
| One-off implementation | | |
| System | +€24k | +€0.7m |
| Bid preparation for first auction | +€9k | +€0.4m |
| Ongoing (annual costs) | | |
| System | | +€0.4m/a |
| Staff costs | | +€2.5m/a |
| External advice | | +€0.4m/a |

The figure shown in Table 35 does not assume any costs of system upgrades or replacement for market participants if a price-based CRM was retained in the I-SEM.

### 4.1.2 CENTRAL AGENCY COSTS

Table 36 illustrates the additional costs for a central agency in moving from a price-based to quantity-based CRM. The main costs are upfront investment in new systems and supporting infrastructure, and ongoing staff costs for two additional full time members of staff to administer the quantity-based CRM. The costs of the new system are based on DECC's estimate of the implementation costs for the proposed quantity-based CRM in GB[102]. .

The figure shown in Table 36 does not assume any costs of system upgrades or replacement for the central agency if a price-based CRM was retained in the I-SEM.

100 Using registered units as a starting position, we first grouped the units by party ownership and secondly removed all the supplier units.

101 Using registered units as a starting position, we first grouped the units by party ownership and secondly removed all the supplier units.

102 https://www.gov.uk/government/uploads/system/uploads/yearttachment_data/file/252743/ Capacity_Market_Impact_Assessment_Oct_2013.pdf

*Table 36 – Change in implementation and recurrent non-market costs for central agency in moving from price-based CRM to quantity-based CRM (2017-2030, €, real 2012 money)*

| €, real 2012 money | Central case for Central agency |
|---|---|
| One-off implementation | |
| System | +€16m |
| Ongoing (annual costs) | |
| Staff costs | +€0.1m/a |

In producing the low and high estimates for Central Agency costs shown in Section 7.4, we have assumed a 50% decrease or increase in costs around the central estimate.

### 4.1.3 REGULATORY DESIGN AND ADMINISTRATION COSTS

The final set of costs relate to the regulatory design and administration costs incurred by the Regulatory Authorities (RAs). The design costs include any costs of external advice while the administration costs include staffing and any additional costs of market monitoring as a result of the CRM.

Table 37 shows the difference in the RA costs in moving from a price-based to a quantity-based CRM. Although there would be a need to review the detailed design of price-based schemes, e.g. to ensure compatibility with the Target Model, the upfront design costs are expected to be €2m higher in moving to a quantity-based scheme.

In addition, we have estimated that an additional full-time member of staff will be required to oversee the operation of a quantity-based CRM.

*Table 37 – Change in implementation and recurrent non-market costs for RAs in moving from price-based CRM to quantity-based CRM (2017-2030, €, real 2012 money)*

| €, real 2012 money | Central case for RAs |
|---|---|
| One-off implementation | |
| Regulatory Design | +€2m |
| Ongoing (annual costs) | |
| Staff costs | +€42k/a |

In producing the low and high estimates for RA costs shown in Section 7.4, we have assumed a 50% decrease or increase in costs around the central estimate.

# 5 ANNEX: CHANGES IN QUANTIFIED RESULTS FROM DRAFT IMPACT ASSESSMENT

Since the Initial IA (IIA), we have carried out further review of the modeling outputs reported in the IIA, including refined assumptions about the structure of renewable support payments and correction of calculation errors. This annex lists the changes from the results reported in the IIA. The overall messages from the modelling results though remain unchanged though from the IIA.

Table 38 shows the change in welfare resulting from efficient ID trading. In the IIA we presented these values in terms of wholesale market costs rather than the change in welfare. For ease of comparison with the values presented in the Final IA, we have presented the values from the IIA in Table 38 in terms of welfare change (i.e. equal and opposite to the values shown in the IIA).

***Table 38 – Updated results for ID modelling revised in the final Impact Assessment compared to the draft Impact Assessment***

| Measure | Scenario | Year / element | Initial IA | Final IA | Source table in Final IA |
|---|---|---|---|---|---|
| Change in wholesale market welfare from efficient ID trading | Base Case A | 2017 | €12m | €5m | Table 14 |
| | | 2020 | €17m | €1m | |
| | | 2025 | €77m | €64m | |
| | | 2030 | €84m | €99m | |
| | Base Case B | 2017 | €17m | €1m | |
| | | 2020 | €24m | €19m | |
| | | 2025 | €12m | €8m | |
| | | 2030 | €19m | €14m | |
| | Base Case A | Cost of net imports (NPV) | -€221m | -€316m | Table 15 |
| | Base Case B | Cost of net imports (NPV) | -€34m | -€94m | |
| | Base Case A | Total NPV | €537m | €441m | Table 13 |
| | Base Case B | Total NPV | €190m | €130m | |

Table 39 shows the updated results regarding the change in consumer bills across alternative CRMs against the baseline of the long-term price based CRM in this final IA alongside the corresponding values in the IIA.

*Table 39 – Updated results for consumer bills under different CRMs revised in the final Impact Assessment compared to the draft Impact Assessment*

| Measure | Scenario | Year / element | Initial IA | Final IA | Source table in Final IA |
|---|---|---|---|---|---|
| Change in consumer bills | ST price-based | 2017 | -€300m | -€318m | Figure 29 |
| | | 2020 | -€302m | -€305m | |
| | | 2025 | -€203m | -€219m | |
| | | 2030 | -€124m | -€158m | |
| | Capacity auction | 2017 | -€161m | -€180m | |
| | | 2020 | -€201m | -€196m | |
| | | 2025 | €134m | €90m | |
| | | 2030 | €141m | €84m | |
| | Energy-only / RO | 2017 | -€255m | -€270m | |
| | | 2020 | -€114m | -€116m | |
| | | 2025 | €29m | €1m | |
| | | 2030 | €14m | -€14m | |
| | ST price-based | NPV | €2846m | €2752m | No longer included in the main body of the IA as consumer surplus presented |
| | Capacity auction | NPV | €724m | €513m | |
| | Energy-only / RO | NPV | €1074m | €928m | |

Table 40 presents the annual wholesale market costs for the reference scenarios in this final IA alongside the values as presented in the IIA.

*Table 40 – Updated results for annual total wholesale market costs revised in the final Impact Assessment compared to the draft Impact Assessment*

| Measure | Scenario | Year / element | Initial IA | Final IA | Source table in Final IA |
|---|---|---|---|---|---|
| Annual wholesale market costs | Base Case A | 2017 | €2407m | €2407m | Table 18 |
| | | 2020 | €2696m | €2697m | |
| | | 2025 | €3086m | €3088m | |
| | | 2030 | €3530m | €3533m | |
| | Base Case B | 2017 | €2489m | €2490m | |
| | | 2020 | €2803m | €2804m | |
| | | 2025 | €3414m | €3415m | |
| | | 2030 | €3943m | €3946m | |