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22nd May 2014
Letter to SEM Committee

Dear Sirs,

Assessment of Generation Adequacy in an Energy-only Market
EirGrid Plc is pleased to provide this report on our modelling work that you have asked us to undertake in support of your minded to decision on the need or otherwise for a separate capacity remuneration mechanism (CRM) in the I-SEM. We received this request towards the end of February 2014, with a requirement to provide a draft report by mid-April and a final report for the SEM committee meeting at the end of May.

We identified a number of potential approaches to this assessment. The options were presented to your team and their consultants on 5 March. The approach adopted was agreed to ensure that the time available to was used effectively and that the outputs would be suitable for your needs at this stage in the I-SEM design.

The modelling is based on the All-island Generation Capacity Statement 2014-2023 methodology with an additional exercise to provide insight into how the generators might operate without an explicit CRM. Modelling of this kind is naturally much more straightforward in a market that is not currently being stabilised by a CRM than in a market such as the SEM.

This report is a factual report of the generation that could be available under various scenarios that the RAs requested that we model and based on the assumptions stated. The output from the modelling is an estimate of the generation surplus or deficit under each scenario. It does not reach any conclusions about how likely these scenarios are to occur, nor is it the purpose of this report to make any recommendations to the SEM committee about the need for a CRM in the I-SEM.

We trust that this report meets your requirements for this stage of the I-SEM design. We are happy to answer any further questions you have about the either the methodology or the assumptions adopted for this work.

Yours sincerely,
Philip O'Donnell
Manager, Energy Systems Analysis

Assessment of Generation Adequacy in an Energy-only Market

Version 1.0

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Executive Summary

EirGrid publish an annual report, called the Generation Capacity Statement (GCS), which assesses future generation adequacy in Ireland and Northern Ireland. The latest GCS, covering the years 2014-2023, projected a generation surplus out to 2023 on an unconstrained All-Island basis. The capacity margin is expected to tighten in the period to 2023 as demand growth erodes excess capacity on the system and some older generation retires. However the capacity assessment in the GCS is based on notifications provided by generators, which are underpinned by the assumption that the existing capacity regime will remain in force. A change to the existing capacity mechanism may lead to a change in the volume of capacity on the island.

This study estimates generation capacity adequacy on an all-island basis if generators were to rely solely on energy revenues to recover their annualized fixed costs. The years 2017, 2020, and 2023 are studied using data from the All-Island Generation Capacity Statement 2014-2023. It has been carried out by EirGrid at the request of the Regulatory Authorities (RAs), and may be published as an annex to the SEM Committee's Proposed Decision on the High Level Design of the I-SEM.

Approach

A selection of methodology options were presented to the RAs, whereupon it was agreed that the methodology used here would be most likely to provide information to the RAs in the short time available. This methodology estimates generation capacity adequacy on an all-island basis, assuming that generators must recover their annualised costs through energy revenues over a range of scenarios and assumptions.

The study first consists of a Cost Recovery Estimation which calculates which generators would not be able to recover their annualized costs from energy payments. A SEM-style market simulation (Plexos) determines generator dispatch volumes. This is divided into their annualised costs to get a Required Average Price.

It is assumed that generators can earn up to €3,000 per MWh on average, with the cut-off point representing a guide as to the level of explicit price cap (such as that used in Euphemia) or implicit (due to real or perceived intervention) price cap. Generators with no run-hours, or with low run-hours that require revenue of more than €3,000 per MWh on average, are assumed to shut down and removed from the generation portfolio.

Two cost recovery scenarios are examined, one in which only Operational & Maintenance (O&M) costs need to be recovered, and another in which both Capital investment costs and O&M costs need to be recovered. The fixed annualised costs are based on the unit type.

Once generation units that have not recovered its costs are removed, adequacy calculations are carried out to determine the level of security of supply for each study year and for a range of scenarios covering fixed cost recovery, demand levels, interconnection capacity and adequacy standard.

Results

The study finds, under the set of specific assumptions used, that a sizable number of generating units do not recover enough energy revenue to cover their costs. From Table 1, it can be seen that this leads to a capacity shortfall in two of the three study years when using the most lenient assumptions i.e. median demand forecast, 8 hours LOLE standard, and a high interconnection reliance.

	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	**2017**	**2020**	**2023**			
Median Demand (O&M costs only)	208	-109	-13	Median	8	690
Median Demand (Capital + O&M costs)	120	-109	-500	Median	8	690

Table 1 Adequacy results for the three study years, assuming a median load forecast, full reliance on interconnector imports, and a security standard of 8 hours LOLE/year. Results are shown for scenarios where only O&M costs need to be recovered by generator units, and both Capital and O&M costs need to be recovered.

Using a tighter security standard of 3 hours LOLE per year, which is currently used in Great Britain and France, reduces adequacy by around 200 MW in all study years. Using a high demand forecast, representing the impact of a 1-in-10 cold winter, has a similar effect. These assumptions increase the capacity shortage in 2020 and 2023, and result in a deficit in 2017 if it is assumed that capital costs need to be recovered.

	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	**2017**	**2020**	**2023**			
Median Demand 3hr LOLE (O&M costs only)	9	-313	-216	Median	3	690
High Demand (O&M costs only)	4	-339	-253	High	8	690
Median Demand 3hr LOLE (Capital + O&M costs)	-79	-313	-698	Median	3	690
High Demand (Capital + O&M costs)	-86	-339	-744	High	8	690

Table 2 Adequacy results showing the impact of tightening the LOLE standard, and of using a higher demand forecast, on the security of supply.

Scenarios are also examined which look at reducing the reliance on interconnector imports for security of supply (Table 3). Reducing reliance on interconnector imports leads to a deficit in all years.

	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	2017	2020	2023			
Median Demand half IC (O&M costs only)	-69	-378	-287	Median	8	375
Median Demand no IC (O&M costs only)	-417	-738	-638	Median	8	0
Median Demand half IC (Capital + O&M costs)	-158	-378	-785	Median	8	375
Median Demand no IC (Capital + O&M costs)	-504	-738	-1125	Median	8	0

Table 3 Adequacy results showing the impact of reducing the reliance on interconnector imports on the security of supply.

Scenarios are also examined looking at the system adequacy when only those units with zero generation in the Cost Recovery Estimation process are removed. This is equivalent to assuming no price cap, and that generators can always achieve their Required Average Price in the energy-only market. One caveat with this scenario is that assuming that there is no price cap tends to magnify any small inaccuracies in the Plexos model.

For example, a unit need only run for one hour to remain in the portfolio when no price cut-off is assumed. A small change in input assumptions or settings could easily shift run times of such units by one hour, meaning that the results with no cut-off price are less robust, and more sensitive to inaccuracies in the model than the other scenarios.

It should also be noted that an uncapped energy-only market is unlikely to be achieved in practice either due to an explicit price cap or due to market failures (e.g. the perceived threat of regulatory or TSO intervention) creating an implicit cap. Therefore this scenario is based on particularly unrealistic assumptions as to the ability of generators to recover their costs. As an example, the 2020 study would have 4 units requiring that prices would go above €3000 MWh for 37 hours on average.

Units with zero generation removed	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	2017	2020	2023			
Median Demand	882	548	155	Median	8	690
Median Demand 3hr LOLE	679	340	-48	Median	3	690
Median Demand half IC	610	273	-119	Median	8	375
Median Demand no IC	259	-84	-470	Median	8	0
High Demand	680	320	-85	High	8	690

Table 4 Results from the Adequacy Calculation where only units with zero running have been removed from the generation portfolio.

In general, the study assumes that generators receive revenue from energy payments only, and that average revenues of €3,000 /MWh are achievable. It may not be possible for a generator to achieve such revenues in reality.

The assumptions used here could lead to frequent periods of high prices within the market. For example, in the 2017 dispatch, while the results indicate no capacity shortage for the least onerous scenario (median demand, 8 hours LOLE standard, and full Interconnection reliance), one remaining generator would require prices of €2,700/MWh for 33 hours of the year. A lower cut-off price could lead to an increase in capacity deficit (or a lowering of capacity surplus) in all cases. Conversely, a higher price-cap than €3,000 could potentially allow higher average prices to be obtained, which would have the opposite effect.

Discussion

While the results presented here should prove useful in informing the RAs, they are limited in their application, and for example should not be used to draw conclusions on price volatility and generator investment risk.

It should be noted that the study here looks at security of supply in the context of revenues from energy only. It indicates that, in certain study years and scenarios, there may not be enough revenue from energy payments to ensure capacity adequacy. However, it does not make suggestions as to how such revenue shortages might be remedied. While this study was requested to assist with the determination of the need for a CRM in the I-SEM, it is possible that revenue shortfalls could be covered through other means, such as system services payments or balancing revenues, or that adequacy could be achieved through the reduction of demand via demand-side management schemes.

This study assumes a dispatch based on SEM-style Short Run Marginal Cost (SRMC) bidding when calculating generator volumes. It does not attempt to model any of the I-SEM designs consulted on.

The methodology here only looks at the provision of energy on an unconstrained system, and transmission and operational constraints have not been considered. Even in cases where capacity adequacy is seen, the generation portfolio may not be sufficient to ensure secure operation of the power system.

1 Introduction

The SEM Committee's Consultation Paper on the I-SEM published on 5 February considers the issue of Capacity Remuneration Mechanisms (CRMs) and sets out a number of CRM designs that may be included alongside the new energy trading arrangements, including the option of an energy-only market with no CRM. The SEM Committee Proposed Decision on the I-SEM, due to be published in June, will set out a preferred option for the energy market and whether a CRM will accompany this.

Forecasting capacity adequacy is essentially a process of comparing predicted generation with predicted demand. While EirGrid already use a rigorous and well-understood technique for modelling capacity adequacy, selecting the assumptions appropriate for this calculation are not so straight forward. Currently, generation adequacy is calculated and reported on an annual basis in the Generation Capacity Statement (GCS).

EirGrid has recently carried out generation capacity adequacy analysis as part of the latest GCS[1]. However, the assumptions in the GCS on which generators will be operating in future years are based on information provided by power generation companies. It is likely that this information assumes that the CPM will still provide them with financial support. In the absence of financial support from a CRM, some generators may no longer be financially viable and could decommission. In this case, the assumptions of generation availability used in the GCS would no longer be valid.

In order to provide the SEM Committee with information on the potential state of generation adequacy beyond 2016 if there was no CRM, and as an input into its decision making on the I-SEM High Level Proposed Decision, the Regulatory Authorities have approached EirGrid to carry out modelling on the implications for generation capacity adequacy in the absence of a CRM as part of the I-SEM design. If any CRM is proposed as part of the I-SEM design, it will need to be compatible with the requirements of the European Commission guidance on State Aid in relation to generation adequacy[2]. This purpose of this study is to identify if energy-only payments would be sufficient to ensure generation capacity adequacy based on a number of simplification, assumptions and scenarios. A broader study should be carried out if a State Aid submission is required.

A selection of methodology options were discussed with the RAs, and it was agreed that the methodology proposed here would be most likely to provide useful information in the short timeframe available within the timeline for the I-SEM high level design. This study uses a methodology to estimate generation capacity adequacy on an all-island basis, assuming that generators must recover their annualised costs through energy revenues. While generators may receive other sorts of payment in the future (such as for ancillary services), the nature of such payments is uncertain, and will be dependent on certain aspects of the I-SEM design which have not as yet been decided on. As such, this study focuses on revenues from energy payments only.

The study consists of two parts. The first part uses a Plexos study to determine generator dispatch volumes, and from this infers which generators would not be able to recover sufficient revenue to remain on the system. The second part uses the results of the Plexos modelling to calculate the

[1] http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf
[2] http://ec.europa.eu/competition/sectors/energy/eeag_en.pdf

system adequacy for future years assuming such generators which do not recover fixed costs from energy revenue are no longer available.

Separate to this study, EirGrid has provided a response to the I-SEM consultation paper (SEM-14-008), which includes a question on the need for a CRM in the future market design. This study was carried out in an objective manner irrespective of the EirGrid Group's position on the need for a CRM.

2 Caveats

While the results presented here should prove useful in informing the RAs, they are limited in their application, and for example should not be used to draw conclusions on price volatility and generator investment risk. The study was undertaken without knowledge of the proposed market design or market power mitigation measures.

This study is concerned with estimating the capacity adequacy of the system as a whole. As such, its focus is not on the financial health of individual generator units. Information from this study will not amount to a recommendation in respect of any possible investment. The processes used by generation companies to decide which units should be withdrawn or kept in the market are likely to be more complex than the Cost Recovery Estimation approach used here.

The operating regime of generators will vary under different market designs, and will be impacted by the make-up of other revenue streams, such as system services. While generators may receive other sorts of payment in the future such as for ancillary services, the nature of such payments is uncertain, and will be dependent on certain aspects of the I-SEM design which have not as yet been decided on, e.g. the operation of a balancing market.

This study looks at security of supply in the context of revenues from energy only. However, in cases where revenue shortfalls leading to a capacity shortage have been identified, it does not infer that a CRM is necessarily required to meet this shortfall. The Cost Recovery Estimation uses a snapshot market study, looking at a likely set of conditions to determine the dispatch of units on the system, in effect an average year. However, in actuality, each year will be different with varying weather conditions and generator forced outages.

The study assumes that generators receive revenue from energy payments only, and that average revenues of €3,000 /MWh are achievable. Many periods of very high market prices would be required for generators with low run-hours to recover their costs. Due to the variable nature of certain aspects of power system operation, such as wind generation, demand, and generator availability, it may not be possible for a generator to achieve such high prices with a level of predictability and regularity.

The market modelling approach here only looks at the provision of energy on an unconstrained system, and transmission and operational constraints have not been considered. Even in cases where capacity adequacy is seen, the generation portfolio may not be sufficient to ensure secure operation of the power system.

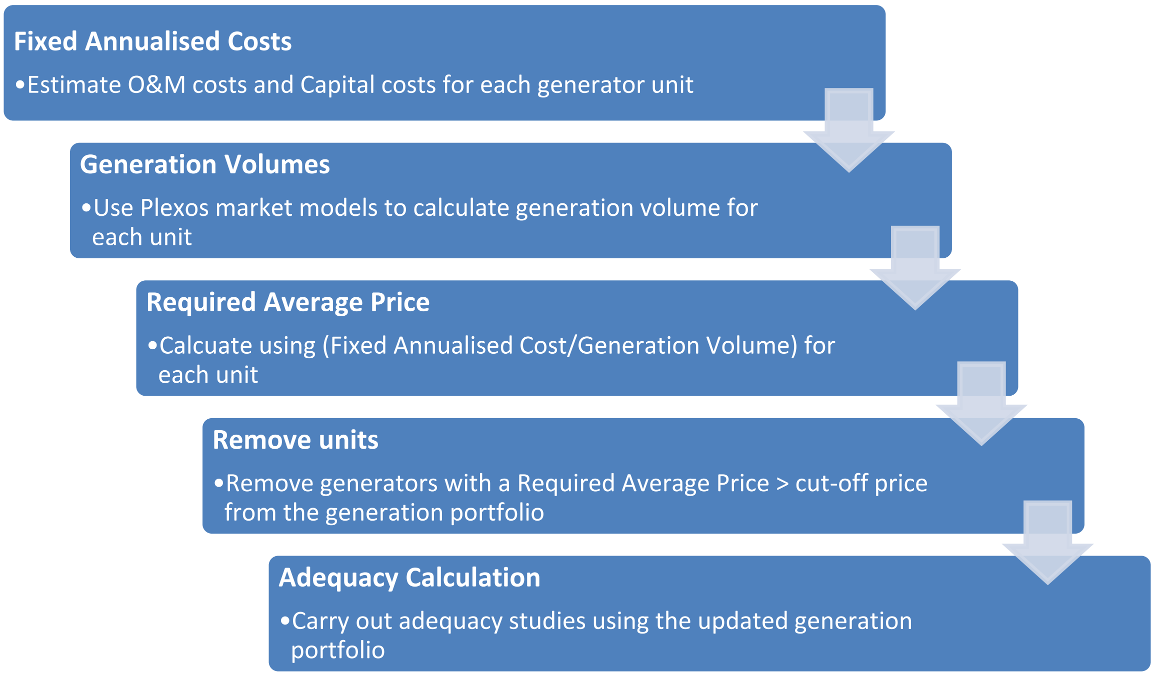
3 Methodology

In essence, this study consists of two components:

1. A market simulation to estimate which generators will not be recover their costs if relying on energy payments (**Cost Recovery Estimation**)
2. An adequacy study determining the surplus or deficit of capacity required to meet the island's adequacy standard, once the above generators have been removed from the generation portfolio (**Adequacy Calculation**).

Studies are carried out for 2017, 2020, and 2023, with a variety of scenarios considered. The studies for each year are carried out independently, and the starting generation portfolio for each year did not take the results from the other years' studies into consideration.

The flow chart below outlines the methodology used.



This study considers revenues from an energy market only, and other potential revenue streams for generators (such as system services) are not accounted for.

It should be noted that the two components of the study are answering different questions and therefore do not necessarily need to make the same assumptions. The Cost Recovery Estimation is attempting to estimate what volumes of generation a unit could expect in a typical year, and the resultant average price it would need to receive in order to recover its costs. The Adequacy Calculation looks at the security of supply situation under a given set of conditions, once the Cost Recovery Estimation results have been taken into account. As such, scenarios which stress the system are considered in the Adequacy Calculation, as the system needs to remain adequate under such conditions in reality.

3.1 Cost Recovery Estimation

To estimate which units can recover costs in each of the study years, a market model calculates the volume that each unit generates (using Plexos software). If, based on this volume, a unit needs to receive an average price which is greater than a predetermined cut-off price, the unit is deemed non-viable.

The following steps outline this process in more detail:

1. An estimation of the costs needed to be recovered annually is made for each generating unit (Annualised Costs).
2. A series of market studies are carried out for each study year, which varies the Forced Outage Rate pattern applied.
3. The average volume of generation for each thermal generator is taken from the market studies, and divided into its Annualised Costs, to get its Required Average Price.
4. Each unit with a generation volume of zero or a Required Average Price greater than the cut-off price is removed from the generation portfolio.

A generator's short run marginal costs (i.e. fuel consumption) are also considered when calculating its required annual revenue. However this tended to add only a small component to the Required Average Price of the units of interest.

For a sample[3] of the Plexos market simulations, an iterative process was examined when removing units from the portfolio, to see if the removal of one unit impacted on the generated volumes of the others. The impact was negligible and had no effect on the end results for the samples studied.

Note that the process described here does not calculate the revenues received for each unit in each study year, but rather looks at what price they would need to receive on average to cover their annualised costs, based on a running regime from an unconstrained short-run marginal cost (SRMC) market. The prices from the Plexos market model itself are not relevant to this study, and are only used in economically optimising the dispatch of units based on each unit's technical characteristics in combination with forecasted fuel prices.

It is possible that the eventual design of I-SEM may not require SRMC bidding from participants. However it is acceptable to assume that an efficient market will converge to a SRMC dispatch. While this should be the outcome of a successful design of the I-SEM, it is not guaranteed. This study does not attempt to model any of the I-SEM designs consulted on.

An estimate has been made of the annual revenue required for each unit to recover its annual costs. These are generalised by plant type rather than reflecting the specific situation of each individual generator. Two annual revenues are examined; the first excludes the generator capital costs, so that generators are only expected to recover their operational and maintenance costs. The second assumes that a generator's capital costs have not been recovered and are included as part of their annual revenue requirement.

[3] Due to time constraints, this could not be carried out for all market simulations

Even where generators have recovered their capital costs, as plant age, major reinvestment may be required to extend their operational life. The scenarios above give a range for annualised revenue requirements into which all plant would fall.

The Cost Recovery Estimation uses a snapshot market study, looking 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 would be more complex. Ideally, a range of assumptions would be used to generate a probabilistic outcome for each generator, however due to time constraints this was unachievable. The results presented here are therefore indicative only and limited in their application.

3.2 Adequacy Calculation

Once generators which did not recover their costs are removed from the generation portfolio, adequacy calculations are then performed.

Determination of capacity adequacy is based on the same methodology used in the GCS[1]. This makes use of AdCal, a software tool which calculates capacity surplus or deficit using probabilistic methods. It weighs up a generation portfolio, with each unit having a forced outage probability, against an input demand curve and calculates the probability of demand not being met in each hour of the study year. The summation of this gives the Loss of Load Estimation (LOLE) for the year. See Appendix 3 of the latest Generation Capacity Statement[1] for more details on this calculation.

A selection of scenarios is examined within the adequacy calculation. These include varying the security standard, the demand profile, and the assumptions on the expected reliance on interconnector imports.

4 Assumptions

The two components of the study have different aims, and assumptions may therefore vary slightly between them. The assumptions are detailed below and any variations are noted.

4.1 Study Years

Three study years - 2017, 2020, and 2023 - are examined. 2017 gives us an indication of how adequacy may materialise in the first year of the new market design. 2020 and 2023 are ideal for modelling purposes as they are far out enough to be representative of the future state of the system, but close enough to give us some certainty regarding policy and other assumptions.

4.2 Annualised Generator Costs

Estimates have been made of the annual revenue required in order for each unit to recover costs. These are generalised by plant type rather than reflecting the specific situation of each individual generator. Two annual revenues are examined; the first assumes that a generator's capital costs have not been recovered and are included as part of their annual revenue requirement. The second excludes the generator capital costs, so that they are only expected to recover their operational and maintenance (O&M) costs.

In reality, many generators in the current SEM would be expected to have recovered their capital costs by now. However as plant age, major reinvestment may be required to extend their operational life. The scenarios above give a range for annualised revenue requirement into which all plant should fall.

Fixed O&M and annualised capital costs are taken from a study[4] carried out by Pöyry in collaboration with EirGrid, and are shown in the table below. These are assumed constant over the study years.

Generator type	Capital Costs (€/kW)	Discount rate	Economic lifetime (years)	Annualised Capital Costs (€/kW/yr)	Annual FO&M Costs (€/kW/yr)
CCGT	750.00	10%	20	€88.09	€35.00
OCGT (gas)	500.00	10%	20	€58.73	€25.00
OCGT (gasoil)	500.00	10%	20	€58.73	€30.00
Coal	1450.00	10%	20	€170.32	€40.00

Table 5 Required recovery costs[1] assumed for each generation type

4.3 Cut-off Price

The cut-off price used to determine whether or not a generator would be viable is €3,000 €/MWh. This price is in line with the proposed European Price cap for the day-ahead price coupling in the European target model.While this price cap is only proposed for the day-ahead timeframe at present, this does not necessarily imply that the intra-day and balancing timeframes will be uncapped[5]. Applying this assumption does not reflect the TSO's prediction on future market design.

For the purpose of this study, any generators requiring an average price above this level are considered unable to recover their costs. The average price required for a typical CCGT as a function of its capacity factor is shown in Figure 1. Any CCGT running less that 5 GWH per year is likely to be considered non-viable if it has to recover its O&M costs only. Assuming it needs to recover capital costs also, it will need to run for 15 GWh in the Plexos study to remain part of the generation portfolio. This represents an annual capacity factor of less than 0.5% for a typical CCGT.

Figure 1 shows that a small change in the dispatch of a unit as calculated by the Plexos market model could change that units cost recovery in the methodology used here. A change of a single percentage point in a generator's capacity factor would have a significant impact on how it would be treated within this methodology.

Finally, one scenario was considered where no cut off price was applied and only generators with zero running hours in Plexos were removed from the generation adequacy model.

[4] Low Carbon Generation Options for the All-Island Market , March 2010

[5] http://www.nordpoolspot.com/Message-center-container/Exchange-list/2013/09/No-522013---Nord-Pool-Spot-to-introduce-new-minimum-and-maximum-price-caps/

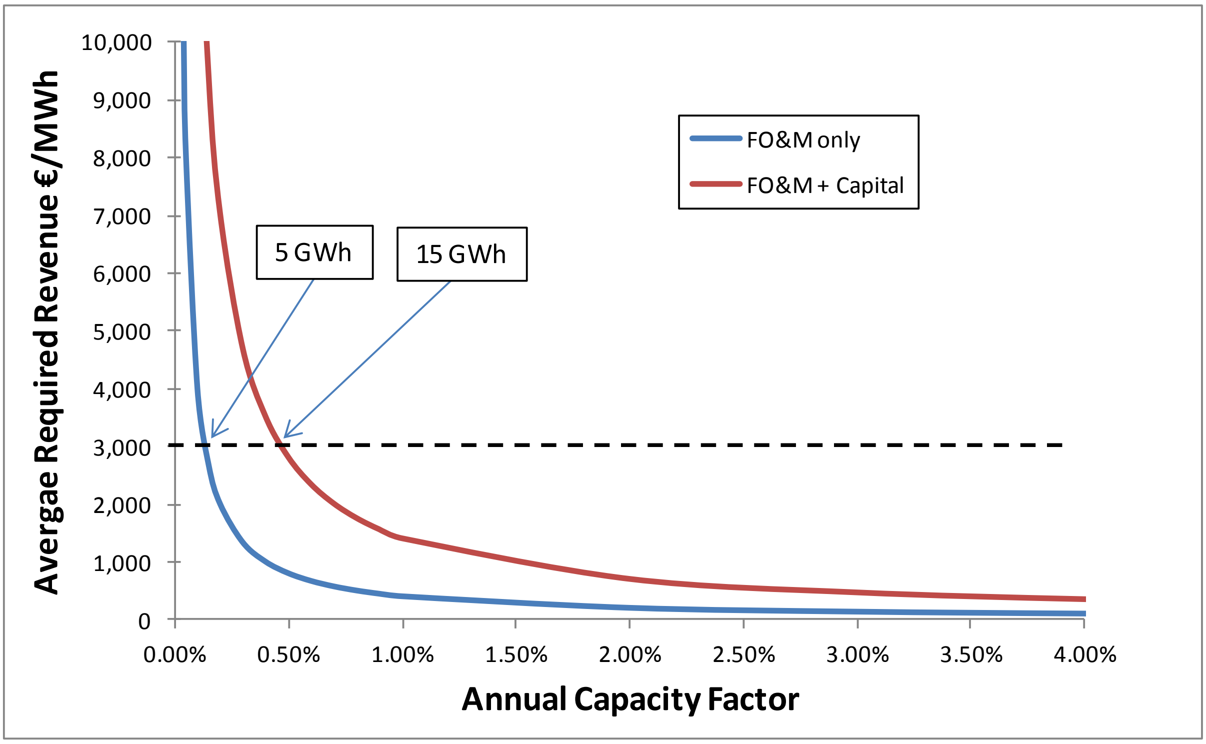


Figure 1 Average price required by a typical CCGT to recover its costs, as a function of its capacity factor. The average price required changes depending on whether or not a generator needs to recover capital costs on top of its O&M costs.

4.4 Market Modelling Software

The market dispatch is modelled using Plexos v6.301. This software creates an annual chronological unit commitment and dispatch schedule with an hourly granularity. The dispatch is obtained on an economic basis. This means the software will switch on and off generation to exactly meet demand in the most economic way possible, taking into account any technical limitations of generators. It does this by calculating the cost of generating each MWh for each generator, given a set of fuel prices and each generators' technical characteristics. It also considers the cost of starting up a generator, and the cost of CO_2 emissions.

Renewable generators are given a zero or very low price to reflect their priority dispatch status (note that these price assumptions are only used for modelling purposes). Interconnector flows are calculated within the model. Plexos estimates prices in each region and determines flows based on arbitrage.

The Plexos software is widely employed in the electricity industry, and is used by many of the world's largest utilities and system operators, as well as the Regulatory Authorities in Ireland and Northern Ireland. Plexos simulation results are subject to regular and rigorous audit.

4.5 Adequacy Standard

The adequacy standard is set to 8 hours LOLE/year for these studies, unless otherwise specified. Currently the generation adequacy standard is 8 hours LOLE/year in Ireland and 4.9 hours LOLE/year in Northern Ireland. The all-island standard used in the existing Capacity Payment Mechanism and GCS is 8 hours LOLE/year.

However it should be noted that the most recent generation adequacy standard proposed for use in Great Britain is 3 hours LOLE/year[6], and the same standard is used in France[7]. This higher standard would be more reflective of the political acceptance of load shedding. A scenario using a standard of 3 hours LOLE/year is therefore examined.

4.6 Demand

Demand assumptions are taken from the latest GCS's[1] median forecast, representing EirGrid's best estimate of demand in the study years.

	TER (GWh)		Transmission Peak (MW)	
Year	Median	High	Median	High
2017	37,021	37,412	6628	6862
2020	38,480	38,981	6849	7104
2023	39,873	40,473	7078	7352

Table 6 Demand forecasts for the SEM assumed in the Adequacy Calculation

The high forecast, based on a 1-in-10 cold winter, is also examined as a scenario in the adequacy assessment to show how the system would perform under times of stress.

Great Britain demand is based on the 'Gone Green' scenario in National Grid's latest Ten Year Statement published in 2013[8].

4.7 Conventional Generation

The RA's latest validated Plexos model is used as a starting point for this study. The initial generation portfolio is taken from the Generation Capacity Statement (GCS) 2014-2023[1]. It matches the base case in that document, which assumes that some older generators will shut down due to age.

Units have been assigned typical forced outage and maintenance rates based on historical data. Initial studies indicated that the choice of forced outage pattern could impact on the generation volume for some units, which could have a bearing on the final results. As such, multiple runs of the model are carried out for each study year using different forced outage patterns. The generation volume for each unit is then calculated by averaging the results from these runs.

For adequacy calculations, the same generation portfolio as in the Plexos market study is used, with the appropriate conventional generators removed as determined by that study. Forced outage rates are taken from the latest GCS[1].

4.8 Interconnection

The existing interconnectors (Moyle and EWIC) are the only ones included in the study. For the Plexos studies used in the Cost Recovery Estimation, market flows on Moyle and EWIC are based on

[6] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/238867/Consultation_on_the_draft_Delivery_Plan__amended_.pdf

[7] http://www.rte-france.com/uploads/Mediatheque_docs/vie_systeme/annuelles/bilan_previsionnel/an/generation_adequacy_report_2012.pdf

[8] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/Current-statement/

the modelled price differential between SEM and BETTA. A representative model of the British power system is therefore included, with a projected British portfolio dispatched on an SRMC basis.

For the Adequacy Calculations, EirGrid has estimated the capacity value of the EWIC interconnector to be 440 MW[9] for the generation adequacy studies carried out in the GCS. This same assumption has been made in these studies, unless otherwise specified. For Moyle, it is assumed to have capacity equivalent to its current available capacity of 250MW. Scenarios where the interconnector contribution towards adequacy is set to either zero or to half of the total import capacity, representing the risk of long-term outages or simultaneous capacity shortages in SEM and Great Britain, are also examined.

4.9 Renewable Generation

Installed RES capacity matches the assumptions outlined in the latest GCS[1], with Ireland meeting the EU 2020 targets of 40% RES-E and Northern Ireland meeting the Strategic Energy Policy of 40% renewables in electricity.

For the Plexos studies used in the Cost Recovery Estimation, hourly normalised regional wind profiles, based on real historical data, are used to capture the intermittent nature of wind and the regional variation of the resource. For hydro, a daily limit constrains how much generation hydro units can produce based on historical average data.

For the Adequacy Calculations, a similar methodology as used in the GCS to account for the capacity from intermittent power sources such as wind and hydro is applied. For wind generation, a capacity credit is allocated towards a given installed capacity of wind which represents that capacity's benefit towards generation adequacy. For hydro, it is assumed that their energy-limited nature does not impact on their contribution towards adequacy, as optimisation of their output can ensure that they are fully available over periods with the tightest adequacy margins. See section 3 of the latest Generation Capacity Statement[1] for more details.

4.10 Fuel & Carbon Price

Fuel prices are taken from the International Energy Association's World Energy Outlook 2013[10] report, as is the forecasted European Carbon ETS price. Carbon prices in Great Britain are set to the Carbon price floor, which is now assumed to be frozen at 2015-16 levels (£18.08 /tonne in nominal terms).

	Unit	2017	2020	2023
Crude Oil	barrel	86.97	88.14	89.54
Natural Gas	MBtu	9.22	9.28	9.33
Coal	tonne	80.63	82.68	84.08
EU Carbon (ETS)	tonne	12.56	15.60	18.64

Table 7 Fuel and Carbon Prices (in 2012 Euro per unit)

The following currency exchange rates are used for adapting the fuel forecast.

[9] Interconnection Economic Feasibility Report: http://www.eirgrid.com/media/47693_EG_Interconnect09.pdf
[10] http://www.worldenergyoutlook.org/publications/weo-2013/

US$/€	1.28
£/€	0.81
US$/£	1.59

Table 8 Currency exchange rates used in the study

5 Results

5.1 Cost Recovery Estimation Results

The table below shows which units are removed in each year as determined by the Cost Recovery Estimation. These units are shown in Table 9.

	Removed (O&M costs only)			Removed (Capital + O&M Costs)		
Gen Type	**2017**	**2020**	**2023**	**2017**	**2020**	**2023**
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	N	Y	N	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	N/A	N/A	Y	N/A	N/A
Gas OCGT	Y	N/A	N/A	Y	N/A	N/A
CCGT	Y	Y	N	Y	Y	Y
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Total Capacity Removed (MW)	2062	1960	815	2152	1960	1368

Table 9 Generators that have been removed from the portfolio for the three study years. Cells marked N/A mean that the generators are due to decommission before that study year.

From Table 9, it can be seen that that the similar units are removed for each study year, irrespective of the whether capital costs are required to be recovered or not. There are a few exceptions to this, the most notable being a single gas CCGT unit in 2023. The removal of this unit has a significant impact on generation adequacy. In the table 'N/A' indicates that the generator is not included in the model for the given year, as the units are already forecasted to have been phased out.

Table 10 gives a summary of the capacity of units that are removed due to the Cost Recovery Estimation process. The capacity of units showing zero generation in the market model output is also shown. These units would not be sensitive to assumptions on costs that need to be recovered, or on the cut-off price, for the methodology used here. They would however be sensitive to other assumptions used by the Plexos simulation to determine economic dispatch.

	Capacity (MW) (O&M costs only)			Capacity (MW) (Capital + O&M costs)		
Study Year	***2017***	***2020***	***2023***	***2017***	***2020***	***2023***
Original conventional generation capacity	8,585	8,255	7,622	8,585	8,255	7,622
Units with zero generation	1,315	1,227	635	1,315	1,227	635
Units that generate but do not recover costs	747	733	180	837	733	733
Remaining conventional capacity	6,523	6,295	6,807	6,433	6,295	6,254

Table 10 Summary of removed generation capacity as determined by the Cost Recovery Estimation process.

The Plexos model simulates a typical year based on the most probable assumptions available at this time. However in any given year there are a number of factors which can affect the runtime of conventional generators. Increased demand or lower wind output would change generation volumes. While the study timescales did not allow for explicit sensitivity analysis around these factors, the range of installed wind and demand in the three study years does provide an indication around the sensitivity of the results to these factors.

The impact that different forced outage patterns would have on the generation volumes of units is considered. A sample of six generator forced outage patterns are used in the Plexos market runs for each year, with generation volumes taken from the average of these results. Ideally a larger sample size would have been used, however due to time constraints this was not possible.

The amount of capacity removed from the generation portfolio depends on the cut-off price assumed. This relationship is shown in Figure 2. This gives an indication of how sensitive the results are to the choice of cut-off price. A small number of units see very little running and have a Required Average Price of greater than €1,000. The majority of units are more financially stable, and would remain operational with a cut-off price of €1,000. The study assumes that generators can, on average, receive up to price cap (i.e. €3,000) for each MWh they produce. Lowering this figure could lead to more plant being removed. Conversely, increasing the cut-off price could lead to more units remaining on the system.

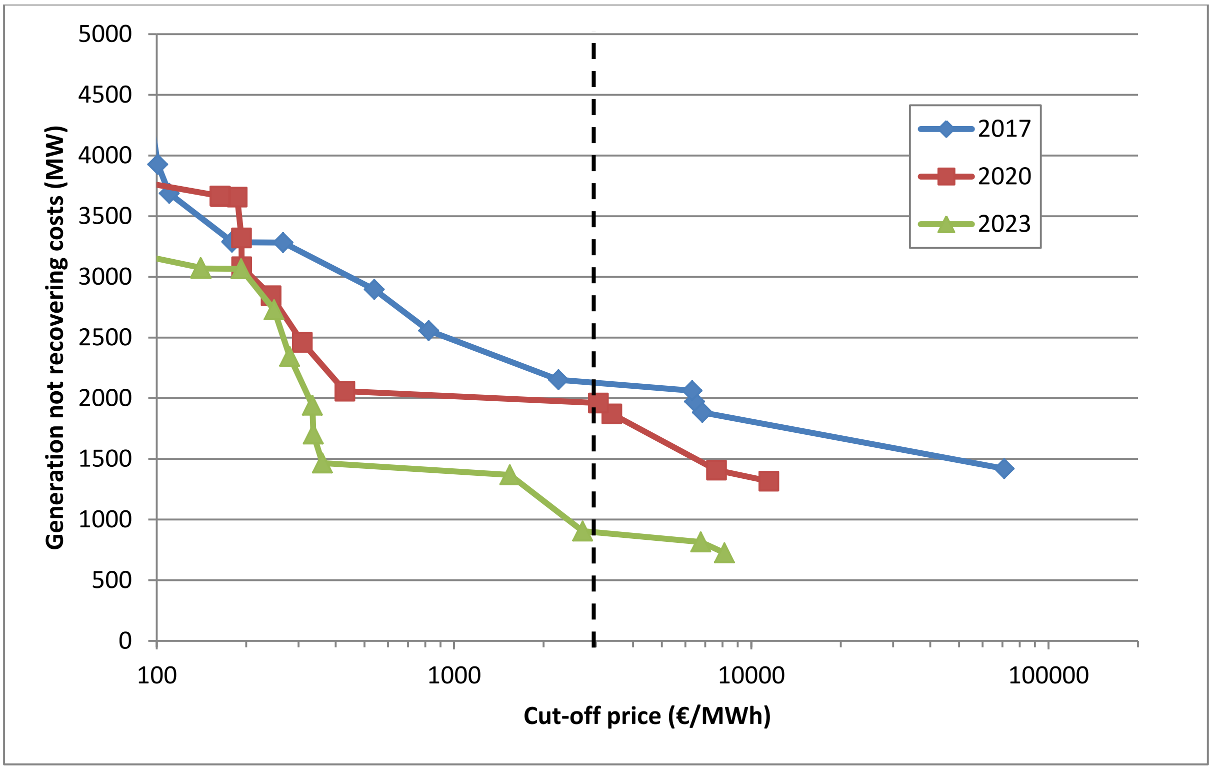


Figure 2 Removed generation capacity plotted against the cut-off price, assuming units need to recover O&M costs only. Decreasing the cut-off price means more capacity would be removed from the generation portfolio, and vice-versa. Note that a logarithmic scale has been used for the cut-off price.

5.2 Adequacy Calculation Results

Once the Cost Recovery Estimation process has identified which units should be removed, Adequacy Calculations are carried out using the resultant generation portfolio. Certain scenarios are examined. These are:

- Reducing the adequacy standard from 8 hours LOLE/year to 3 hours LOLE/year
- Reducing the reliance on interconnectors to half of the available import capacity ('half IC')
- Reducing the reliance on interconnectors to zero ('no IC')
- Using a high demand forecast, representing the impact on capacity adequacy of a particularly cold (1-in-10 year) winter ('High demand')

A set of studies are also carried out looking at the system adequacy when only those units with zero generation in the Cost Recovery Estimation process are removed. This is equivalent to assuming no cut-off price, and that generators can always achieve their Required Average Price in the energy market.

5.2.1 Adequacy Results: Overall

Table 11 below shows the results for all scenarios examined, assuming generators need to recover O&M costs only. The impact of the scenarios is examined in more detail in later tables. As can be seen, 2020 and 2023 show a capacity deficit in all scenarios.

O&M costs only	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	**2017**	**2020**	**2023**			
Median Demand	206	-114	-1	Median	8	690
Median Demand 3hr LOLE	6	-319	-204	Median	3	690
Median Demand half IC	-72	-383	-280	Median	8	375
Median Demand no IC	-420	-743	-626	Median	8	0
High Demand	0	-341	-242	High	8	690

Table 11 Capacity adequacy for all scenarios examined, assuming generators need to recover O&M costs only. Cells highlighted in red indicate a shortage of capacity.

Adequacy drops between 2017 and 2020, as more units are removed according to the Cost Recovery Estimation, and demand increases. Conversely the deficit shrinks slightly between 2020 and 2023. This is primarily caused by a CCGT not recovering its costs in 2020, but doing so in the 2023 study. It is therefore removed from the 2020 portfolio but is present in the 2023 one. Note that all study years are examined independently, so that a closure assumed for one study year does not impact the portfolio in another year.

An assumption limiting the run hours of two large coal units in 2023 due to emissions restrictions also impacted the adequacy in that year.

Table 12 below shows the results for all scenarios examined, assuming generators need to recover their annualised capital costs plus their O&M costs. Once again 2020 and 2023 are in deficit, with only the least onerous scenario in 2017 showing adequate generation capacity.

Capital + O&M costs	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	**2017**	**2020**	**2023**			
Median Demand	118	-114	-499	Median	8	690
Median Demand 3hr	-83	-319	-699	Median	3	690
Median Demand half IC	-161	-383	-767	Median	8	0
Median Demand no IC	-507	-743	-1,126	Median	3	0
High Demand	-89	-341	-745	High	8	690

Table 12 Capacity adequacy for all scenarios examined, assuming generators need to recover capital costs and O&M costs. Cells highlighted in red indicate a shortage of capacity.

In the capital cost recovery scenario, the same generators are removed in all years according to the Cost Recovery Estimation. The declining capacity situation is therefore caused by increasing demand, and an assumption limiting the run hours of two large coal units in 2023 due to emissions restrictions.

5.2.2 Adequacy Results: Scenarios

The least onerous case studied shows adequate margin in 2017 only. A supply shortage is seen in 2020 and 2023. This assumes that close to full imports from both interconnectors can be obtained when required, that demand will follow an average year (as opposed to a particularly cold one), and that it is acceptable for 8 hours of load to be shed on average per year. Other scenarios have been examined which vary these assumptions.

5.2.2.1 *Lower Reliance on Interconnection*

It is possible that capacity shortfalls here could coincide with those in Great Britain, or that the interconnectors could suffer a long term outage, and imports on the interconnectors would not be ensured. The study therefore includes scenarios assuming that only half of the interconnectors' import capacity can be relied upon, and also assuming a zero reliance on interconnector imports. The results of these scenarios show that reducing the assumed reliance on interconnector imports leads to a capacity shortfall in all years, and this deficit is quite substantial in 2023.

	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	**2017**	**2020**	**2023**			
Median Demand half IC (O&M costs only)	-72	-383	-280	Median	8	375
Median Demand no IC (O&M costs only)	-420	-743	-626	Median	8	0
Median Demand half IC (Capital + O&M costs)	-161	-383	-767	Median	8	375
Median Demand no IC (Capital + O&M costs)	-507	-743	-1,126	Median	8	0

Table 13 Reducing the assumed reliance on interconnector imports leads to a capacity shortfall in all years.

5.2.2.2 *Higher Demand Forecast*

To run a secure system, the TSO needs to prepare for all likely eventualities, not just average or mean conditions. A scenario using a high demand forecast, representing the impact of a particularly cold (1-in-10 year) winter is included. The impact of this scenario effectively reduces adequacy by between 200 MW and 250 MW, and leads to a capacity shortfall in 2017 if generators are required to recover their capital costs.

	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	**2017**	**2020**	**2023**			
Median Demand (O&M costs only)	206	-114	-1	Median	8	690
High Demand (O&M costs only)	0	-341	-242	High	8	690
Median Demand (Capital + O&M costs)	118	-114	-499	Median	8	690
High Demand (Capital + O&M costs)	-89	-341	-745	High	8	690

Table 14 Increasing the demand forecast leads to a capacity shortfall in all years if generators are required to recover their capital costs.

5.2.2.3 *Tighter Adequacy Standard*

The current adequacy calculation assumes a standard of 8 hours LOLE per year. A system that has an 8 hour LOLE standard will shed load for 8 hours of the year **on average**. This means that some years will see more hours of load shedding. It is debatable as to whether even 8 hours of lost load would be acceptable, politically or otherwise. For every hour of lost load, there would be additional hours of very tight margins where emergency measures would be in place and public announcements would be made. As such, a scenario examining a tighter standard of 3 hours LOLE/year, in line with the standard used in France and proposed for Great Britain, is carried out.

The impact of this scenario effectively reduces adequacy by around 200 MW, and leads to a capacity shortfall in 2017 if generators are required to recover their capital costs..

	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	2017	2020	2023			
Median Demand (O&M costs only)	206	-114	-1	Median	8	690
Median Demand 3hr LOLE (O&M costs only)	6	-319	-204	Median	3	690
Median Demand (Capital + O&M costs)	118	-114	-499	Median	8	690
Median Demand 3hr LOLE (Capital + O&M costs)	-83	-319	-699	Median	3	690

Table 15 Using a tighter security standard leads to a reduced margin.

5.2.2.4 No price cap

A set of studies are also carried out looking at the system adequacy when only those units with zero generation in the Cost Recovery Estimation process are removed. This is equivalent to assuming no price cap, and that generators can always achieve their Required Average Price in the energy-only market.

One caveat with this scenario is that assuming that there is no price cap tends to magnify any small inaccuracies in the Plexos model. For example, some OCGTs have a very low minimum load (e.g. 4 MW) and low start-up costs. In a small number of hours, these generate at minimum load, allowing the OCGT to recover its costs in the energy market, even though the decision to dispatch it at minimum load may have been based on an inaccuracy within the model. This means that the results with no cut-off price, shown below in Table 16, are less robust, and more sensitive to inaccuracies in the model than those from the other scenarios.

It is not clear that an uncapped energy-only market would be achievable in practice. As an example, the 2020 study would have 4 units requiring that prices would go above €3,000 MWh for 37 hours on average.

Units with zero generation removed	Capacity Adequacy (MW)			Load Forecast	LOLE (hrs/yr)	IC Reliance (MW)
Name	2017	2020	2023			
Median Demand	879	544	167	Median	8	690
Median Demand 3hr LOLE	676	335	-36	Median	3	690
Median Demand half IC	607	268	-112	Median	8	375
Median Demand no IC	256	-89	-458	Median	8	0
High Demand	677	318	-74	High	8	690

Table 16 Results from the Adequacy Calculation where only units with zero running have been removed from the generation portfolio.

6 Conclusions

The above results illustrate the modelled outcomes if generators are required to recover their costs from energy payments only. They indicate a capacity shortfall in two of the three study years when using the most lenient assumptions i.e. median demand forecast, 8 hours LOLE standard, and a high interconnection reliance. Introducing a higher demand forecast, or applying a tighter security standard, would lead to a higher deficit (or lower surplus) in all years. Removing reliance on interconnection leads to a deficit in all years.

This study uses a Plexos model simulation to calculate the volume of generation for each generator. The study then assumes that all of a units costs are recovered through energy payments for this generation. If a generator needs a price of over €3,000/MWh, in order to recover its costs it is removed from the generation portfolio.

We have assumed that a generator can receive up to €3,000 /MWh for all of its run hours. However this may not be achievable in practice. The cut-off price assumed here of €3,000 MWh may also be perceived as unrealistic by investors or market participants, leading to market exit or lack of entry.

This assumption on which generation would be removed therefore represents a lower bound, rather than a realistic estimation. Assuming a lower figure for the average price that a generator can obtain could lead to more generation being removed, and a lower capacity surplus (or greater shortfall) in many cases. Conversely, a higher price-cap than €3,000 could potentially allow higher average prices to be obtained, which would have the opposite effect.

It should be noted that the study here looks at security of supply in the context of revenues from energy only. It indicates that, in certain study years and scenarios and based on the assumptions, there may not be enough revenue from energy payments to ensure capacity adequacy. However, it does not make suggestions as to how such revenue shortages might be remedied. It is possible that revenue shortfalls could be covered through other means, such as system services payments, or that adequacy could be achieved through the reduction of demand via demand-side management schemes.

This study assumes a dispatch based on SRMC when calculating generator volumes. It does not attempt to model any of the I-SEM designs consulted on. However it is possible that generating units that see little or no running in an energy market would be active in a balancing market, and achieve sufficient revenues through the balancing price. It does not consider bidding rules or other market power mitigation measures.

A selection of methodology options were presented to the RAs, and it was agreed that the methodology proposed here would be most likely to achieve meaningful results in the short timeframe allocated. While it is hoped that the results presented here are useful, they are limited in their application, and for example should not be used to draw conclusions on price volatility and generator investment risk.