Options for the Capacity Adequacy Standard in the I-SEM

Contents

1. Introduction

Security of supply is a high priority for EU Member States, National Regulatory Authorities for energy (NRAs) and Transmission System Operators (TSOs). Under current EU legislation[1] there is an obligation on each Member State to monitor the security of electricity supply within their territory over the medium to long-term and each member state is entitled to set and monitor the level of Security of Supply deemed appropriate for its own needs. However, in the context of the Internal Energy Market (IEM), approaches to generation adequacy should be co-ordinated.

The principal aim of energy policy in the European Union (EU) is to ensure competitive, secure and sustainable energy for the economy and society. The objective to deliver a sustainable, secure energy system and a competitive IEM means that security of supply will need to be addressed in a regional context in order to maximise the benefits of the IEM.

To deliver a competitive IEM, the European Commission has been leading the process to implement the EU Target Model for electricity markets. Through this, new energy market arrangements are being developed to allow for greater cross border trade in electricity. EU Member states have the responsibility to comply with the requirements of the EU Target Model, and in Ireland this is the main driver for the introduction of the I-SEM. Against this backdrop, it is important to begin to consider ways to improve current and future generation adequacy and risk assessments at national, regional and European levels.

In Ireland, the TSO is charged[2] with reporting and advising on security of supply in electricity through adequate planning and operation of transmission capacity. Indeed, in most EU countries, TSOs are the responsible bodies for monitoring and reporting on generation adequacy.

This TSO information paper sets out some background to the current approach to reporting on adequacy, and considers the implications of moving to a different standard. In order to reassess the adequacy standard, we examined a number of factors, some of which are themselves difficult to define or subject to change.

2. What is Capacity Adequacy?

Capacity adequacy can be defined as the ability of the electricity system to meet the aggregate power and energy requirement of all consumers at almost all times. It would be prohibitively expensive to guarantee supply at all times. Capacity adequacy assessment is essentially a comparison of generation supply with electricity demand. Thus, to measure generation adequacy, we need to assess both the generation resources and the forecast demand on a system.

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[1] Directive 2003/54/EC and EU Directive 2005/89/EC

[2] Statutory Instrument 60 of 2005

Capacity adequacy can be assessed in different ways. A relatively simple approach examines the **margin** between the amount of generation plant installed in a system and the peak electricity demand – this does not take into account the possibility of plant not being available at times of need.

A **probabilistic** approach seeks to capture the uncertain nature of power plant availability, by scheduling plant maintenance at periods of lower demand and assigning a suitable forced outage rate to each generation unit. For any hour of the year, we can make a probabilistic assessment which convolves the forced outage rates of a whole portfolio of plant on a system, and compare it to the forecasted demand for that hour. This results in a particular probability of failure for that hour, a Loss of Load Probability (LOLP). The LOLP values can be used to quantify the likely total number of hours of failure. For example, a 10% LOLP for one hour implies a Loss of Load Expectation (LOLE) of 6 minutes. When summed over a whole year the total LOLE gives an indication of the ability of the generation plant to serve the load

An adequacy standard can be set which is a target value for the annual LOLE. If a system is found to have a LOLE far higher than the set standard, then it is at risk of a substantial amount of load shedding over that standard. Conversely, if a system's calculated LOLE is far lower than the standard, then we could say that there is an excess of plant and there might be a wasting of resources.

To set an LOLE standard, we need to take into account a number of issues:

- The relationship between the MW capacity of plant added and the LOLE improvement which it results in (this is evaluated through probabilistic modeling)
- The cost of this additional plant
- The benefit derived from the additional plant.

Ideally, a balance should be struck between the cost of additional plant and the benefit accrued.

LOLE is a probabilistic measure – it seeks to quantify over the course of a year, the likely number of hours of failure. However, it can be expected in any one year that the dice may fall kindly or unluckily. Even with a system which meets the set standard, it is still possible to have more hours of failure than that standard. Conversely, it is quite possible to have a very low outcome number of hours of failure in a year if the dice fall kindly and/or other mitigation measure save the system from any substantial load shedding.

While we refer to generation plant in this paper, it is recognised that other means can also be employed to help meet the demand. These include demand-side resources and interconnection, both of which can be modelled in EirGrid's capacity assessment software

Existing Reliability Standards for Generation Adequacy

In the SEM, the LOLE standard is currently set at 8 hours per year for All-island studies as well as Ireland-only studies. This has evolved from earlier measures.

In the early 1990s, a standard of 1.5 failure days per year was in place in Ireland, using a methodology that looked at the top 50 daily peaks in the year. Upon review, this was changed to assess adequacy on an hourly basis over the entire year. This was done principally so that the impact of scheduled plant maintenance, which was then giving cause for concern, could be modelled. With the change, it became appropriate to express the standard in hours/year. Analysis showed that a value of 8 hours/year would require the same level of installed capacity, and therefore give the equivalent level of security, as the previous standard. The appropriateness of the methodology and standard were confirmed in 1994 by consultants appointed by the Dept. of Transport, Energy & Communications.

Previous to the introduction of the SEM in 2007, the standard in Northern Ireland was set at 0.7 failure days/year, based on the top 50 daily peaks. Comparative studies carried out prior to the SEM establishment showed that this was equivalent to 4.9 hours/year. Therefore we use this standard of 4.9 hours when assessing Northern Ireland as a separate jurisdiction, with limited interconnection to Ireland.

We use the current adequacy standard of 8 hours per year in different studies:

- The Generation Capacity Statement addresses security of supply by determining whether there is a surplus or deficit of plant over the next decade. Stakeholders in the market can use the various scenarios examined to assess future needs and opportunities.
- The Capacity Requirement for the current SEM Capacity Payment Mechanism is calculated to meet the Adequacy Standard.

3. Rationale for reassessing the standard

There is widespread recognition of a need for improved assessment of generation and security of supply in the internal market given the impact of increasing penetration of renewable energy sources and greater market integration.

A recent survey conducted by the Electricity Coordination Group (an expert group of the European Commission) highlighted that there are a range of standards and metrics used in European countries, see Table 1. A standard based on the LOLE metric is most common, while others use reserve margin or LOLP. Many have no official standard.

We need to take care when comparing generation adequacy standards used in different countries, as the specific methodologies and the definition of the metrics used may vary between them. For example, the Great Britain standard of 3 hours LOLE per annum assumes that the TSO has additional measures above those assumed in setting the capacity requirement, which can be used to mitigate potential load shedding events.

Country/ Jurisdiction	Generation Adequacy Standard	Metric Used
GB	3 hours LOLE p.a.	LOLE, EEU, frequency and duration, de-rated capacity margins.
France	3 hours LOLE p.a.	LOLE
Germany	No Standard	n/a
Spain	10% reserve margin	Capacity Margin
Belgium	16 hours LOLE p.a. non interconnected, 3 hours LOLE p.a. with interconnection taken into account	LOLE
Ireland	8 hours LOLE p.a.	LOLE
Netherlands	4 hours LOLE p.a.	LOLE
Austria	No Standard	n/a
Bulgaria	optimal LOLE and amount of cold reserve	LOLE
Cyprus	20% reserve margin	Capacity Margin
Denmark	No standard, but the TSO, which is responsible wishes to keep the Security of Supply at the current level	.
Estonia	10% reserve margin	Capacity Margin
Finland	No Standard	n/a
Hungary	LOLP of 1%	LOLP
Italy	No Standard	n/a
Latvia	No Standard	Capacity Margin
Lithuania	No Standard	n/a
Luxembourg	No Standard	n/a
Malta	No Standard	n/a
Poland	No Standard	n/a
Portugal	LSI≥1,0 with 95% exceeding probability; and LOLE < 8h/year (taking into account the lack of operational reserve)	Load Supply Index (LSI) and Loss of Load Expectation (LOLE)
Romania	25% Reserve Margin(Non-standard) 10% Reserve margin (standard)	Capacity Margin
Slovakia	No standard	n/a
Slovenia	LOLE 8 hours p.a.	LOLE
Sweden	No standard	n/a

Table 1 Generation adequacy standards and metrics used in Europe (adapted from ENTSO-E Report of the European Electricity Coordination Group on 'The Need and Importance of Generation Adequacy Assessments in the European Union')

4. Developing a Regional Approach

European Union is building an internal market for energy, with the aim of delivering energy supplies that are affordable, secure and sustainable. The process of European regional electricity market integration is a key stepping stone towards the full realization of the internal energy market. The primary mechanism to ensure electricity market integration (coupling) is through the implementation of the European Electricity Target Model (EU Target Model) as set out in the EU's Third Energy Package, and through increased physical interconnection between countries/markets. The EU Target Model is a set of harmonized arrangements for the cross-border trading of wholesale energy and balancing services across Europe.

It is well recognised that the regional initiative process has already delivered significant progress towards achieving the Internal Electricity Market (IEM), leading to more competitive, liquid and transparent wholesale markets, while safeguarding security of electricity supply, especially in periods of high demand. There is, however, a growing concern that electricity markets, with increasing shares of (variable) renewable electricity generation, will not be able to deliver sufficient generation capacity to meet electricity demand at all times in the future. The challenge to develop the IEM and meet the renewable electricity targets raises a number of important questions around security of supply and, in particular, about ensuring generation adequacy.

In the context of evolving EU energy markets development, the European Commission recently published a document, “Generation Adequacy in the internal electricity market - guidance on public interventions” which stated that “Member States’ generation adequacy assessments need to take account of existing and forecast interconnector capacity as well as the generation adequacy situation in neighbouring Member States.” This view is also supported by the work of the European Commission’s Electricity Coordination Group.

There is certainly merit to developing a coordinated approach between Member States that also reflects the various specific and unique characteristics of each electricity power system in the EU. As the primary aim is to ensure security of supply, the methodology for determining generation adequacy is best determined at a Member State level in coordination with regional electricity systems.

Generation adequacy assessment requires a judgement about likely energy market developments as well as wider economic developments. It will vary with the maturity and nature of the region’s economy. As an economy gets wealthier and more reliant on a high-quality electricity supply, a higher standard may be more optimal where the increased benefit outweighs the increased cost.

As Ireland and Northern Ireland are already using similar assessment methodologies to those used in Great Britain and France, applying a coordinated regional generation adequacy standard is arguably a prudent next step. Great Britain has recently completed a review of the adequacy standard that should be used. Following a detailed analysis, DECC has selected an adequacy standard of 3 hours LOLE to be used in the Great Britain Capacity Market. France also uses an adequacy standard of 3 Hours LOLE.

This coordinated regional approach may facilitate greater cross-border participation in generation capacity markets and lead ultimately to a regional generation capacity market. By adopting a coordinated generation adequacy standard with Great Britain and France, Ireland and Northern Ireland can - in the context of an integrated market - ultimately will deliver the generation adequacy standard at a lower overall cost. With sufficient interconnection and market integration between Ireland and Northern Ireland, Great Britain and France, surplus generation in these neighbouring countries may help alleviate adequacy concerns in Ireland in the future. A coordinated regional generation adequacy standard could be the first step along this road.

5. Are the standards used in Northern Ireland, Ireland and SEM still appropriate?

The standards currently used in the SEM were set back in 2007. Since then, there have been changes to the economy. A more higher-tech economy has more stringent needs for high quality electricity supply. The quality of electricity supply is an important consideration for foreign direct investment, as noted in a recent report by EY[3]:

“The quality of energy supplies is central to attracting foreign direct investment (FDI) and enhancing the All-Island’s economic competitiveness. The report indicates that two-thirds of indigenous and multinational companies see access to a high quality electricity supply as “very important” to their

[3] http://www.ey.com/IE/en/Industries/Power---Utilities/EY-future-energy

continued operation in Ireland. A further 60% of energy firms emphasised the importance of favourable policy and regulatory factors in encouraging new investment"

With the introduction of the I-SEM, it is perhaps timely to re-assess the suitability of the current standard in the context of a wider EU framework. To tighten the standard would introduce a certain cost. However, the benefits must be weighed against this cost.

It would not be cost-effective to 'gold-plate' the system, i.e. to build so much extra plant to reduce the LOLE to practically zero. However, it is possible to estimate the costs and benefits of any proposed change in the standard and to seek to identify whether the extra plant costs can be justified by extra benefits in terms of improved reliability. In order to carry out this analysis, we need to examine a number of factors:

Cost of New Entrant

The Cost of New Entry (CONE) or the Best New Entrant (BNE) represents the cheapest cost of a new generator, often a peaking plant.

In Great Britain, CONE is described as 'the rental rate of the marginal peaking plant; that is the yearly amount of revenue needed to pay for capacity such that the discounted value of its operations is zero over its technical operating lifetime, assuming the plant does not earn energy market revenue.'

For the SEM, the Regulatory Authorities believe that the current Capacity Payment Mechanism is tailored to ensure that it would pay a Best New Entrant (BNE) peaker generator at a sufficient rate to cover its long run costs, given forward looking estimates of its running and all its other revenues, including ancillary services revenues.

The BNE cost in the SEM has varied over the years since 2007, due to different capital costs, etc. The maximum value was in 2009 at €87.12 per kW per year, while the minimum was of €64.73 per kW per year in 2007.

The SEM Committee has recently proposed the estimated fixed costs of a BNE Peaking Plant, minus revenues from infra-marginal rent and ancillary services, for the trading year 2016, to be €65.50 per kW per year.

Value of Lost Load (VOLL)

The value of lost load (VOLL) is a measure of the economic value of an amount of electricity that is not delivered to end consumers (i.e. is 'unserved') as a result of a planned or unplanned supply outage. In essence, the VOLL is the economic value that customers place on the cost of being disconnected, or what they would be willing to pay to avoid an interruption, and is expressed in euros. In many electricity systems, the VOLL estimates are used to evaluate the cost-benefit of reliability to derive a standard for generation adequacy.

While VOLL seeks to define a financial amount per MWh lost, it is very difficult to take into account the overall reputational damage that could be done if load-shedding were to be perceived as a common occurrence.

The calculation of VOLL includes multiple variables and depends on the context in which it is assessed, including: the type of customers, the time of year, the time of week and day, the duration and size of an outage and availability of advanced warnings. While there is no internationally accepted method for calculating the value of lost load (VOLL), there are several accepted ways to measure the cost of an outage and subsequently, the VOLL. The most commonly used methods are:

1. **Revealed preferences:**
   This method is based on historical data and calculates expenses that customers incurred in purchasing back-up equipment or other mitigating approaches to avoid power outages.

2. **Stated preferences:**

   This method is based on customer surveys and interviews to measure the VOLL. Respondents are asked to how much they are willing to pay to accept an outage of their electricity supply. This survey method was used to calculate VOLL in a recent analysis undertaken by the Department of Energy and Climate Change in the UK[4].

   This work surveyed domestic and SME electricity users and was used to estimate the VOLL in "terms of the willingness-to-accept (WTA) payment for an outage and willingness-to-pay (WTP) to avoid an outage of different lengths, seasons, days of the week and times of the day." This information was used to calculate a single average VOLL.

3. **Macroeconomic method (or estimate of production function)**

   This method estimates VOLL as the ratio of Gross Value Added (in € millions) of a sector and the amount of electricity consumed by that sector (GWh). This gives the value this sector generates per kilowatt hour and is roughly equivalent to the economic value that would be lost in the case of an interruption, e.g. see the paper from the Economic and Social Research Institute[5].

4. **Case studies:**

   This estimates the Value of Lost Load using cost estimates from previous supply outages.

As noted, while there is no single definitive way to calculate VOLL, each of the methods presented above are recognized as reasonable and practical ways to calculate VOLL. In the UK, VOLL has been calculated as a weighted average of different customer types based on customer survey data.

In 2007 the SEM Committee[6] decided that VOLL should be set at €10,000/MWh for the calendar years 2007 and 2008. And it was decided that the value of VOLL should be increased annually according to the consumer price index. Applying this method, the SEM Committee set 2015 VOLL at €10,988.9/MWh[7].

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[4] See Annex C: Reliability Standard Methodology, 2013, London Economics Analysis
[5] Eimear Leahy and Richard S.J. Tol , *An Estimate of the Value of Lost Load for Ireland*, 2010
[6] AIP-SEM-07-484
[7] See SEM Committee decision on the Value of Lost Load (VOLL) 2015

Expected Unserved Energy (EUE)

When assessing adequacy in terms of LOLE, the standard is given in terms of hours, without reference to how large any load-loss will be in MWh terms. Another quantity called Expected Unserved Energy (EUE) quantifies the amount of MWh expected to be lost. This quantity can be used with the VOLL to assess the financial impact of load loss.

However, the theoretical calculation of EUE could be significantly lower than the operational reality. The theoretical EUE is simply the gap between the forecast load and the expected amount of available plant. If a system is under stress, then the volume of load-shedding is likely to be in excess of this idealised gap. As the operator will not know exactly what the demand peak will be in advance, she will act in a prudent manner and schedule more load to be shed than is forecast to be not servable in order to avoid potential instability in the system and uncontrolled load-shedding. In practical terms, it is likely that load-shedding can only be implemented in blocks of a certain, agreed size. Figure 1 below shows an illustration of a load-shedding event. In Ireland and Northern Ireland, the TSO will typically shed load in blocks of 50 MW.

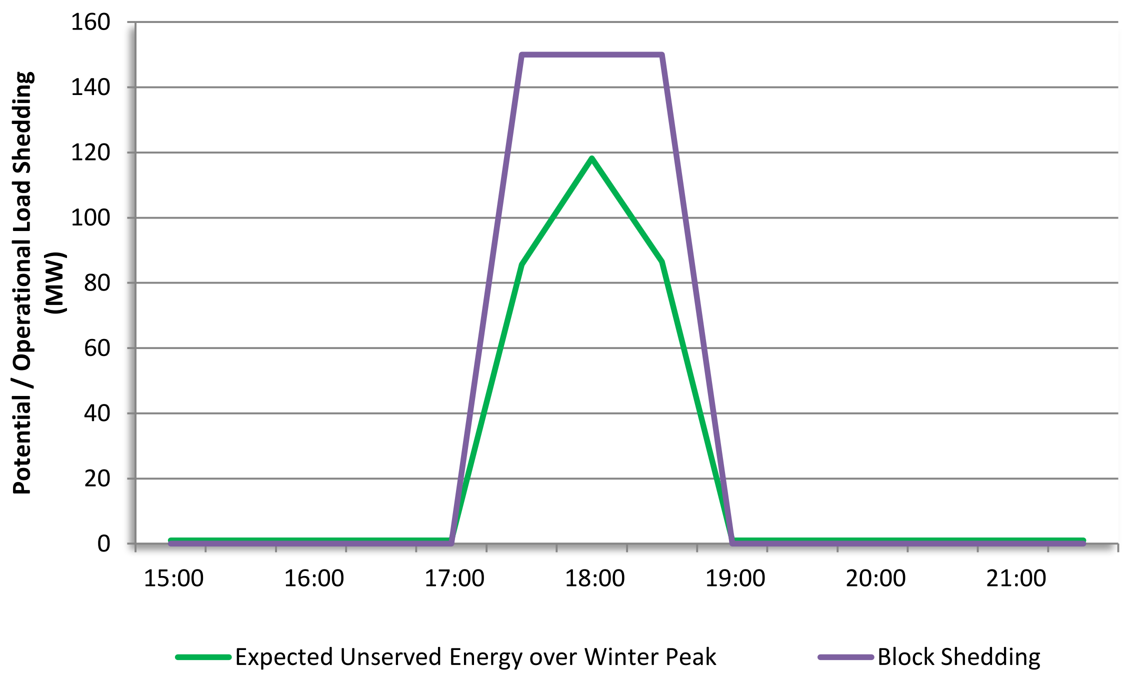

Figure 1 During a load-shedding event, the operator carries out load-shedding in blocks of 50 MW. And so the actual load shedding would be greater than the theoretical.

In our analysis of Unserved Energy, we also have to consider the requirement for minimum operational reserve – this is the amount of generation plant that the operator must retain at all times to ensure system stability, particularly at times of system stress. The operator will implement load-shedding before eating into the minimum level of operational reserve. This is another reason to consider a slightly higher level of EUE than is suggested by theoretical modelling. The current policy specifies that the minimum level of operational reserve should be 100 MW on the island of Ireland.

6. Impact of Change in Adequacy Standard on the Capacity Requirement

To investigate the impact of changing the current adequacy standard, EirGrid has modelled the effect of tightening the LOLE standard for the SEM from the existing level (8 hours), through a range of values, to 1 hour. In order to have a more robust assessment, we carried out this exercise for different years and different scenarios with varying levels of plant and demand.

The figure below shows the results of these studies. More and more plant is required as the standard tightens from 8 to less than 1 hour LOLE. For example, at 3 hours, the average of these cases is approximately 220 MW – this is the amount of real plant that needs to be added to improve from an 8 hour standard to 3 hours. Real plant is plant that has realistic availability, i.e. with scheduled and forced outages. (Perfect plant would have 100% availability.)

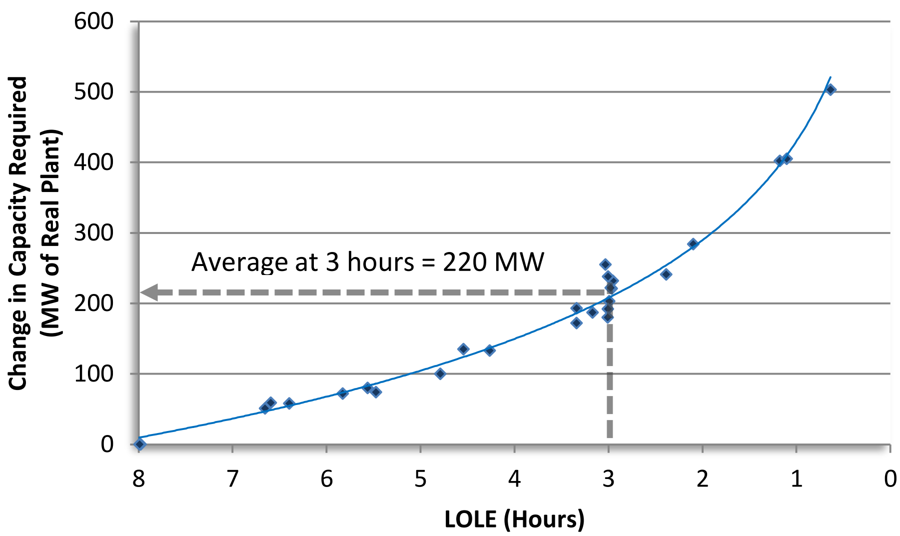

Figure 2 Each data point represents the result of a particular scenario. As more plant is added, the LOLE standard tightens. The thin blue trend line shows that this is not a linear relationship, rather an exponential one.

In order to fully assess the impact of a change in the adequacy standard we need to determine the costs and the benefits.

The costs are the additional resources required to deliver the higher standard such as more demand side response, high availability generation or additional support via interconnectors. We must identify the marginal costs of delivering the additional resources required for the higher standard.

The benefit from a higher adequacy standard is greater reliability which we can measure as a reduction in demand that is not met.

Cost

We can quantify the cost of improving the adequacy standard by costing the extra capacity required. This can have different values in different settings:

- the Best New Entrant (BNE) cost in the SEM has varied from €65 to €87 /kW per year
- the Net Cost of New Entry (CONE) in the recent auction for Great Britain varied between £49/kW[8] for a CCGT, £29/kW for an OCGT, and the actual clearing price of £19.40/kW.

Source	Cost per kW per year	Cost of 220 MW of extra capacity
Highest BNE in SEM (2009)	€87	€19.2m
SEM – Proposed Best New Entrant 2016	€65.50	€14.4m
GB Capacity Auction 2014 CONE for a CCGT	€67*	€14.7m
GB Capacity Auction 2014 CONE for an OCGT	€40*	€8.7m
GB Capacity Auction 2014 Clearing Price	€27*	€5.8m

Table 2 Comparison of different costs of new generation. *Assume an exchange rate of ~1.37

Benefit

We can also examine the benefit that a change to the security standard can bring to customers.

With a standard of 8 hours Loss of Load Expectation, we can estimate how many MWh of energy are not served over these expected 8 hours of lost load. With a more rigorous standard, we would expect that less energy would be unserved, i.e. that more energy would be served. By switching to a lower standard, what then is the saving in Unserved Energy? For example, in the SEM and in an operational context, the average reduction in unserved energy could be of the order of 1500 MWh per year if we move to a 3 hour standard.

In order to quantify the financial benefit of NOT losing this load each year, we can use the Value Of Lost Load parameter (VOLL), measured in € per MWh. This is a difficult quantity to define, depending, as it does, on the type of load that is affected, the time of year, and for how long any power outage might last. The SEM-Committee decided in December 2014 that the VOLL for 2015 be set at €11,000 per MWh.[9]

National Grid UK employ the London Economics' 2013 VoLL study, which suggests using a weighted average VoLL figure for domestic and SME customers of £17,000/ MWh[10]. This is also the figure used in DECC's draft reliability standard.

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8 Electricity Market Reform – Capacity Market, DECC, 23/6/2014

9 http://www.allislandproject.org/en/TS_Decision_Documents.aspx?article=8418dcf9-369f-43cb-a29a-424a9fb69db0

10 National Grid's Proposed New Balancing Services: Draft Impact Assessment, Nov 2013.

Source	VOLL, per MWh	Value of 1500 MWh of Expected Unserved Energy per year
SEM	€11,000	€16m
National Grid	€23,300	€35m

Table 3 Calculation of the value of Unserved Energy

Using these different estimations of VOLL, we can calculate the value of 1500 MWh of Expected Unserved Energy to be between 16 and 35 million euro. These figures can be compared with the costs in the previous Table 2.

7. Summary

As TSOs, we at EirGrid and SONI have been requested to examine the implications of changing the adequacy standard. We have presented the results of this analysis here, particularly with regards to the change in capacity requirement resulting from a tightening of the LOLE standard.