I-SEM PLEXOS Validation, 2018-19

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1 Introduction

1.1 Background

The all-island Single Electricity Market (SEM) in Ireland and Northern Ireland was introduced in 2007 and will continue under current arrangements until the implementation of the new Integrated Single Electricity Market (I-SEM) arrangements, originally planned to take effect in Quarter 4 2017 and now planned for 23rd May 2018[1].

In September 2017, the Commission for Regulation of Utilities (CRU) and the Utility Regulator for Northern Ireland (UREGNI), jointly known as the Irish Regulatory Authorities (RAs), engaged Baringa Partners LLP (Baringa) under the work package titled "Consultancy Assistance to Support PLEXOS Validation and Directed Contracts 3". This is similar to a support contract between the RAs and Baringa agreed in March 2017, "Consultancy Assistance to Support PLEXOS Validation and Directed Contracts 2" which covered the final months of SEM.

NOTE: Following the implementation of the "Integrated Single Electricity Market" (I-SEM) market arrangements in May 2018, the all-island electricity market will still be referred to as the "Single Electricity Market" (SEM), but, for the purposes of this document, we refer to the existing arrangements as the "SEM" and the new arrangements as the "I-SEM".

In this document we describe the work carried out by Baringa under Work Stream 1:

- Work Stream 1. Validation of the I-SEM PLEXOS model

The model produced as a result of this work is referred to in this report as the "2017 I-SEM Validated model". This report documents the changes made to the previous SEM Validated model to allow for the development of an I-SEM Validated model, covering the period 23rd May 2018 until the end of 2019.

The 2017 I-SEM Validated model will cover the period from 23rd May 2018 until the end of 2019, and will be used by the RAs for Rounds 1-4 of I-SEM Directed Contracts (DCs), in addition to other modelling requirements. Minor updates will be made to the I-SEM Validated model during R2-R4 of I-SEM Directed Contracts, consistent with the approach used in SEM and the RAs' minimal change principle for the introduction of DCs under I-SEM arrangements.

1.2 Scope

1.2.1 In Scope

The scope of the validation exercise is limited to the forward-looking PLEXOS model. This model is used by the RAs to calculate the DC strike price formulae and volumes in I-SEM, as well as for the calculation of the PSO CfD reserve prices, PSO benchmark price setting and for other modelling purposes.

[1] SEMC, I-SEM Project Plan Quarterly Update, December 2016, SEM-17-002

We have validated input data to the model to allow it to be used to provide I-SEM electricity market projections for 2018 and 2019, from the point of transition to I-SEM. The areas of input data that have been validated and updated include:

- Outages
  - Planned maintenance
  - Interconnector forced outages
- Demand
- Wind generation
- GB bids on interconnectors
- Embedded generation

The following settings and methodologies have been updated in the I-SEM model:

- PLEXOS version updated to 7.300 R04 64bit
- Rounded relaxation self-tuning increment (reduced to 0.2)
- Price cap and floor level
- Inclusion of interconnector ramp rates (at a level consistent with the SEM "Aggregate Interconnector Ramp Rate")
- Recovery of start and no-load costs ("uplift")
- TLAFs
- Stochastic wind, demand and forced outage profiles
- Treatment of interconnectors under I-SEM arrangements

In the following sections of this report we describe each of these areas in turn, outlining the changes made with respect to the previous validated model and the effects on the Day Ahead power price and generator dispatch.

With agreement from the RAs, a number of parameters that were validated in the most recent model validation (June 2017) have not been changed in this update. Given the close proximity between the two model validations, it was determined that these parameters were unlikely to have changed and were still valid for the I-SEM model.

These parameters include:

- Generator submitted data
  - Marginal Generation Costs
  - No-load Costs
  - Start Costs
  - Technical Offer Data
- Generator forced outage rates
- Hydro plant daily generation volumes

- Embedded generation

1.2.2 Out of Scope

The I-SEM Validated PLEXOS model has been set up to give a good projection of power prices from the Day-Ahead-Market, though there is obvious uncertainty in these projections due to the I-SEM DAM not being operational yet to provide data for calibration and validation. Undertaking a backcast of the DAM or of the EUPHEMIA algorithm used to settle the DAM is out of scope for this work.

1.3 Comparison with previous models

Throughout this report, comparisons are made to the modelled DA power price, as incremental changes are made to the model. Though the focus in this report is the power price, other market indicators have been investigated as part of the validation: uplift, generation mix, interconnector flows, and plant merit order.

The starting point for comparisons in this report is the model used for the R22 DC strike price formulae update in August 2017, updated with the dummy commodity prices presented in Table 1. In the main, updates are applied cumulatively throughout the report. Where comparisons are made, the sources of the old and new assumptions are clearly stated.

Table 1 Commodity price and exchange rate assumptions used in this report

	Q1 2018	Q2 2018	Q3 2018	Q4 2018
Gas p/th	50.0	43.0	43.0	50.0
LSFO $/t	300	300	300	300
Gasoil $/t	550	550	550	550
Coal ARA API2 $/t	90.0	90.0	90.0	90.0
Carbon €/t	8.00	8.00	8.00	8.00
USD per EUR	1.1657	1.1657	1.1657	1.1657
GBP per EUR	0.88923	0.88923	0.88923	0.88923

1.4 Market Information Paper

In developing an I-SEM Validated PLEXOS model for 2018-2019, Baringa has made a number of changes to the previous SEM Validated model for 2017-2018. Recognising that there are many options when developing a model for a market that does not yet exist and so lacks outturn data, Baringa published an information paper in October 2017 outlining the key issues in modelling I-SEM in PLEXOS, and sought the feedback of interested parties. The paper outlined different options for resolving these issues, and our suggested approach at that time[2]. The technical discussion in this validation report uses much of the material in the information paper.

A survey was released in conjunction with the information paper to allow interested parties to provide their opinions on our analysis. Responses were received from a range of parties including generators, vertically integrated utilities, suppliers and academics.

There was broad agreement with our proposed approach, though not universal, and there were a number of specific suggestions for alternative approaches. We have considered all comments received, and have responded to these in the relevant sections of this report where relevant.

A summary of survey responses is provided in Appendix A.

[2] https://www.semcommittee.com/node/2622

2 I-SEM model updates

2.1 Introduction

A number of overarching assumptions and changes to model settings were required in developing a model that can be used for projecting generation and prices under I-SEM for the period 2018-19 in a manner that is robust and internally consistent. These assumptions and model settings are discussed below.

2.2 Assumptions

The process of developing a model for new market arrangements is one that requires a number of assumptions to be made about participant behaviour, in the absence of outturn market data that can be used as evidence.

Overarching Assumptions

1. All forecast generation and demand will clear in Day-Ahead Market
    a. While this is unlikely to be true, we assume that the real DAM will be liquid enough that prices from the DAM will be very close to a scenario where all generation and demand clears in the DAM
    b. Actual demand and generation may vary from forecasts, and this will lead to real time imbalances, but this is balanced after the Day-Ahead stage
2. Generator bidding behaviour will settle down quickly after an initial "learning period"
    a. Experience of new arrangements in other markets suggests that there may be an initial period where generator behaviour and resulting prices are somewhat erratic as generators "learn" how to operate in the market
    b. We assume that this learning period will be short, and that generators will quickly revert to "steady state" bidding behaviour, with cost levels based on SEM data and projections for commodity prices.
    c. The I-SEM model represents "steady state" behaviour only, and does not model the learning period
3. Generators have a good view of their likely scheduling and have the capabilities to bid in a manner that reflects their actual costs and technical constraints
4. Generators will seek recovery of start and no-load costs in the DAM by internalising these in their offers

When developing this model, validating against outturn I-SEM data is not possible, as it does not yet exist. However, once I-SEM data becomes available it will be possible to validate the above list and other assumptions described in this report, should the RAs choose to do so.

2.3 PLEXOS model settings

2.3.1 Replicating EUPHEMIA scheduling algorithm

PLEXOS is the RAs' chosen software for the I-SEM model used to project EUPHEMIA cleared Day-Ahead-Market prices.

PLEXOS is an advanced market modelling tool, incorporating a number of approaches to the modelling of interconnected markets, and alternative pricing algorithms ranging from marginal cost pricing through to game-theory approaches. It is used worldwide by energy companies, investors and system operators.

PLEXOS simulations are based on a mathematical programming formulation of power market dynamics. PLEXOS can apply linear and mixed integer programming solution techniques to determine the dispatch and pricing outcomes, taking full account of short-term dynamic constraints including ramp rates and min on/off times. This approach provides results that fully capture the complexity of power markets. It is also conceptually similar to the way in which the current SEM market dispatch software works.

Under I-SEM arrangements the market schedule and resulting prices will no longer be set using the current SEM market dispatch software. The EUPHEMIA algorithm will be used exclusively for establishing the Day-Ahead market schedule[3]. The EUPHEMIA algorithm is already used widely across European electricity markets. Unlike the SEM market algorithm, EUPHEMIA does not explicitly account for generator technical and commercial parameters such as start costs, no-load costs, and minimum run times. However, EUPHEMIA provides participants with a selection of order types, allowing many generation parameters to be represented. It should be noted that in I-SEM there will be a requirement for unit based bidding, whereas in most other markets EUPHEMIA allows portfolio bidding. Unit based bidding increases the onus on accurate representation of technical and commercial parameters at the unit level, as these are not "averaged" through a generation portfolio.

The key order types available in EUPHEMIA are as follows:

- **Simple Hourly Orders** consisting of a price and quantity pair for a given hour;
- Block Orders applying to multiple hours:
  - **Simple Block Orders** consisting of a price with a fixed quantity over a set time
  - **Profiled Block Orders** consisting of a price with a varying quantity over a set time
  - **Linked Block Orders** introducing conditionality whereby the acceptance of a 'child' or 'grandchild' block is dependent on the acceptance of a 'parent' block
  - **Exclusive Groups** consisting of Simple or Profiled Block Orders where the combined acceptance ratio cannot exceed 1
  - **Flexible Block Orders** consisting of a price and quantity pair for a set duration but with the block start time not specified;

[3] http://www.sem-o.com/MarketDevelopment/Pages/EUPHEMIA.aspx

- **Complex Orders** consisting of simple orders with constraints such as Minimum Income Conditions, Scheduled Stop or Load Gradients.
  - Each order type allows different technical and commercial data to be represented, but no order type allows for full representation as per current SEM market software. A summary of how the different order formats can be used is given in Table 2.

Exactly which of these order types will be available to I-SEM market participants is currently still undecided, the desire to make all available being constrained by run-time requirements for modelling on a pan-European basis. Block orders in particular make the algorithm slow to solve.

While PLEXOS provides a great deal of flexibility for modelling energy markets, there are no explicit settings for replicating all of the EUPHEMIA order types above. Baringa has shown previously that it is technically possible to replicate results from EUPHEMIA using Linked Block Orders and Complex Orders using PLEXOS[4], using "Decision Variables", validating this against the outputs of the SEMO EUPHEMIA trials. However, there are difficulties in replicating these orders in full for use in a PLEXOS model to be used for operational purposes:

1. The process of replication requires the development of a highly complex PLEXOS model with slow run times and additional post processing requirements:
   a. This introduces significant risk of error in implementation
   b. This introduces significant extra effort in using the model in each DC round
2. A view must be taken of the bidding behaviour of each generator, in terms of the order type selected for each unit for each time period in the model; and this raises the following issues:
   a. Participants would be expected to refine their bidding strategies dynamically in light of experience and changing market conditions, so a static view is unrealistic
   b. Across the market as a whole, there is a very large number of combinations of daily generator choices for order types and other parameter choices such as the configuration of block periods, parent-child relationships, and Minimum Income Conditions
   c. This is difficult to predict *a priori* for specific generators, and is outside the scope of the work being considered in this project

Because PLEXOS has additional functionality for representing specific technical and commercial constraints directly, e.g. it is not constrained to hourly block representation, there is an alternative approach to forcing PLEXOS to replicate exactly each EUPHEMIA order type. This alternative is to allow PLEXOS to run in its normal mode, taking into account all technical and commercial constraints and balancing supply and demand at least cost. While this approach results in different algorithms in PLEXOS and EUPHEMIA, it can give similar outputs in terms of prices and generation.

[4] Replicating EUPHEMIA Day-Ahead order formats in PLEXOS, Adrian Palmer, PLEXOS Users Group Meeting Barcelona 2017, https://energyexemplar.com/clientarea/?view=presentations

Table 2 Summary of EUPHEMIA order types

Order Type	Features	Limitations	Potential Application
Simple Hourly Orders	Orders in each hour clear independently	Risk of technically infeasible schedules for baseload and mid-merit generators, as minimum on and off times are not represented	• Flexible peaking generators • Hydro generators • Pumped storage • Load
Simple Block Orders	Block duration can represent minimum on time constraints. 'All or nothing' acceptance criteria proxies Minimum Stable Generation (MSG)	Participant needs to pre-determine the hours in which the block applies	• Baseload generators • Mid-merit generators • Less flexible peaking generators • Load
Profiled Block Orders	Profile shape can reflect technical ramp constraints and/or expectations of market value (e.g. lower volumes offpeak)	Participant needs to pre-determine the profile shape based on market fundamentals as well as internal constraints	• Baseload generators • Mid-merit generators • Hydro generators
Linked Block Orders	No-load and start costs may be allocated to parent block, allowing competitive pricing of incremental energy in child blocks. Allows reflection of higher costs for part-loading. Sale and purchase blocks may be linked.	Risk of price formation volatility if not enough price makers[5] use other order types. Other power exchanges have limited the number of child blocks per parent, reducing potential flexibility.	• Mid-merit generators • Pumped storage
Exclusive Groups	Allows participant to submit alternative profiles for the market algorithm to optimise, without risk of over-commitment	Risk of price formation volatility if not enough price makers use other order types. Algorithm delivers market optimal outcomes, which may not be the profit maximising outcome for participant. Cannot be combined with Linked Block Orders.	• Mid-merit generators • Hydro generators • Energy limited plant • Load response
Flexible Block Orders	Fixed duration and volume block with flexible start time to be optimised by market algorithm	Other power exchanges have limited the number of Flexible Block Orders per portfolio.	• Energy limited plant • Flexible peaking generators • Load response
Complex Orders	Allows participant to specify a Minimum Income Condition (e.g. for start cost recovery) and Load Gradient (to proxy ramp rates)	May require active strategies to manage risk of being scheduled for multiple starts or below Min Stable Level	• Baseload generators • Mid-merit generators • Less flexible peaking generators

[5] Price-makers refer to dispatchable or controllable generators

Baringa uses PLEXOS to model a number of European electricity markets which use EUPHEMIA to settle their DAMs, and undertakes regular backcasts to validate this approach. When performing a backcast model the following historical inputs are used in PLEXOS:

- Actual plant availability in each market
- Actual spot commodity prices (fuel and carbon prices)
- Actual hourly electricity demand in each market
- Wind, solar and hydro inflow profiles

The PLEXOS model uses technical and commercial data to calculate generator bids, schedule the market in each hour, and set hourly prices. While some historical information can be obtained and included in the model, it should be noted that some is unknown, and when this is the case we need to use typical or 'generic' values in lieu of actual data. For instance, historical plant availability data (hourly data for each individual generating unit) is incomplete in most markets, especially with respect to distributed generation; electricity demand data does not always take account of autogeneration or demand that is embedded in low voltage networks; meteorological data (wind and solar irradiation) is unavailable at the granularity of individual plant and individual hours; and net transfer capacities on interconnectors may not exist in the public domain for each interconnector in each hour.

Focusing first on the most proximate market to SEM, i.e. GB, we observe good agreement between the prices from PLEXOS and those from the price exchanges. Figure 1 shows backcast GB monthly baseload results, while Figure 2 and Figure 3 show the diurnal shape for Summer and Winter respectively. Given only a subset of historical inputs are used in the backcast, the results are in our judgement close enough to the outturn EUPHEMIA results to justify use of the PLEXOS algorithm. Our analysis suggests that in 2016 EUPHEMIA was used to schedule generation in DAMs (N2EX and APX) equal to approximately 60% of demand, and so the DA price can be considered a good reference price to validate PLEXOS against.

We have performed similar analysis for other European markets using the Baringa North West Europe PLEXOS model. Figure 4 shows Day-Ahead baseload power prices for 2015 from both EUPHEMIA and from the Baringa NWE PLEXOS model, run in backcast mode. It can be seen that while there are some differences, given the range of input uncertainties the baseload power price is well captured by PLEXOS, despite the differences in the scheduling algorithm. Though there are some differences in individual countries, there is no systematic bias between EUPHEMIA and PLEXOS.

Figure 1 Monthly GB DA baseload power prices, historical vs PLEXOS backcast

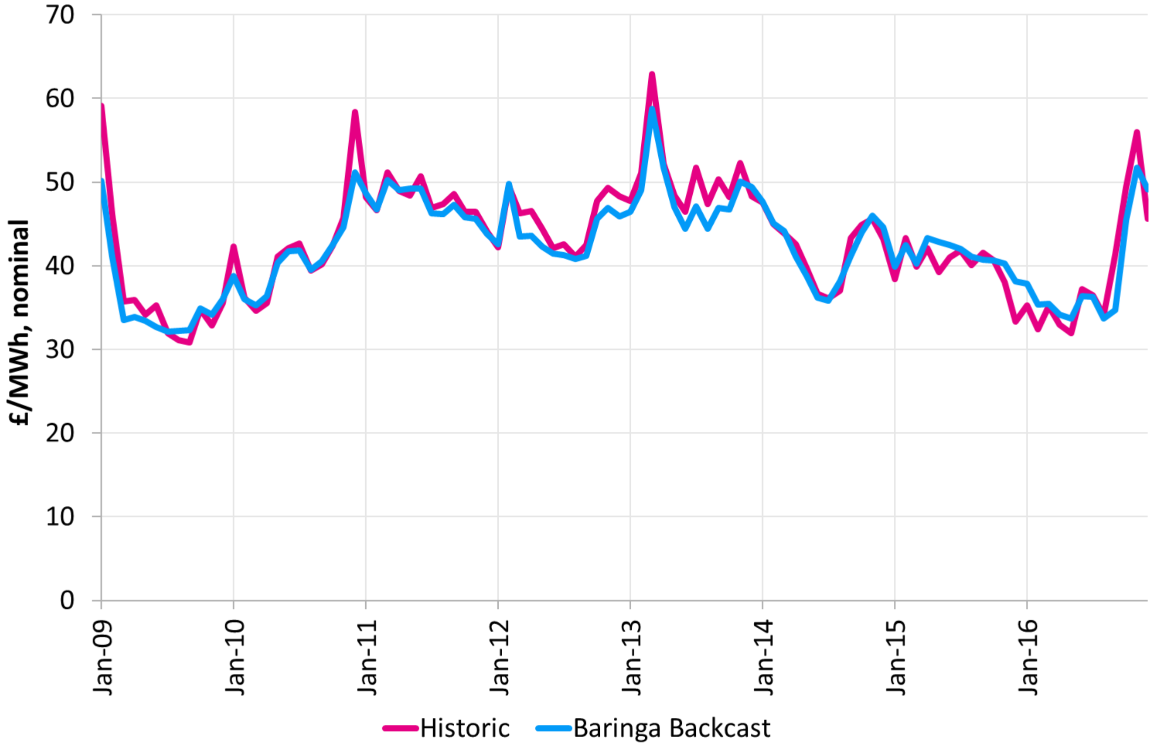


Figure 2 Average Summer diurnal GB DA price profile, historical versus PLEXOS backcast

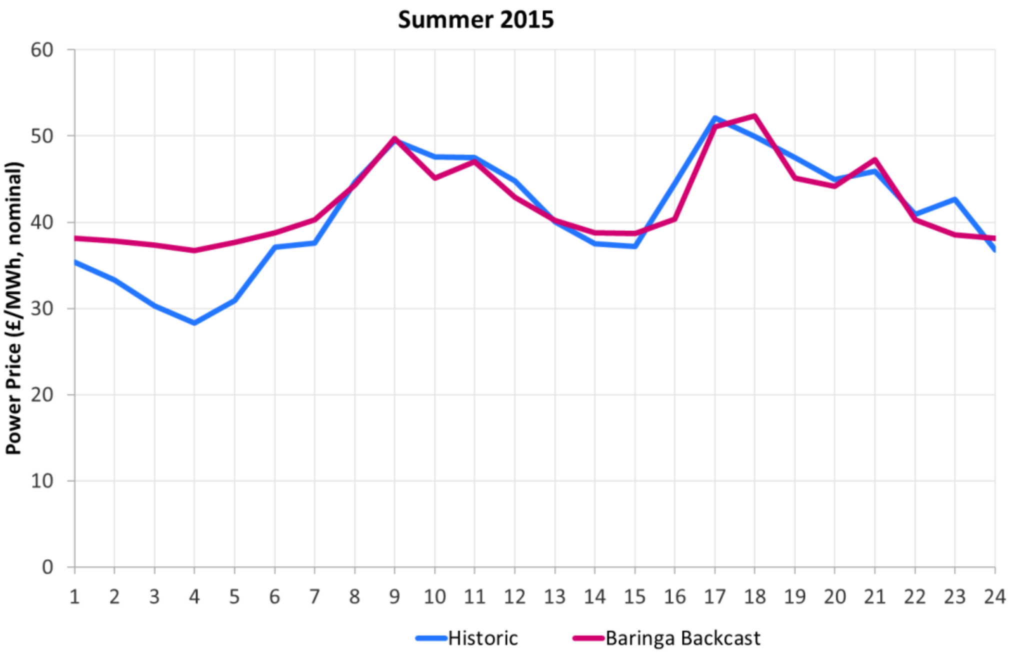


Figure 3 Average Winter diurnal GB DA price profile, historical versus PLEXOS backcast

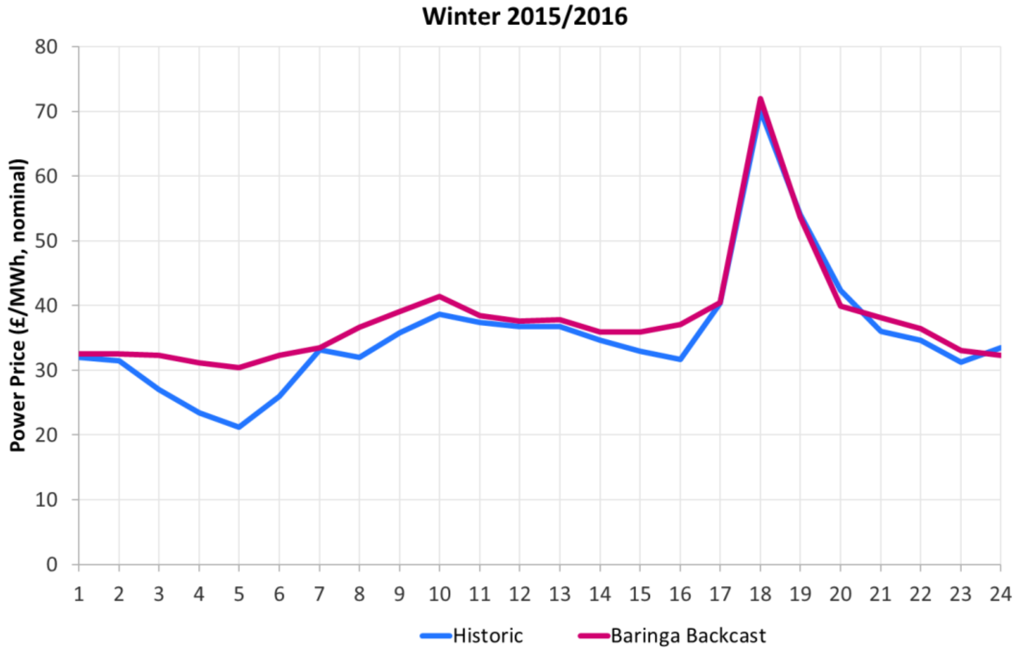
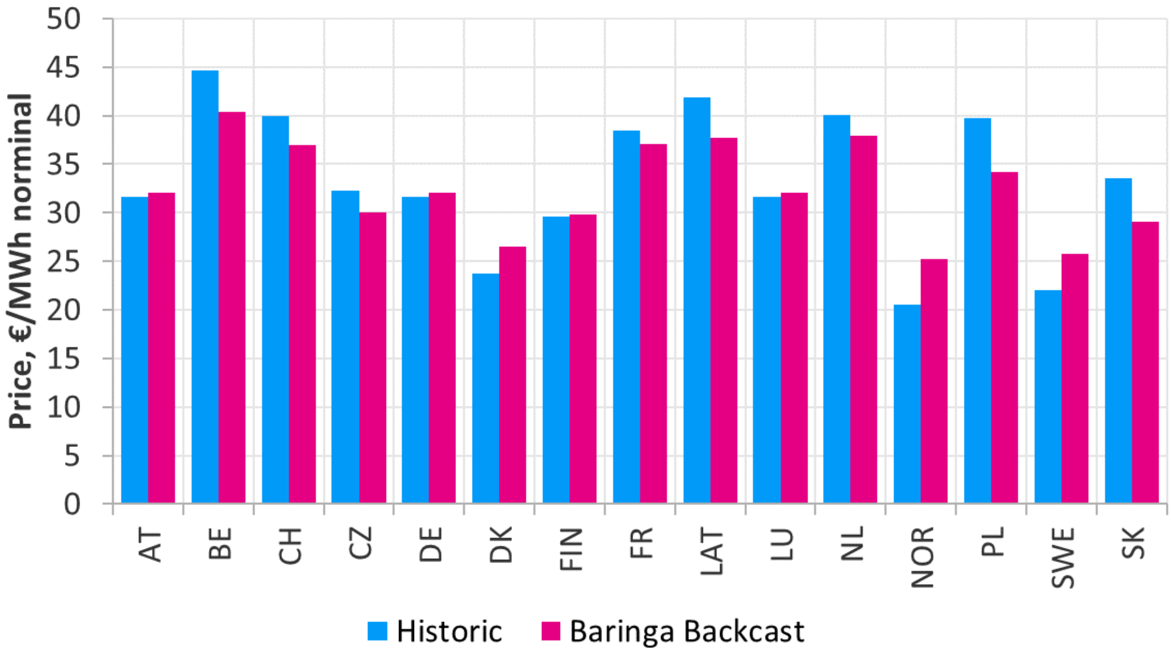


Figure 4 2015 Annual average DA baseload power prices, historical vs backcast



2.3.2 PLEXOS Version

The 2017 I-SEM Validated PLEXOS model has been updated to PLEXOS version 7.300 (R04 64bit) from the previously used PLEXOS version 6.207. Version 6.207 is somewhat outdated (last updated 2012) and is now unsupported by the software providers, Energy Exemplar. Using version 6.207 was deemed to provide a risk to both the RAs and market participants when developing future (I-SEM) models, as there is no support for model issues that may arise. Additionally, there have been significant improvements in the performance and functionality of PLEXOS in the multiple incremental versions that have been released since 6.207.

When upgrading to PLEXOS version 7.300 the only change necessary has been to change the sign of the interconnector “Loss Incr Back”, representing losses on the interconnectors when importing to SEM, due to a change of sign convention in the software. Upgrading to PLEXOS 7.300 has resulted in a small improvement in performance, and a reduction in infeasibilities. The effect on the DA price is minor, an increase of 0.03€/MWh, and no significant change to generation mix or interconnector flows has occurred.

2.3.3 Solver setup

2.3.3.1 Mode

Previous SEM Validated models have used “Rounded Relaxation” (RR) as the solver mode for the optimisation. Rounded Relaxation refers to a specific unit commitment method, which is similar to the “Lagrangian Relaxation” method used in the current SEM market software. It offers a good compromise between capturing individual unit commitment, which is important for a market like SEM with a few large units, and tractable model run times. Alternative approaches are: (i) to use a linear optimiser (worse unit commitment but fast performance and more straightforward treatment of interconnectors) and (ii) Mixed Integer Programming, MIP, (better unit commitment and optimality but significantly worse performance). The run time of the I-SEM Validated model is important as this model is used by the RAs for a number of regular processes, and made public for use by market participants.

Table 3 Solver approach for I-SEM

Solver Approaches	Pros	Cons	Applicability to I-SEM model
1. Linear solve	Interconnector flows (based on a shadow price) match what we expect from market without adjustment True optimal result Fast run time	Does not respect generator technical constraints (i.e. min stable level, min up/down times etc.) Different price shape to that observed for SEM (peak too low)	🔴

2. Rounded Relaxation	Approximates generator technical constraints Allows for 3 state start costs Reasonable run times	Not true optimal result Interconnectors require calibration to dispatch correctly in presence of uplift	
3. Mixed Integer Programming	Correctly models generator technical constraints Can provide true optimal result if precision is high enough Shadow increased and uplift decreased, requiring less interconnector calibration than RR	Slow performance – requires simplification in problem formulation to allow for tractable run times Interconnectors require calibration to dispatch correctly in presence of uplift	

We have tested using both linear optimisation and MIP as possible alternatives to RR.

Linear gives fast solve times, correct interconnector dispatch (i.e. dispatched on a shadow price that includes start and no-load costs), but gives significantly different price shape. Whilst Linear can give good results for large liquid markets, for smaller "blocky" markets like SEM having a good representation of unit commitment is key to simulating prices, especially in peak periods.

MIP is used in the EUPHEMIA market software to settle the market under I-SEM arrangements. Two survey respondents suggested the use of MIP over RR for this reason. However, given that the I-SEM model will not seek to replicate the operation of the EUPHEMIA software, but rather its outputs (as described in Section 2.3.1 above), it is not necessary to move to MIP simply to be like EUPHEMIA. The argument for potentially using MIP over RR shall be based on the quality of solution and the performance of the model.

The benefits of using MIP that unit commitment decisions are made correctly, the solution can be made to be truly optimal, and shadow prices increase whilst uplift decreases – meaning that interconnectors require less calibration to flow as expected.

However, in our testing it was found that using MIP gave unacceptably long run times, ~100x longer than using Rounded Relaxation. Run times can be reduced by simplifying the model, removing the 3 state (hot/warm/cold) start costs and replacing with a single start cost for each generator. This represents a reduction in the granularity of information being used in the model, and ignores the real variation in start costs that generators experience due to down time, but gives a significant speed up. Further improvements to performance could be found by increasing the "MIP gap" threshold. It was found that this could be increased from 0.01% to 0.025% with no impact on projected price levels. With these two performance improvements implemented the MIP model had a run time of ~4x the RR model, which was still deemed unacceptable.

If performance issues are ignored, when a single start cost model was run in RR and MIP it was found that the total system costs seen by the optimiser were similar, but the MIP solution had baseload prices that were higher by ~1.4€/MWh. We do not expect prices to rise simply as a result of using the MIP-based EUPHEMIA algorithm, given prices observed in other markets currently settled using EUPHEMIA, and so it is difficult to explain the increase observed here on a fundamentals basis.

MIP did show a clear improvement in the treatment of uplift, with unit commitment constraints resulting in a higher shadow price and correspondingly lower uplift levels. This improves the dispatch of interconnectors (which dispatch on shadow in the model but on full price in reality).

Where the RAs' PLEXOS model is validated in the future, we recommend that the RAs consider testing MIP again – carefully choosing a single start cost for each plant and validating a MIP solution against EUPHEMIA-derived I-SEM DA prices and schedules available at that time. The use of a multi-core solver licence (currently unavailable to the RAs) could also be investigated as a method of reducing MIP run times to acceptable levels.

Taking all of the above into account, we have decided to continue to use RR for the I-SEM validated model. It allows for the inclusion of three start costs (i.e. hot, warm, cold) whilst keeping reasonable run times and price levels consistent with SEM arrangements.

2.3.3.2 RR Self Tune

When using Rounded Relaxation, initially a linear solve is performed, with units available to be turned part "on". The solver then commits units to be fully on or off, based on whether their linear "on" state is above or below a threshold value. PLEXOS offers the ability for the model to 'self tune' the threshold used for Rounded Relaxation unit commitment. With this functionality the model tests a number of threshold values in turn and chooses the one that gives the optimal results. The previous 2017 SEM Validated model uses a 'self-tuning increment' of 0.05, meaning that each simulation is run a number of times between a threshold value of 0.1 and 0.9 inclusive.

We have tested increasing the self-tune increment from 0.05 to higher values – in effect making the modelling less refined but faster – and the effect on price and generation volumes. We have found excellent replication of results at significantly higher self-tune increments. Table 4 shows DA power price and run time for decreasing granularities (i.e. higher increments). At a self-tune increment of 0.2, there is negligible difference with the previous 0.05 setting.

Table 4 Testing Rounded Relaxation threshold

Setting	DA power price 2018, €/MWh	Run time, mins
Self-Tune 0.05	50.0	35
Self-Tune 0.1	50.0	21
Self-Tune 0.2	50.0	14
Self-Tune 0.3	50.1	12
Fixed threshold 0.5	51.4	7

Figure 5 and Figure 6 show the diurnal shape of DA price for Winter and Summer using 0.05 and 0.2 self-tune values for the Rounded Relaxation settings. Both DA price profiles look very similar and we have decided to use a value of 0.2 for the self-tune increment in the I-SEM Validated model.

Figure 5 Hourly Winter DA power price profile with varying self-tuning increments

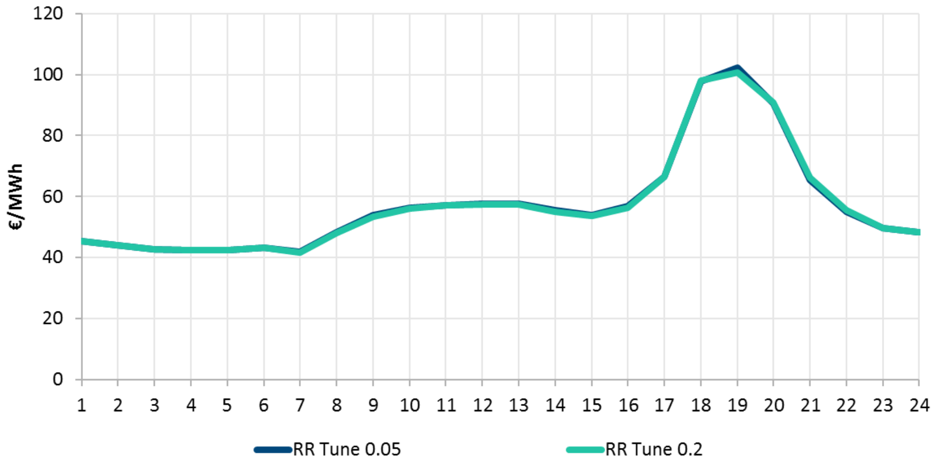
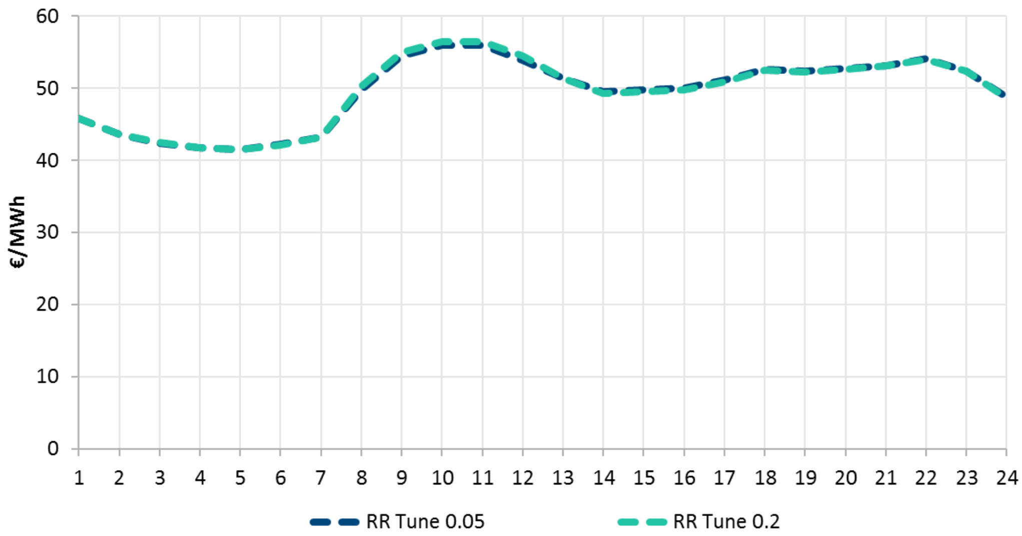


Figure 6 Hourly Summer DA power price profiles with varying self-tuning increments



2.3.4 Price caps and floors

In the previous SEM validated model there is a price cap and floor of €1000/MWh and - €100/MWh respectively. Under EUPHEMIA the cap and floor levels are €3000/MWh and -€500/MWh respectively and the I-SEM model has been updated to reflect these levels. There are no significant changes to the Day-Ahead price as a result of this update.

2.3.5 Horizon settings

2.3.5.1 Short-term horizon

The trading day arrangements of EUPHEMIA and the current SEM software differ in both granularity and start time.

Table 5 Trading day arrangements SEM / I-SEM

Property	SEM	EUPHEMIA (I-SEM)
Settlement granularity	Half-hourly	Hourly
Trading day start	6am	11pm

In the modelling information paper we proposed changing the short-term horizon to match the EUPHEMIA trading day, both granularity and trading day start time. However, following testing we have decided to implement the change in granularity but not the change in trading day start time.

Changing from Half-hourly to hourly granularity had no real impact on dispatch or DA power prices, and so this change has been implemented in the I-SEM Validated model. This change decreases runtimes by ~50%.

However, changing from a 6am to an 11pm start time for the trading day had a significant impact on dispatch and prices (reduction in baseload DA prices of ~1 €/MWh). This is an unexpected result, and not one that we expect to see in the real market.

PLEXOS uses a finite decision horizon, with perfect foresight. In reality, market participants have a near infinite decision horizon, but with increasingly imperfect foresight the further out the horizon (so called "myopic foresight"). In this way the PLEXOS decision horizon is different than the real decision horizon in two dimensions. Using a shorter, finite, horizon in PLEXOS reduces the information available in the optimisation problem, and approximates the information available in reality (i.e. in an infinite horizon with myopic foresight) while using perfect foresight. This allows PLEXOS to give similar results to those observed in reality.

The near infinite myopic horizon found in reality is robust to changes in the start time of the decision horizon, as this is a small edge effect compared with a long decision horizon. We have tested using a much longer horizon (~72 hours) in PLEXOS and find that with a longer horizon the solution is fairly robust to changes in start time, as we would expect. However, for the shorter horizon used in the current SEM Validated model it seems that the solution is dependent on the start and end time of the horizon, as observed when changing from a 6am start to an 11pm start. It is not clear exactly what is causing this difference, especially as a lookahead is present to give visibility of the pick up in demand during the morning of the next trading day. We observe large swings in hydro generation with the two different start times, but this could be a symptom of something else rather than the cause.

The previous 6am start time with a 6-hour lookahead has been found previously to give a reasonable approximation of generator dispatch seen in the market. It is not expected that dispatch will change simply due to the change of start time of the EUPHEMIA trading day, and we do not wish to introduce change to the model that is not expected in I-SEM. For this reason we have decided to keep the trading day in the model as 6am-5am.

The settings used in the I-SEM model are as follows:

1. Short-term horizon granularity
    a. Hourly
2. Start of trading day

    a. 6am
3. Look-ahead
    a. 6x hourly steps, 6am-12noon, to allow the model to see morning demand pick up in the subsequent trading day, and keep plant online to meet this

2.3.5.2 Long-term horizon

The long-term horizon has been extended to 2019 (as compared to 2018 in the previous SEM model).

2.3.6 Solver settings

The Validated 2017 I-SEM validated model will keep the same solver setting as the previous SEM validated model, using Xpress MP with default settings. For larger problems, performance improvements can be made through both "concurrent" solve algorithms and by using a multicore Xpress MP licence to run in parallel. However, the I-SEM Validated model results in a relatively "small" problem (i.e. fewer than 250,000 non-zeros) that does not benefit from these methods.

Baringa has tried altering these settings with no effect on performance, and so has made no changes from the previous SEM model settings.

3 Uplift and Scarcity

3.1 Uplift

Uplift in SEM represents the recovery of start-up and no-load costs of generators. The previous SEM uplift algorithm takes account of price volatility as well as the cost of uplift to consumers; and in so doing, it tends to dampen price spikes compared with outturn prices observed in EU markets.

In I-SEM, as in EU markets, there will not be an explicit Uplift algorithm and these costs will be internalised within the prices that generators offer into the market. It is not clear how uplift costs (essentially the start-up and no-load costs of generators) will be incorporated within offer prices by generators once I-SEM goes live, or how uplift pricing will interact with the EUPHEMIA algorithm for market coupling. It is possible that the uplift will remain broadly unchanged in I-SEM, as generators seek to replicate current revenue levels in their offers. Alternatively, generators may change pricing behaviour to be in a manner more typical of Continental markets where EUPHEMIA is used.

3.1.1 Start cost level

One important assumption is around the costs that generators are seeking to recover. The current "start costs" in the previous SEM Validated model have been validated against SEM market submissions, and so can be considered cost-reflective under the SEM Bidding Code of Practice. However, we note that these start costs for SEM generators are generally higher than those observed for similar plant in other markets, i.e. GB. It may be that greater competitive pressures under I-SEM could lead to a reduction in start costs recovered through the market. Conversely, due to the greater risk of imbalance under I-SEM "risk premia" may increase. It is difficult to speculate on the net effect of these offsetting factors at this stage.

Therefore, in the absence of any other evidence, we are keeping the start costs from the previous SEM Validated model for use in the I-SEM model. Given the close proximity of the previous validated model (June 2017) to the I-SEM model, it is assumed that generator start costs will not have moved significantly and remain relevant for the I-SEM period being modelled. As I-SEM market data becomes available it will become possible to update these values.

3.1.2 Uplift cost recovery method

Outlined in Table 6 below are a number of possible approaches to the modelling of uplift in I-SEM:

1. Make uplift costs linear
2. Use the previous SEM uplift algorithm
3. Use the "Korean" uplift algorithm[6]
4. Use a custom uplift algorithm

[6] The "Korean" uplift algorithm is based on that used in the South Korean cost based pool, which in turn is based on the old GB Power Pool. In PLEXOS it is referred to as "CBP" (cost based pool).

Table 6 Uplift approach for I-SEM

Uplift Approaches	Pros	Cons	Applicability to I-SEM model
1. Make uplift costs linear (so that they form part of the shadow price reported by PLEXOS)	This ensures recovery of all start-up and no-load costs Interconnector flows (based on a shadow price) match what we expect from market	Does not respect generator technical constraints (i.e. min stable level, min up/down times etc.)	
2. Use Rounded Relaxation and retain the previous SEM uplift algorithm	Generators recover all start-up and no-load costs	Uplift is smeared across all periods to reduce volatility as per previous SEM software, but this is unlikely in I-SEM when uplift will be formed through individual generator decisions	
3. Korean uplift algorithm	Represents one simple strategy generators may take at an individual level to ensure full cost recovery	Assumes generators have perfect foresight of how long they will be scheduled for and spread start-up and no-load costs across each interval of contiguous operation as uplift over SRMC	
4. Custom uplift algorithm	Provides flexibility in the cost recovery algorithm used	Requires evidence of what generators' behaviour is likely to be in order to formulate a bespoke algorithm	

The chosen approach for the I-SEM validated PLEXOS model is to use the Korean uplift algorithm. This algorithm is easy to implement in PLEXOS, and has the benefit over the SEM uplift algorithm of representing one simple strategy generators may take at an individual level to ensure full cost recovery, as they will have to do in I-SEM. Generators increase their bids to ensure recovery of start and no-load costs, based on perfect foresight of the duration of each period of operation, smearing their costs over the periods of operation.

Using the Korean algorithm, uplift is increased in peak periods and reduced in off-peak periods when compared with SEM uplift, as shown in Figure 7 and Figure 8. Using Korean uplift to represent generators in I-SEM would suggest a change in generator behaviour that pushes down prices in more competitive periods and up in less competitive periods. This seems a reasonable way for generators to behave in a market like I-SEM with no explicit bidding code of practice in the Day-Ahead-Market.

Figure 7 Winter Uplift Profile with SEM uplift and Korean Uplift

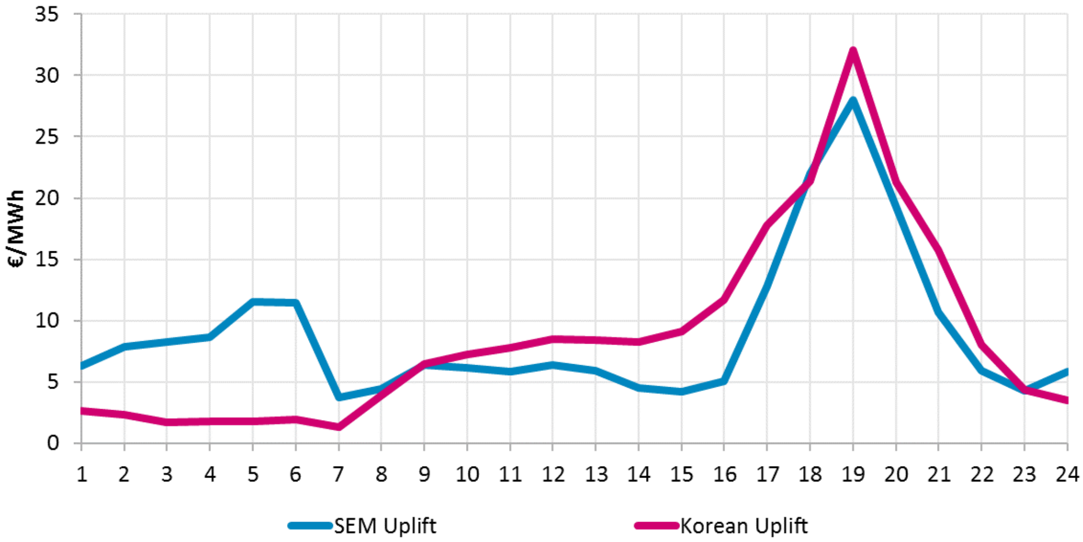


Figure 8 Summer Uplift Profile with SEM uplift and Korean Uplift

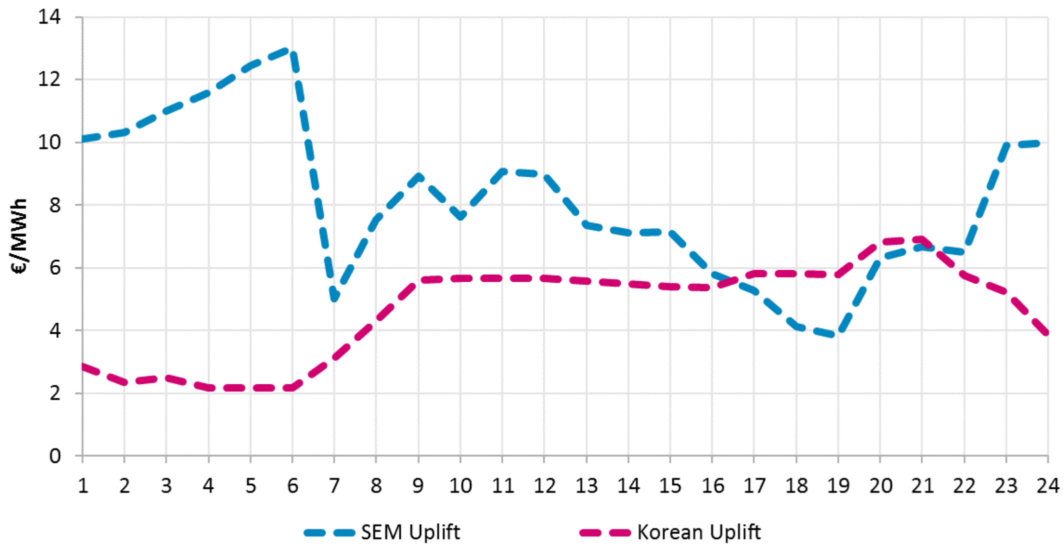


Figure 9 and Figure 10 show the impact on hourly winter and summer price profiles of running the SEM Validated model using the Korean uplift versus the previous SEM uplift algorithm.

As a result of using Korean uplift, there is more "shape" to prices, and a decrease in baseload prices of 2.11 €/MWh. Given that the previous SEM uplift algorithm (Uplift Approach No. 2) is calibrated to reduce volatility in uplift rather than just to minimise overall uplift levels, it is perhaps to be expected that Korean uplift should produce lower uplifted price levels but with higher peak/off-peak shape (ie higher volatility).

Figure 9 Hourly Winter DA power price profile with Korean uplift costs

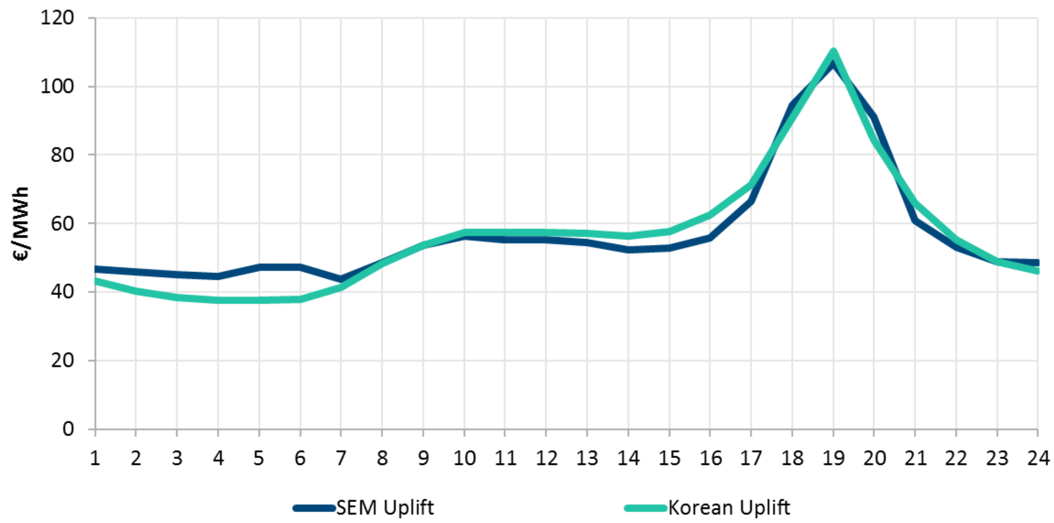
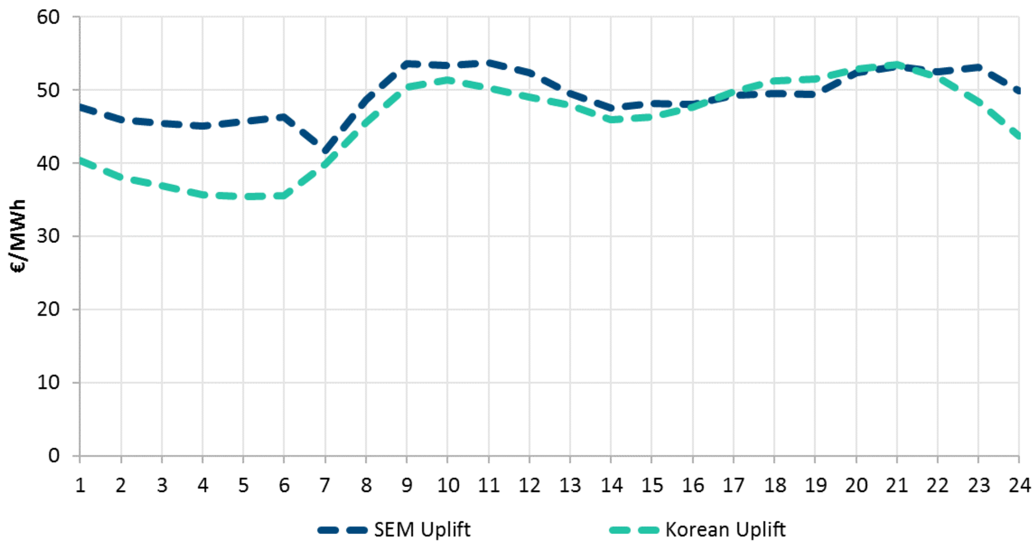


Figure 10 Hourly Summer DA power price profile with Korean uplift costs



The difference in baseload price of -2.11 €/MWh observed between Korean and SEM uplift here is higher than suggested in the I-SEM modelling information paper, where different commodity prices were used. Whilst we have observed Korean uplift to give consistently lower results, the degree to which it is lower has been found to be quite dependent on the particular scenario, often as a result of interconnector flows and the flexibility they provide the SEM (i.e. reduced starts). We note that the change in prices due to moving away from SEM uplift is significant, but we think it is justified due to the improvement in price shape when using Korean uplift, which better reflects how we expect generators to bid under I-SEM rules. There is significant uncertainty about how power prices will change as a result of I-SEM, and we believe change to baseload prices of -2.11 €/MWh to be in the correct direction and within reasonable bounds.

One survey respondent suggested that a Custom uplift algorithm should be implemented after a period of I-SEM operation, when observed generator behaviour and market data become available. This would introduce a level of flexibility into the model not allowed by the Korean uplift function, and could give results more reflective of observed behaviour. Whilst we do not think this should be implemented at this stage (due to lack of market data), for any future validation it is an area that the RAs may wish to consider.

Respondents to the survey were in broad agreement with using Korean uplift, though two suggested it should not be used as it pushed up prices. In our testing this does not occur outside of peak periods; using Korean uplift actually reduces baseload prices, as described above.

3.2 Scarcity

Scarcity bidding refers to the practice whereby generators may bid above their short-run marginal cost levels (including start-up and no-load costs) to seek extra profits to recover fixed costs and earn a return on capital (to the extent this is not possible through the Capacity Remuneration Mechanism, CRM). In a market with unrestricted bidding, in principle this behaviour could happen anytime, but is likely to be significant only when capacity is 'scarce', i.e. when the capacity margin is low due to a combination of high demand and/or low plant availability. Bidding above short-run marginal costs is not currently allowed in SEM under the Bidding Code of Practice, but in I-SEM generators will be free to bid at whatever level they wish in the Day-Ahead-Market, cost-reflective or otherwise (in the Balancing Market, restrictions will remain on cost-reflective bids).

In other European markets using EUPHEMIA some level of historical scarcity pricing has been observed, though in recent years this has all but disappeared and is not visible in the forward curves of any major market. This is primarily a result of falling demand and relatively high capacity margins.

It is possible that scarcity pricing might be a feature of I-SEM in the future, particularly where the new CRM sends an exit signal, and capacity margins become tighter. However, at this stage in the absence of historic data we do not believe it possible to speculate on the extent of future scarcity pricing. While scarcity is likely to be low, if it is excluded from the model it is possible that forward prices, particularly peak prices, could be underestimated in the I-SEM PLEXOS model towards the end of the modelled horizon.

However, a further consideration is the effect of the new CRM, which in our view will reduce the incentive on generators holding Reliability Options to push DAM prices above the RO strike price (~€500/MWh).

Given the lack of evidence of scarcity, and the disincentives to increase prices about the RO strike price for some generators, the decision is not to include scarcity pricing in the I-SEM model. Our assumption is that all bidding is cost-reflective, including start and no-load costs.

4 Generator data

4.1 Generators added and removed

There have been no commissioning or decommissioning updates since the previous SEM model validation in June 2017. The model has been extended to 2019. We have checked with the TSOs and market participants that there is no current plan to close Ballylumford B4 and B5 before this time (potentially as a result of losing their current local reserve contract), nor Lough Ree or West Offaly who lose their PSO levy support at the end of 2019).

4.2 Generator data

4.2.1 Validation methodology

The previous 2017 SEM model validation involved a comprehensive collection and validation of SEM generator data. This data must be fully cost-reflective under the SEM TSC.

Our assumption is that this data is:

1. A true reflection of generator technical and commercial properties,
2. Is the most complete and best source of this data at this time, and
3. Is unlikely to materially change from now to Q4 2019.

Once I-SEM begins it will be possible to see generator bids in the DAM and the Balancing Market and test the assumptions above, but as the I-SEM Validated Model is to be produced before I-SEM goes live this source of data is not available at this time.

We have used the generator properties from the recently validated SEM model (June 2017) without change for the I-SEM model.

4.3 Hydro and pumped storage

The representation of hydro and pumped storage generators has not changed since the previous 2017 SEM Validated model. Hydro plant are represented as run-of-river with limited storage, having a daily limit on generation but with the flexibility to choose when in the day to run to meet this limit. Pumped storage is modelled using a head reservoir and tail reservoir with losses incurred when pumping from tail to head.

Both hydro and pumped storage are modelled without min stable levels, consistent with the approach used in the previous SEM validated model. Pumped storage is assumed to ramp to full capacity within the 1-hour granularity of the model, and so ramp rates are omitted.

4.4 Outages

4.4.1 Planned maintenance

Outage information for planned maintenance has been updated to the most recent public schedule published by SEMO on their website. The 2018 outages are from the Committed Outage Programme and the 2019 outages are from the Provisional Outage Programme, both published at the end of September 2017. Outages and capacity reductions are applied to generation plant in the model as per the SEMO schedules.

The changes in outage schedule are small when looked at market-wide, resulting in a decrease in the DA price of 0.32€/MWh.

4.4.2 Forced outages

The forced outage rates for generators used in the I-SEM model were unchanged from those used in the previous SEM validated model. Given that there is no evidence that forced outage rates are likely to decrease significantly in the future, we have again used the historic rates (2013-2015) as collated by the TSOs to ensure the correct plant availability for the system.

However, individual plant that incurred a High Impact Low Probability (HILP) event over this historic period may not incur such an event in the future, and vice versa for plant that did *not* incur such an event historically. To avoid locking in pessimistic or optimistic forced outage rates for individual plant in the forward-looking model, forced outages rates have been averaged (on a capacity-weighted basis) over plant types. This averaging process results in projected system availability matching the availability seen historically, but avoids locking in historic HILP for individual plant. Gas-fired plant were initially separated into peakers and CCGT/CHP, but there was no significant difference in historic forced outage rates, and so a blended rate was used for all gas-fired generators. Table 7 shows the average historic forced outage rates by plant type as used in the model.

Interconnector forced outage rates are included in the I-SEM Validated model, having previously been omitted, and set at 6.9% as per the SEM Committee CRM decision paper published in April 2017[7]. This value has been calculated from historic outages, but does not included the large outage incurred by Moyle on one of its two lines from 2012-2016. Baseload DA power prices are increased by 0.6 €/MWh as a result of including interconnector forced outage rate.

[7] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-022%20CRM%20Parameters%20Decision%20Paper_1.pdf

Table 7 Forced outage rates by plant type

Generator Type	Historic (used in validated model)
Gas	6.2%
Oil	2.0%
Coal	9.1%
Peat	7.9%
Hydro	4.5%
Pumped Storage	6.0%
Distillate	2.4%
Waste	6.7%
Biomass	6.1%
Interconnector forced outage rates	6.9%
SEM wide	6.1%

5 System data

5.1 Embedded generation

Embedded generation is represented using an hourly profile, defined for both weekdays and weekends. This remains consistent with the 2017 SEM Validated model, using the TSOs' latest assumptions and matches the GCS 2017-2026, but extended to cover 2018-2019.

5.2 Demand side units

Demand side participation through individual and aggregated demand side units (DSUs) remains the same as the previous June 2017 SEM Validated Model, which reflect the latest capacity forecast in the TSO GCS 2017-2026. Similar to generator start costs, it is assumed that DSUs will bid in similar levels under I-SEM.

It is not clear at this stage how DSUs will be allowed and incentivised to participate in the DAM under I-SEM. We assume that DSUs will be able to bid in a similar manner to previous SEM arrangements, and include DSU as per the previous SEM validated model.

DSU is separated into three tranches, and a single marginal cost is given for each, as shown in Table 8 below. The values shown have been derived from historic SEM commercial offer data. The increase of the highest priced tranche, from 999 €/MWh to 2800 €/MWh, makes no difference to results as this tranche is never used in the model.

Table 8 DSU tranches and prices

DSU Blocks	Quantity (MW)	Price (€/MWh)
DSU 1	100	535
DSU 2	150	640
DSU 3	85	2800[8]

Given the current lack of clarity around exactly how DSU will participate in the I-SEM DAM, we have tested removing DSU completely. This made no significant difference to results, as DSU is little used when present.

As more clarity is given on how DSU will participate in I-SEM DAM the assumptions around DSU can be revisited.

[8] 2800 €/MWh is the value for the highest priced tranche, as calculated from historic SEM commercial offer data. In the previous SEM Validated model this was set to 999 €/MWh, to allow the highest price tranche to be used under a price cap of 1000 €/MWh. In the I-SEM Validated model the cap has been raised to 3000 €/MWh, allowing us to use the real value of 2800 €/MWh for highest priced tranche.

5.3 Interconnectors

Interconnector planned outages have been updated as per the latest release on the SEMO website.

Forced outages for interconnectors have been included, as described in Section 4.4.2.

Losses for both East-West and Moyle are consistent with TSOs' current assumptions and have not been changed in the 2017 I-SEM Validated model.

Moyle's export capacity is assumed to be 80MW from 2018 – Dec 2019, consistent with its contracted capacity on the GB side. Whilst Moyle owners Mutual Energy are seeking to gain short-term increases in this capacity limit, this has not been agreed by Ofgem or the SEM RAs and so is not considered in the I-SEM validated model.

Interconnector ramp rates have been included at 5MW/min for each interconnector, matching limits imposed by the TSOs and planned for implementation in EUPHEMIA[9]. This inclusion of these ramping constraints has little effect on dispatch or DA price.

5.4 TLAFs

Transmission Loss Adjustment Factors (TLAFs) assume the published TSO values for 2017/18. Updating TLAFs does not have a significant effect on output DAM price or generation volumes.

5.5 Wind and Demand

5.5.1 Wind and demand profiles

The previous SEM Validated Model approach for including wind and demand load profiles at a half-hourly level was to use a base year of outturn half-hourly data. The base year in the 2017 SEM Validated Model, 2015, is aligned to the Generation Capacity Statement 2017-2026 for both wind and demand profiles. Using a single base year for wind and demand presents the issue that it builds into the forward-looking model any atypical behaviour seen in the historical year used.
There is no reason to expect wind or demand profiles to change as a result of the move to I-SEM. However, as part of producing a robust I-SEM Validated Model we have investigated the approaches described in Table 9.

[9] SEM-17-067 Ramping Constraints on Euphemia Algorithm
https://www.semcommittee.com/news-centre/ramping-constraints-euphemia-algorithm

Table 9 Wind and Demand profile approaches for I-SEM

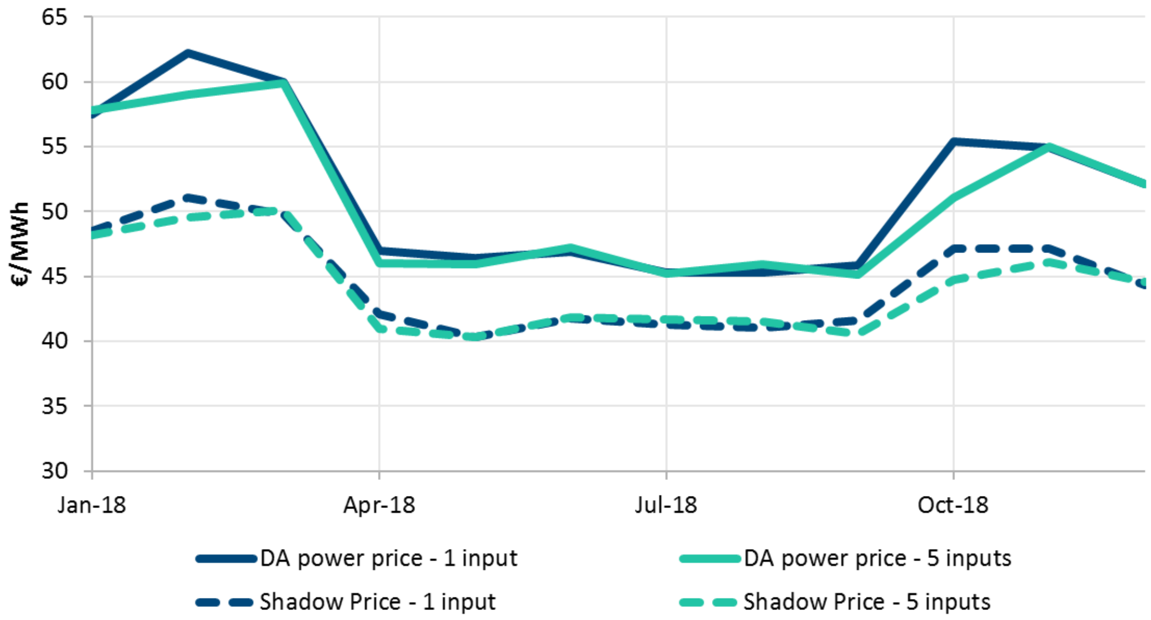
Wind and Demand Profiles	Pros	Cons	Applicability to I-SEM model
1. Use the current base year, 2015, as per the 2017 Model Validation	Approach in SEM 2017 Validated model and aligns to the GCS Using a single year for both wind and demand ensures correct correlations	Some atypical demand and wind in Q4 of 2015 which gives unusual results in these months in all future years of the model	
2. Use a different base year (e.g. 2012)	Using a single year for both wind and demand ensures correct correlations Baringa identified 2012 as being a "typical" year	Risk of atypical demand and wind not yet identified being built into results in all future years of the model	
3. Use correlated wind and demand profiles from multiple base years using a Monte Carlo simulation	Reduces the risks associated with using a single base year	Increases run times – but this can be offset by using the rounded relaxation self-tune increment and short-term horizon settings outlined previously	
4. Use a fundamentals based approach for wind and demand	Detailed bottom up view of wind and demand	This is a complicated modelling exercise and is out of scope due to the timings of producing an I-SEM Validated Model	

We have gathered historical wind and demand profiles from the TSOs for 2007-2015. The wind profiles are for two regions only, NI and ROI, rather than the 13 regions used in the previous SEM Validated Model. Given the purpose of the model is for unconstrained price projections (ie no transmission constraints) we believe this granularity is sufficient.

We have used approach 3 in Table 9, using multiple base years of correlated wind and demand profiles under a Monte Carlo simulation, and then taken the mean price from all runs as the output from the model. Running in Monte Carlo mode increases run times. However, due to savings made elsewhere (RR self-tune, hourly granularity) it was found that 5 wind and demand profiles could be used and the runs times increased back up to the level of the previous SEM validated model, but with the increased Monte Carlo functionality. The I-SEM validated model has 5 base years of wind and demand profiles (2011-2015), and uses 2 wind regions (NI and ROI).

Figure 11 shows the impact, on monthly DA powerprices and shadow prices, of using multiple wind and demand profiles. Some of the previous monthly “spikes” and “troughs” are smoothed out by averaging over 5 base years. Baseload prices are reduced by 0.73€/MWh primarily due to an increase in the average wind load factor, from 30% to 31%, which now matches the long run average exactly.

Figure 11 Monthly DA power price profile with multiple wind and demand profiles



5.5.2 Forced outages

Forced outages are also stochastic, and we have included these as part of the Monte-Carlo runs described above, with a different outage pattern being used for each base year run. There was no significant impact on the DAM price as a result of using stochastic forced outages.

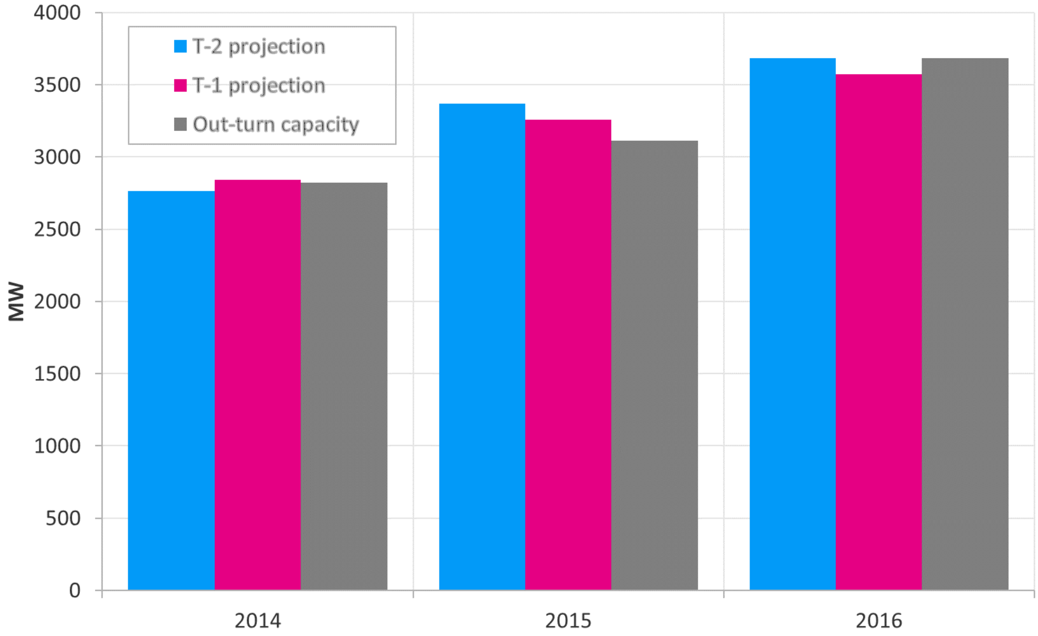
5.5.3 Wind capacities

One respondent to the I-SEM modelling survey queried the use of the 2017 GCS wind capacity figures in the I-SEM Validated model, suggesting that it assumed a build rate that was unlikely to be met. The GCS capacity figures have been derived by probability weighting potential projects based on development status and we consider it to be the best available source of such capacity projections.

We have investigated previous GCS capacity projections for 1 and 2 year ahead (“T-1” and “T-2”), for the period of installation 2014-2016, and not found any directional bias. Figure 12 shows projections and outturn capacities for each year.

Given there is no apparent bias in the GCS capacity figures for the last few years, the 2017 I-SEM Validated model therefore uses the wind capacities as published by the 2017-2026 GCS as the best available source of such data.

Figure 12 GCS projected and outturn wind capacities



6 GB and Interconnectors

The treatment of interconnectors is related to the treatment of GB. The previous SEM Validated Model does not represent GB prices, but rather GB bids on the interconnectors.

6.1 Treatment of GB

In treating the interconnected electricity market of GB there are a number of approaches that could be followed. Representing interconnected markets in PLEXOS is always a trade-off between:

- Quality of representation
- Ease of updating
- Modelling an overall region that is not too disproportionate relative to the size of the home market (avoiding PLEXOS optimising interconnected market at expense of market of interest)

The change to I-SEM arrangements does not materially change how GB should be represented. There are a number possible approaches to modelling GB in an I-SEM PLEXOS model:

1. Fixed hourly price series
2. Fully detailed plant level representation
3. Representative stack (for instance, 1 Nuclear, 1 Wind, 2 CCGT, 1 Coal, 1 OCGT plant)
4. Single GB gas generator with calibrated heat rate to reflect Interconnector bids

Table 10 summarises the pros and cons of each approach. In the previous SEM Validated Model Option 4 is used, a single GB generator calibrated using recent historical data, as this is quick to recalibrate for a model that is used regularly. The move to I-SEM market arrangements will have little effect on the GB market, and so we have kept the single GB generator approach in the I-SEM Validated Model.

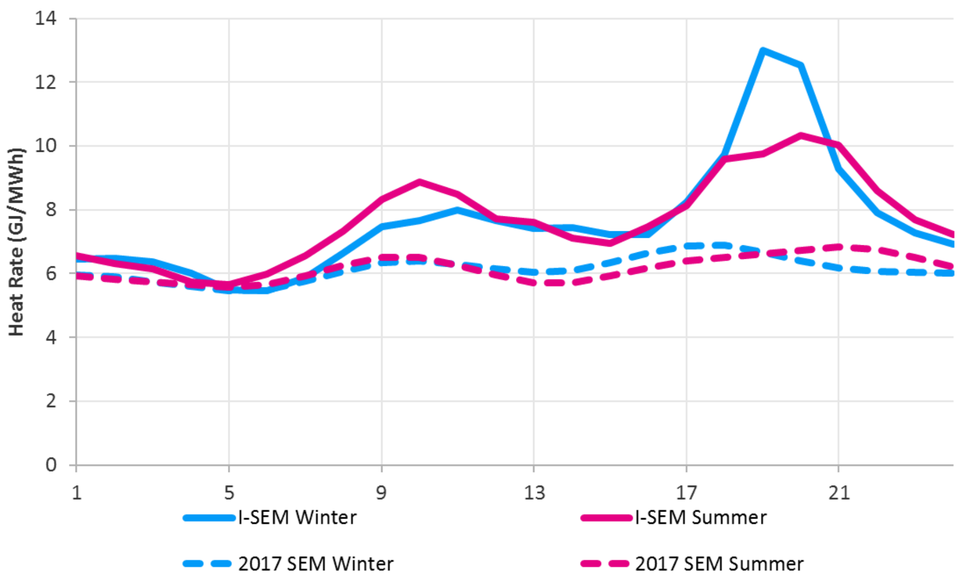
The GB generator in the PLEXOS model represents bids on the SEM-GB interconnectors (ICs) rather the wholesale price of electricity in the GB market. This methodology uses a single GB Gas generator object in PLEXOS with a heat rate that represents GB bids on the ICs based on the prevailing cost of gas in GB (NBP gas and EUA carbon).

Under SEM arrangements, IC imports receive SEM capacity payments, but under I-SEM this distortion is removed, which will likely reduce imports into I-SEM. To calibrate the dummy GB generator, spot power price data for GB (June 2015 – May 2017) was first compared with corresponding spot gas and carbon prices, and the half-hourly implied heat rate found. These half-hourly heat rates were aggregated to give an average hourly heat rate for Summer and Winter. These hourly heat rate curves are shown in Figure 13 and represents implied heat rate (including start cost recovery) of the marginal price-setting unit in GB.

Table 10 Approaches for modelling GB

GB representation	Pros	Cons	Applicability to I-SEM model
1. Fixed hourly price series	• Simple to implement in PLEXOS • Quick to run	• Needs a way of calculating GB price (another model) • Assumes SEM is price taker • Does not reflect commodity changes	
2. Full GB representation in PLEXOS	• Excellent GB price calculation	• Slow to run • Requires a lot of maintenance • Optimiser “favours” larger market	
3. Simplified GB stack	• Good GB price calculation • Reasonable run times	• Requires regular maintenance of stack properties, which is quite difficult	
4. Single GB generator	• Quick to run • Quick to recalibrate	• GB price calculation not as accurate as the above methods • Embeds recent historical behaviour into GB bids	

Figure 13 Implied heat rate of the marginal price-setting unit in GB



Some survey respondents queried the use of GB power price data covering price spikes seen in late 2016, for calibrating a forward-looking model. We believe that it is correct to use data covering this period, as the average clean spark spread of the GB data used matches the clean spark spread in current forward curves for 2018 and 2019. Furthermore, we have found if this data is excluded there is a negligible impact on the calculated heat rate, and so we have kept it in.

Another survey responder suggested averaging by 4 seasons rather than 2. If this approach is used there is a significant spike in heat rates for the Winter season, as Winter 2016 data becomes more dominant without the averaging of the shoulder months present in the 2 season approach. We have decided to keep 2 seasons only, but use all data.

By using the spot GB power price to calibrate the dummy GB generator, any "uplift" in GB (i.e. recovery of start and no-load costs) is included in the implied heat rate based on recent historical market behaviour, and no additional uplift mechanism is required for GB bids.

6.2 Treatment of Interconnectors

Under I-SEM arrangements, interconnectors will be scheduled on the I-SEM full DA power price (i.e. equivalent to current SMP) and the GB full DA power price. However, as Rounded Relaxation is being used in the I-SEM model, IC flows will be scheduled on "shadow price" within the PLEXOS model, excluding uplift. GB prices in the I-SEM model do not have uplift applied within the model, but do contain recovery of start and no load costs in the marginal heat rate of the GB dummy generator, through the calibration against GB price data. I-SEM prices are initially formed as a shadow price excluding start and no-load cost recovery, which is then added through the Korean uplift algorithm. If there is no calibration of GB prices or interconnector charges, interconnector flows in the PLEXOS model will tend to over-schedule exports from SEM to GB versus those from the EUPHEMIA software as the I-SEM shadow price does not include start and no-load costs but the GB shadow price does.

A number of options exist for tackling this issue. Below we highlight two potential solutions:

1. Use historical SEM uplift to calibrate the GB interconnector bid heat rate:
    - This is the approach used in the previous SEM validated model, whereby historical SEM uplift and SEM capacity payments were removed from historical GB DA prices to calculate the implied GB interconnector bids, before calculating the implied heat rate of the gas generator representing GB IC bids. Under I-SEM, we would no longer remove capacity payments from GB DA prices but would continue to remove uplift;
    - The benefit of this approach is that it is a continuation of the current methodology and reduces the number of changes in the modelling. It would be easy to recalibrate the GB interconnector bid heat rate omitting uplift and using the most recently available data;
    - However, there is an issue with this approach in that it assumes the nature of SEM uplift seen historically will continue in I-SEM. This assumption is likely to be wrong for two reasons:
        a. Interconnector behaviour in I-SEM will likely change (higher exports to GB, lower imports from GB) due to the cessation of the SEM capacity mechanism which encourages imports, which will in turn increase uplift in I-SEM (uplift has been found previously to be quite sensitive to interconnector flows, due to the flexibility that the ICs provide to the system);

b. If the PLEXOS model is changed to use Korean uplift rather than SEM uplift, then we are taking the view that the within-day shape of uplift will be different under I-SEM, and this new pattern will not be reflected in historical SEM uplift data used to calibrate the GB IC bid.

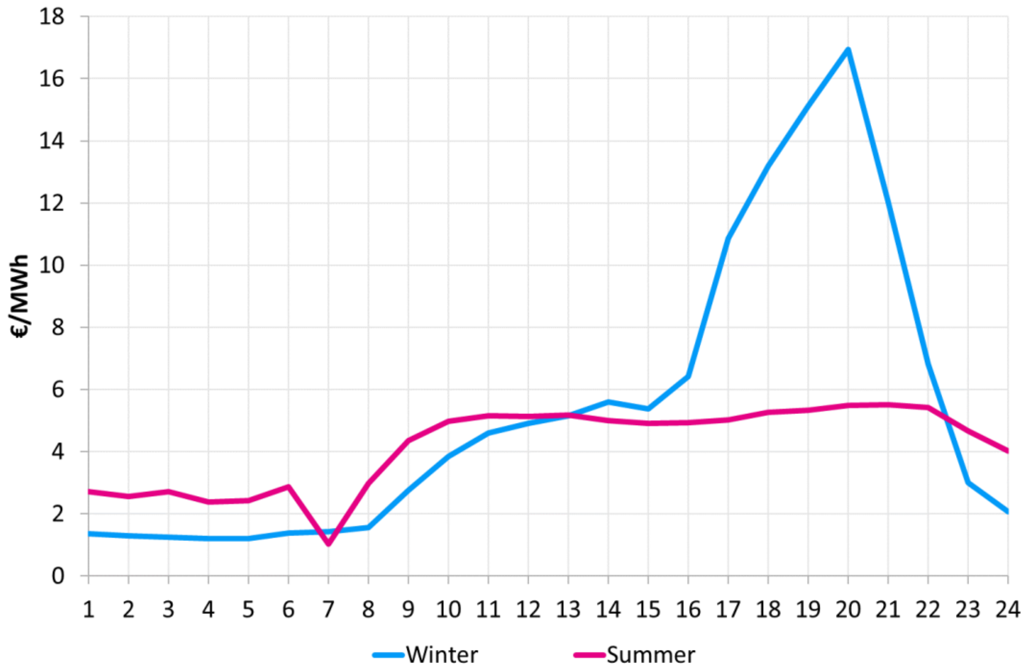
2. Use an I-SEM model to predict I-SEM uplift, then use this in future runs:
   - This can be implemented through wheeling charges on the interconnector, bringing the I-SEM price that the PLEXOS model effectively sees an increase from the shadow price to "full price";
   - A first pass model run can output detailed hourly uplift levels;
   - These hourly uplift values are then averaged to give hourly uplift for 2 seasons (Summer and Winter);
   - The second pass model run uses these hourly uplift levels to give a more refined view of uplift to the interconnector, and re-dispatch to give final price and quantity levels.

For the I-SEM Validated model, we have opted to use Method 2, using a first pass model run of I-SEM to set the uplift values to be used as wheeling charges on the interconnectors in all future runs.

These averaged uplift values may change in the future in response to commodity swings and capacity changes.

Figure 14 shows the diurnal uplift values used as wheeling charges on the Interconnectors.

Figure 14 Hourly uplift values used as wheeling charges on the interconnectors



6.2.1 Combined effect of updates to GB and interconnectors

The combined effect of the above changes is to increase exports from SEM, as shown in Figure 15. This is due to the removal of SEM capacity payments to GB bids on the interconnectors.

Hourly prices for winter and summer are shown in Figure 16 and Figure 17. There is a decrease in winter baseload prices of 0.8 €/MWh (due to decrease uplift coming from interconnectors being more marginal more often and reducing generator starts) and an increase in summer baseload prices of 0.6 €/MWh (coming from increased exports leading to a rise in shadow price).

Figure 15 Net exports, with and without changes to GB and interconnectors

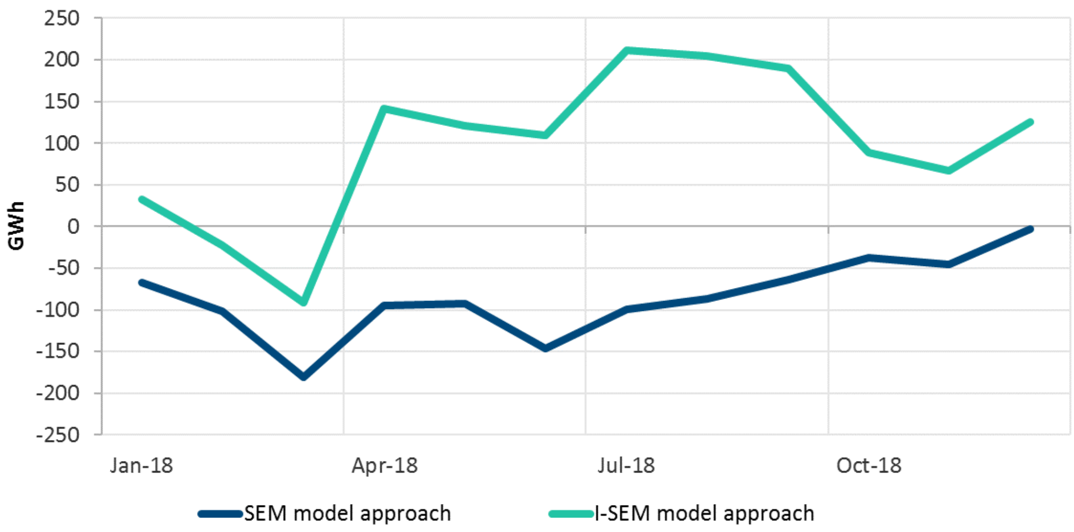


Figure 16 Hourly Winter DA price profile, with and without changes to GB and ICs

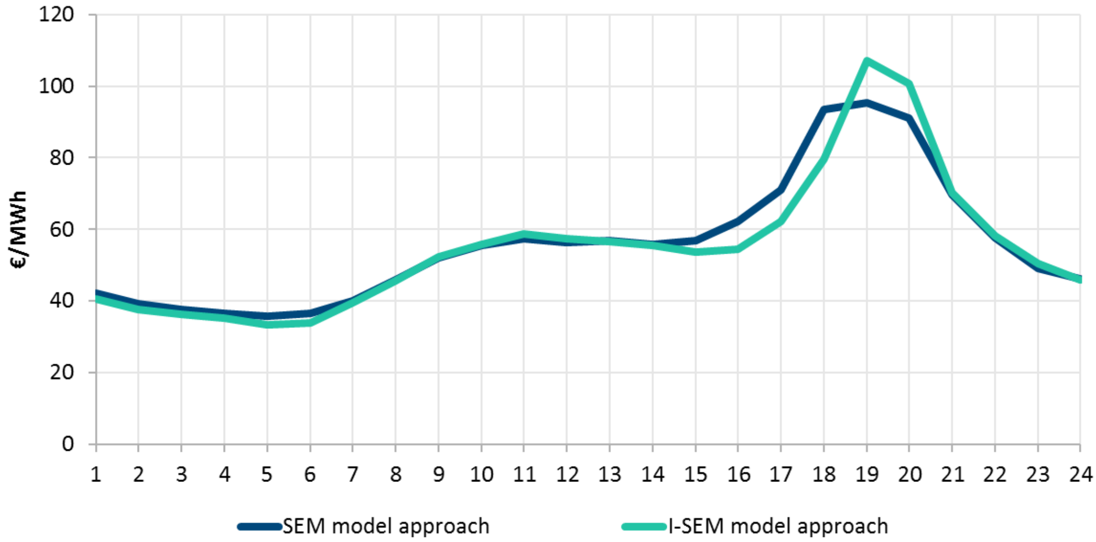
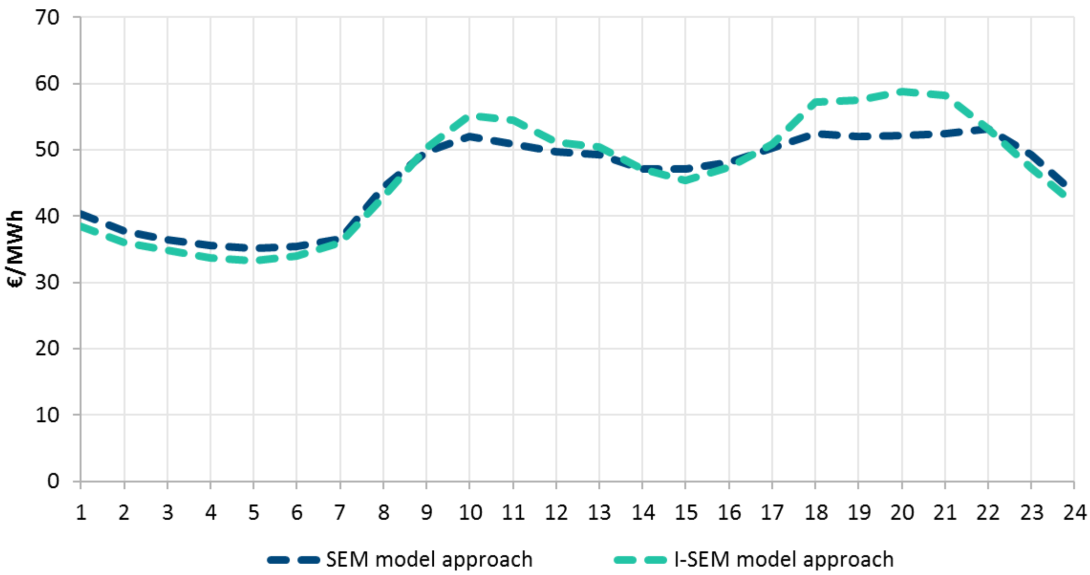


Figure 17 Hourly Summer DA price profile, with and without changes to GB and ICs



7 Fuel adders and input sheet

7.1 Fuel Adders

Fuel adders remain the same as for the previous 2017 SEM Validated Model, other than RoI Short-term Gas Capacity (STGC) charges which have been updated to the latest values for 2017/18.

7.2 Commodities price input sheet

As in previous updates of the validated model, a fuel input sheet is supplied to be used in conjunction with the model. This can be used to convert market fuel prices to the correct format and basis for the PLEXOS model. As per the 2017 SEM Validated model the fuel inputs sheet produces PLEXOS inputs for carbon prices as well as fuel prices, and is named the “Commodities price input” sheet. The updated STGC charges described above are included in the I-SEM Commodities price input sheet.

8 Final Results

8.1 Final model results

The final I-SEM Validated model includes all of the changes described in the previous sections.

8.1.1 Baseload power price

Annual baseload DA power price has reduced from 53.2 €/MWh using the previous SEM model to 50.8 €/MWh in the I-SEM Validated model, a decrease of 2.5 €/MWh (5%). This is primarily a result of the change in uplift, from SEM to Korean, as shown in Figure 18.

Figure 18 Changes in annual average baseload DA power price, from SEM to I-SEM model

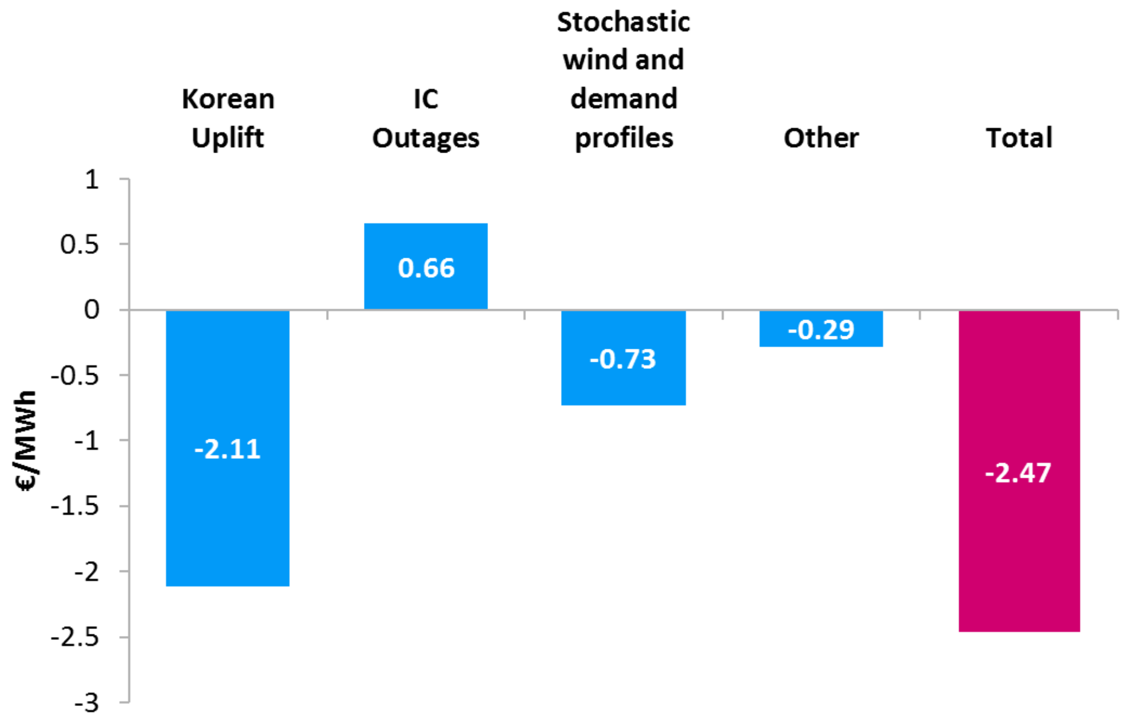


Figure 19 shows the monthly baseload shadow and DA power price. It can be seen that the power price in the I-SEM Validated model shows a smoother seasonal shape, a result of using 5 base years for wind and demand profiles. Also, the difference between shadow and power price (i.e. uplift) is decreased, shown separately in Figure 20. This is a result of using the Korean uplift algorithm rather than the SEM uplift algorithm.

Figure 19 Monthly shadow and DA power price, with and without all changes included

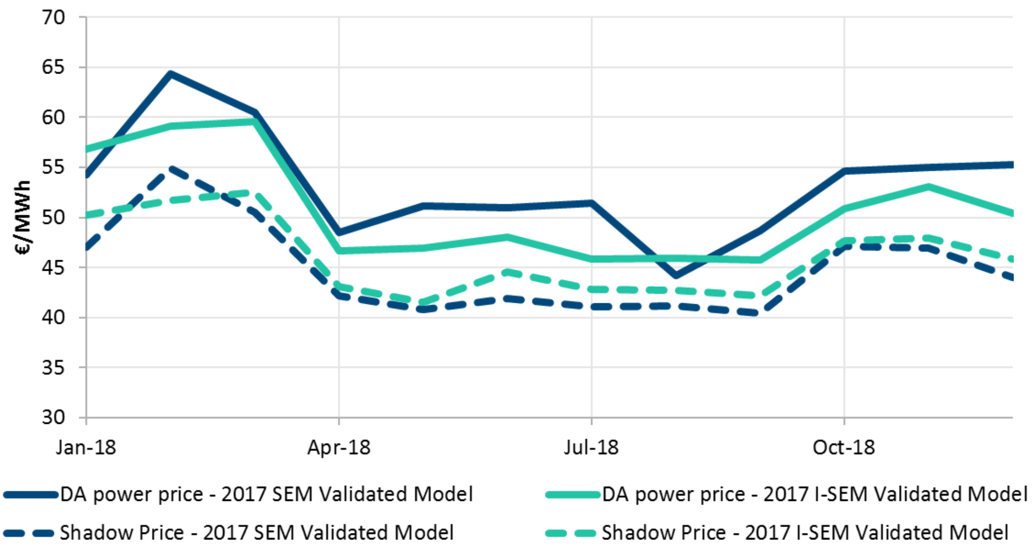
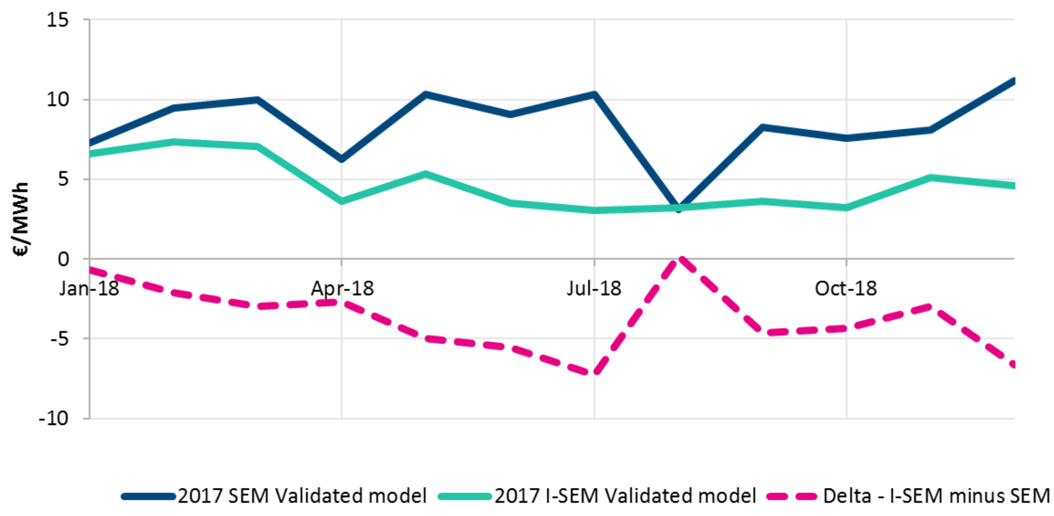


Figure 20 Monthly uplift values, with and without all changes included



8.1.2 Diurnal price shape

Figure 21 and Figure 22 show the average hourly power price for winter and summer respectively.

It can be seen that in the I-SEM model there is more shape to prices, particularly in summer months, primarily a result of using the Korean uplift algorithm which gives more shape to uplift.

Figure 21 Hourly Winter DA power price profile, with and without all changes included

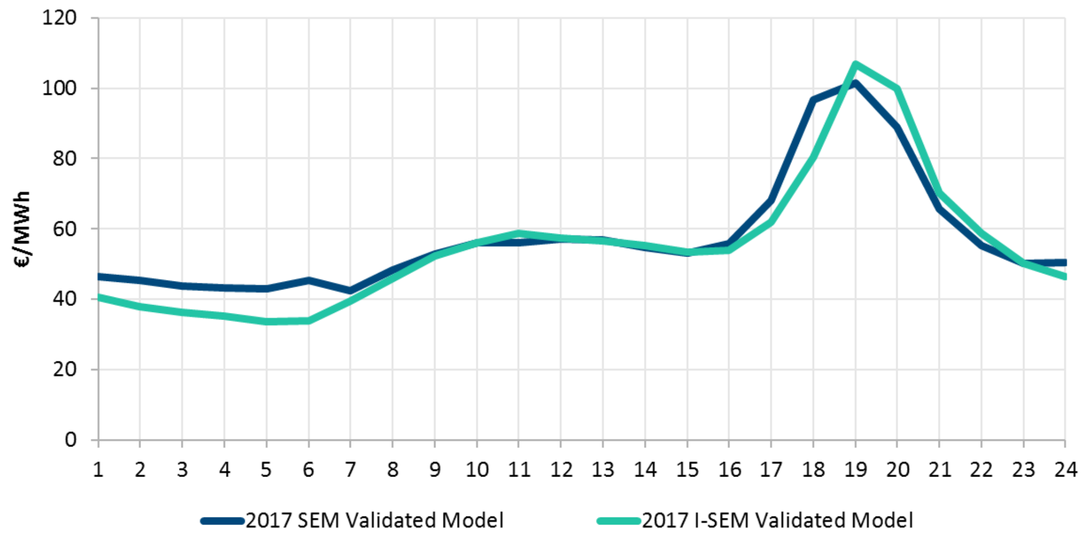
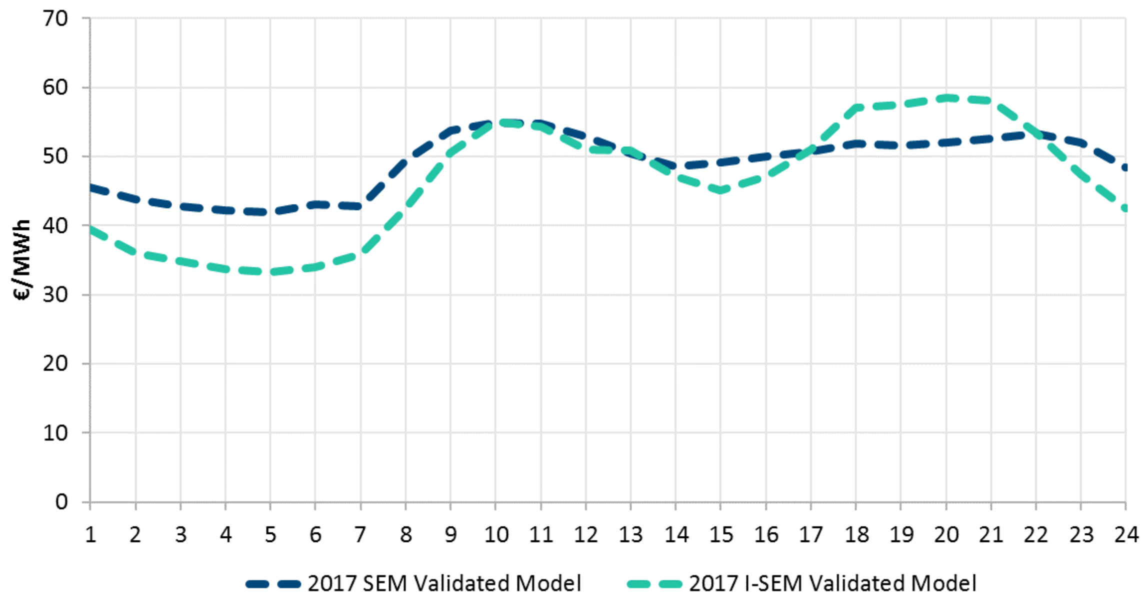


Figure 22 Hourly Summer DA power price profile, with and without all changes included



8.1.3 Interconnector flows

Net exports are from SEM are shown in Figure 23 below, for the previous SEM model and the I-SEM model. It can be seen that there is an increase in exports, a result of removing the distortion in GB bids due to receiving SEM capacity payments.

Figure 24 shows net monthly import and export volumes from the I-SEM Validated model. It can be seen that there is a seasonality to flows, exporting in summer and more balanced in winter.

Figure 23 Net exports, with and without all changes included

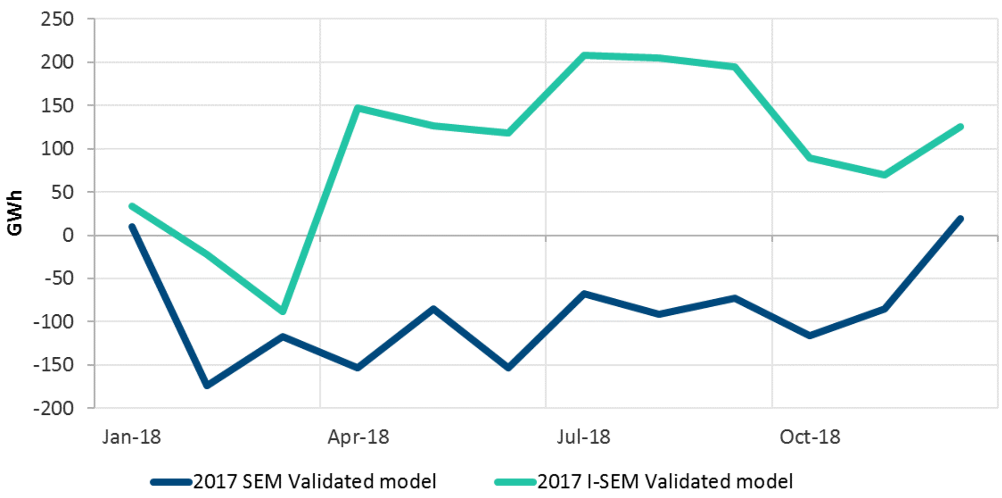
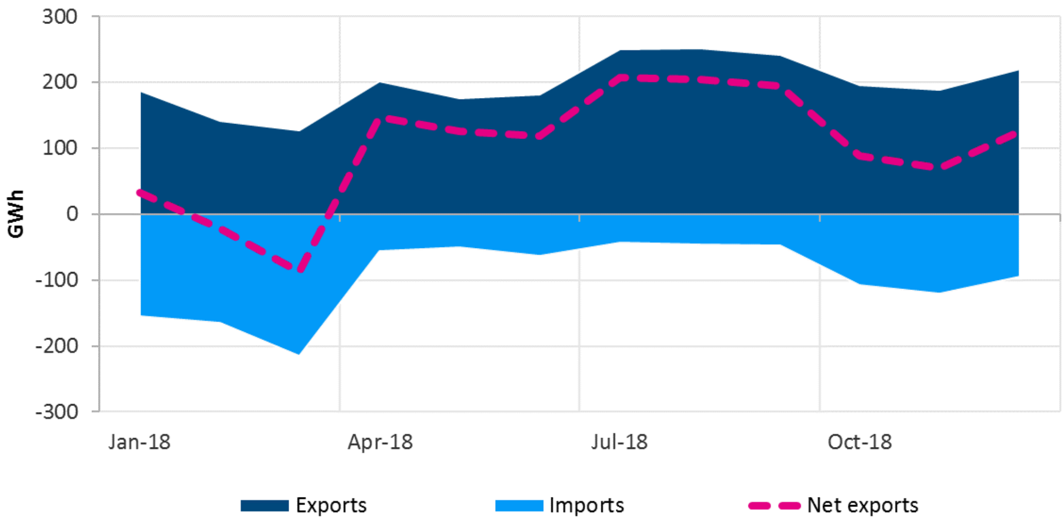


Figure 24 I-SEM Validated model interconnector flows



8.1.4 Generation mix

The generation mix is broadly unchanged from the previous SEM model to the I-SEM Validated model. Increased exports are met by increased generation for both gas and coal plant. Figure 25 shows the generation by plant type for the I-SEM Validated model. Table 11 shows generation by plant type across the SEM Validated model and the I-SEM Validated model. There is a small increase in wind generation due to the change in average load factor when using 5 base year profiles.

Figure 25 Generation by plant type

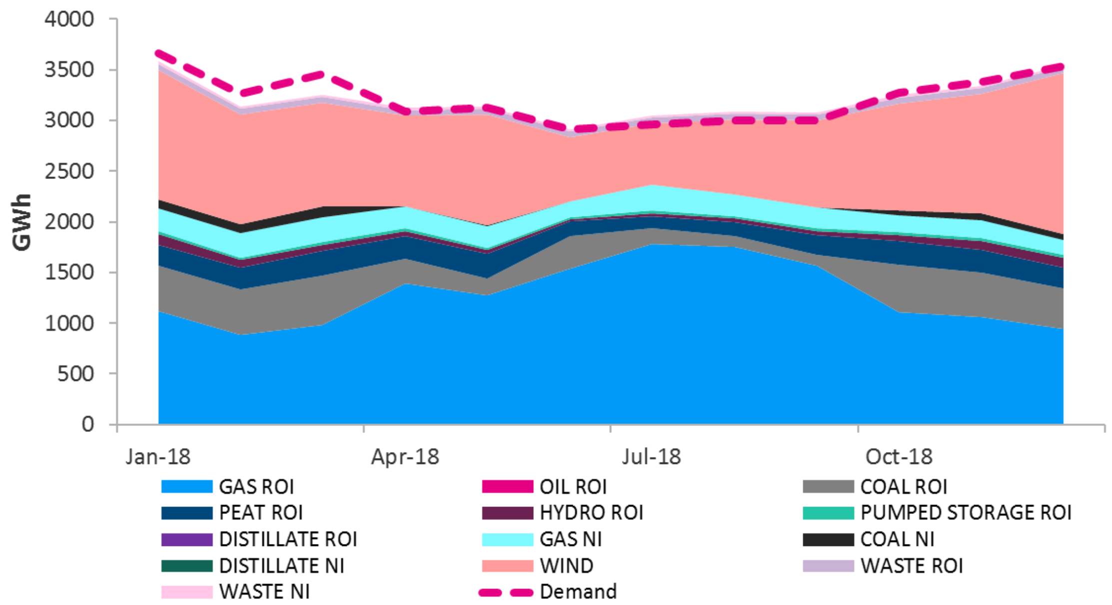


Table 11 Generation by plant type comparison

Generation (MW)	2017 SEM Validated Model	2017 I-SEM Validated Model
GAS ROI	15003	15399
OIL ROI	3	3
COAL ROI	3006	3801
PEAT ROI	2476	2390
HYDRO ROI	691	689
PUMPED STORAGE ROI	142	320
DISTILLATE ROI	5	1
GAS NI	1810	2457
COAL NI	324	456
DISTILLATE NI	0	0
WIND	11559	12049
GB IC Bid	8172	5871
WASTE ROI	688	684
WASTE NI	260	260

8.2 Supplied models

This report is supplied to the RAs with two versions of the validated PLEXOS model:

1. RAs' model
   - Includes VOM costs, supplied by market participants on a confidential basis as part of the previous SEM Validated model process in June 2017.
2. Public model
   - All confidential data removed

Appendix A Summary of survey results

On the 10th of October 2017 an Information paper was published on the SEM Committee website. An online survey was opened to allow feedback from interested parties, with ten days to respond.

The survey was started by 28 individuals, but feedback to our questions was only given by 7 individuals. The 7 responses covered organisations representing generators, vertically integrated utilities, suppliers and academics.

Table 12 below summarises the feedback received through the survey.

Table 12 Summary of survey responses

Modelling approach	Agree	Disagree	No Comment	Additional comments
1. Assumptions around volumes cleared in the DAM and generator bidding behaviour	7	0	0	Difficult to ascertain generator behaviour in the absence of historic data. Assumptions may need to be revised after a market learning period
2. Use PLEXOS default mode	7	0	0	Changes may be required after a market learning period.
3. Upgrade to PLEXOS version 7.300	7	0	0	n/a
4. Update Rounded Relaxation increment to 0.2	5	2	0	MIP suggested as the preferred solver mode by two respondents
5. Update price cap and floor	7	0	0	n/a
6. Change modelling horizon	5	2	0	A longer look ahead suggested by one respondent A shorter look ahead suggested by a second respondent
7. Keep SEM PLEXOS solver settings	6	0	1	n/a
8. Keep SEM generator start costs	7	0	0	Start costs should be reviewed after a period of I-SEM operation
9. Change SEM uplift to Korean Uplift	2	3	2	Custom uplift suggested by one respondent

				Two respondents suggested Korean uplift resulted in higher prices vs. SEM uplift
10. Exclude scarcity bidding from model	7	0	0	One respondent suggested a scarcity adder may be required after a period of I-SEM operation
11. Representation of GB as a single gas generator	6	1	0	One respondent suggested a simplified GB stack approach Another respondent suggested increasing the granularity of GB price shape representation
12. Interconnector flows and uplift wheeling charge	7	0	0	One respondent referenced using a MIP based solution
13. Stochastic wind and demand profiles	7	0	0	Wind should be scaled by region on a quarterly basis
14. GSC used as a source for wind and demand projections	6	1	0	One respondent stated that wind projections should be capped at the average of the past three years projections
15. Generator data to remain consistent with the 2017 SEM Validated model	7	0	0	Three respondents suggested data be updated after an initial learning period