PLEXOS Validation for 2017-18

CLIENT: CER / UREGNI

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Version History

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1 Introduction

1.1 Overview

In March 2017, the Commission for Energy Regulation (CER) 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 2". This is an extension to a similar support contract between the RAs and Baringa agreed in July 2015, "Consultancy Assistance to Support PLEXOS Validation and Directed Contracts".

In this document we describe the work carried out by Baringa under Work Stream 2:

- Work Stream 2. Validation of the SEM PLEXOS model used to set Directed Contract strike prices and volumes for 2017 – 2018

The model produced as a result of this work is referred to in this report as the "2017 Validated model".

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 the SEM.

We have validated all input data to the model to allow it to be used to provide SEM electricity market projections for 2017 and 2018, up until the point of transition to I-SEM. The areas of input data that have been validated and updated include:

- Generator submitted data
  - Marginal Generation Costs
  - No Load Costs
  - Start Costs
  - Technical Offer Data
- Hydro plant daily generation volumes
- Outages
  - Planned maintenance
  - Forced outages
- Demand
- Embedded generation

- Wind generation
- Demand side units
- Interconnectors
- GB bids on interconnectors

In the following sections of this report we describe each of these areas in turn, outlining the changes made over the previous validated model and the effects on SMP and generator dispatch.

1.2.2 Out of Scope

With agreement from the RAs, a number of model settings and methodologies that were validated in the most recent backcast have not been changed in this update.

The following settings and methodologies were agreed to be out of scope and have not been changed:

- PLEXOS version (6.207 R03 32bit)
- Solver and mode (Xpress MP, Rounded Relaxation)
- Rounded relaxation self-tuning increment (0.05)
- Modelling of hydro and pumped storage plant without minimum stable levels

Though out of scope for this update, the following recommendations were made by Baringa for any future PLEXOS SEM / I-SEM market models used by the RAs:

- Update PLEXOS version to 7.300 R04 64bit
- Reduce rounded relaxation self-tuning increment to 0.1
- Inclusion of interconnector ramp rates (at a level consistent with the SEM "Aggregate Interconnector Ramp Rate")

The model has been validated with data extending to the end of 2018, though it should be noted that the validation does not take account of the change of market structure that will result from the planned switch to I-SEM in May 2018. The validated model is only valid for the current SEM, up until the point of transition to I-SEM.

1.3 Market Participant Responses

As part of the validation exercise, all major market participants were contacted with a request for details of the technical and commercial properties of their plant. Market participants are thanked for responding to this request and to follow-up questions in a timely and thorough manner.

1.4 Comparison with previous models

In the following sections, comparisons are made to the modelled SMP as incremental changes are made to the model (each change builds on the previous changes that have been discussed). Though the focus in this report is SMP, other market indicators have been investigated as part of the validation: generation mix, interconnector flows, and plant merit order.

The comparison in this report is against the model used for the R20 DC strike price formulae update in March 2017 (though updated with the dummy commodity prices presented in Table 1). The last validated model made available to market participants was in June 2016, and some small changes were made between this and the version used in R20, as documented in the notes published by the RAs with each DC subscription. 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 2017	Q2 2017	Q3 2017	Q4 2017
Gas p/th	49.0	44.0	44.0	49.0
LSFO $/t	275	275	275	275
Gasoil $/t	450	450	450	450
Coal ARA API2 $/t	75.0	75.0	75.0	75.0
Carbon €/t	6.00	6.00	6.00	6.00
USD per EUR	1.0533	1.0533	1.0533	1.0533
GBP per EUR	0.8555	0.8555	0.8555	0.8555

2 Generator data

2.1 Generators added and removed

In January 2016, one gas-fired unit at Ballylumford (B6) was decommissioned, and has been removed from the model. Belfast Waste to Energy is scheduled to come online in early 2018 and has been added to the model.

2.2 Generator submitted data

2.2.1 Validation methodology

Market participants were requested to submit technical and commercial cost data for the major generation plant in the market. All generator data was validated against recent submissions to the market.

Market submission data was supplied by the Single Electricity Market Operator (SEMO), collated for the period 1st Oct 2015 – 31st Dec 2016. The submission data consisted of:

- Commercial offer data (COD)
  - Price/Quantity pairs
  - Start-up costs
  - No-load costs
- Technical offer data (TOD)
  - Max capacity
  - Min stable level
  - Min on/off times
  - Hot/warm/cold start times
  - Ramp up/down rates between min stable level and max capacity

Using the generator parameters supplied by market participants for this round of the validation, the market submissions were recalculated by Baringa, and compared with the actual submitted values.

Where the calculated submissions did not match the actual submissions, there was further investigation to understand the discrepancy. Particular attention was paid to December 2016, being the last month of historic data that was used to validate this forward looking model.

Where there were discrepancies, market participants were contacted and in many cases supplied additional information to explain any differences in assumptions. Only when the differences in the calculated and original submitted values were acceptably small were the generator parameters deemed to be "valid" for use in the forward looking model.

In a small number of cases market participants highlighted that plant properties had changed since the 1st Jan 2017, in which cases recent market submission data was collected for the plant in question to validate the new parameter values.

2.2.2 Marginal Generation Costs

Marginal generation costs are defined as those incurred for the last, or *marginal*, MWh of output, and are expressed in €/MWh or £/MWh. Marginal costs can be calculated from the price/quantity pair Commercial Offer Data (COD). Historic commodity prices, along with the submitted heat rates, load points, variable O&M (VOM), mark-ups and Transmission Loss Adjustment Factors (TLAFs), were used to calculate the daily average generation cost at different load points for all plant.

During the validation exercise it was noted that some generators are submitting significantly different bids into each trading window (i.e. Within Day, Ex-Ante). The 2017 Validated model has been validated against the Within Day window bids, as this is the closest market to Ex-Post II against which DC strike prices are referenced.

It was also noted during the validation process that some Northern Irish generators have recently started including gas capacity charges into their bids, and this practice has been replicated in the 2017 Validated PLEXOS model described here.

Table 2 Data used to validate marginal generation costs

Market submissions	Calculated using generator parameters
Price Quantity	Incremental heat rates Load points VOM (€/MWh, £/MWh) Mark up TLAF Historic fuel prices Historic carbon prices Historic FX rates Fuel adder assumptions

For many generators there was good agreement between the market submissions and calculated costs, though initially for some generators the difference was deemed unacceptably high.

The most common reasons for differences were:

- Different fuel adder assumptions
- Mark-ups on incorrect bands
- Inclusion of gas capacity charges in bids

- Difference in the number of price quantity pairs

Market participants were in many cases willing to share confidential data detailing the breakdown of their bids on a small number of days, which was extremely useful in pin-pointing where the differences in assumptions were. This data was used only for the validation exercise described here, and will not be used for any other purpose.

There were some changes in generator properties compared with previous years for individual generators, but for the system as a whole there was no significant movement, and no systematic change.

2.2.3 No-Load Costs

No-load costs are defined as those costs incurred per hour of operation, regardless of output level, and are expressed in €/h or £/h. No-load costs are submitted by market participants directly to the market. Historic commodity prices, along with the submitted no-load fuel usage, VOM and TLAFs, were used to calculate a daily no-load cost.

Table 3 Data used to validate no-load costs

Market submissions	Calculated using generator parameters
No-load cost	No-load fuel usage VOM (€/h, £/h) TLAF Historic fuel prices Historic carbon prices Historic FX rates Fuel adder assumptions

Where there was not good agreement initially, this lack of agreement was again primarily due to:

- Different fuel adder assumptions
- Inclusion of gas capacity charges in bids

2.2.4 Start Costs

Start costs are defined as those incurred per start of a generation plant, and are expressed as €/start or £/start. Start costs are submitted by market participants directly to the market, and are given for Hot, Warm and Cold starts. Historic commodity prices, along with the submitted start-up energy requirement (on a hot/warm/cold basis), the split of fuels (for multi start fuel plant), VOM and TLAFs, were used to calculate daily start costs.

Table 4 Data used to validate start costs

Market submissions	Calculated using generator parameters
Start costs (Hot/warm/cold)	Start-up energy (Hot/warm/cold) Start fuel split %, if multiple start fuels VOM (€/start, £/start) (Hot/warm/cold) TLAF Historic fuel prices Historic carbon prices Historic FX rates Fuel adder assumptions

Again, differences in the market submissions and calculated costs were primarily due to:

- Different fuel adder assumptions
- Inclusion of gas capacity charges in bids

2.2.5 Technical Offer Data

Technical offer data is primarily submitted to the market in the same format that is required for the PLEXOS model. As with COD, historic Technical Offer Data (TOD) from the market was used to validate the generator parameters submitted to the RAs.

Table 5 Data used to validate start costs

Market submissions	Generator parameters
Max capacity	Max capacity
Min stable level	Min stable level
Min on/off times	Min on/off times
Hot/warm/cold start times	Hot/warm/cold start times
Ramp up/down rates Ramping Breakpoints	Ramp up/down rates

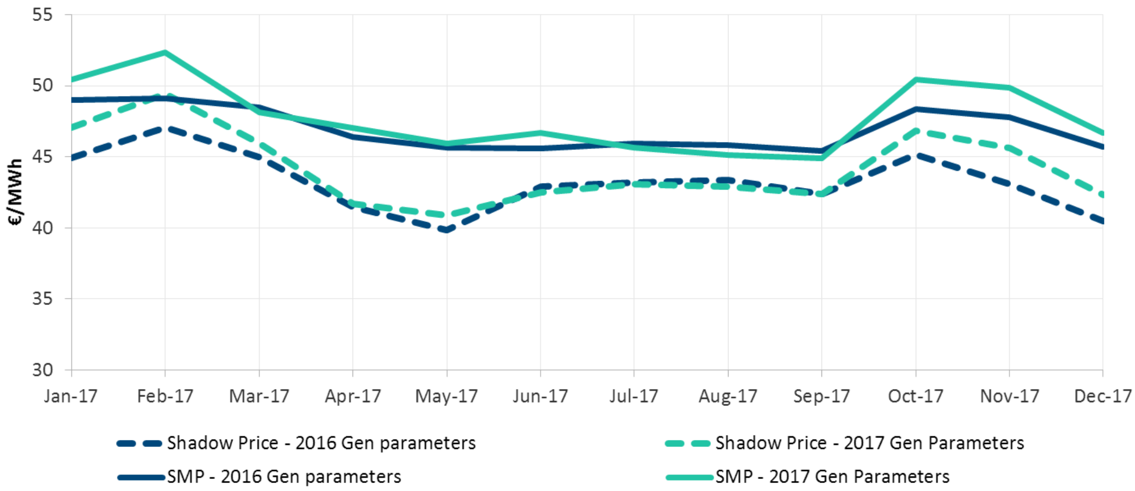
In most cases good agreement was found.

In some cases the generator submission has not been used, in favour of the average (mode) seen in the historic market submissions. In all such cases, generators have been informed of the change and have agreed to it.

2.2.6 Effect of changes on output

The effect of updating all generator properties using the valid parameters described above was to increase SMP slightly in winter but with limited difference in summer. Figure 1 below shows the monthly profiles for shadow price and time-weighted price for 2017 using both the 2017 and 2016 validated generator parameters. The overall impact of updating generator parameters for the 2017 Validated model is an average increase in SMP of 0.8 €/MWh. There are no significant changes in the mix of generator types that are generating (gas, coal, distillate, etc.), though some individual plant have moved in the merit order and so see changes in load factor as a result.

Figure 1 2017 monthly shadow and SMP, with and without generator parameter changes



2.3 Hydro and pumped storage

The representation of hydro and pumped storage generators has not changed in the 2017 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 last backcast validation. Pumped storage is assumed to ramp to full capacity within the 30 minute granularity of the model, and so ramp rates are omitted.

2.4 Outages

2.4.1 Planned maintenance

Outage information for planned maintenance has been updated to the most recent public schedule published by SEMO on their website. Planned outages for 2017 and 2018 use the schedule published in May 2017. Outages and capacity reductions are applied to generation plant in the model as per the SEMO schedule.

The changes in outage schedule are small when looked at market-wide, and do not have a significant effect on SMP.

2.4.2 Forced outages

Market participants were requested to supply forced outage rates for all plant. The rates received were similar to those received in previous validation processes.

Historic forced outages were supplied by the TSOs for the period 2013-2015 and the average forced outage rate was determined by Baringa. This is the same approach as was used in the 2016 validated model.

It was found that the historic rates from the TSOs were systematically higher than the rates provided by market participants. The reason for this is that individual plant do occasionally incur significant failures that result in very long duration outages, so called “High Impact Low Probability” events (HILP). While an individual generator may not expect such an event to incur, at a market-wide level it is likely that some of these events do occur, resulting in lower system availability.

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 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 6 shows the average historic forced outage rates by plant type as used in the model.

These are the same values as used in the 2016 Validated model, ie there is no resulting change to SMP or generation volumes due to the 2017 Validated model outage rates.

Table 6 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%
SEM wide	6.1%

3 System data

3.1 Demand

Demand has been updated to match the TSOs' latest assumptions, consistent with the median Total Electricity Requirement (TER) forecast in the All-Island Generation Capacity Statement GCS 2017-2026. Annual energy and peak demand projections for 2017 are lower than in the previous GCS. This has resulted in a slight decrease in both annual and peak demand of approximately 0.6% and 0.3% respectively in 2017, and a decrease in annual demand of 0.2% and an increase in peak demand of 0.8% in 2018, as shown in Table 7.

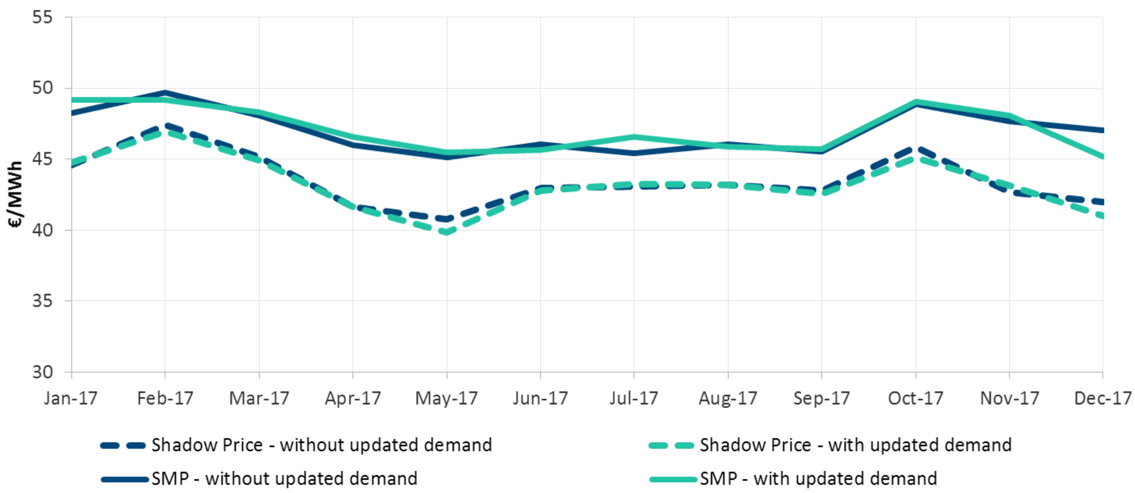
Table 7 Change in GCS electricity demand forecasts

Energy Forecast	*Units*	GCS 2016-2025	GCS 2017-2026	Difference
All Island TER 2017	*GWh*	38,038	37,793	-0.64%
All Island TER Peak - 2017	*MW*	6,888	6,866	-0.32%
All Island TER 2018	*GWh*	38,745	38,663	-0.21%
All Island TER Peak 2018	*MW*	6,938	6,991	0.76%

The base year used to create the half hourly demand profile has been updated to 2015, matching that used in the GCS 2017-2026, and consistent with the base year used for wind generator load factor profiles.

Updating the demand assumptions to match the GCS 2017-2026 has only a minor effect on SMP and Shadow price, as shown in Figure 2.

Figure 2 2017 monthly shadow and SMP, with and without updated demand



3.2 Embedded generation

Embedded generation is represented using an hourly profile, defined for both weekdays and weekends. This has been updated using the TSOs' latest assumptions and matches the GCS 2017-2026. The change is small, and there is no significant effect on SMP.

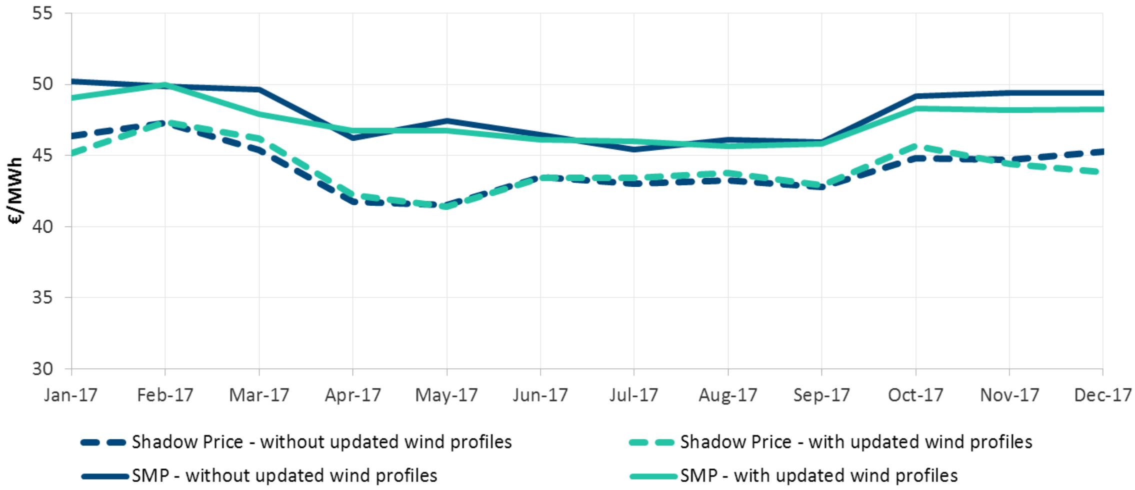
3.3 Wind generation

Wind capacity and load factor assumptions have been updated to match those in the GCS 2017-2026.

In the 2017 Validated model the half hourly wind load factor profiles use 2015 as the base year for all forward projections, compared to a 2009 base year in the 2016 Validated model (and used for R16-R20 of DC updates). The 2015 base year used for wind profiles is consistent with the 2015 base year used for demand profiles, ensuring wind-demand correlations are captured. The capacity factor in 2015 (i.e. Market Scheduled Quantities, before any constraints are applied) was 31%. The long run average for the SEM is 30%, as outlined in the GCS 2016-2025. In the 2017 Validated model the 2015 profiles have been normalised to match the long run average of 30%, which has entailed scaling to give a small decrease in output.

The result on SEM prices of updating the wind load factor profiles is shown in Figure 3, with a small decrease in SMP of 0.56 €/MWh on average, primarily due to increased generation in the high priced Winter months.

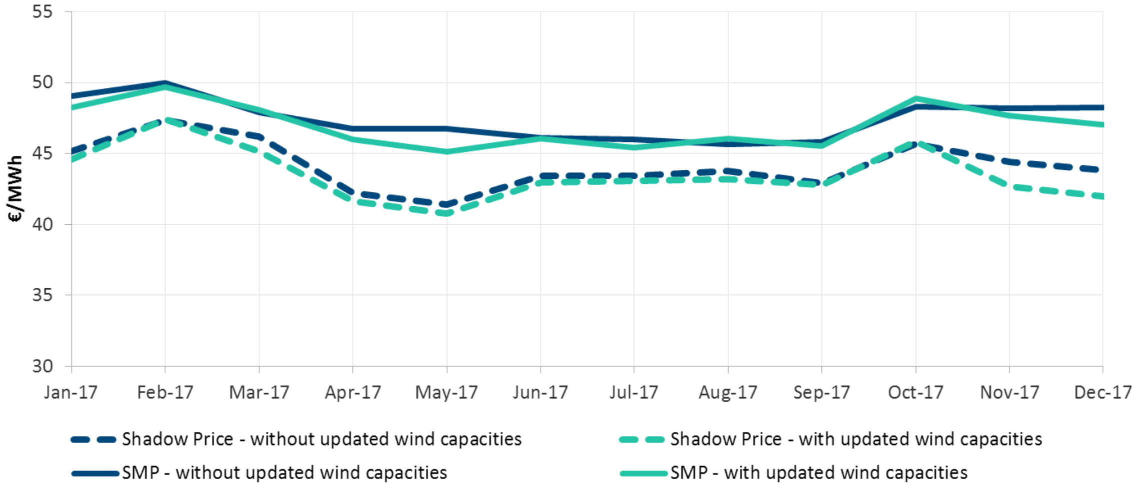
Figure 3 2017 monthly shadow and SMP, with and without updated wind load factor profiles



Wind capacities have been updated to match those forecast in the GCS 2017-2026, where previously the Winter Outlook 2016-17 was used. For 2017 and 2018 the GCS 2017-2026 forecast is based on proposed projects, with a de-rating to account for the likelihood that not all of these projects will be completed. Updating to the latest GCS assumptions results in an increase in assumed wind generation capacity of approximately 611MW as of January 2017.

Including these updated wind capacities in the 2017 Validated model results in a decrease in SMP of 0.41 €/MWh on average, as shown in Figure 4

Figure 4 2017 monthly shadow and SMP, with and without updated wind capacities



3.4 Demand side units

Demand side participation through individual and aggregated demand side units (DSUs) has been updated to include the latest capacity forecasts in the TSO GCS 2017-2026, 335MW for 2017 and 2018.

DSUs may submit two elements of cost as part of SEM:

- Marginal price (€/MWh or £/MWh), and associated quantity (MW)
- Turn down costs (€/turndown or £/turndown)

The representation of DSUs in the 2017 Validated PLEXOS model only allows a marginal price to be used. If the turn down costs are ignored this makes DSU seem to be a lower cost resource is really the case. To include the turn down cost in the marginal cost structure in PLEXOS, we have assumed an average load factor and duration for each DSU, based on historic operation. We have used market submissions and MSQs for calendar year 2016 to find these assumptions for DSU operation and average submitted costs.
After converting individual DSU costs to a marginal only basis, we grouped the DSUs into three tranches, with total capacities and average prices described in

Table 8.

Table 8

DSU Blocks	Quantity (MW)	Price (€/MWh)
DSU 1	100	535
DSU 2	150	640
DSU 3	85	999

Tranche 3 was calculated to have a higher marginal price than is shown, but is capped at 999 €/MWh to allow this capacity to be available to the PLEXOS model, which has a price cap of 1000 €/MWh.

DSU is rarely used in the PLEXOS model, and the update to DSU described above has little effect on output SMP or generation volumes.

3.5 Interconnectors

Interconnector assumptions are unchanged from those used in R16-R20 of DC strike prices.

Moyle is assumed to be running on full import and export capacity (approximately 450MW and 295MW respectively), but is on partial outage during February to September 2017. In October 2017 the export capacity is assumed to drop to 80MW, as per the current agreement on Transmission Export Capacity (TEC) that Moyle have with National Grid.

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

3.6 TLAFs

Transmission Loss Adjustment Factors (TLAFs) assume the published TSO values for 2016/17, as per R20.

4 Modelling methodologies

4.1 GB bid representation

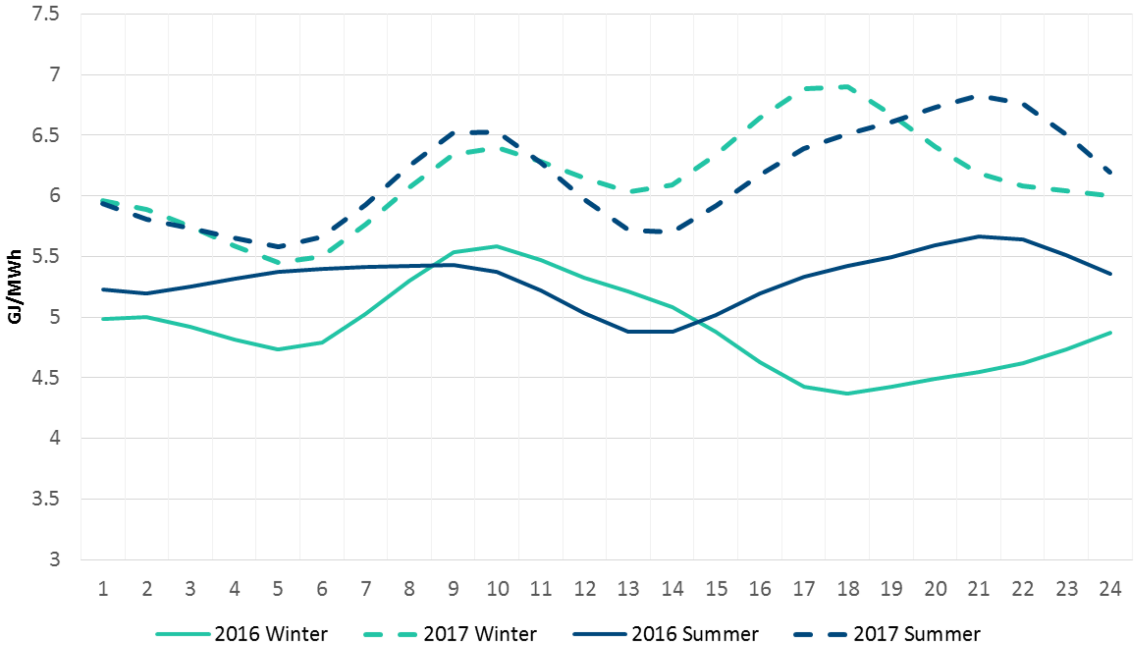
GB bids on the interconnectors are represented using a gas-fired generator. It should be noted that it is *bids* that are being calculated, rather the wholesale price of electricity in the BETTA market. Bids are typically lower than GB wholesale prices, as interconnector bids that clear in the SEM on shadow price will receive additional revenues through SEM capacity payments and uplift. The uncertainty associated with these potential revenues results in a risk premium that slightly increases bids when compared to a scenario of perfect foresight from GB market participants.

To ensure that there is no confusion over the interpretation of the GB bids, the region “BETTA” in the PLEXOS model has been renamed “BETTA IC bid”.

A regression has been performed comparing historic GB bids on the interconnectors with historic gas and carbon prices, on a half-hourly basis for the period June 2015 – May 2017. This represents a more recent horizon versus the 2016 Validated model (Jan 2014 – Dec 2015). Using this regression, the implied heat rate for the single gas plant representing GB interconnector bids was calculated.

In the same methodology as the 2016 Validated model, an hourly heat rate has been calculated for the 2017 Validated model, as shown in Figure 5, which shows a diurnal shape that varies with season. The diurnal shape of GB bids does not quite match the shape of GB power prices, as may at first be expected, due to bidders removing SEM uplift and capacity payments from bids. SEM uplift is reasonably correlated with GB wholesale prices, and its removal has the effect of diluting the typical shape of GB prices in the GB interconnector bids.

Figure 5 Heat rate used to represent GB interconnector bids, 2016 vs 2017 Validated models



The effect of the higher GB heat rate is to reduce imports and increase exports over the interconnector, with net exports close to 0 – matching recent historical flows. Interconnector flows are shown in Figure 6 and Figure 7 for models using the 2016 calibrated GB interconnector (IC) bid heat rates and the new 2017 Validated GB IC bid heat rates respectively.

Figure 6 Interconnector flows using 2016 Validated GB IC bid heat rates

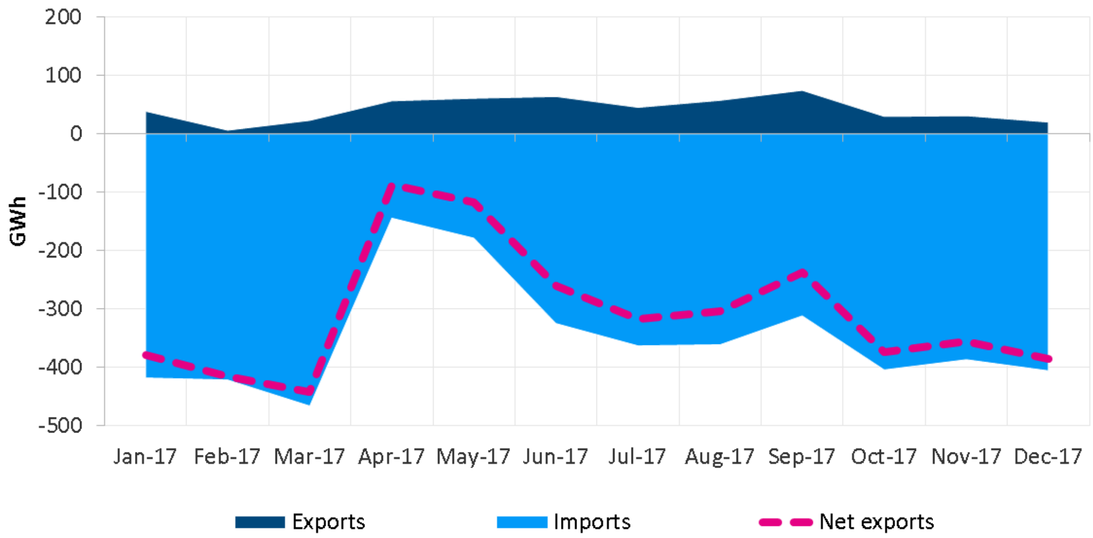
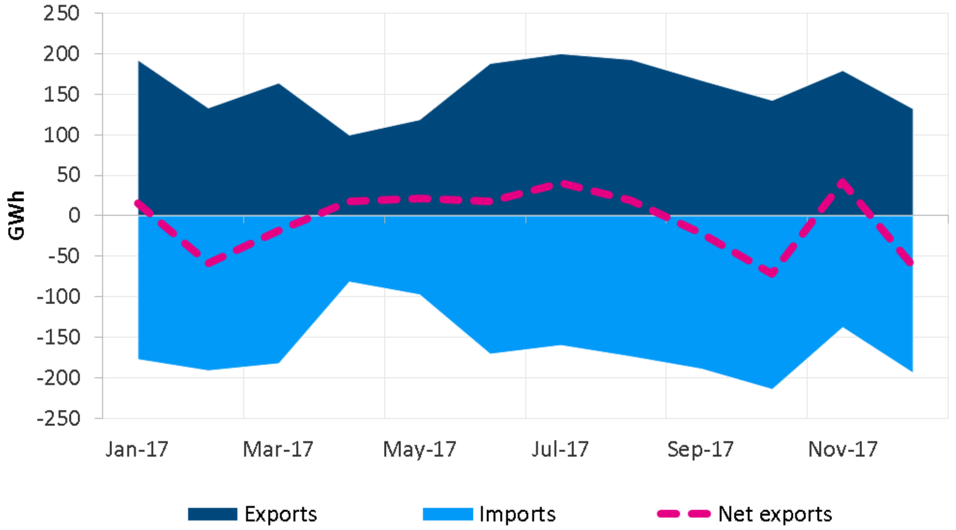
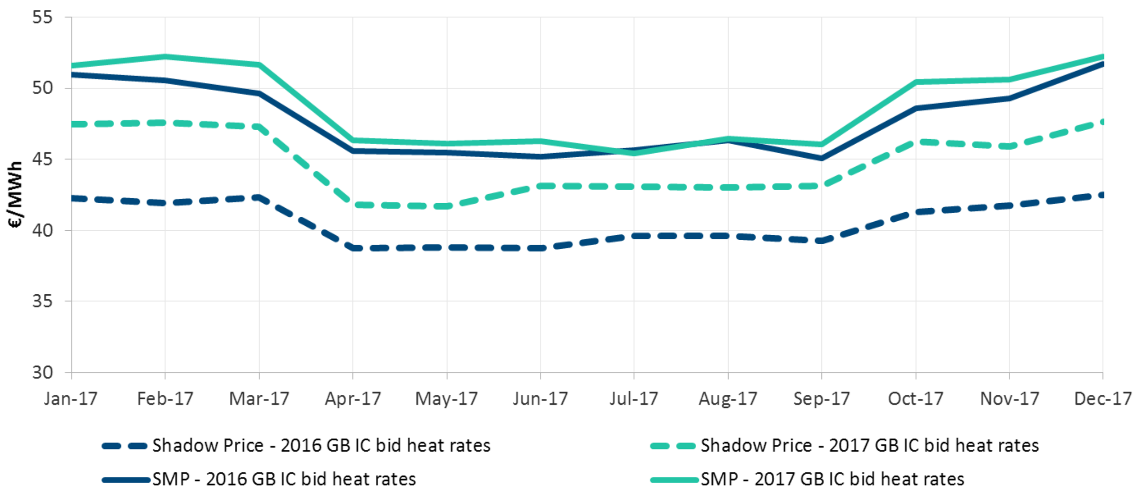


Figure 7 Interconnector flows using 2017 Validated GB IC bid heat rates



SMP is increased by approximately 0.9€/MWh as a result of updating the 2017 Validated GB IC bid heat rates in the model. Figure 8 below details the monthly time-weighted shadow price and SMP, with and without the updated GB interconnector bid heat rates. It can be seen that shadow price has increased markedly, but uplift (SMP minus shadow) has reduced, such that SMP is only slightly increased. This is due to the interconnector bid heat rate being higher, increasing shadow costs, but also being close to marginal more often, and so the interconnectors' flexibility is being used to cover short term fluctuations in net demand, reducing the number of peaking plant starts and therefore reducing uplift.

Figure 8 2017 monthly shadow and SMP, with 2016 and 2017 Validated GB IC bid heat rates



5 Fuel adders and input sheet

5.1 Fuel Adders

Market participants were requested to submit details of any additional costs that increase the cost of fuel used above the standard market traded prices, so called “fuel adders”.

Using the responses, and publicly available costs (for gas network charges for example), fuel adders have been updated. To ensure the confidentiality of generator costs, the updates to fuel adders are always blended between market participant submissions, and none of the updated values come from any single participant.

Most of the fuel adder changes are minor with no significant effect on plant dispatch or SMP.

5.2 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 2016 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 latest 2017 Validated model fuel adder assumptions are included.

6 Final Results

6.1 Final model results

The final validated model includes all of the changes described in the previous sections. The net effect on SMP is an increase in summer months of approximately 0.9€/MWh and in winter months of 1.8€/MWh, as shown in Figure 10 and Figure 11.

Figure 9 Monthly shadow and SMP, with and without all changes included

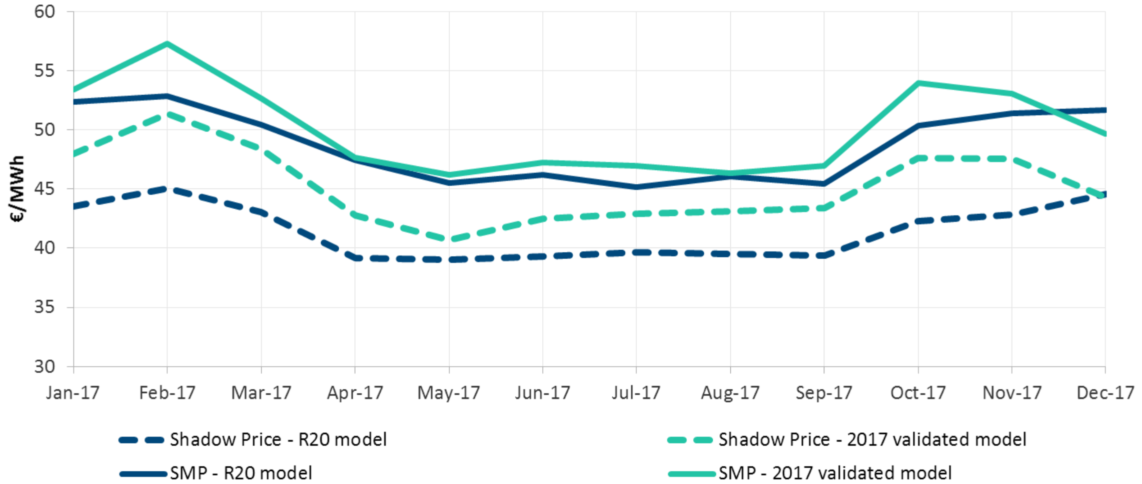


Figure 10 Hourly Summer SMP profile, with and without all changes included

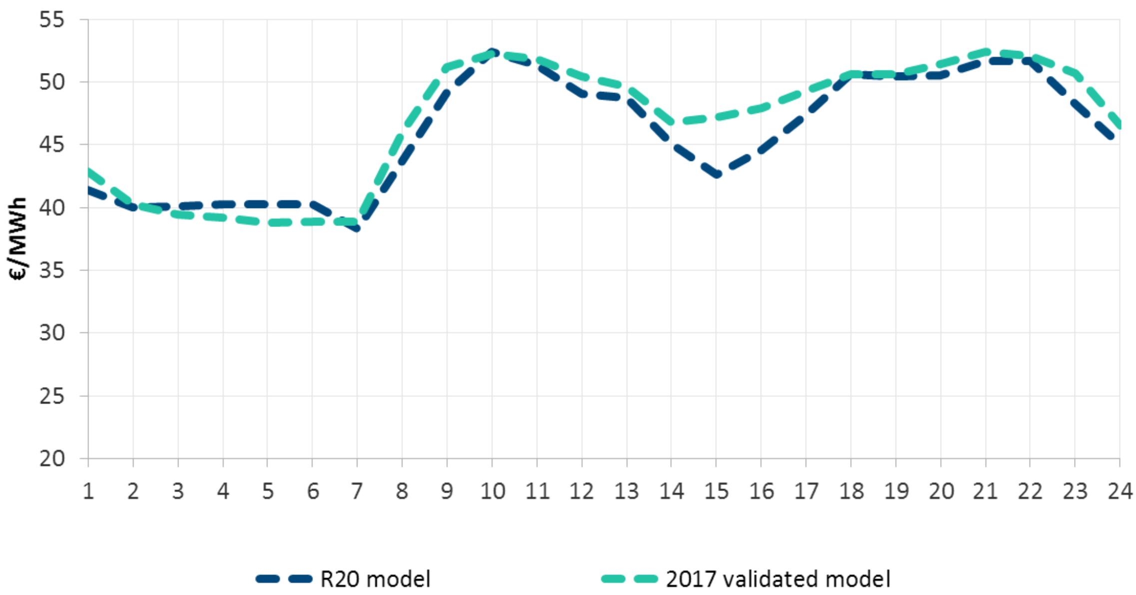
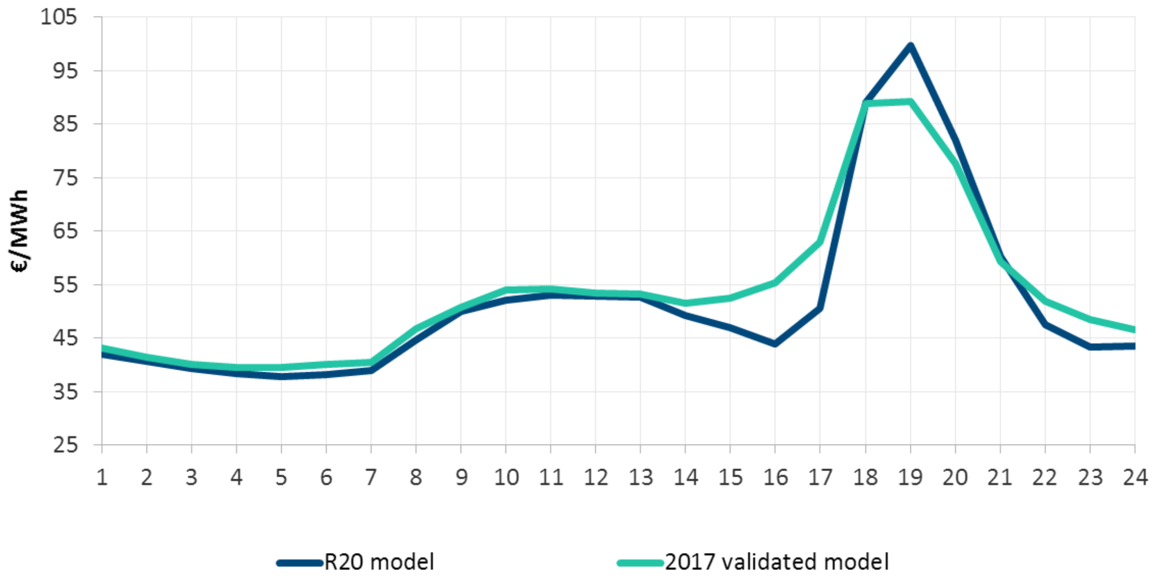


Figure 11 Hourly Winter SMP profile, with and without all changes included



Interconnector import flows have reduced and export volumes from SEM to GB have increased due to the increased heat rate of the GB interconnector bid, as per Section 4.1. ROI gas and increased wind volumes on the system compensate for the drop in imports, shown for the 2017 Validated model in Figure 12. Interconnector flows are shown for the 2017 Validated model in Figure 13.

Figure 12 Generation by plant type

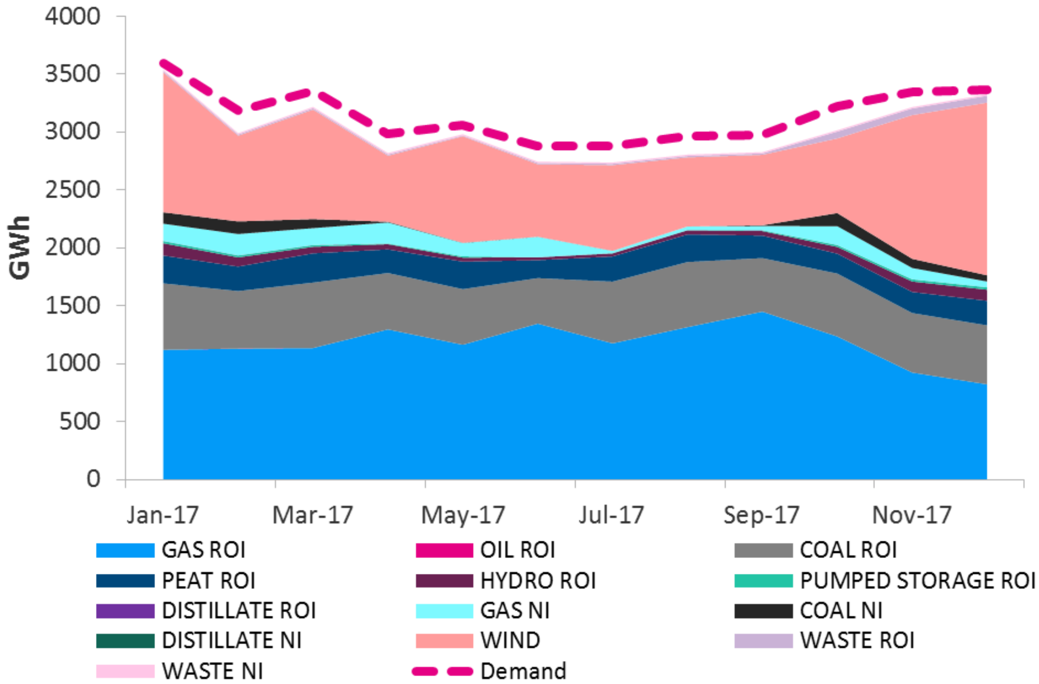
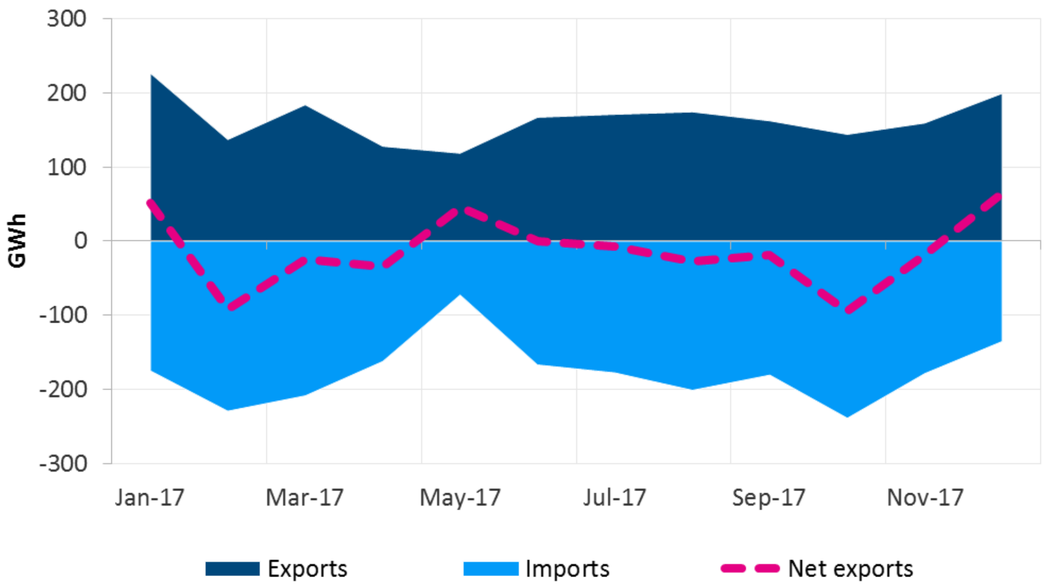


Figure 13 Combined interconnector flows



6.2 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
2. Public model
   - All confidential data removed