I-SEM Validated model – Re-issue following correction to embedded generation assumptions

CLIENT: **CRU/URegNI**

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Introduction

In November 2017 the Regulatory Authorities for the Single Electricity Market (RAs) in Ireland and Northern Ireland published their I-SEM Validated PLEXOS model, validated for the period 2018-19[1]. This model was developed with technical support and validation from Baringa[2], who provided an accompanying information paper that described the changes made to the RAs' validated model to allow it to be used for the period 2018-19, and the resulting changes to the outputs from the model.

Quality Assurance performed by Baringa as part of Baringa's support to the RAs for Directed Contracts Round 2 has highlighted an error in the Validated PLEXOS model published in November 2017. The error results in no generation from embedded plant for calendar year 2019.

This note covers the following:

- Explanation of error
- Analysis of impact on results coming out of the model
- Analysis of impact on pricing of Round 1 Directed Contracts

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".

[1] https://www.semcommittee.com/publication/i-sem-plexos-model-validation-2018-2019-information-paper-0

[2] Baringa's formal role was as follows: to provide technical support to validate the RAs' PLEXOS model for the period Q2 2018 to Q4 2019 inclusive, in the process validating the PLEXOS model algorithms, modelling assumptions and model input data, engaging with market participants including the TSOs, transferring knowledge to RA staff, and preparing a report for publication by the RAs on the whole validation exercise.

Issue

The Validated PLEXOS model includes a representation of transmission demand that contains two components:

- Underlying demand
  - This is based on the “Total Electricity Requirement” (TER) definition of demand as outlined by the Transmission System Operators (TSOs) in their Generation Capacity Statement
- Embedded generation
  - Small scale generation that reduces net transmission demand
  - The assumption around the level of embedded generation is consistent with that used by the TSOs in coming up with the TER demand figures, and is supplied by the TSOs

Embedded generation is included in the Validated PLEXOS model through the “Fixed Generation” property applied to the SEM Region, as shown in Figure 1. CSV files are used to set the level of output from embedded generation in each hour of the year. A different CSV file is used for each year, as shown in Figure 2

Figure 1 Implementation of embedded generation in Validated PLEXOS model

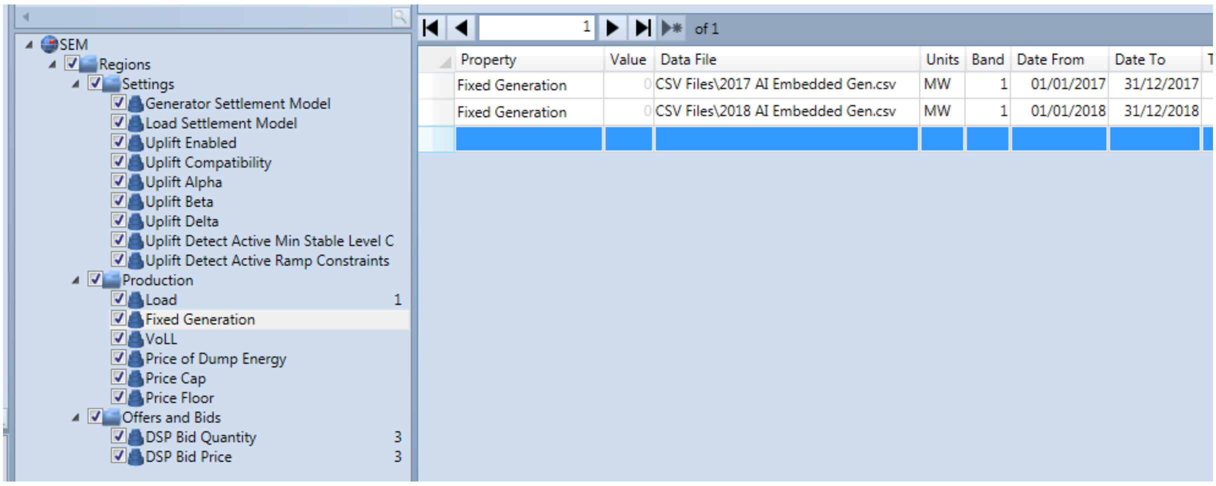
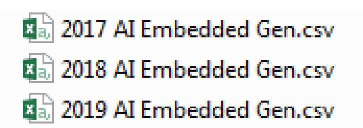


Figure 2 Embedded generation CSV files in Validated PLEXOS model

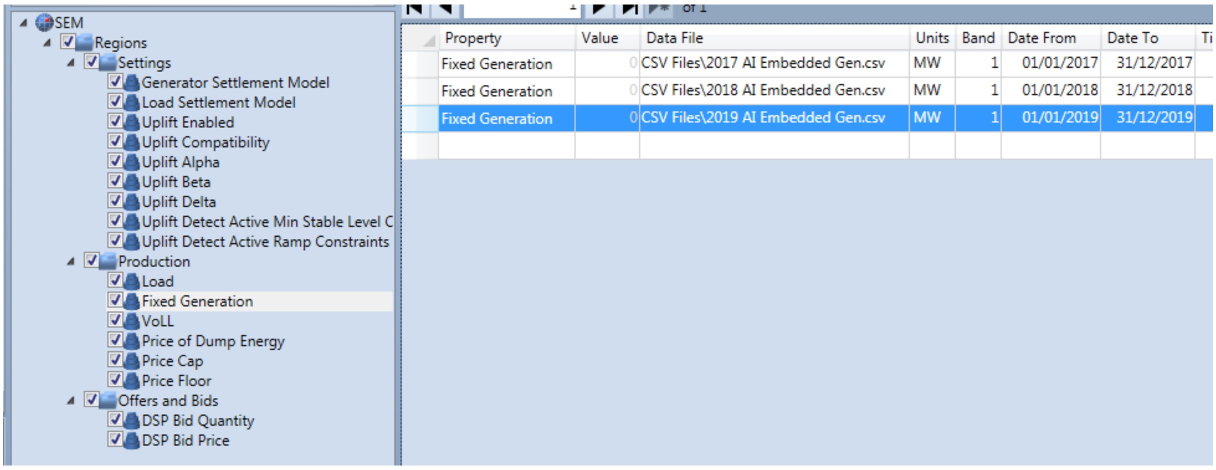


The error now identified in the Validated PLEXOS model published in November 2017 is that there is no reference to the 2019 embedded generation CSV file in the PLEXOS model, as can be seen in Figure 1. This results in the default value of 0 MW being assumed for the output of embedded generation in every hour of 2019, rather than the output levels consistent with the TSOs’ assumptions. The TSOs’ assumption for the output of embedded generation for 2019 is that it operates between 205MW and 283MW, with an average output of 242MW.

Impact on Validated model

To assess the impact of this error we have corrected the reference to the 2019 embedded generation CSV file in the Validated PLEXOS model, as shown in Figure 3.

Figure 3 Correction to embedded generation in Validated PLEXOS model



We have re-run the Validated PLEXOS model with this correction to embedded generation, using the same commodity price assumptions outlined in the information note published with the Validated PLEXOS model in November 2017. The only change to the Validated PLEXOS model has been to include this missing embedded generation.

In the tables and charts below we outline the key impacts of this change.

Price

The impact on 2019 Baseload prices is a decrease of ~3% on average, as outlined in Table 1. The impact is higher in quarters of tighter capacity margin. With the correction made, there is little change in the 2019 prices when compared to the 2018 prices.

Table 1 Impact on Baseload power price (€/MWh)

Period	Validated model, November 2017 published	Validated model, March 2018 corrected	Delta due to correction (%)
Q1 2018	57.9	57.9	0.0%
Q2 2018	46.7	46.7	0.0%
Q3 2018	46.3	46.3	0.0%
Q4 2018	51.5	51.5	0.0%
Calendar Year 2018	*50.6*	*50.6*	*0.0%*
Q1 2019	61.0	57.7	-5.5%
Q2 2019	47.5	46.6	-1.9%
Q3 2019	46.1	45.9	-0.3%
Q4 2019	52.4	50.9	-2.9%
Calendar Year 2019	*51.8*	*50.3*	*-2.8%*

The hourly price shape for Winter and Summer prices is shown in Figure 4 and Figure 5. The largest impact of the inclusion of embedded generation is seen in peak periods in Winter, the period of tightest capacity margin.

Figure 4 Hourly power price, Winter months 2019 (€/MWh)

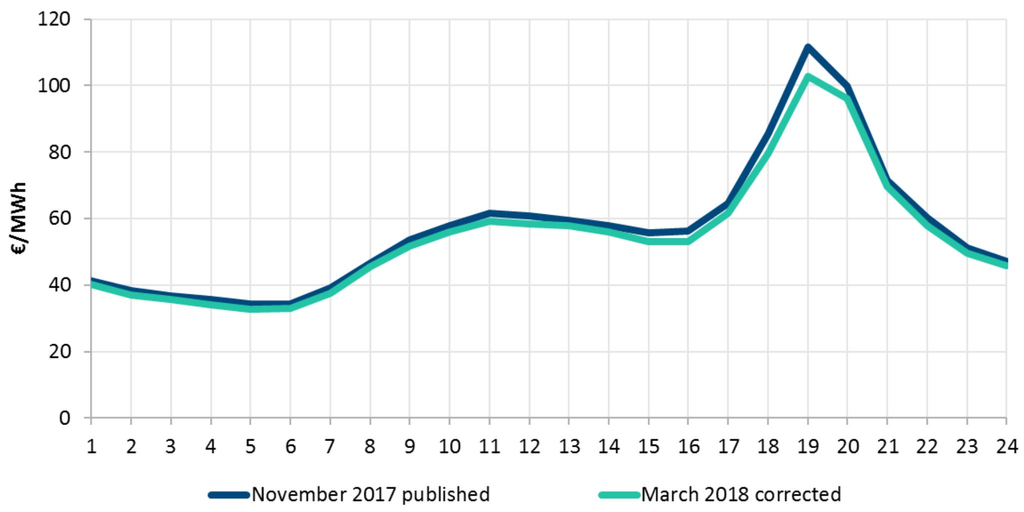


Figure 5 Hourly power price, Summer months 2019 (€/MWh)

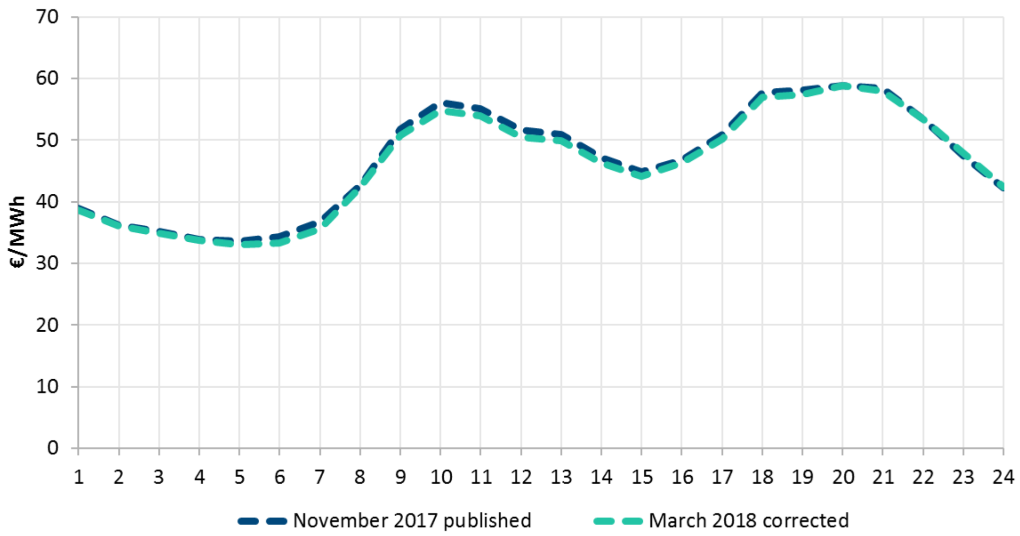
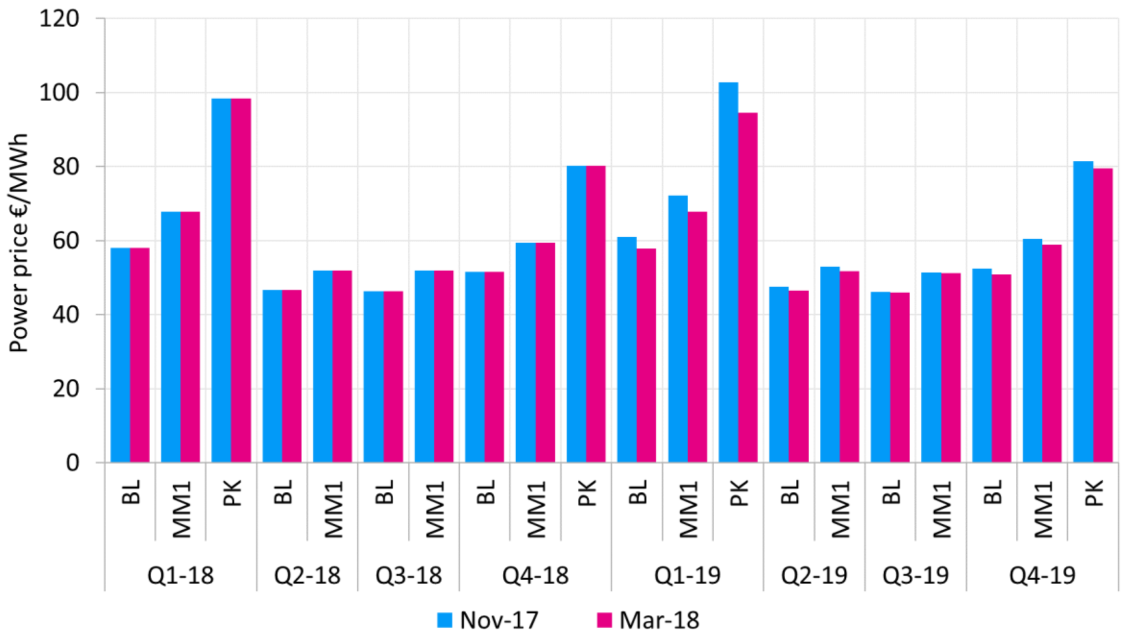


Figure 6 shows the prices from the November 2017 and March 2018 models mapped to Directed contract types for 2018 and 2019. It can be seen that the impact of the correction is greater for contracts of tight capacity margin, i.e. Peak vs Mid-merit and Baseload, Q1 vs Q2.

Figure 6 Validated model prices mapped to Directed Contracts (€/MWh)



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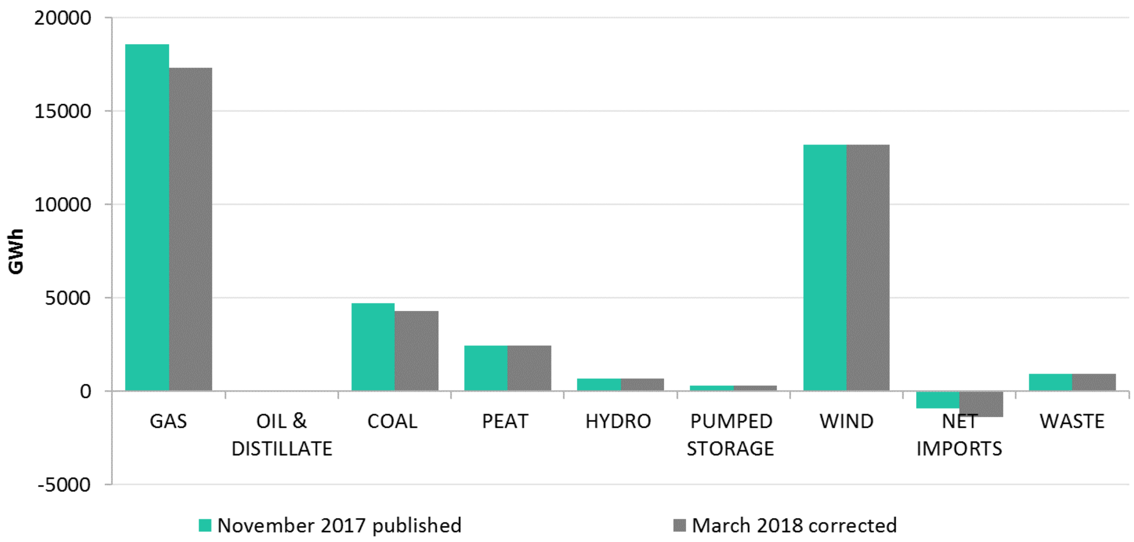
Generation

The inclusion of embedded generation has displaced other sources of generation. Table 2 shows the generation volumes for each plant category for 2019. The biggest absolute difference in generation volumes as a result of the inclusion of embedded generation comes from ROI Gas fired generation, with significant reductions in volume for other Gas and Coal fired generation and interconnector imports. The biggest relative difference is seen for peaking plant (Oil and Distillate fired). Low carbon sources of generation are not displaced by embedded generation and see minimal change in volumes. Figure 7 shows the same data, aggregated on an All-Island basis.

Table 2 Generation volumes, by plant type, 2019 (GWh)

Generator Type	Validated model, November 2017 published	Validated model, March 2018 corrected	Delta (GWh)
GAS ROI	16100	15080	-1020
OIL ROI	21	10	-11
COAL ROI	4150	3847	-303
PEAT ROI	2466	2448	-18
HYDRO ROI	690	690	0
PUMPED STORAGE ROI	311	312	2
DISTILLATE ROI	2	1	-1
GAS NI	2472	2267	-206
COAL NI	579	466	-113
DISTILLATE NI	0	0	0
WIND	13201	13193	-8
GB IC Bid	6164	5723	-440
WASTE ROI	684	682	-2
WASTE NI	260	260	0

Figure 7 Generation volumes, by All-Island plant type, 2019 (GWh)



Impact on Round 1 Directed Contracts

The Validated model published in November 2017 was used without alteration to calculate the formulae used to set Round 1 Directed Contract strike prices.

To understand the impact of the error on the formulae used in Round 1 the corrected Validated model has been used to repeat the R1 analysis.

The formulae coefficients used to set R1 Directed Contract strike prices have been recalculated using outputs from the corrected model. Using commodity prices and FX from 14th of November 2017, the resulting prices from the two sets of R1 DC formulae are shown in Table 3.

R1 DC prices for Q1 2019 decrease by approximately 5% as a result of correcting the missing embedded generation issue.

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Table 3 Prices from R1 formulae, commodity forwards and FX as of 14/11/2017 (€/MWh)

Contract period	R1 formulae, published Dec 2017	R1 formulae, Corrected March 2018	Delta due to correction (%)
"Q2"-18 BL	48.42	48.42	0.0%
"Q2"-18 MM1	53.74	53.73	0.0%
Q3-18 BL	45.95	45.95	0.0%
Q3-18 MM1	51.18	51.18	0.0%
Q4-18 BL	50.37	50.37	0.0%
Q4-18 MM1	58.53	58.53	0.0%
Q4-18 PK	79.21	79.21	0.0%
Q1-19 BL	61.90	58.80	-5.0%
Q1-19 MM1	73.26	69.34	-5.4%
Q1-19 PK	104.57	98.83	-5.5%

Power prices predicted by the model remain significantly higher in Q1 2019 than Q4 2018, after correcting the missing embedded generation issue. Aside from the missing data error, there are differences between the assumptions used to represent Q4 2018 and Q1 2019. These are:

- Demand profiles (based on 5 historical years of outturn demand, on average 4% higher in Q1)
- Large outage at Great Island assumed in Q1 2019
- Gas Short Term Capacity charges are significantly higher in Q1 than Q4, increasing the marginal cost of gas for generators who are exposed to these charges by approximately 35%
- Commodity price and FX differences increase gas prices by approximately 8% in Euro terms in Q1 2019 when compared with Q4 2018. Other commodities shown little movement
- Other small differences (other planned and unplanned outages, wind capacities and profiles)

Figure 8 shows quantitatively the magnitude of these differences on the final Baseload price for the quarter. Changes to the model were made cumulatively, moving from Q4 2018 assumptions to Q1 2019 assumptions. The approach was as follows:

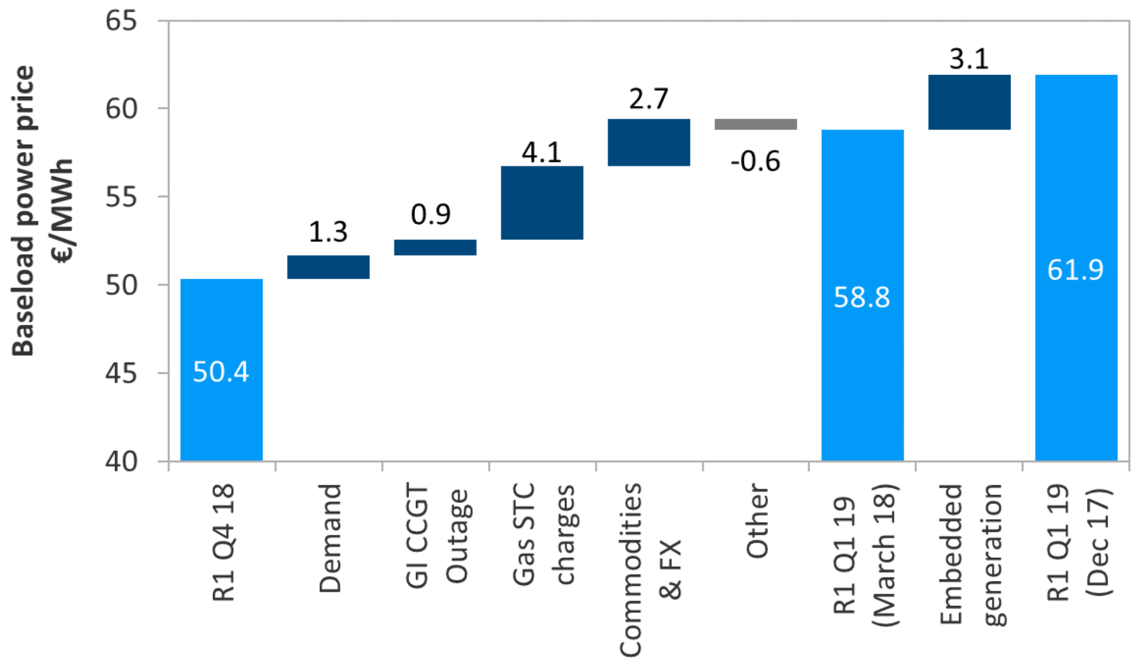
1. Start with relevant R1 (Dec 2017) assumptions for Q4 2018 and Q1 2019
2. Adjust Q1 2019 assumptions to match Q4 2018:
    a. Use Q4 2018 demand profiles
    b. Remove large Great Island outage
    c. Use Q4 2018 gas short term capacity charges
    d. Use Q4 2018 commodity and FX assumptions
    e. Embedded generation included
3. Run the Q1 2019 horizon, cumulatively moving from Q4 2018 assumptions to Q1 2019 assumptions:
    a. Change demand profiles to match Q1 2019
    b. Include Great Island outage assumption to match Q1 2019
    c. Change gas short term capacity charges to match Q1 2019
    d. Change commodity and FX assumptions to match Q1 2019
4. The deltas shown in the waterfall chart below come from the difference in Q1 2019 Baseload power price results from successive model runs as outlined above

5. The remaining delta between R1 Q4 2018 and R1 Q1 2019 (March 18) Baseload prices is labelled “Other”, and covers all other small differences in assumptions between these quarters (other planned and unplanned outages, wind capacities and profiles)
6. Finally, embedded generation was removed to test the difference between the models used for R1 Q1 2019 in March 2018 and December 2017

While effort has been made to separate these factors, it should be noted that in any complex market model such as the RAs’ Validated Model the various input factors combine in a non-linear way to give the outputs, and if the order of testing was to be altered the precise numbers would change slightly. However, the result of the testing above show the relative magnitude of the different assumptions used for Q4 2018 and Q1 2019.

It can be seen that a number of factors lead to a higher price in Q1 2019. After correcting for the missing embedded generation in 2019 (3.1 €/MWh), the largest single drivers of Baseload price are commodity related – gas wholesale prices and short terms capacity charges. An 8% increase in gas prices results in a 2.7 €/MWh rise in power prices, predominantly shadow price (2.35 €/MWh) related. High Q1 short term capacity charges result in a 4.1 €/MWh rise in power prices, split between shadow price (1.6 €/MWh) and uplift (2.5 €/MWh) due to these charges affecting peaking plant with start costs to be recovered over short running times.

Figure 8 Waterfall chart of factors driving price delta between Q4 2018 and Q1 2019 (€/MWh)



Summary

An error has been identified in the RAs Validated PLEXOS model, published in November 2017. Embedded generation was not included in the model for calendar year 2019.

The correct inclusion of this embedded generation has an impact on prices of 2.8% for Cal 2019.

The RAs' Validated model was used for Round 1 of Directed Contracts, where the issue affected all Q1 2019 contracts. Correcting for the issue and recalculating the R1 Q1 2019 formulae coefficients results in DC strike prices for Q1 2019 that are approximately 5% lower than those found using the R1 formulae published in December 2019.

We have corrected the issue in the model and provided the RAs with two corrected versions:

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

Version History

Version	Date	Description	Prepared by	Approved by
1.0	14th March 2018	Final	Baringa Partners LLP	Baringa Partners LLP

Contact

Baringa Model Validation (RAsModelValidation@baringa.com)

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