



Validation Report for I-SEM PLEXOS Model, 2018-2023

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Report qualifications/assumptions and limiting conditions

NERA was commissioned by the Commission for Regulation of Utilities of Ireland and the Utility Regulator of Northern Ireland, collectively the “Regulatory Authorities” or the “client”, to update and validate the Regulatory Authorities’ PLEXOS Model of the I-SEM electricity market (*i.e.*, the electricity market of Ireland and Northern Ireland that will take effect after the “I-SEM Go Live” date) to produce this accompanying report. The primary audience for this report includes the stakeholders in the electricity market of Ireland and Northern Ireland.

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NERA has provided to the Regulatory Authorities a public and a confidential version of a PLEXOS model of the electricity market of Ireland and Northern Ireland along with supporting spreadsheets and data files (collectively the “Model”), where we expect the Regulatory Authorities will make the public version available for download on the internet. The results produced by the Model may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. In particular, actual results could be impacted by future events which cannot be predicted or controlled, including, without limitation, changes in business strategies, the development of future products and services, changes in market and industry conditions, the outcome of contingencies, changes in management, changes in law or regulations. NERA accepts no responsibility for actual results or future events. No obligation is assumed to revise the Model to reflect changes, events or conditions which occur subsequent to the date hereof. NERA shall have no responsibility for any modifications to, or derivative works based upon, the Model made by the client or any other third party.

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Acronyms Used in Report

CFD	Contract for Differences
CHP	Combined Heat and Power
CO ₂	Carbon Dioxide
CPS	Carbon Price Support
CRU	Commission for Regulation of Utilities
DSU	Demand Side Unit
FOM	Fixed Operating and Maintenance
FOR	Forced Outage Rate
GB	Great Britain
GCS	Generation Capacity Statement
GJ	Gigajoule
I-SEM	Integrated Single Electricity Market
MIP	Mixed Integer Programming
MW	Megawatt
MWh	Megawatt Hour
NI	Northern Ireland
P-Q	Price-Quantity
QA	Quality Assurance
RAs	Regulatory Authorities
ROI	Republic of Ireland
RR	Rounded Relaxation
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
TLAFs	Transmission Loss Adjustment Factors
TSOs	Transmission System Operators
UREGNI	Utility Regulator of Northern Ireland
VOM	Variable Operating and Maintenance

Executive Summary

NERA was engaged by the Commission for Regulation of Utilities (“CRU”) of Ireland and the Utility Regulator of Northern Ireland (“UREGNI”), collectively the Regulatory Authorities (“RAs”), to update and validate the RAs’ PLEXOS Model of the I-SEM electricity market. Our assignment was to produce a PLEXOS model of the I-SEM valid from I-SEM Go Live through 2023.¹

We started with the previous PLEXOS model which covered 2018 to 2019 (“2018-2019 I-SEM Validated Model”). To extend the model to 2023 we extended the forecasts for load, wind capacity, embedded generation, and generator outages to 2023, using data from the transmission system operators (“TSOs”) of Ireland and Northern Ireland. We also assessed what new thermal generation units might come online before the end of 2023 and what units might retire. Ultimately, we included no new units in the model as no units met the TSOs’ criteria for inclusion in their adequacy studies. We retire the Tarbert plant at the end of 2022, as reflected in the TSOs’ capacity adequacy analysis. We also retire the Marina CC plant and the AD1 unit at the Aghada plant at the end of September 2018, reflecting their actual retirement dates.

Based on data requests to the generation companies, and subject to our and the RAs’ review, we updated certain generator technical and commercial offer parameters.

While the actual I-SEM went live before this report will be published, the bulk of the validation work was completed before the go-live date, and moreover it was outside of our scope to review the initial I-SEM data. Thus, in our validation of an I-SEM model through 2023 (as well as in the previous validation of the 2018-2019 I-SEM Validated Model), the consultant must decide how to model the I-SEM without using actual I-SEM data to guide its decisions. We spend much of the report below reviewing the various options for modeling the I-SEM, assessing the pros and cons of different approaches, and showing the effect of those choices on PLEXOS results.

In the end, we recommend maintaining each of the I-SEM modeling decisions from the previous 2018-2019 I-SEM Validated Model. For example, we maintain cost-based offers by the generators and the use of the so-called Korean uplift algorithm to determine prices that incorporate the recovery of generators’ start-up and no-load costs. We also maintain the rounded relaxation solver. Firstly, the choices made in the 2018-2019 I-SEM Validated Model were reasonable, and secondly, we believe it would be premature to adjust the PLEXOS modeling approach of the I-SEM without using actual I-SEM data to support potential changes. We recommend, however, that the RAs re-evaluate the modeling choices once enough actual I-SEM data are available to help determine which choices produce results that better match the prices, unit dispatch, and interconnector trade in the I-SEM.

¹ SEM Committee Information Note (SEM-18-004) confirmed that a validated SEM PLEXOS model up to 2023 is required in order to facilitate the RAs in fulfilling its modelling requirements including the completion of its Existing Capacity Price Cap assessments and Unit Specific Price Caps assessments for the upcoming capacity auctions (*i.e.* T-1: Capacity Year 2019-20 and T-4: Capacity Year 2022-23).

I. Introduction

NERA was engaged by the RAs to update and validate the RAs' PLEXOS Model of the I-SEM electricity market.

Note about I-SEM vs. SEM

SEM stands for the Single Electricity Market, the single market for Ireland and Northern Ireland. I-SEM stands for Integrated-Single Electricity Market, where the integration is with the wider electricity markets of Europe.

Throughout this report, we use "I-SEM" to refer to the market under the new "I-SEM" trading arrangements. We use "SEM" to refer to the market under the prior trading arrangements, *i.e.*, the market that went live in November 2007 and continued until I-SEM Go Live.

A. Scope

The RAs engaged NERA to update and validate the PLEXOS model from I-SEM Go-Live through the end of 2023. In practice, the model we delivered to the RAs allows for model runs for the entirety of 2018 through 2023 even though I-SEM Go-Live occurred after the beginning of 2018.

Our assignment includes two principal steps.

- 1) Validate and update the input data (system input data and generator technical and commercial offer data) from the 2018-2019 I-SEM Validated Model, *i.e.*, the most recent Validated I-SEM PLEXOS Model produced before our engagement.² The resulting model is to be valid for 2018 through the end of 2023.
- 2) Review and update, as appropriate, the PLEXOS modeling settings from the 2018-2019 I-SEM Validated Model.³

² The Information Paper for this prior validated model was published on the SEM Committee website on 23 November 2017. We refer to this model as the "2018-2019 I-SEM Validated Model." Baringa Partners LLP performed this most recent validation. See <https://www.semcommittee.com/news-centre/i-sem-plexos-model-validation-2018-2019-information-paper>. This internet link, and all other internet links in this report, are valid as of 6 November 2018, unless otherwise noted.

³ NERA notes that a primary purpose of the prior validation of the 2018-2019 I-SEM Validated Model was to assess how the I-SEM trading arrangements should be modeled in the PLEXOS model. As part of our scope, we have reviewed the modeling decisions made in the prior validation exercise. However, we note that a *de nouveau* assessment of how to model the I-SEM trading arrangements in PLEXOS is outside of the scope of our current validation assignment.

An I-SEM “backcasting” exercise is outside the scope of our engagement and is not possible before enough data from the I-SEM become available.⁴ The RAs may wish to include a backcasting exercise in future validations of the I-SEM PLEXOS model, once enough actual I-SEM data are available.⁵

Note on timing: The bulk of our validation was completed by the middle of May 2018. The RAs requested us to finalize our validation when EirGrid published the 2018-2027 All-Island Generation Capacity Statement (“2018 GCS”).⁶ Our scope to update the 2018-2023 I-SEM Validated Model based on the 2018 GCS was limited to updating the forecast for demand and wind capacities and to the retirements of two units (AD1 and Marina CC).⁷ In all other aspects, our model reflects data available to us prior to our completion of the bulk of the validation in May 2018.

B. Treatment of I-SEM

The I-SEM will reflect several important changes in how generators bid into the market and how prices are formed, as compared to the way the SEM works. Various important changes are outlined in Table 1 below.

⁴ Backcasting refers to running a model to “backcast” a historical period. In a backcast, the modeler uses some historical data as inputs then runs the model to see how well it reproduces important historical results, such as market prices.

⁵ There is not a clear definition of what would constitute “enough” I-SEM data to analyze to support potential changes to the validated PLEXOS model. For context, a full year of data would allow one to observe seasonal patterns, but assessing less data, *e.g.*, several months of data, may also be useful (when NERA validated PLEXOS for the RAs about one decade ago at the beginning of the SEM, we utilized less than one year of data as that was all that was available at that time).

⁶ The TSOs produce an All-Island Generation Capacity Statement annually. That report presents expected future available generation capacity on the Island of Ireland. The 2018 GCS is available here http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_2018.pdf.

⁷ The 2018 GCS also includes an update to the quantity of Demand Side Units in the SEM / I-SEM – however, we already had reflected that update in our work through May 2018, as Eirgrid had previously provided us with preliminary information on the Demand Side Unit capacity that would be reflected in the 2018 GCS (and the Demand Side Unit capacity in the published 2018 GCS is unchanged from the preliminary information we had received).

Table 1: Differences Between SEM and I-SEM⁸

SEM	I-SEM
Generator offers include separate start, no-load, and incremental energy costs	Offers no longer include these separate costs; yet, generators will have flexibility to present various offer types including simple hourly orders, block orders, and complex orders
Market prices include an uplift that allows for recovery of start and no-load costs ⁹	There is no separate uplift; nonetheless the price may include no-load and start cost recovery to the extent generators incorporate those costs in their offers
Generators are constrained by bidding principles to offer cost-reflective bids	Generators are not constrained by cost-reflective bidding in the day-ahead I-SEM market
Generators provide explicit technical limits such as minimum runtimes as part of their offers into the SEM	Generators do not provide these limits explicitly, but may structure their offers in a way that reflects those limits

Despite these differences, the 2018-2019 I-SEM Validated Model maintained the basic structure of the RAs' validated models prior to the 2018-2019 I-SEM Validated Model. Those prior models covered the *SEM* trading arrangements. As with the *SEM* Validated PLEXOS Models, the 2018-2019 I-SEM Validated Model includes:

- 1) Cost-reflective bidding, *e.g.*, commercial offers based on fuel, CO₂-emission, and Variable Operation and Maintenance (“VOM”) costs;
- 2) Explicit use of separately stated generator start, no-load, and incremental costs, along with explicit use of generator technical requirements such as minimum runtimes; and
- 3) Use of an explicit uplift algorithm to determine prices that reflect recovery of start and no-load costs.

⁸ The report accompanying the recent 2018-2019 I-SEM Validated Model discusses differences between the SEM and I-SEM in more detail. See Section 2 of “I-SEM PLEXOS Validation, 2018-19”, Baringa Partners LLP, 16-November-2017. We refer to this report as “2018-2019 I-SEM Model Validation Report”. It is available here <https://www.semcommittee.com/news-centre/i-sem-plexos-model-validation-2018-2019-information-paper>.

⁹ See Section III.B below for a description of uplift.

Effectively, by maintaining this structure, the previous 2018-2019 I-SEM Validated Model assumes that in the I-SEM:

- 1) Generators will seek to structure their offers to recover their costs including start and no-load costs, without bidding above their costs; thus resultant I-SEM prices will also reflect this cost-recovery;¹⁰ and
- 2) Generators will seek to structure their offers so they only operate within their stated technical limits (for example, generators may use block orders that restrict their operations to those limits).¹¹

We maintain this basic structure – and the underlying assumptions behind this structure – in the current validation. Firstly, it was outside the scope of our validation to investigate a *de nouveau* approach to modeling the I-SEM arrangements in PLEXOS. Secondly, we agree with the principles underlying the decision to maintain the SEM structure. At least on a *prima facie* basis, we agree that one should not expect the transition to I-SEM to lead to significantly different prices than those that would occur in the SEM. We also recognize, however, the possibility that the transition to the I-SEM could lead to noticeable (if not necessarily major) differences from SEM results. Yet we believe it would be premature to prejudge, as part of our current scope, what the effect of the I-SEM arrangements will be on results in the All-Island market.

The RAs may wish to re-evaluate the modeling approach for the I-SEM once enough actual I-SEM data are available. Comparing the results of the PLEXOS I-SEM model to actual I-SEM results could help inform future decisions on the various modeling questions discussed in this validation report (and in the prior 2018-2019 I-SEM Model Validation Report).

We also note that market participants will likely go through a learning process following the transition to the I-SEM rules. Even assuming that generators will decide they wish to recover their costs in the I-SEM in a similar manner to how they did in the SEM, generators may require some trial and error to arrive at a bidding strategy that accomplishes that goal. We do not incorporate a learning period in the 2018-2023 I-SEM Validated Model.

C. Report Structure

We divide the remainder of this report into three sections: Section II covers our update to PLEXOS data (with that section divided between generator, fuel, and system data), Section III addresses PLEXOS modeling assumptions and methods, and finally, Section IV summarizes the results of the 2018-2023 I-SEM Validated Model.

¹⁰ See also Section III.C below about scarcity prices and Section III.B below about recovery of start costs under uplift.

¹¹ See Section 2.3.1 of the 2018-2019 I-SEM Model Validation Report for a discussion of block orders.

D. Quality Assurance

NERA prides itself on delivering accurate and thoroughly checked work products to its clients. Each team member on this project has self-checked their work. More important, every aspect of the 2018-2023 I-SEM Validated Model has been independently checked by a different team member from the person who originally did the work. Further, this report has been subject to NERA's formal peer review process, where it is reviewed by a senior NERA consultant outside of the project team. Please see Appendix I for details of NERA's quality assurance process.

II. PLEXOS Data

A. Generator Data

1. Generators added and removed

We do not include any new dispatchable thermal or hydro units in the 2018-2023 I-SEM Validated Model. As of the time of our validation, no proposed dispatchable thermal or hydroelectric units met the TSOs criteria for inclusion in their adequacy studies.¹² We do, however, reflect new wind, embedded generation (*i.e.*, behind-the meter generation), and demand-side units in the 2018-2023 I-SEM Validated Model, as discussed later in this report.

Several generation companies have publicly discussed plans to retire generation units at the start of I-SEM or not long thereafter. In most cases these units did not win a contract to supply capacity in the I-SEM. The RAs informed us that none of these retirements are firm as of the time we essentially finalized our analysis in late October 2018, aside from the AD1 and Marina CC retirements that have occurred (we also note that Ballylumford units B4 & B5 recently received a derogation to allow for early closure, but we do not retire these in PLEXOS as discussed in footnote 14).¹³ Consequently, all other existing units in the 2018-2023 I-SEM Validated Model will remain through 2023, with one exception:

- The 2018 GCS identifies the Tarbert plant as retiring by the end of 2022. In reflection of this, and following discussion with the RAs, all four Tarbert units retire on 31 December 2022 in the 2018-2023 I-SEM Validated Model.

The RAs intend to update the 2018-2023 I-SEM Validated Model accordingly as other plans for retirements or new unit construction become firm.¹⁴

We also removed Belfast Waste, a generation project also known as Bombardier, from the 2018-2023 I-SEM Validated Model. EirGrid informed us that Bombardier's generation is now reflected in the embedded generation files for the All-Island market, as Bombardier will not be dispatchable (see Section II.C.1 for a discussion of embedded generation). It would therefore be double counting to include Bombardier explicitly in the PLEXOS model.

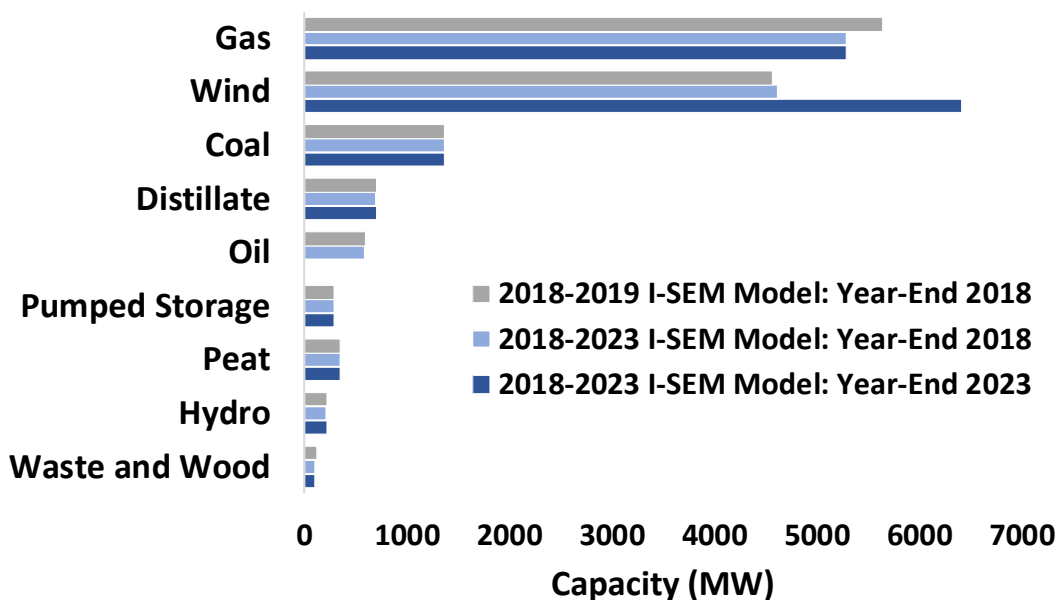
¹² The Island of Ireland has two TSOs: EirGrid for Ireland and SONI for Northern Ireland.

¹³ The 2018 GCS identifies AD1 and Marina CC retiring by the end of 2018. The RAs informed us that these units retired at 11pm on 30 September 2018 and 8am on 30 September 2018, respectively. We retire them at those times in PLEXOS.

¹⁴ Ballylumford units B4 & B5 have both received a derogation to shut down, decision as of 09/11/2018, <https://www.uregni.gov.uk/news-centre/utility-regulator-decision-published-aes-derogation-request> (link valid as of 19/11/2018). However, it is outside of our scope to reflect this retirement in the 2018-2023 I-SEM Validated Model, as our scope only included updates as of the 2018 GCS.

Figure 1 below shows total generation capacity by fuel in the 2018-2023 I-SEM Validated Model and compared with the 2018-2019 I-SEM Validated Model).

Figure 1: Generation Capacity in 2018-2023 I-SEM Validated Model vs. 2018-2019 I-SEM Validated Model¹⁵



2. Generator technical and commercial data

We contacted all the generation companies in Ireland and Northern Ireland, asking them to review and update the technical and commercial data for their generation plants as represented in the RAs' I-SEM PLEXOS model.¹⁶ We asked for any updates that would apply following I-SEM Go-Live, *e.g.*, a generator may intend to change the VOM cost amounts that it will seek to recover in the I-SEM.¹⁷ Some generation companies did update their VOM costs. However, generation companies, in general, commented that their commercial offer strategy in I-SEM was under development or subject to change based on their experience in the I-SEM. In light of this, the RAs may wish to review the VOM costs in a future I-SEM PLEXOS validation, once enough actual I-SEM data are available.

¹⁵ The capacities in the table above do not include embedded generation and do not include small scale wind in Northern Ireland (which is part of embedded generation in the 2018-2023 I-SEM Validated Model).

¹⁶ The 2018-2023 I-SEM Validated Model (in line with previous validated PLEXOS models) does not individually represent wind units and embedded generation units, so we did not contact generation companies about these units.

¹⁷ We model three types of VOMs for generation units: a VOM/MWh, and VOM/hour (applies ever hour of operation but does not vary with output) and a VOM/start. Generators do not necessarily have all three VOMs.

While we performed a high-level review of the generators' data for reasonableness, we did not perform a comprehensive "from-scratch" validation of all generator commercial and offer data. From discussions with the RAs, we agreed that a comprehensive review was not needed as part of our validation assignment given that a comprehensive validation of this data was performed as recently as 2017.¹⁸

We focused our review on the data changes that generators proposed. We reviewed proposed changes to generator data for reasonableness, and also reviewed the changes with the RAs. As needed, we followed up with the generation companies to clarify the changes they suggested, which in some instances led to adjustments to the proposed changes. We also adjusted the start costs for peat and waste units to deal with an uplift issue we identified.¹⁹

The public version of the 2018-2023 I-SEM Validated Model, and the accompanying Excel generator dataset (PUBLIC GEN DATA 2018-23.xlsx), reflect the updated generator data, with the exception of generator VOM costs and markups, which are included neither in the public validated model nor in the public Excel generator dataset. However, we delivered to the RAs a confidential 2018-2023 I-SEM Validated Model which includes generator VOM costs and markups.

The largest effect on prices from our changes to generator data is related to changes in the markups of a particular generation station—as shows in Figure 9 below, this in isolation led to a drop in prices of €0.7/MWh on average (changes in wind generation and generator outage schedules also led to drops in prices). Other generator data changes tend to have smaller effects – and these changes (as well as some minor changes in system data) basically cancel each other.

3. Hydro and pumped storage data

We have maintained the hydro and pumped storage data from the 2018-2019 I-SEM Validated Model in the 2018-2023 I-SEM Validated Model. The RAs informed us that there have been no material changes of circumstance that would justify changing this data.

¹⁸ See Section 2.2 of "PLEXOS Validation for 2017-2018", 26-July-2017, Baringa Partners LLP, available here: <https://www.semcommittee.com/news-centre/sem-17-056-baringa-sem-plexos-forecast-model-2017-18>.

¹⁹ As was done in the 2018-2019 I-SEM Validated Model, in the 2018-2023 I-SEM Validated Model we model peat and waste generation units as having no fuel costs for generation. In this way, these units run when available. When these units come back from an outage, of course they must incur start costs in order to begin generating again (fuel costs at startup plus and VOM/start costs). Sometimes, under the uplift algorithm in PLEXOS, these units require an uplift payment in order to recover their start costs over the horizon considered by that algorithm. Yet, in practice in the Validated Model these units will generate at full output for long enough a period where they would be virtually guaranteed not to need an uplift in retrospect. To prevent these units from setting uplift, we set their start costs including start fuel requirements to zero in the 2018-2023 I-SEM Validated Model.

4. Outages

a. Scheduled outages

We updated scheduled outages in the 2018-2023 I-SEM Validated Model to reflect an updated 2018 and 2019 outage schedule provided to NERA by the Generation Outage Planning unit within EirGrid.²⁰ For 2020, we used a planned outage schedule published on the SEMO website.²¹ In choosing to use two data sources (directly from EirGrid for 2018-19 scheduled outages and from the SEMO website for 2020), we relied on the most up-to-date data available to us for each year of outages. The outage schedules also include outages on the interconnectors between Great Britain and the SEM.

At the time we completed the bulk of our validation prior to May 2018, we were not aware of an outage schedule for 2021 to 2023 inclusive. For each of those years, we utilized an average-year outage schedule, by averaging the 2018 to 2020 (inclusive) outage plan. Appendix II describes our averaging method.

We also implemented a change where in PLEXOS we reflect partial outages using the “Units Out” and “Outage Rating” properties, where previously the “Max Capacity” property was adjusted for partial outages.

b. Forced outages

The 2018-2019 I-SEM Validated Model included the forced outage rates (“FORs”) in Table 2 below, where each unit in a generator type is attributed the same FOR.

Table 2: Forced Outage Rates by Generator Type

Generator Type	Forced Outage
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%

²⁰ Sent to NERA via email on 06 April 2018. We finished the bulk of our validation about one month after that date. At that time, we understood that those schedules were more up to date than the most recent schedules published on the SEMO website as of that time. It was outside of our scope to add new information about outages schedules beyond the update we received via email on 06 April 2018.

²¹ “2020 All-Island Provisional Outage Programme.xlsx,” downloaded from www.sem-o.com – version available as of when we finished the bulk of our validation (May 2018).

These rates are the capacity-weighted averages of historical forced outage rates, by category, for the units in the SEM. An important aspect of this averaging approach is that it spreads the implied likelihood of lower-probability major outages evenly across all generators of a certain type, even though only certain units might have experienced those lower-probability outages historically.²²

In contrast to this, some generation units of the same type may have different forward-looking FOR rates, but the averaging method does not allow for such differences. For the benefit of consistency, and in recognition of the advantages of such an approach, we have maintained the FORs from the previous validation exercise.

However, we also recognize the trade-offs between using uniform versus individual FORs for generators, and we recognize that these trade-offs may be re-evaluated in future validations.

For the interconnectors between Great Britain (“GB”) and the SEM, we use the same 6.9% forced outage rate used in the 2018-2019 I-SEM Validated Model.

B. Fuel Data

1. Fuel and CO₂ Prices in the All-Island Market

We include the indicative fuel and CO₂ prices from Table 3 below in the 2018-2023 I-SEM Validated Model.²³ We use the same prices each year from 2018 through 2023. While, in reality, market fuel price expectations are not necessarily constant from now through 2023, we adopt this approach because:

- When the RAs use the model for forecast purposes, they will update the fuel price input data. It was not part of our scope to provide a precise forecast of commodity prices.
- The yearly results from our test runs thus show the isolated effect of changes in the from-year-to-year supply and demand balance, which may help readers understand how the validated model changes from year to year.

²² For example, there may be ten generators of a certain type, and hypothetically two of them had extended forced outages of four months in the historical period examined. Those two units will likely have significantly higher historical FORs than the other similar units. However, it is potentially a coincidence that those two units specifically had longer outages, and any of the ten units would risk having low-probability extended outages in the future. By averaging across all ten units, the forced outage rates for every unit of this type will reflect the risk of such low-probability but significant events.

²³ While the commodity prices in this table are indicative, we set the prices to be in line with market data available around the time we updated and validated the PLEXOS model (based on prices from Bloomberg LP), reflecting when we performed the bulk of our validation, prior to May 2018.

Table 3: Indicative Commodity Prices used in 2018-2023 I-SEM Validated Model

Commodity	Q1	Q2	Q3	Q4
Gas (p/th)	52	40	41	49
LSFO (\$/t)	350	350	350	350
Gasoil (\$/t)	580	580	580	580
Coal ARA API2 (\$/t)	70	70	70	70
Carbon (€/t)	13	13	13	13

We have produced a spreadsheet that calculates the fuel price inputs to the 2018-2023 I-SEM Validated Model. We have provided this spreadsheet to the RAs (Fuel Inputs 2018-2023.xlsx), and we understand it will be published with the public version of the 2018-2023 I-SEM Validated Model. We started with the fuel spreadsheet associated with the 2018-2019 I-SEM Validated Model and updated it so that it produces PLEXOS inputs through Q4 2023.

We used the same fuel transportation costs as present in the 2018-2019 I-SEM Validated Model. The previous validation was performed twelve months ago, and we are not aware of any significant changes in fuel transportation costs. Should significant changes in fuel transportation costs occur in the future, the RAs may wish to update the fuel spreadsheet accordingly. Importantly, the previously validated fuel spreadsheet had already incorporated the 2017 through 2018 Short Term Capacity tariffs for Ireland, where we understand those were the most recently published Short Term Capacity tariffs from Gas Networks Ireland as of May 2018, the date by which the bulk of our analysis was completed.²⁴

We used indicative foreign exchange rates of 1.25 \$/€ and 0.90 £/€ to convert non-euro denominated commodity prices to euros,²⁵ and we expect the RAs would update these as well for their future PLEXOS runs.

2. Carbon price support in Great Britain

The UK Government has implemented a carbon price support scheme. The RAs have informed us that this scheme does not apply to generation units in Northern Ireland. Nonetheless, we reflect the UK's carbon price support when modeling *Great Britain's* electricity market in PLEXOS. For GB, the total CO₂ price equals the traded EU Emissions Trading System CO₂ price plus the UK's Carbon Price Support ("CPS"). The 2018-2019 I-SEM Validated Model also used the CPS to model GB prices.

²⁴ It is outside of our scope to update fuel transport charges to reflect Gas Networks Ireland tariffs for the 2018-2019 period.

²⁵ In line with FX rates as of when we performed the bulk of our validation (prior to May 2018), according to Bloomberg LP.

In the 2014 UK Budget, the CPS was frozen at £18/t from the 2016-17 UK fiscal year through the 2019-2020 fiscal year.²⁶ (The UK Budget’s fiscal years start on 1 April). We maintain the £18/t CPS through the end of 2023 in the 2018-2023 I-SEM Validated Model. Statements in the UK Government’s Autumn Budget 2017 support this decision.²⁷ We expect that the RAs, for any official model runs they do, will update the PLEXOS model to reflect any future change in the UK Government’s plans for future CPS rates.

C. System Data

1. Embedded generation

Consistent with prior validations, we represent generators in PLEXOS in one of three ways:

- 1) We model dispatchable thermal, hydroelectric, and pumped storage generators as individual units, with their own properties.
- 2) We model wind as individual generation units by region in PLEXOS, where each PLEXOS wind “unit” is actually an aggregation of *all* the wind generators in a certain geographical area.
- 3) We model non- (or partially-) dispatchable generators as embedded generation whose output is fixed in advanced as an input to the model.

For the third approach – the subject of this section – we obtained hourly profiles for embedded generation from EirGrid.

The embedded generation files show *gross* generation from the embedded generators, rather than *net* generation provided to the transmission grid. The gross vs. net distinction matters for generators that are co-located with a load. For example, a factory may have a co-located combined heat and power (“CHP”) plant. That generator may produce 0.5 MW (gross output) and the factory’s load may be 0.3 MW, so the net output provided to the grid is the difference between the two, 0.2 MW in this case. The demand data and generator data in the 2018-2023 I-SEM Validated Model are consistent. The demand data reflects the TSOs’ forecast of “Total Energy Requirement,” which is total gross demand even if that demand is, in practice, served by behind-the-meter

²⁶ 2014 UK Budget available here https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/293759/37630_Budget_2014_Web_Accessible.pdf.

²⁷ The UK Government’s 2017 Autumn Budget noted that “The government is confident that the Total Carbon Price, currently created by the combination of the EU Emissions Trading System and the Carbon Price Support, is set at the right level, and will continue to target a similar total carbon price until unabated coal is no longer used. This will deliver a stable carbon price while limiting cost on business.” The 2017 Autumn Budget is available here https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/661480/autumn_budget_2017_web.pdf

generation.²⁸ Thus, it is correct that the embedded generation files used in the PLEXOS model should include behind-the-meter gross generation.

Specifically, the embedded generation that we include in the 2018-2023 I-SEM Validated Model reflects the generation for the various generator units that EirGrid lists as Partially/Non-Dispatchable in its 2018 GCS.

- One exception is the wind capacity in Ireland and the large-scale wind in Northern Ireland. We model those directly in PLEXOS (the small-scale wind in Northern Ireland is part of the embedded generation, however).
- Further, certain small-scale generators on the island of Ireland are co-located with loads that bid into the market as Demand Side Units (“DSUs”), where these DSUs tend to bid with *negative* incremental prices. The generation from these units is not included in the embedded generation files from EirGrid, even though it is, in a strict sense, embedded generation. Instead, we account for their generation through the DSU modeling discussed in the next section.

In the 2018-2023 I-SEM Validated Model, we include an explicit embedded generation amount for each hour of the modeling horizon. In previous validated PLEXOS models, the embedded generation profiles represented averages that applied during certain “timeslices”, *e.g.*, averages over the hours of the day on weekdays and on non-weekdays.

2. Demand side units

Demand participation is growing in the SEM. DSUs represent demands that effectively participate in the market as generators, except that a DSU’s “generation” is negative load. The 2018 GCS lists a total of 606 MW total of DSUs across Ireland and Northern Ireland, an increase from the 335 MW of DSUs listed in the 2017 GCS. DSU offers into the SEM include a shutdown cost (basically the DSU equivalent of a generator’s start-up cost) plus one or several price-quantity (“P-Q”) pairs that reflect the incremental payments DSUs require to reduce load.²⁹ The previous 2018-2019 I-SEM Validated Model represented the DSUs in a simplified fashion, as three P-Q pairs, where the P-Q pairs were the same throughout the 2018-19 horizon of that model. Thus, the 2018-2019 I-SEM Validated Model simplified DSUs as follows:

- Instead of separate fixed shutdown costs and incremental demand reduction prices, the 2018-2019 I-SEM Validated Model only had per MWh demand reduction prices (but those

²⁸ In other words, the Total Energy Requirement would include the 0.3 MW of demand in the example just given, even though the local generator serves that demand.

²⁹ A series of P-Q pairs show a DSU’s (or a generator’s) offer data. For example, a DSU’s first two P-Q pairs may be 10 MW and €100/MWh then 7 MW and €120/MWh, meaning that the up to 10 MW of demand reduction would be provided at a €100/MWh incremental rate and the next 7 MW at a €120/MWh incremental rate.

per MWh prices were basically blended prices that incorporated both the incremental demand reduction prices from the P-Q pairs and the shutdown cost);

- Instead of representing each DSU separately, the 2018-2019 I-SEM Validated Model aggregated the DSUs into three P-Q pairs;
- Whereas, in actuality, DSUs may vary their offers throughout the year, the 2018-2019 I-SEM Validated Model used the same P-Q pairs throughout the modeling horizon.

We maintain this basic methodology and adopt refinements as discussed later in this section. DSUs are rarely dispatched in our test runs of the 2018-2023 I-SEM Validated Model, with the exception of certain negative price DSUs (discussed later). As such, we are comfortable maintaining the simplified DSU representation from the 2018-2019 I-SEM Validated Model. However, the effect of DSUs on the market may increase over time as DSU capacity increases or as the manner in which DSUs participate in the market changes. The RAs may therefore wish to re-evaluate the PLEXOS representation of DSUs in future validations.

As briefly introduced in the embedded generation section, certain DSUs bid at negative prices. Thus, these DSUs offer to *pay* to reduce their load. At first, this is surprising. One might expect that a DSU would *need to be paid* to reduce its load. Having discussed this issue with EirGrid, we now understand why these DSUs often bid negative prices.³⁰

The 2018-2019 I-SEM Validated Model did not reflect these negative price DSUs directly. Instead, we understand the relevant generation was included in the embedded generation files. In this validation, the associated generation is no longer in the embedded generation files. As such, we include the negative price DSUs in the 2018-2023 I-SEM Validated Model. For simplicity, we represent these as zero-priced demand reduction, rather than negative price demand reduction. As shown in Table 5, we assume 37 MW of these DSUs in the 2018-2023 I-SEM Validated Model.

The 2018-2019 I-SEM Validated Model included the DSU values from Table 4:

Table 4: Demand P-Q Pairs, 2018-2019 I-SEM Validated Model

<u>DSU Blocks</u>	<u>Quantity (MW)</u>	<u>Price (€/MWh)</u>
1	100	535
2	150	640
3	85	2,800

³⁰ These DSUs are industrial loads with CHPs, where the loads do not want to turn off their CHPs. Basically, these industrial loads put their full load into the market, assuming that their CHP is not generating. The DSUs then bid a negative price as a DSU to “reduce” that load. In reality, by “reducing” its load this DSU is simply maintaining its generation at its CHP (and the lower net load that results).

In the 2018-2023 I-SEM Validated Model, we include five demand P-Q pairs as shown in Table 5.

Table 5: Demand P-Q Pairs, 2018-2023 I-SEM Validated Model³¹

DSU Blocks	Quantity (MW)	Price (€/MWh)
1	37	0
2	4	45
3	270	453
4	70	551
5	119	1,483

We calculated these P-Q pairs using the actual commercial offer data from the DSUs in the SEM. Appendix III presents our method in detail, including an explanation of why we included five P-Q pairs versus the three in the 2018-2019 I-SEM Validated Model.

We used DSU offer data from the SEM for our analysis, as no I-SEM data were available as of when we completed the bulk of our validation. Effectively this assumes that DSUs will bid in the I-SEM similarly to how they bid into the SEM. The RAs may wish to reconsider DSU modeling once they have reviewed I-SEM data.

Even with the zero-price DSUs, the effect of DSUs on average prices in PLEXOS is minimal: if the P-Q pairs from Table 5 were completely removed from PLEXOS, baseload prices would only increase by about €0.24/MWh. Almost all of that effect is from the 37 MW of zero-cost DSUs. The incremental effect of the final four P-Q pairs is less than €0.01/MWh.

3. Interconnectors

SEM has two interconnectors with Great Britain: Moyle and the East-West Interconnector. The 2018-2023 I-SEM Validated Model includes both (as do previous validated PLEXOS models). We are aware that other interconnectors from the Island of Ireland to GB or the rest of Europe have been proposed. Yet, we have not included any potential new interconnectors in the 2018-2023 I-SEM Validated Model, as we understand the proposed new interconnectors are all still in the preliminary stage.

We have maintained the technical parameters of the interconnectors from the 2018-2019 I-SEM Validated Model. As in previous validated models, we reflect Moyle's contract capacity in the 2018-2023 I-SEM Validated Model. In PLEXOS, through November 2019 Moyle's capacity is 80 MW in the SEM to GB direction, and starting in December 2019 it is 307 MW.

³¹ The first P-Q pair in Table 5 is 37 MW at a zero price. In practice, this results in 37 MW of load reduction in PLEXOS in every hour.

For Moyle’s capacity post December 2019, we relied on a future schedule of Moyle’s contracted capacity as stated in a recent consultation paper (while that consultation is still open,³² after discussing the matter with the RAs, we agreed that this future capacity schedule was appropriate for inclusion in the 2018-2023 I-SEM Validated Model). See Table 6 below.³³

Table 6: Moyle Capacity, West to East, in 2018-2023 I-SEM Validated Model

Dates	West to East Capacity (MW)
10 November 2017 – 30 November 2019	80
1 December 2019 – 31 May 2020	307
1 June 2020 – 31 October 2021	250
1 November 2021 – 31 March 2022	160
1 April 2022 – Onwards	500

We note that particularly in the direction of the SEM to GB, contract capacity on Moyle is lower than the maximum transfer capacity on Moyle. Once enough actual I-SEM data are available, the RAs may wish to use that data to assess how well the capacity limits in the I-SEM PLEXOS Model (based on the *contract* capacity on Moyle) reflect actual trading over Moyle in the I-SEM.

4. Transmission loss adjustment factors (TLAFs)

We use the most up to date TLAFs as published by EirGrid available as of May 2018 (by when our analysis was substantially completed), *i.e.*, the 2017 to 2018 TLAFs, in the 2018-2023 I-SEM Validated Model.³⁴

5. Wind and demand

We use an hourly demand forecast covering the years 2018 through 2023 in the 2018-2023 I-SEM Validated Model. Our demand forecast reflects the peak demand and total annual energy requirements forecast from the 2018 GCS. Specifically we used the “median” forecasts from the 2018 GCS, shown in Table 7.

³² It was open as of when we had finished the bulk of our validation, *i.e.*, as of May 2018.

³³ “Moyle Interconnector Limited, Interconnector Capacity Calculation”, June 2017, Consultation Document (See Contracted Capacity from Table 1), available here http://www.mutual-energy.com/wp-content/uploads/downloads/2017/06/Moyle_Capacity_Calculation_2017_consultation_web.pdf.

³⁴ See <http://www.eirgridgroup.com/customer-and-industry/general-customer-information/tlafs/>. It is outside of our scope to update to the 2019 tariffs.

Table 7: Demand Forecast for the All-Island Market

Year	Peak Demand (GW)	Total Energy Requirement (TWh)
2018	6.90	38.5
2019	7.07	39.7
2020	7.31	41.4
2021	7.51	43.0
2022	7.85	45.5
2023	8.07	47.8

We used historical hourly demand profiles to shape the GCS forecasts of peak demand and total annual energy to hourly forecasts.³⁵ We produced five versions of our 2018 through 2023 hourly demand forecast, each based on a different base year demand profile. We used historical hourly demand from 2012 to 2016 to produce five different demand shaping patterns. Each of the five versions of our demand forecasts from 2018 through 2023 line up with the forecast from Table 7. The only difference among the five forecasts is how the total annual energy from Table 7 is distributed within each year of the forecast (where the different in-year distributions are based on the five historical hourly demand patterns from 2012 to 2016).

Our wind forecast is based on the 2018 GCS's forecast of wind capacity in Ireland and Northern Ireland, shown in Table 8 below.³⁶

Table 8: Wind Capacity Forecast

At Year End	ROI Wind Capacity (MW)	NI Large Scale Wind Capacity (MW)
2018	3,500	1,123
2019	3,970	1,140
2020	4,200	1,230
2021	4,470	1,230
2022	4,850	1,230
2023	5,190	1,230

³⁵ PLEXOS has a built-in functionality that produces hourly demand forecasts based on: a) a peak demand forecast; b) a total energy forecast; and c) an hourly profile.

³⁶ The GCS publishes a forecast of *annual* wind capacity; in PLEXOS we add wind on a monthly basis, extrapolating between the annual capacities. This is a small change from the 2018-2019 I-SEM Validated Model, which added wind on a quarterly basis. We felt it was appropriate to switch to a monthly basis given the relatively high amounts of wind capacity that the TSOs forecast will be installed in the I-SEM in the coming years.

In Northern Ireland, the wind forecast is split between small- and large-scale wind. Table 8 above reflects large scale wind. Small scale wind is accounted for in the embedded generation profiles we include in the 2018-2023 I-SEM Validated Model.

In the actual PLEXOS model, there are two wind generation units, one for Ireland and one for Northern Ireland. Each unit has the corresponding wind generation capacities from Table 8 above.³⁷

We use historical wind profiles to determine wind availability in PLEXOS on an hourly basis. As with load, we use profiles from 2012 to 2016.

The 2018-2019 I-SEM Validated Model included five correlated wind and demand profiles. This means that the 2015 wind profile is linked to the 2015 demand profile and so on. We maintain that method. Using five years' worth of wind data is particularly important because wind availability may change significantly from year to year. The use of five years further helps to ensure that the average wind generation in PLEXOS reflects a longer-term average of wind availability. On the other hand, a carefully chosen single year could also represent average wind conditions. Yet, a single wind year, even if the annual capacity factors is correct, may understate or overstate expected wind generation in the various months and seasons of the year.

We maintain the correlation of wind and demand profiles noting that:

- Correlation allows for PLEXOS to account for the possibility that weather patterns may affect wind *and* demand in a (to-some-extent) linked fashion, *e.g.*, the potential for low wind generation aligned with very cold temperature (hence high demand) over an extended period in a given winter.
- We considered two alternatives to correlating wind and demand profiles:
 - a) using a single demand profile with multiple wind profiles and
 - b) using multiple demand and wind profiles, in an uncorrelated fashion (though this adds to the number of needed samples).³⁸
- We tested those two options versus the default option of correlated wind and demand profiles, but did not find a substantial difference in resulting average prices. Nonetheless,

³⁷ The 2018-2019 I-SEM Validated Model also included the same two wind units in PLEXOS. In contrast, various validated PLEXOS models prior to that one split wind in ROI up into several sub-geographic areas, each of which was represented with a separate unit in PLEXOS. For consistency, we maintain the use of a single wind unit for ROI. This approach is reasonable, given that the validated PLEXOS model recreates *unconstrained* prices, that is, prices without any transmission constraints.

³⁸ There are 25 possible combinations of load and wind profiles when the five samples are uncorrelated ($5 \times 5 = 25$).

we decided to maintain the *status quo* of correlated samples, for consistency of approach and considering the conceptual reasoning behind correlating the profiles.

We note that use of five samples, *versus* using one sample as has been done in the validated models prior to the 2018-2019 I-SEM Validated Model, increases PLEXOS runtimes. Should runtime become more of an issue in the future, the RAs may wish to re-evaluate the question of how many profiles to use. For example, it may be that a Mixed Integer Programming (“MIP”) modeling approach is preferred at some point in the future. Switching to a simple wind and demand profile would mitigate the runtime disadvantage of MIP.³⁹

³⁹ In this case, it would be of paramount importance to pick a wind profile that represents average wind availability, preferably representing average availability in each of the four quarters of the year.

III. PLEXOS Modeling Assumptions and Methods

A. PLEXOS Model Settings

1. Solver: RR vs MIP

Determining unit-commitment is a classic problem of power sector modeling. Power plant units are either offline or online. Decisions to shutdown an online plant or startup an offline plant have ramifications:

- When plants shutdown, they tend to need to stay offline for a minimum amount of time before going back online. Plants that startup tend to need to stay online for a minimum amount of time before they can be shutdown; and
- The actual startup process typically requires fuel plus the incurrence of monetary costs (a VOM cost per start).

Complicating the unit-commitment problem further, most units have a minimum stable level of generation, where if they are online they must generate at least that level. In short, optimizing unit commitment is a *non-linear* problem. Optimizing non-linear problems poses challenges. PLEXOS offers three standard methods to optimize unit commitment and deal with the non-linear problem:

- 1) **Linear Relaxation.** Under this approach, the non-linear unit dispatch decision is artificially converted to a linear problem. While linear problems solve relatively quickly, this comes at the cost of ignoring a significant feature of the power sector (that units cannot be “fractionally” online).
- 2) **Rounded Relaxation (RR).** Under RR, PLEXOS performs an initial linear relaxation, which may result in “fractional” unit commitments: Unit A might be 60% online. Then PLEXOS rounds these fractional unit commitments up or down, to decide if the unit is online or offline. However, the resulting unit commitment may be sub-optimal, due to the relatively blunt approach of rounding. In other words, a different unit commitment decision may have resulted in lower costs. The RR self-tuning feature (discussed in the next section) helps mitigate this drawback of RR.
- 3) **Mixed Integer Programming (MIP).** Under the MIP approach, PLEXOS attempts to find the optimal least-cost unit commitment decision.

To date, as far as we are aware, every validated PLEXOS model of the SEM has adopted the RR approach. While we recommend the RAs continue to use RR, we recommend re-evaluating this in future validation exercises, particularly once one can compare PLEXOS I-SEM Model results to enough actual I-SEM data.

We do not recommend use of Linear Relaxation, as we believe it is appropriate to use a unit commitment approach that reflects distinct online or offline states.

We considered the trade-offs between MIP and RR. In theory the MIP approach will provide a superior unit dispatch to RR, but MIP also takes substantially longer to run than RR. A main driver of how long MIP takes is the Relative Gap parameter.⁴⁰ We found that MIP runs take about 17 times longer than RR runs at a 0.01% Relative Gap.⁴¹

As a threshold matter, the 17 times longer of MIP would likely be viewed as intolerable. However, different model settings can significantly reduce MIP runtime, for example:

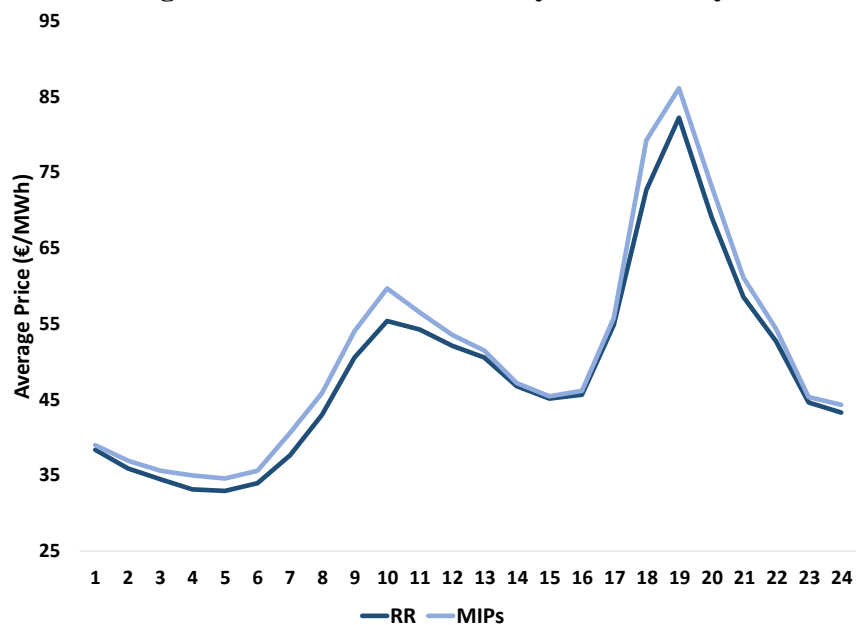
- Increasing the Relative Gap – potentially could achieve a significant runtime reduction with little change in the PLEXOS model’s results;
- Reducing the number of samples of load, wind, and forced outages;
- Use of a single start state versus three start states. The 2018-2019 I-SEM Validated Model incorporated three start states (hot, warm, and cold), and we continue to recommend this approach. However, switching from three start states to one could significantly reduce runtime.

Importantly, MIP produces noticeably different results versus RR in a few areas. For example, MIP appears to produce higher prices on average than RR. In a sample run, we found average baseload MIP prices were €2.06/MWh higher than when using the RR solver. This is similar to the €1.4/MWh average baseload price difference between MIP and RR identified by Baringa in the previous validation report.⁴² We also found the difference in prices to vary depending on the hour of the day, with the greatest difference during the higher-price hours, as illustrated in Figure 2.

⁴⁰ Basically, this is the gap between the currently considered solution and a bounding solution (the best known bounding linear solution). While this is not the gap versus the true optimal solution, the smaller the gap, the more optimal the resulting solution, all things equal. For the purposes of this report, what matters is that a lower Relative Gap increases precision but also increases runtime.

⁴¹ Specifically we looked at the RR solution using a 0.2 RR self tune and rounding up thresholds ranging from of 0.1 to 0.9. See Section III.A.2 for more details.

⁴² See Section 2.3.3.1 of the 2018-2019 I-SEM Model Validation Report.

Figure 2: RR vs MIP Prices by Hour of Day

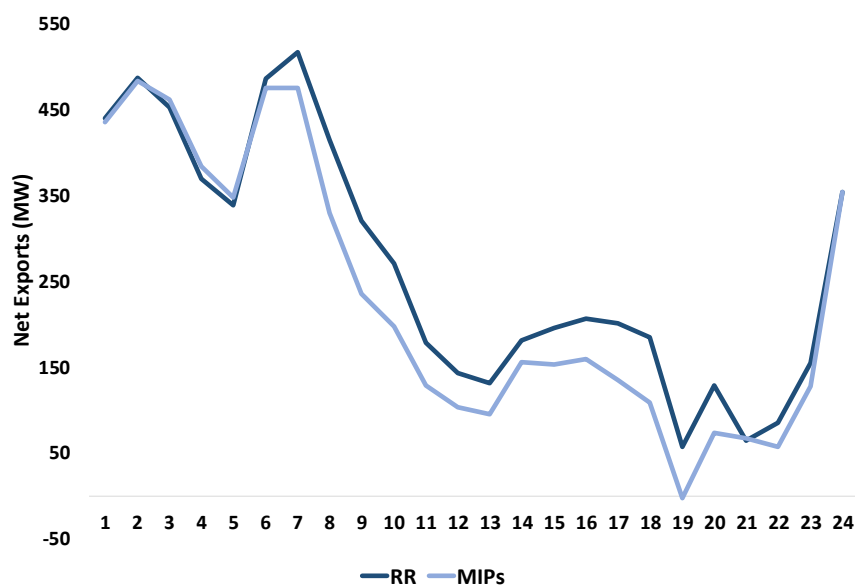
Notably, MIP and RR prices reflect different relative compositions of shadow price and uplift. We found MIP to have higher shadow prices and lower uplifts, on average, as shown in Table 9 below.

Table 9: Test Comparison of MIP and RR, 2019 Prices

Run Type	Price (€/MWh)	Shadow Price (€/MWh)	Uplift (€/MWh)
MIP	50.7	49.8	0.9
RR	48.6	45.6	3.1
Delta	2.1	4.2	-2.2

As illustrated in Figure 3, we also noticed differences in the interconnector flows, both on average and in the typical hourly pattern.

Figure 3: RR vs MIP, Average Net Exports to GB, by Hour of Day⁴³



The choice of MIP vs. RR is related to the interconnector flows, at least indirectly, through uplift. As explained more in Section III.D.2 of this report, the 2018-2023 I-SEM Validated Model includes a wheeling charge on the interconnectors for the following reason: PLEXOS determines interconnector flows based on shadow price differences between the SEM and GB. In the model, shadow prices in GB already include the cost recovery captured with an uplift, whereas uplift is an add on to SEM prices. We add a wheeling charge equal to expected uplift to account for this difference. In the MIP runs the wheeling charge is much smaller as uplift is much smaller. Generally, we view this as an advantage of MIP.

Our view is that these differences between MIP and RR deserve further investigation. The best way to evaluate these differences is with real I-SEM data against which to compare the results of the I-SEM validated model. We view it as premature to change methods without data to back up a potential change. We recommend keeping RR, also considering that previous versions of the validated PLEXOS model (using RR) have been calibrated to actual SEM results.⁴⁴

⁴³ Reflects the average of hours where power flow from the SEM to GB (exports) as positive numbers and hours where power flow from GB to the SEM (imports) as negative numbers. For example, one hour may have exports of 100 MW and the next may have imports of 50 MW, which is *negative* 50 MW of exports. These two are averaged to reflect 25 MW of net exports $(100 + \textit{negative } 50)/2$.

⁴⁴ We understand that the I-SEM price formation algorithm will use a MIP approach. But this fact on its own does not, in our view, dictate the use of MIP for the validated PLEXOS model. As discussed, the MIP approach requires much longer runtimes. Ultimately, we suggest judging the validated PLEXOS models of the I-SEM (the 2018-

2. Solver: RR Self Tune

While RR incorporates the relatively rough approximation of rounding to determine unit commitment, a “self-tuning” feature in PLEXOS improves the optimality of the RR results. In the 2018-2019 I-SEM Validated Model, the self-tuning increment was set to 0.2, with the lowest RR threshold set to 0.1 and the highest to 0.9. Each day:⁴⁵

- PLEXOS first runs with an RR threshold of 0.1;
- PLEXOS then re-runs the day with an RR threshold of 0.3 (0.1 + the self-tuning increment of 0.2);
- PLEXOS continues to increase the RR threshold by the self-tuning increment, re-running the day with RR thresholds of 0.5, 0.7, and 0.9;
- PLEXOS stops with 0.9 (the highest RR threshold in the model settings);
- PLEXOS compares the results for the day from each of the RR thresholds, and selects the least-cost result;
- PLEXOS moves on to the next day and repeats.

We adopt this same approach. As a test, we explored alternate self-tuning increments of 0.1 and 0.3. We found small differences in average prices in the SEM among those three options. On average, none of those options is different from any other by more than €0.02/MWh in our test runs.

Conceptually, a self-tune increment of 0.1 should improve the optimality of the results. However, given the small effect of such a change we do not believe it is worth the cost of longer runtimes.

Our initial testing indicates that increasing the self-tune increment to 0.3 might also be acceptable, as we found very low price differences relative to the 0.2 increment. Nonetheless, we recommend maintaining the 0.2 self-tune increment, for consistency with the previous validation and because it does allow for the potential of more optimal results.

3. Solver Steps, Look-Ahead, and Model Granularity

As in the 2018-2019 I-SEM Validated Model, the 2018-2023 I-SEM Validated Model runs using a daily optimization step, where unit dispatch is optimized one day at a time. Further, we maintain

2019 model, the current 2018-2023 model, and any future I-SEM PLEXOS models) based on their ability to replicate the results of the I-SEM, even if the validated models rely on a different solver.

⁴⁵ This process happens every day in the model because the 2018-2023 I-SEM Validated Model – as did previous validated models – determines unit commitment on a *daily* basis.

the six hour look-ahead period as part of each daily optimization.⁴⁶ Average prices from the PLEXOS model are somewhat sensitive to the length of the look-ahead period. We found prices went down by about €0.98/MWh on average when the look-ahead period was extended to 12 hours instead of 6 hour, and prices rose by about €2.94/MWh on average when the look-ahead is eliminated entirely. This is not unexpected, as longer look-ahead periods allow more foresight, which results in more optimal dispatch decisions, typically resulting in lower prices.

The SEM explicitly incorporated a six hour look-ahead period as part of its price formation, but the I-SEM will not. Nonetheless, using a look-ahead period in PLEXOS effectively allows for a compromise between how PLEXOS dispatches units and how dispatch decisions are made in actual power sectors. PLEXOS determines daily dispatch with perfect foresight for the day plus for the look-ahead period, but with no information beyond that look-ahead period. In reality, in contrast, market participants may look as far into the future as they wish but with increasingly imperfect foresight.

We also maintain the 6am start time for each trading day in PLEXOS. As far as we are aware, each prior validated PLEXOS model of the SEM also utilized assumptions of a daily dispatch starting at 6am with a six hour look-ahead. However, the RAs may wish to re-evaluate these settings – particularly the 6am start time for the day and the six hour look-ahead – once enough actual I-SEM data are available.⁴⁷ Our *a priori* expectation is that the start time of the trading day will not affect resulting prices. In practice, we have observed a modest effect on prices when changing this setting in PLEXOS to the actual start time of the trading day in I-SEM. The previous 2018-2019 I-SEM Model Validation Report also noted such an effect. Our view is that the appropriateness of any changes in dispatch or prices that result from changes to the start of the trading day or the length of the look-ahead in PLEXOS will best be evaluated once enough actual I-SEM data become available.

The 2018-2023 I-SEM Validated Model uses an hourly granularity, maintaining the assumption from the 2018-2019 I-SEM Validated Model. This reflects the actual interval length in the I-SEM Day-Ahead market.

4. Price caps and floors

We have not changed the €3,000/MWh and -€500/MWh cap and floor values in the 2018-2023 I-SEM Validated Model – we understand these will be the values in the I-SEM.

⁴⁶ With the six hour look-ahead, PLEXOS actually optimizes dispatch over a 30 hour period (six hours longer than the 24 hour day). However, PLEXOS only keeps the first 24 hours of results from that optimization. PLEXOS then begins another dispatch optimization for 30 hours (starting with the unit commitment at the end of the 24th hour of the prior day's optimization).

⁴⁷ The RAs may evaluate the daily dispatch choice in PLEXOS as well, but we note that longer dispatch periods may add to run time. Further, if the dispatch optimization period is too long, the resulting prices and dispatch may reflect too much foresight.

5. Start states

We maintain the three-state start cost approach from the 2018-2019 I-SEM Validated Model. This approach better reflects actual unit start costs (versus using a single start cost). The downside is that the runtime is longer. Should a future validation consider a MIP approach, it may be appropriate to re-evaluate the start-state choice at that time.

6. PLEXOS version

We maintain the 2018-2019 I-SEM Validated Model's use of PLEXOS Version 7.300 R04 64bit.

B. Uplift

Before delving into uplift modeling in PLEXOS, we present a brief primer for those who may be unfamiliar with it. Uplift is an important aspect of the PLEXOS modeling of the SEM and I-SEM.

Uplift Explained

Uplift reflects an adder to the electricity price. Every hour, the final electricity price reflects what is called the shadow price plus an uplift. Electricity is bought and sold at that final price, *e.g.*, a price of €60/MWh may represent a €6/MWh uplift and a €54/MWh shadow price. The uplift may vary every hour, and it may be zero. While not every market includes an uplift to prices, the SEM did.

In the SEM, the shadow prices reflect the incremental cost of serving one additional MWh of load – basically the *incremental* generation cost. The uplift value adds to the shadow price, so that generators may recover their start-up and no-load costs in addition to recovery of their incremental generation costs. Depending on the situation, the shadow price alone may allow some but not all generators to recover their costs. Uplift deals with situations where the shadow price is not enough for one or more generators. Actual market operators use algorithms to determine the needed uplift in every hour, and programs like PLEXOS use similar or identical algorithms to the ones the market operators use. Different uplift algorithms are utilized in different markets (and are available within PLEXOS).

In the I-SEM, there will not be an uplift added to shadow prices. Rather, we expect that generators will form their commercial offers such that they can recover start-up and no-load costs in addition to incremental generation costs. Thus, in the I-SEM, we expect the resulting prices will reflect start-up and no-load cost recovery, even without an uplift.

1. Uplift vs. other cost-recovery options

The 2018-2019 I-SEM Validated Model included uplift, despite the fact that the actual I-SEM will not include an explicit uplift calculation. The logic for this choice is that in the I-SEM, generators

will seek to continue to recover their start-up and no-load costs, and will structure their bids into the I-SEM to recover those costs. Thus, prices in I-SEM will also reflect this cost recovery. We generally agree with this logic.

There are several modeling approaches in PLEXOS to reflect recovery of start-up and no-load costs in prices. Using an uplift algorithm is one such approach. Alternatively one can turn off uplift but model generator bids such that they include recovery of start and no-load costs.

Without assessing actual I-SEM data, it is challenging to determine the best approach for incorporating start and no-load cost recovery into an I-SEM PLEXOS model. We therefore recommend the continued use of uplift in the 2018-2023 I-SEM Validated Model. Once actual market data are available, the RAs may wish to consider testing other modeling approaches.

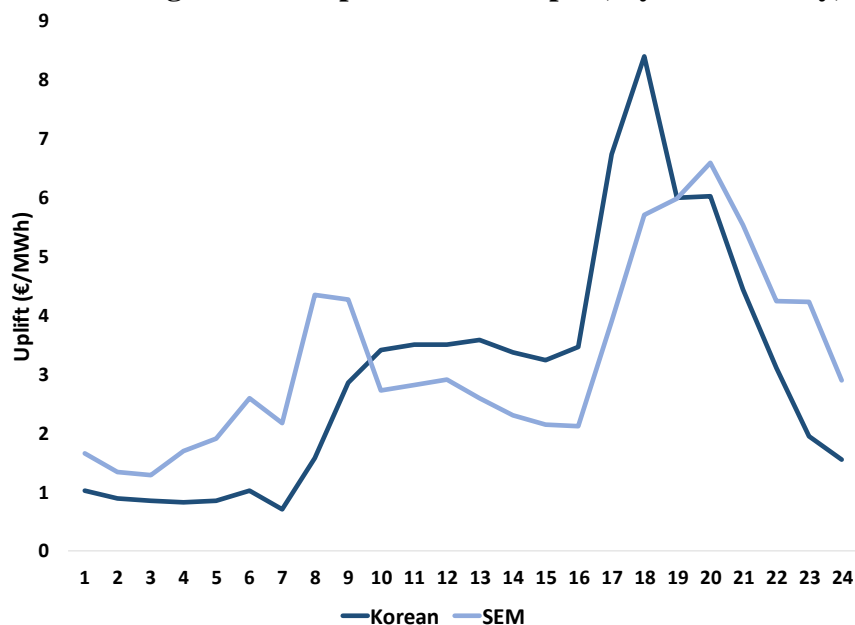
2. Choice of uplift

PLEXOS offers three uplift options: the so-called “Korean Uplift” (an uplift that mimics a cost-based pool), the SEM Uplift (developed specifically to match the actual uplift in the current SEM), and a custom uplift approach.

The 2018-2019 I-SEM Validated Model used the Korean Uplift, and we recommend maintaining that choice. Without assessing I-SEM data, it is challenging to determine the uplift approach that will best replicate prices in the I-SEM. For this reason, we believe it would be premature at this stage to change the choice of uplift in the 2018-2023 I-SEM Validated Model.

We investigated the use of SEM Uplift as an alternative to the Korean uplift. The two methods produce different patterns of uplift, as shown in Figure 4 below.

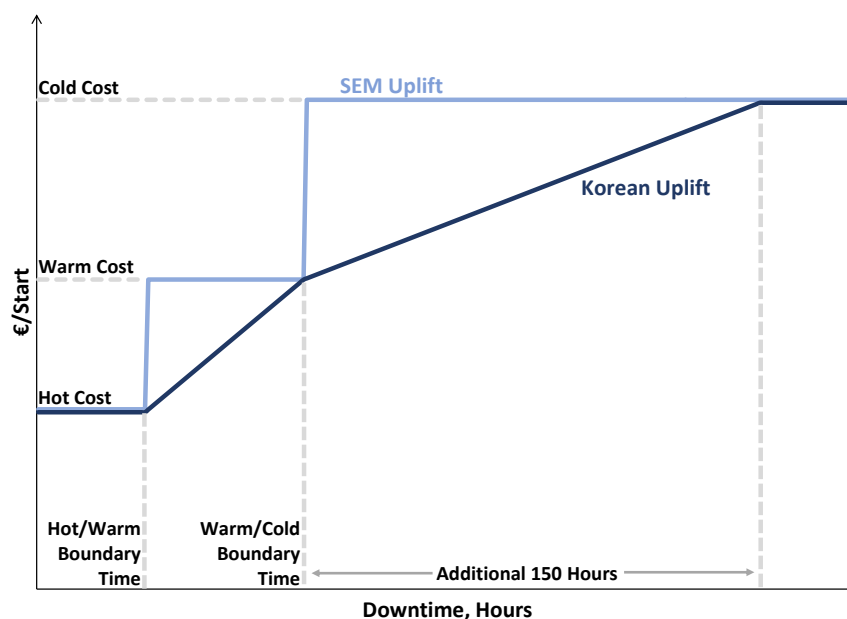
Figure 4: Average Korean Uplift vs. SEM Uplift, by Hour of Day, 2019



In the above run, for example, the SEM Uplift price exceeded the Korean Uplift price by €0.32/MWh on average. Baringa also found that SEM Uplift exceeded the Korean Uplift in its recent validation exercise.⁴⁸ As shadow prices are basically the same regardless of the uplift method, these uplift price differences also result in total prices being higher when using the SEM uplift.

The two uplift methods incorporate start costs differently. Our assessment indicates that this is a principal driver – and likely the most important driver – of the difference between the two uplifts. In its recent assessment (“Baringa Clarification Note”), Baringa also found that different treatment of start costs drove the difference in average prices produced by the two uplift methods.⁴⁹ Figure 5 below highlights the difference:

Figure 5: Start Costs as Reflected in Korean and SEM Uplift



PLEXOS takes as input three start cost amounts (hot, warm, and cold) as well as the time duration between start states.⁵⁰ Figure 5 above shows how the two uplift methods use this data to determine start costs as a function of time since a generation unit shuts-down.⁵¹ As seen in that figure, the SEM approach treats start costs as a step function of the three start costs. The Korean uplift also

⁴⁸ 2018-2019 I-SEM Model Validation Report.

⁴⁹ “I-SEM Validated Model –Clarifications following Information Session”, Baringa Partners LLP, 21/12/2017 (“Baringa Clarification Note”), available here <https://www.semcommittee.com/news-centre/i-sem-plexos-validation-clarification-note>.

⁵⁰ Conceptually, the longer a unit is offline, the higher the cost to start up that unit to bring it back online, though for some units start costs are basically constant regardless of how long the unit has been offline.

⁵¹ Start costs include both the cost of the fuel used at startup and non-fuel VOM/start costs.

treats the “hot” start cost as a flat line. However, Korean uplift transitions gradually from “hot” to “warm” and from “warm” to “cold”, using linear extrapolation. Notably, start costs in the Korean uplift are lower than those in the SEM uplift, except at the “boundary” points above, where the two methods reflect the same start costs.

Thus, the key question is which approach better reflects how generators will attempt to recover their costs in their offers into the I-SEM. Prior to the beginning of the I-SEM, it is challenging to answer this question. We considered several factors when deciding to maintain the use of the Korean uplift in the 2018-2023 I-SEM Validated Model (these are not necessarily in order of importance):

- At least to some degree, we do expect that start costs will increase gradually as the time from a unit’s shutdown increases.⁵²
- The SEM uplift approach to start cost mirrors how uplift is calculated in the SEM, where generators present three-start-state offers with boundary times. Yet, even in the SEM, we recognize the possibility that, depending on how generators form their start cost offers, the Korean uplift treatment could better represent the level of generators’ start costs as time elapses from a shutdown.
- It is uncertain what level of start costs generators will attempt to recover in the I-SEM. The VOM/start component of start costs may include costs that are *not* immediate “hard” costs. For example, VOM/start may include estimated avoided FOM costs and or a risk component. We understand there is much uncertainty about whether in the I-SEM generators will seek recovery of the same VOM costs/start they offered into the SEM market. Theoretically, the effective VOM/start cost recovery could go up or down. However, we understand that there is a general expectation that generators may only be able to recover lower VOM costs/start in the I-SEM. While we do not express a formal opinion on the level of VOM costs/start recovery in the I-SEM, we do recognize that observation in making our choice.

The choice of the Korean uplift introduces a new time parameter not needed in the SEM uplift. As seen in Figure 5, under the SEM uplift approach units face “cold-state” start costs at the so-called “warm-cold boundary.” Under the Korean uplift, there is a gradual transition to the cold-state start costs. In the 2018-2019 I-SEM Validated Model, this latter transition happens over 150 hours. We tested the effect on prices of using a shorter time, 72 hours, and found a relatively small average price difference of €0.77/MWh. We have decided to maintain the 150 hour assumption. Given the many uncertainties around start cost recovery in the I-SEM – and the different ways that start cost recovery might be reflected in PLEXOS – we recommend the 150 hour parameter be re-evaluated as part of a comprehensive effort to refine generator offers and price formation once enough actual I-SEM data are available.

⁵² We recognize that the reality is likely to be more complex and individual units may have costs that change in a non-linear fashion.

C. Scarcity

The I-SEM does not have the same cost-based day-ahead bidding constraints on generators that the SEM has. Thus in theory, generators could extract scarcity rents when the supply-demand balance is tight. We do not include scarcity pricing in the 2018-2023 I-SEM Validated Model, however. We find that it would be premature to speculate as to how generators might bid to incorporate scarcity rents in the I-SEM. Further, the one-sided Contract for Differences (“CFD”) mechanism of capacity contracts in the I-SEM may reduce the incentive generators might otherwise have had to increase their offers in times of scarcity. As with other issues, we recommend re-evaluating this issue with actual I-SEM data.

D. Great Britain and Interconnectors

1. Great Britain

Like previous validated PLEXOS models, the 2018-2023 I-SEM Validated Model includes a representation of Great Britain in order to model trade between the Ireland & N. Ireland market and GB. There are several options to model GB, including:

- 1) Representing GB as pre-determined fixed prices, where the SEM can sell or buy electricity at those prices across the interconnectors. This approach is rejected because prices in GB would change with different fuel prices. Fixing GB market prices would then likely lead to unrealistic flows on the interconnector when forecasted fuel prices differ from historical fuel prices.
- 2) Representing the entire GB market, in detail. We did not adopt this choice. It would require great expense and time to develop an entire GB model. Further, the goal of the Validated Model is to produce accurate I-SEM results. GB is far larger than the SEM. So, incorporating a full GB market could cause the optimization to focus on that market instead of the SEM.
- 3) Building a small representation of GB, whose only purpose is to produce GB prices that help determine the interconnector flows.⁵³ This is the approach of the 2018-2019 I-SEM Validated Model, and we adopt this approach as well. In this approach, the GB “market” is far smaller than the SEM market, so PLEXOS will focus on optimizing the SEM.

Under approach 3), we include a single generator in GB, which operates as a gas-fired unit. We give this generator a GJ/MWh heat rate that varies with hour of the day and season of the year. We use two seasons, “summer” and “winter”, defining summer as quarters 2 and 3 and winter as quarters 1 and 4. In effect, this approach sets the GB price in PLEXOS as a factor times the “all-

⁵³ Under this approach, the GB market has a demand that is large enough where it could absorb full flow on the interconnectors from SEM into GB. Similarly, the GB market contains generators that have enough generation capacity so that, at full output, all of the internal GB demand is satisfied and the interconnectors flow at full capacity into the I-SEM.

in” gas price, where that factor changes with hour and season, and where the “all-in” gas price also includes CO₂ and transport charges. The CO₂ price for GB includes the UK’s Carbon Price Support price, discussed in Section II.B.2 above. This approach is also consistent with the 2018-2019 I-SEM Validated Model.

We calculated historical average hourly heat rates in GB using data from January 2016 to December 2017. We averaged these heat rates by hour of day, producing separate averages for “summer” (Q2 and Q3) and “winter” (Q1 and Q4). The 2018-2019 I-SEM Validated Model also incorporated heat rates calculated by averaging two years of historical data.

Figure 6 and Figure 7 below show the previous heat rates in the 2018-2019 I-SEM Validated Model and the heat rates that we determined for the 2018-2023 I-SEM Validated Model.

Figure 6: GB Heat Rates, 2018-2019 vs. 2018-2023 I-SEM Validated Models, Summer

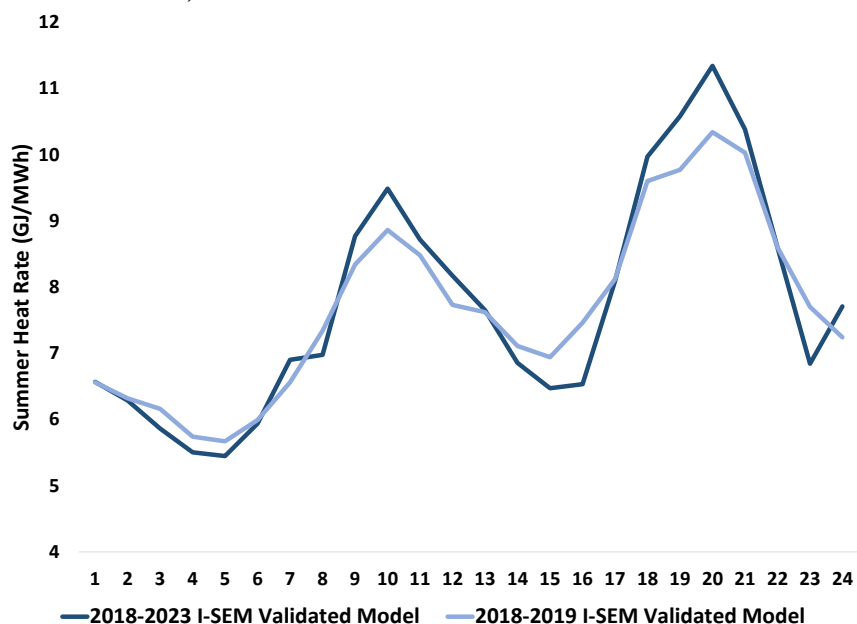
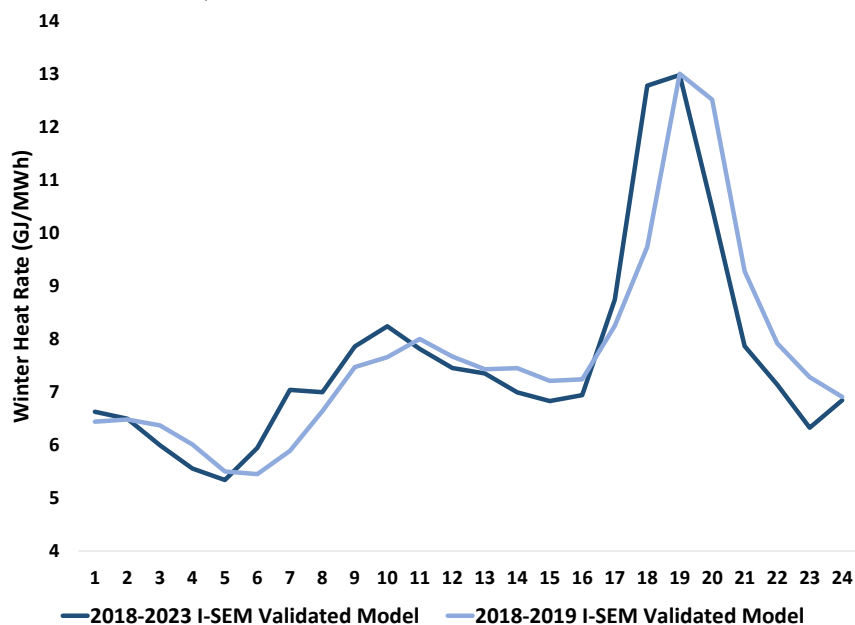


Figure 7: GB Heat Rates, 2018-019 vs. 2018-2023 I-SEM Validated Models, Winter



Even within approach 3), there are various ways to model GB prices. One could adopt a more complex method than “(heat rate) x (all-in gas price)”. Or, one could keep that method but calculate heat rates with a different approach or based on a different historical data period.

We recognize that without assessing I-SEM data, it is challenging to determine the best approach for modeling trade with GB in the I-SEM. Without having access I-SEM data when we performed the bulk of our validation, we favored consistency with the 2018-2019 I-SEM Validated Model. Furthermore, we view the average heat rate approach as a reasonable and appropriate approach to approximate the GB market. The RAs may wish to re-evaluate this approach with actual I-SEM data (including flows with GB).

2. Interconnectors

As discussed above, we include uplift in the 2018-2023 I-SEM Validated Model as a method to produce prices that reflect recovery of start and no-load costs. This affects how we model the interconnectors. PLEXOS optimizes the interconnectors based on the **shadow prices** in the SEM and GB. However, we model GB such that its shadow prices include recovery of start and no-load costs. In contrast, in PLEXOS the shadow prices of the I-SEM do not include full start and no-load recovery, as those are recovered via uplift. Thus the shadow prices in the two markets are not comparable on a consistent basis. We resolve this potential discrepancy by adding a wheeling charge to trade between the SEM and Great Britain. The wheeling charge is set equal to the average uplift in PLEXOS for the SEM region, on an hour-of-day and seasonal basis, updating the wheeling

charges for each year from 2018 through 2023.⁵⁴ PLEXOS adds the wheeling charge to the shadow price in the SEM when optimizing trade over the interconnector, thus resolving the discrepancy, at least on average. The previous validation also adopted this wheeling charge approach (though it used the same wheeling charges in both the years it covered, 2018 and 2019).

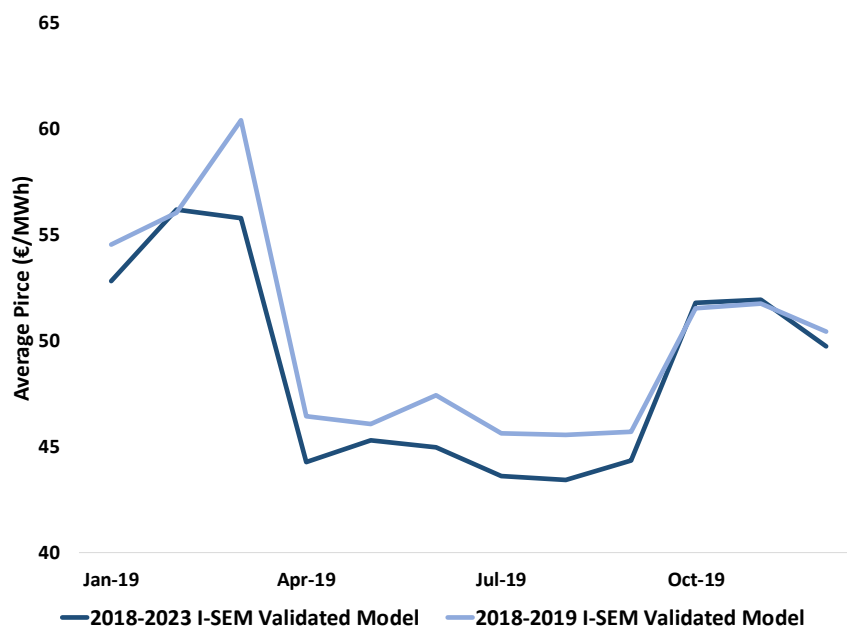
⁵⁴ We determine the wheeling charges with an initial test run of PLEXOS to calculate average uplift in the SEM. The wheeling charge accounts for uplift by making trade relatively more attractive in the from-GB-to-SEM direction.

IV. Summary of Results of the 2018-2023 I-SEM Validated Model

A. Average Power Prices

We compared prices from the 2018-2023 I-SEM Validated Model to the previous 2018-2019 I-SEM Validated Model, using 2019 as a sample year. Average baseload prices are €1.44/MWh lower in 2019 as compared to the 2018-2019 I-SEM Validated Model. Figure 8 shows the monthly price pattern.

Figure 8: Comparison of 2018-2023 and 2018-2019 I-SEM Validated Models (Year 2019)



The 2018-2023 I-SEM Validated Model's prices basically follow the same monthly pattern as the previous Validated Model's prices, but are lower in most months, with prices in March 2019 being notably lower in particular.

A relatively small driver of the change in average prices between the two models (about €0.1/MWh) is that the 2018-2023 I-SEM Validated Model has somewhat different indicative fuel prices than the 2018-2019 I-SEM Validated Model. Thus if changes in fuel prices are accounted for, average prices are about €1.34/MWh lower in the 2018-2023 I-SEM Validated Model than in the 2018-2019 I-SEM Validated Model. Changes in system and generator data caused the change of €1.34/MWh in average prices, driven by three changes in particular (Figure 9 shows the quantitative effects of these changes):

- 1) For March 2019, the main driver is the fact that a particular generator that tends to operate with higher capacity factors in the winter was offline for almost the entire month of March 2019 in the 2018-2019 I-SEM Validated Model. In the 2018-2023 I-SEM Validated Model, the updated outage data from EirGrid no longer has that specific outage in March 2019.

- 2) We updated the offer markups at a particular generation station to better reflect how that station offers into the market, including adjusting the MW point above which those markups apply. To some extent these changes had offsetting effects, but on balance they lowered prices by €0.7/MWh on average.
- 3) The TSOs' wind capacity forecast increased after the 2018-2019 I-SEM Validated Model was published.⁵⁵

All other changes in the 2018-2023 I-SEM Validated Model basically cancel each other out so the change in price can be explained with only the four drivers in Figure 9.

Figure 9: Drivers of Changes Between 2018-2023 and 2018-2019 I-SEM Validated Models, Considering Average Baseload Prices for 2019 (€/MWh)

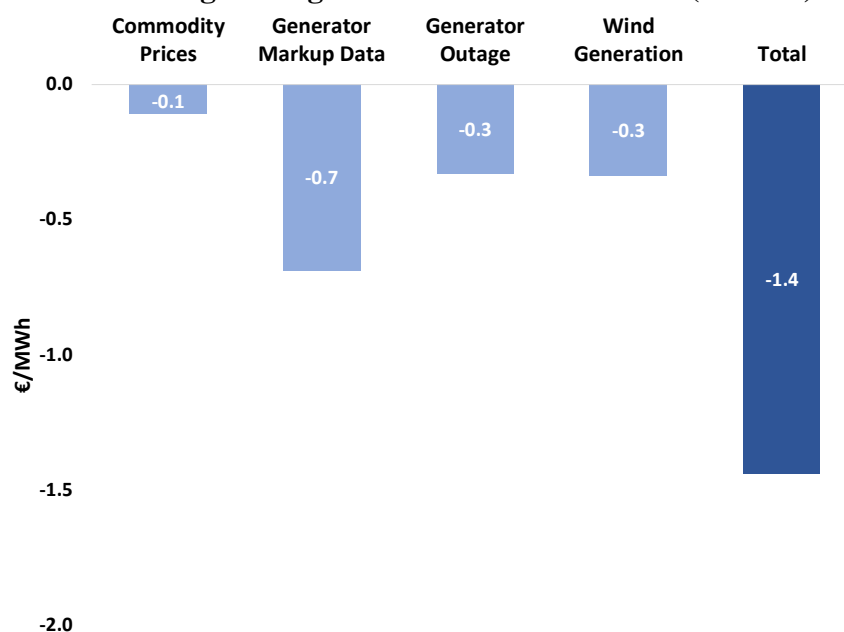


Figure 10 and Figure 11 below show by month the shadow price and uplift components of the price in the I-SEM Validated models, comparing the 2018-2023 version to the 2018-2019 version, where the largest change is in the uplift component.

⁵⁵ Further, the 2018-2019 version of the model relied on historical average wind availability from 2011 to 2015, and the current 2018-2023 version uses 2012-2016 data (2016 wind availability data being recently made available by the TSOs). Overall, wind availability is slightly lower in the year 2016 profile that replaces the year 2011 profile. However, monthly wind distribution is somewhat different between the 2016 and 2011, which contributes somewhat to the differences seen in the monthly pattern of prices. We include this small adjustment to the wind availabilities in the wind generation item from Figure 9.

Figure 10: Total and Shadow Prices in 2018-2023 and 2018-2019 I-SEM Validated Models

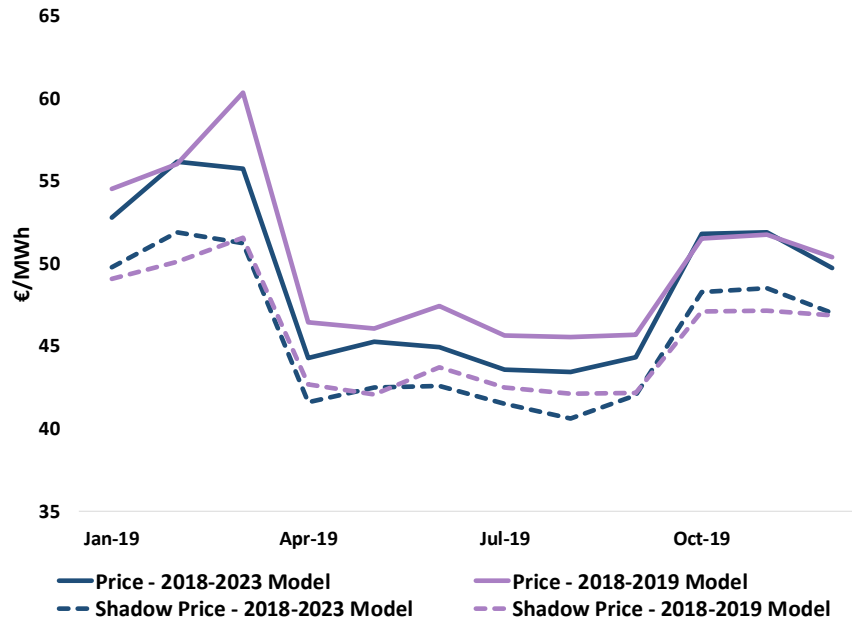


Figure 11: Uplift in 2018-2023 and 2018-2019 I-SEM Validated Models

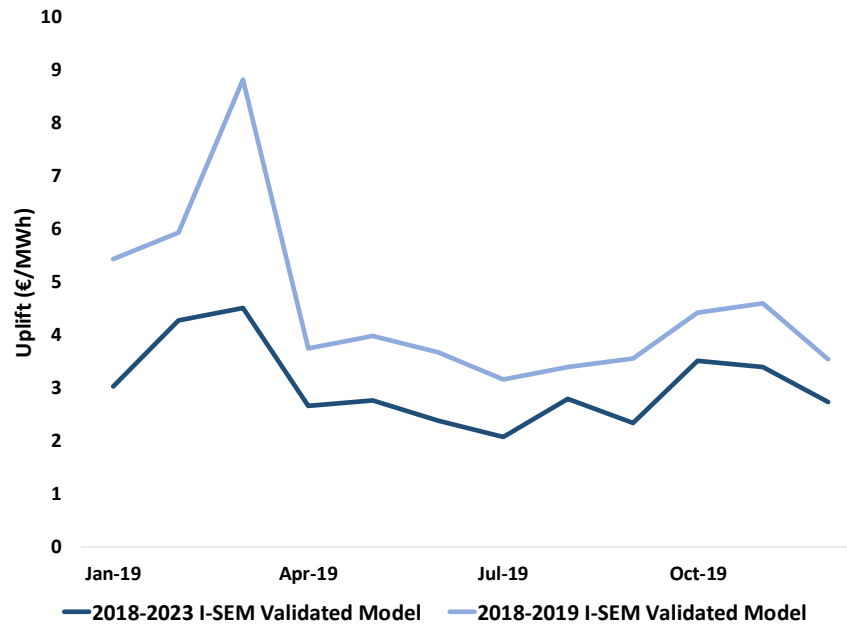


Figure 12 shows the changes in average prices on an hourly basis in the summer and winter.

Figure 12: Hourly Prices in 2018-2023 and 2018-2019 I-SEM Validated Models

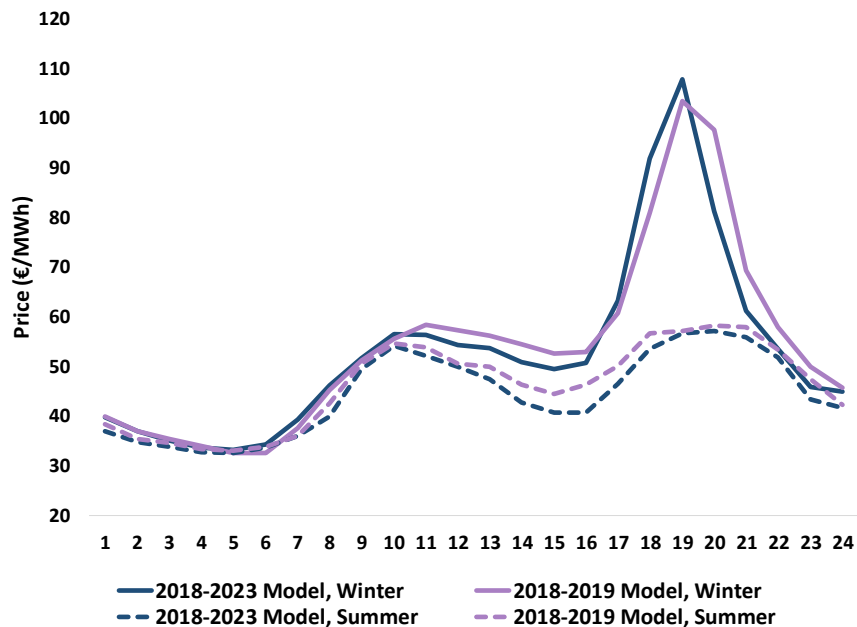
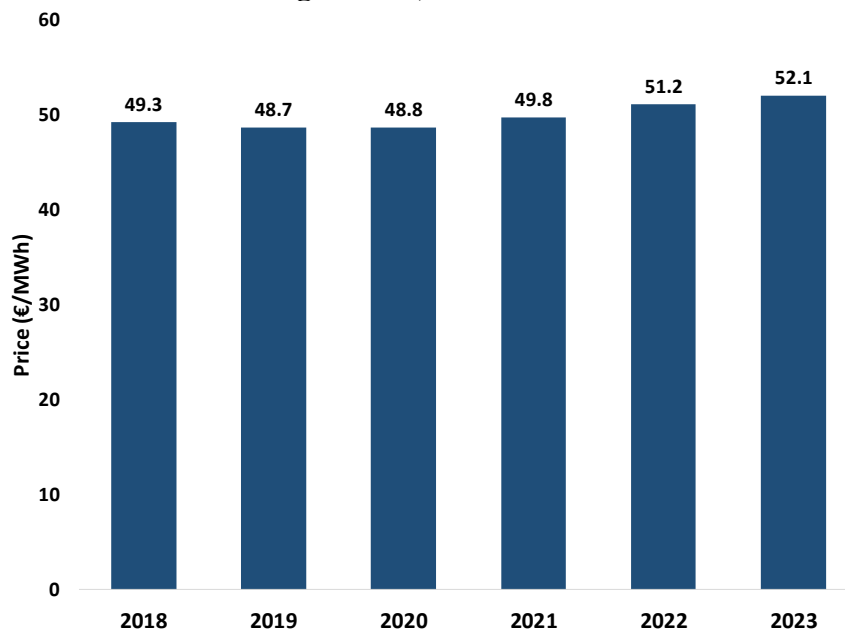


Figure 13 shows the annual average prices from 2018 to 2023.

Figure 13: Annual Average Prices, 2018-2023 I-SEM Validated Model



Overall there is a small upwards trend in prices. As we assume the same fuel prices each year, the supply and demand balance is the driver of changes in electricity prices over the years of the model.

This small upwards trend in prices is driven by load growth (slightly) outpacing the increase in wind generation from increased wind capacity.⁵⁶

B. Generation and Interconnector Flows

Figure 14 shows average interconnector flows. Net flows out of the I-SEM into GB are noticeably higher, on average. The lower prices in the I-SEM in the 2018-2023 validated model is likely the driving factor behind this.

Figure 14: Net Exports, in 2018-2023 and 2018-2019 I-SEM Validated Models

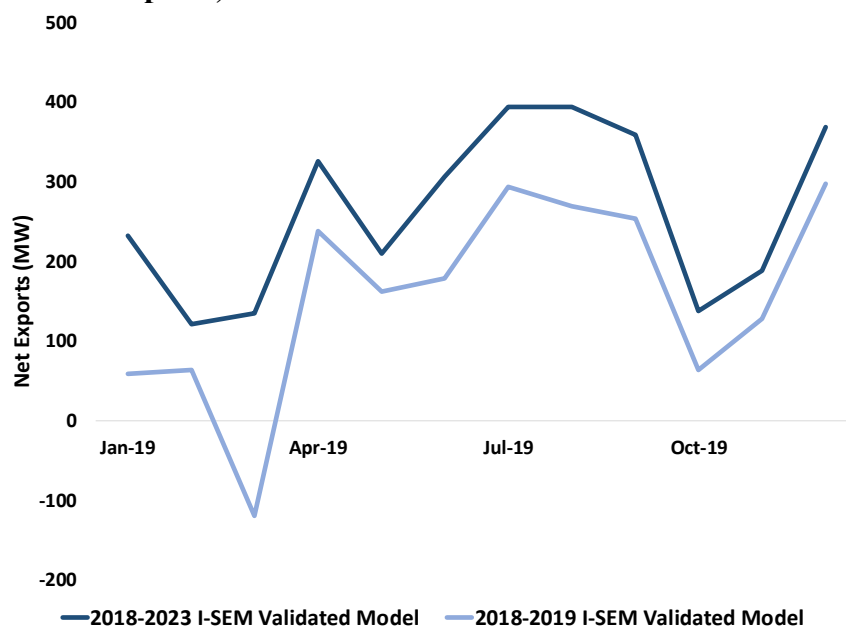


Figure 15 shows average hourly generation by plant type by month, and Figure 16 shows total generation.

⁵⁶ The other changes in supply – the retirements of AD1, Marina CC, and Tarbert – minimally contribute to the rise in prices.

Figure 15: Average Generation (MWh/h) by Plant Type

Figure 15a: 2018-2019 I-SEM Validated Model (2019 Sample Year)

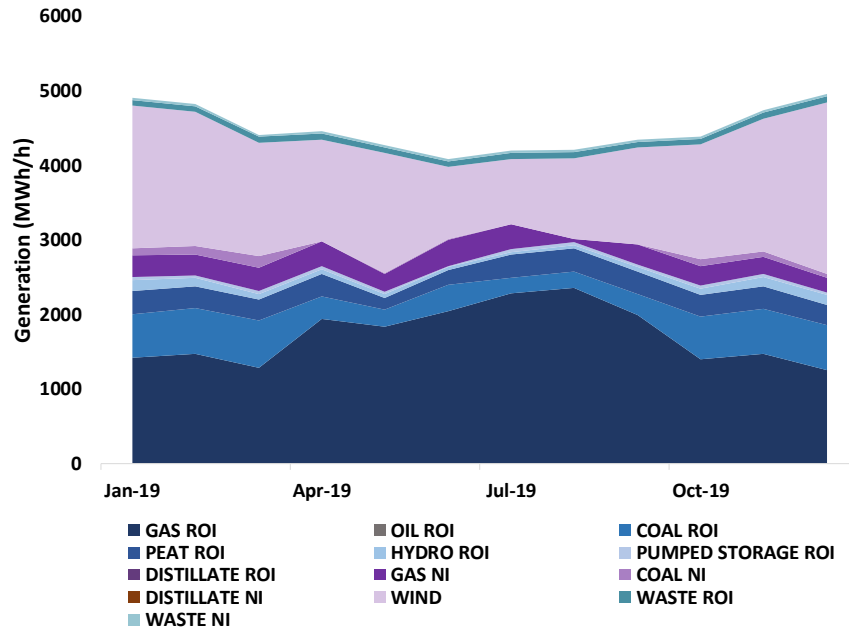


Figure 15b: 2018-2023 I-SEM Validated Model (2019 Sample Year)

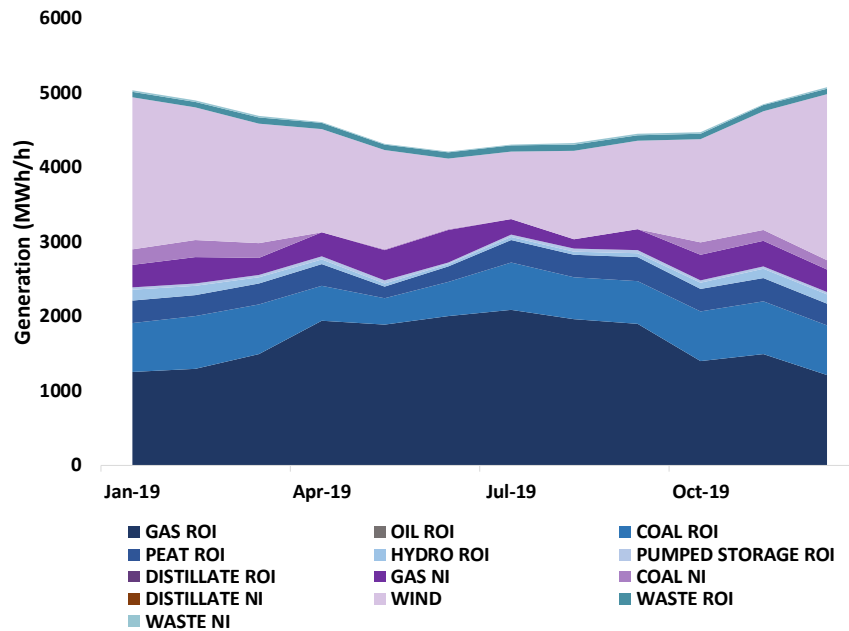
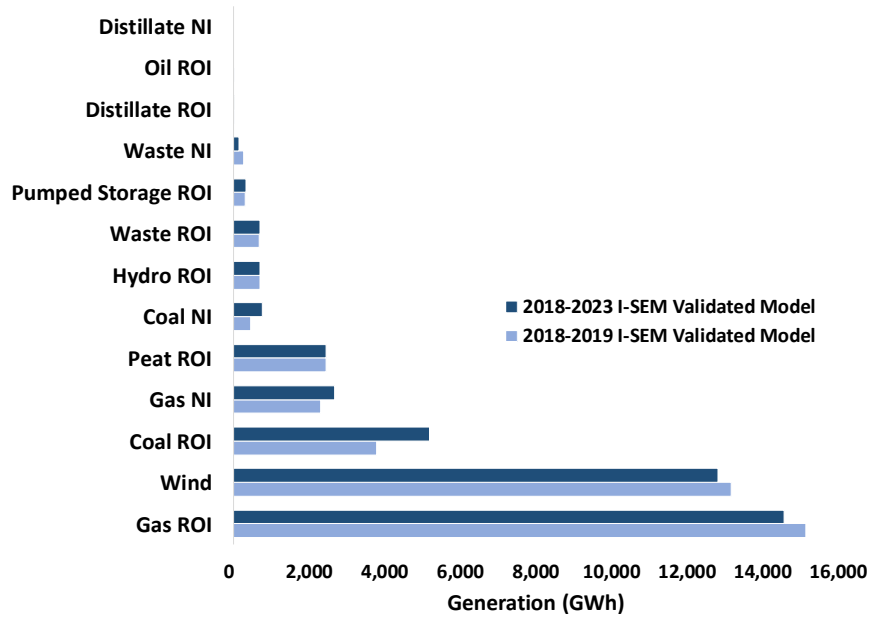


Figure 16: Total Generation by Plant Type in 2018-2023 and 2018-2019 I-SEM Validated Models (2019 Sample Year)



Appendix I. NERA Quality Assurance

This appendix provides the details of the checks NERA performed to ensure the accuracy and quality of the 2018-2023 I-SEM Validated Model.

Generator data. A critical quality assurance (“QA”) step is to assure that the underlying data are reasonable and apt for the PLEXOS model. We asked every generation company to review, and update as needed, the PLEXOS data for their generators as represented in the previous 2018-2019 I-SEM Validated Model.

- We asked the generation companies to explain the changes in data; where the explanations were not satisfactory, we followed up with the generators. In some cases this process identified errors in the data originally proposed by the generation companies, which the generation companies subsequently corrected. In some cases, the generation companies had simply provided the wrong data. In other cases, there was an initial confusion about how data are correctly to be represented in PLEXOS.
- We independently reviewed the proposed new data for reasonableness. We also provided all proposed new data to the RAs, for their review.
- We also reviewed the generator data that the generation companies did *not* update, *i.e.*, the data that was unchanged since the 2018-2019 I-SEM Validated Model. We did not perform a comprehensive validation of this unchanged data, however, as such a review was conducted as recently as 2017.⁵⁷ The RAs agreed with this approach. Rather, we reviewed the unchanged generator data for reasonableness, looking for any outliers or inconsistent data. For example, we noticed that the summer capacity rating of one unit was slightly higher than its winter rating. We would expect the reverse, so we contacted the owner of that plant, which confirmed the summer capacity rating should be lower than the winter rating, and the owner provided the updated value.

System data. We obtained system data from official market sources. It was outside of our scope to independently assess the accuracy of this data, *e.g.*, whether the peak demand forecast published by the TSOs is correct. Nonetheless, we reviewed the system data to identify inputs that appeared erroneous on their face, though in practice we did not find any such data.

After we initially populated 2018-2023 I-SEM Validated Model with data, we performed a comprehensive check to assure ourselves that the actual data was what we intended that data to be. Work initially performed by one project team member was independently checked by a different team member.

⁵⁷ See discussion in II.A.2 above.

We checked data in multiple ways. For example, the PLEXOS model uses five different *hourly* load forecasts from 2018 to 2023, each based on a different historical profile and each reflecting the 2018 GCS demand forecast. After creating that file we checked that:

- The peak demand in each year (2018 to 2023) indeed matched the target peak demand from the 2018 GCS (and matched the target total energy requirement from the 2018 GCS). We ensured that this was the case for all five forecasts based on the different historical profiles.
- That the shape of demand from the five 2018 to 2023 forecasts indeed lined up with the historical years upon which they were based.

We performed similar checks for the wind profiles we used.

With embedded generation, we did not second guess the details of the hourly files we received from EirGrid (that was beyond our scope). But we did ensure that the growth of embedded generation over the 2018 to 2023 period as reflected in the 2018 GCS broadly lined up with detailed hourly files.

We also performed various checks on the outputs of the 2018-2023 I-SEM Validated Model. We confirmed that the wind and embedded generation from the model outputs matched what we expected it to be from the model inputs. We also confirmed that the total generation in the I-SEM lined up with the forecast for total energy requirements that produced the inputs to the model (adjusting for trade with Great Britain).

Finally, we reviewed various aggregate outputs of the model, including the level of dispatch for the various generation units and market prices. It was beyond our scope to check that PLEXOS's dispatch and price algorithms worked correctly. But we did check the reasonableness of the results, *e.g.*, that cheaper generators ran more than more expensive generators and that prices were higher (all things equal) when load was higher.

Appendix II. Calculation of “Average-Year” Scheduled Outages

We calculate an average-year outage schedule, averaging the 2018 through 2020 outage schedules. We apply the average-year schedule each year 2021 through 2023. We calculate the average-year outage schedule as follows

- 1) For each unit, we collected every outage from the 2018 through 2020 schedules. For example, a unit may have three outages in this combined outage collection: 1 April to 18 April 2018, 12 August to 20 August 2019, and 5 June to 28 June 2020.
- 2) We combined all those outages into a “generic-year” schedule. Continuing the example above, this generic year would have the same three outages, but now they are no longer tied to a specific year. Sorting the outages from step 1, they are: 1 April to 18 April, 5 June to 28 June, and 12 August to 20 August.
- 3) The lengths of the outages in the “generic year” from step 2) are 18, 24, and 9 days, respectively, for a total of 51 days. In reality, those three outages occur over a three year period. So, we resized the outages by dividing by three. The same three outages are reduced in the “generic year” to lengths 6, 8, and 3 days. We place these reduced-length outages at the center of the original outages range. For example, the 12 Aug to 20 Aug outage would become a 15 Aug to 17 Aug outage.
- 4) There is an issue, however, when the outages from step 3) overlap. For example, one generic outage might be from 6 July to 10 July (five day outage) and another might be 8 July to 11 July (four day outage). As a unit cannot be “doubly out” on a single day, we would combine the outages into one continuous nine day outage (nine is the sum of the length of the two individual outages).
- 5) There is a second issue, that outages from step 3) may be “too close” to each other. For example, one outage may be from 5 June to 9 June and another from 11 June to 14 June, thus allowing the unit to be able to generate for a single day only before going offline again.⁵⁸ We also combine these outages into one continuous outage.
- 6) The same generic-year outages are then applied in each of 2021 to 2023.

⁵⁸ The issue of such an example is that, in PLEXOS, units with high start costs and or long minimum times up and down may not be able to get into a normal dispatch rhythm if they are only available for a single day.

Appendix III. DSU Methodology

In PLEXOS, we represent DSUs with the five P-Q pairs of Table 10 below (which is a copy of Table 5 above).

Table 10: Demand P-Q Pairs, 2018-2023 I-SEM Validated Model

<u>DSU Blocks</u>	<u>Quantity (MW)</u>	<u>Price (€/MWh)</u>
1	37	0
2	4	45
3	270	453
4	70	551
5	119	1,483

We calculated these P-Q pairs based on 2017 data, as follows.

DSU Block 1 represents DSUs that on average bid *negative* incremental prices in 2017. These DSUs were dispatched almost every hour they were available. For simplicity we represent them at a €0/MWh price in PLEXOS. These units in total were scheduled at 30 MW on average in 2017, which we scaled up to the 37 MW from Table 10 to line up with the 2018 GCS, as discussed at the end of this appendix.

DSU Block 2 represents DSUs with low but positive average incremental offer prices – in practice there was one such DSU, which was often but not always scheduled in 2017. The €45/MWh price from Table 10 is that DSU’s average incremental price from 2017⁵⁹ plus its average shutdown cost divided by (average scheduled quantity times average length of dispatch in hours). We assigned this DSU a quantity equal to its average scheduled quantity when dispatch in 2017, scaled up the same way as DSU Block 1.

DSU Blocks 3-5 represent DSUs that rarely if ever were dispatch in 2017. For each of these we calculated a price equal to the weighted average for 2017 of: *each interval* in 2017’s average offered dispatch costs.⁶⁰ We assigned each DSU a quantity equal to its average quantity offered to the market in 2017. We aggregated the various DSUs into three groups of similar prices. Within each group we calculated the weighted average price and the total quantity. DSU blocks 3 to 5 of Table 10 reflect these prices and quantities (with the quantities scaled up the same way as DSU Blocks 1 and 2.)

As discussed above, we started with 2017 quantities for the DSUs and then scaled them as follows:

⁵⁹ Specifically the DSU’s incremental price from its first P-Q pair, as in this case the price from its second P-Q pair was high enough that it rarely if ever was dispatched at that higher price.

⁶⁰ For each interval, we calculated its average cost per MWh assuming the DSU would be dispatched at its full offer quantity for one hour in length. We then took a weighted average of those averages from each interval.

- We added up the maximum offer quantities for all the DSUs active in 2017, a total of 494 MW.
- We noted that Appendix 2 to the 2018 GCS identifies 606 MW of DSUs between Ireland and Northern Ireland, or 23% more than the 494 MW we calculated for DSUs in 2017.
- We scaled up each DSU Block by 23% to determine the quantities for PLEXOS (Table 10 reflects the scaled-up quantities).

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