NERA
ECONOMIC CONSULTING

SEM PLEXOS Model Validation (2021-2029) and Backcast

Prepared for the Commission for Regulation of Utilities of Ireland and the Utility Regulator of Northern Ireland

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Report qualifications/assumptions and limiting conditions

NERA was commissioned by the Commission for Regulation of Utilities ("CRU" or "client") to update and validate the CRU's and Utility Regulator of Northern Ireland's ("UREGNI") Model of the Single Electricity Market ("SEM"), to perform a backcast of the same PLEXOS Model against historical market data (post I-SEM implementation, Go-Live date of 1 October 2018), and to produce this instant report. The primary audience for this report includes the stakeholders in the electricity market of Ireland and Northern Ireland.

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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
CRM	Capacity Remuneration Mechanism
DAM	Day Ahead Market
DCs	Directed Contracts
DSU	Demand Side Unit
ECA	Economic Consulting Associates
EWIC	East-West Interconnector
FOM	Fixed Operating and Maintenance
FOR	Forced Outage Rate
GB	Great Britain
GCS	Generation Capacity Statement
GJ	Gigajoule
I-SEM	Integrated Single Electricity Market
IDM	Intraday Markets
LSFO	Low Sulphur Fuel Oil
MIP	Mixed Integer Programming
MW	Megawatt
MWh	Megawatt Hour
MR	Maintenance Rate
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
SNSP	System Non-Synchronous Penetration
TLAFs	Transmission Loss Adjustment Factors
TSOs	Transmission System Operators
TTF	Transfer Title Facility
UREGNI	Utility Regulator of Northern Ireland
USE	Unserved Energy
VOLL	Value of Lost Load
VOM	Variable Operating and Maintenance

Executive Summary

NERA was engaged by the Commission for Regulation of Utilities ("CRU") to update and validate the CRU and Utility Regulator of Northern Ireland ("UREGNI")'s PLEXOS Model of the Single Electricity Market ("SEM"), and to backcast that model against historical SEM data (post I-SEM implementation - from Go-Live date of 1 October 2018). CRU and UREGNI are collectively known as the Regulatory Authorities ("RAs"). NERA's assignment was to produce a PLEXOS Model of the SEM validated for the 2021 to 2029 period ("2021-2029 SEM PLEXOS Model" or "SEM PLEXOS Model" or "PLEXOS Model") and to perform a backcast, where NERA compared SEM PLEXOS Model results against SEM outturn data post I-SEM implementation.

Basic Approach of 2021-2029 SEM PLEXOS Model

The basic approach of 2021-2029 SEM PLEXOS Model is the same as that of prior SEM PLEXOS Models. The basic approach is that generators structure their offers to recover their incremental fuel and CO_2 costs as well as recover their variable operation and maintenance ("VOM") costs. Further, under this basic approach, PLEXOS seeks to minimize total costs including incremental generation costs, start costs and no-load costs. PLEXOS also adds an uplift to the resulting market price, as needed, to ensure the final market price compensates generators for their start and no-load costs. This basic approach in the SEM PLEXOS Model differs from the SEM rules since I-SEM Go-Live. Since I-SEM Go-Live:

a) there is no longer an uplift added to SEM prices (there was such an uplift before I-SEM Go-Live) and

b) generators do not explicitly declare their start and no-load costs as part of their offers into the Day Ahead Market ("DAM") (the generators did explicitly include these costs in their offers before I-SEM Go-Live; since I-SEM Go-Live, generators may instead seek recovery of start and no-load costs indirectly through their I-SEM offers, e.g. through offers with minimum income conditions).

NERA maintain the basic structure of prior SEM PLEXOS Models because:

1) it is straightforward to implement, update, and maintain in PLEXOS; in contrast, switching to an approach that explicitly mirrors the SEM since I-SEM Go-Live would require a significant redesign of SEM PLEXOS Model, and it is unclear whether changing to an explicit I-SEM approach would improve accuracy;

2) it aligns with economic, power market, and electricity sector modelling principles; and

3) this approach has good alignment with historical data in NERA's backcast.

Updating the PLEXOS Model

NERA started with the previous SEM PLEXOS Model which covered 2019 through 2025 ("2019-2025 SEM PLEXOS Model"). To extend the model to 2029, NERA extended the forecasts for load, wind capacity, embedded generation, and generator outages to 2029, using data from the Transmission System Operators ("TSOs") of Ireland and Northern Ireland. NERA also assessed what new thermal generation units may come online before the end of 2029 and what units may retire. NERA added three new gas turbine plants (Grange Backup Power Limited, Data and Power Hub Services, and EP Kilroot) representing a total of 879 MW of new generation capacity. NERA retired the Tarbert plant, Aghada CT1 and the Kilroot coal units at the end of 2023, and NERA retired the Moneypoint plant at the end of 2025, each as reflected in the TSOs' All-Island Generation Capacity Statement 2021-2030 ("2021 GCS").[1] NERA also retired the Edenderry peat/biomass unit at the end of 2023. As of the writing of this report, the planning permission for Edenderry peat will expire at the end of 2023, though NERA understand that Bord na Móna is applying for a planning permission extension.[2] Users of the 2021-2029 SEM PLEXOS Model may choose to negate the Edenderry retirement in the Model if they wish to run scenarios assuming that unit continues to operate beyond 2023. Load growth in the SEM PLEXOS Model is served by new renewable capacity (particularly wind), new thermal generation units and increased imports, where import capacity itself is expanded in the Model when new interconnectors are added in the future.

NERA added two new interconnectors to the 2021-2029 SEM PLEXOS Model: the proposed Celtic interconnector and the Greenlink interconnector. The proposed Celtic interconnector connects the French electricity market to the SEM, and, as a result, NERA also developed a representation of the French market in the 2021-2029 SEM PLEXOS Model. NERA also added wheeling charges to the interconnectors to correct for an internal PLEXOS calculation issue. The wheeling charges ensure that trade between SEM and external markets is modelled on a comparable basis. The use of wheeling charges is for a technical reason related to how PLEXOS treats uplift (discussed in detail in the body of this report). For clarity, the wheeling charges are a tool used to improve the PLEXOS SEM Model, but do not reflect any actual tariffs imposed on interconnector trade.

NERA also added several new batteries to the PLEXOS Model. NERA understands that existing and planned batteries in the SEM are contributing (and will increasingly contribute in the future) to DS3 services.[3] Furthermore, batteries provide system reliability in peak load conditions. Notwithstanding, currently planned battery capacity is small relative to renewable and thermal capacity. Furthermore, the energy market participation by batteries may be limited due to charging and discharging losses, cycling limitations and costs, and contractual requirements and economic incentives to participate in DS3 instead of energy markets (the SEM PLEXOS Model only models the SEM energy market, and does not model the DS3 market). However, the importance of

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1 Available for download here: https://www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf. This internet link, and all other links in this report, are valid as of 22 October 2021, unless otherwise noted.

2 Users of the 2021-2029 SEM PLEXOS Model may choose to negate the Edenderry retirement in the Model if they wish to run scenarios assuming that unit continues to operate beyond 2023.

3 DS3 (Delivering a Secure, Sustainable electrical System) services help the SEM power system accommodate increasing quantities of intermittent non-synchronous renewable generation.

batteries in energy markets may increase in the future, as more battery capacity comes online. Further, costs, market practices, and technical norms may evolve in the future to better support batteries in energy markets.

NERA updated certain generator technical and commercial offer parameters, based on data received from a data request to all generation companies and NERA's subsequent analysis.

NERA continues the use of DSUs in the Validated PLEXOS Model. NERA notes that total DSU capacity is now 658 MW, according to the 2021 GCS. While 658 MW of DSUs can provide significant reliability benefits to the SEM, the effect on average DAM prices (and the effect on PLEXOS Model prices) is relatively small, as the large majority of the DSU capacity offers into the SEM at high prices where these DSUs will be rarely dispatched. NERA updated the DSU approach in PLEXOS to account explicitly for historical dispatch levels of DSU capacity.

NERA also considered the effect of assetless traders on the SEM DAM. NERA notes that assetless traders arbitrage between the DAM and the intra-day markets of the SEM. NERA's assessment is that the presence of assetless traders in the SEM indirectly increases the accuracy of the SEM PLEXOS Model.

- The PLEXOS Model includes all *physical* supply and demand in the SEM, regardless of whether that supply and demand participates in the DAM, but the PLEXOS Model does not include assetless traders;

- The DAM includes most but not all of the *physical* supply and demand in the SEM, but does include assetless traders.

Assetless traders contribute to arbitrage between the different markets in the SEM, and thus help bring the all-supply-and-all-demand approach of the PLEXOS SEM Model in line with DAM prices. Basically, assetless traders make up for the missing physical demand and supply that does not participate in DAM directly. In theory, one approach to build the SEM PLEXOS Model would be to directly include all (and only) the DAM participants including assetless traders. NERA do not recommend that approach, as market participants may move in and out of the DAM, plus it would be challenging to forecast assetless trader offers in the market for the next month much less in 2029. Rather, the presence of assetless traders in the actual DAM helps make the SEM PLEXOS Model more accurate.

Backcast Against Historical SEM Data

NERA performed a detailed iterative backcast of the PLEXOS Model against outturn results of the SEM market, starting from I-SEM Go-Live in October 2018. NERA ran the backcast using actual historical demand, wind generation, fuel prices, and generator availability. Using actual historical data allowed NERA to evaluate PLEXOS's ability to predict prices for a specified supply and demand situation. Overall, the backcast gave NERA confidence in the ability of the SEM PLEXOS Model to recreate SEM prices and generator operations, given specified fuel market conditions and supply and demand conditions. Consequently, the backcast gives NERA confidence in the ability of the SEM PLEXOS Model to forecast SEM DAM prices and generator operations, though the accuracy of such a forecast is of course dependent on accurate inputs for the PLEXOS model, most critically future demand, fuel prices, unit outages, wind and renewable expansion, and generator retirements and additions.

NERA ultimately produced two final backcast SEM PLEXOS Model runs. Firstly, NERA ran the backcast using historical demand in the SEM's DAM. This approach helps test PLEXOS settings in a controlled DAM environment. Secondly, NERA ran the backcast using historical metered demand in the SEM. This approach helps test how PLEXOS will run in forecast mode, given that the SEM PLEXOS Model reflects all forecasted supply and demand in the SEM, whether or not it participates in the DAM.[4] As already discussed, the presence of assetless traders in the DAM helps with the alignment of full supply and demand with DAM results.

The backcast model reasonably replicates average SEM prices and the seasonal pattern of these prices. NERA's backcast using DAM demand produced prices only €1.55/MWh below historical SEM DAM prices (a difference of 3.1%), over the backcast period of October 2018 through April 2021. NERA's backcast using metered demand produced prices €0.31/MWh above historical SEM DAM prices (a difference of 0.6%). See Table 1 below. The closeness of these backcast prices to historical prices give NERA confidence in the reasonableness of the SEM PLEXOS Model.

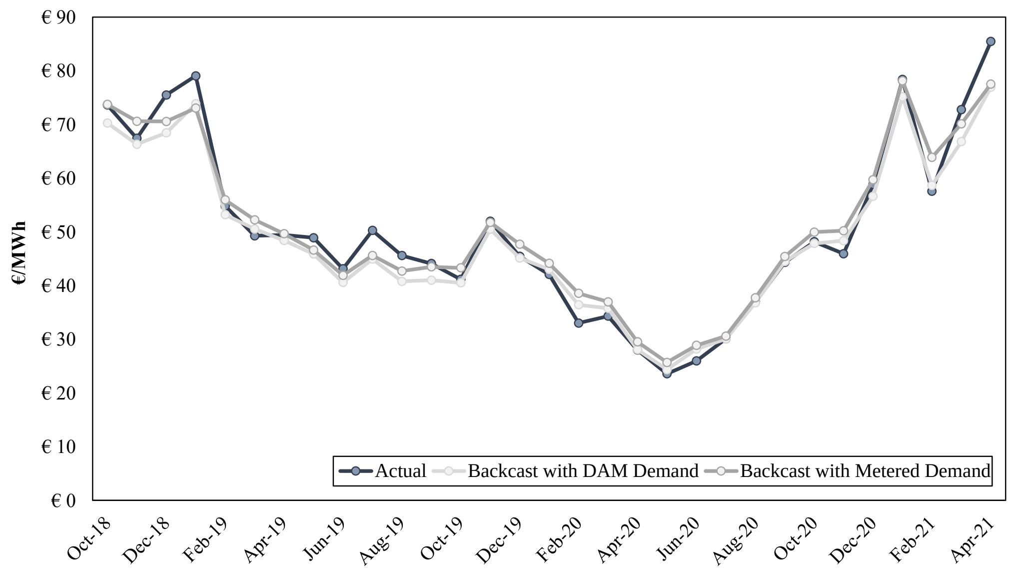
Table 1: Average Prices Backcast vs. Historical, Oct-2018 through April-2021

Backcast Run	Backcast Average Price	Historical Average Price	Delta (€/MWh)	Delta (%)
DAM Demand	€48.96	€50.51	- €1.55	-3.1%
Metered Demand	€50.82	€50.51	€0.31	0.6%

Figure 1 below shows significant alignment of monthly backcast and historical prices.

4 Supply and demand in the DAM generally aligns with total supply and demand in the SEM. Yet, some supply and demand settles in the Intra-Day Markets or in the Balancing Market. Further, some supply is "behind-the-meter" and directly serves demand. In each backcast approach and in the forecast SEM PLEXOS Model NERA ensured that supply and demand were reflected on a comparable basis. In practice, in the backcast models this meant that NERA used somewhat lower quantities of demand than the literal DAM and metered demand, to make sure the backcast demand aligned with the supply resources in the backcast model – NERA discuss this subtlety below in Section 3.1.1.

Figure 1: Average Monthly Backcast and Historical SEM Prices, Oct-2018 through April-2021



Additionally, the backcast matched the pattern of higher prices in peak hours and lower prices in off-peak hours. Notwithstanding this, NERA observed that the backcast model tended to produce prices somewhat lower than historical prices in peak hours and somewhat higher than historical prices in off-peak hours. See Table 2 below.

Table 2: Average Prices Backcast vs. Historical, Peak, Mid-Merit, and Off-Peak, Oct-2018 through April-2021[5]

Season	Backcast Average Price	Historical Average Price	Delta (€/MWh)	Delta (%)
Winter Peak	€76.71	€84.32	- €7.61	-9.0%
Mid-Merit	€52.32	€53.34	- €1.02	-1.9%
Off-Peak	€39.89	€35.85	€4.04	11.3%

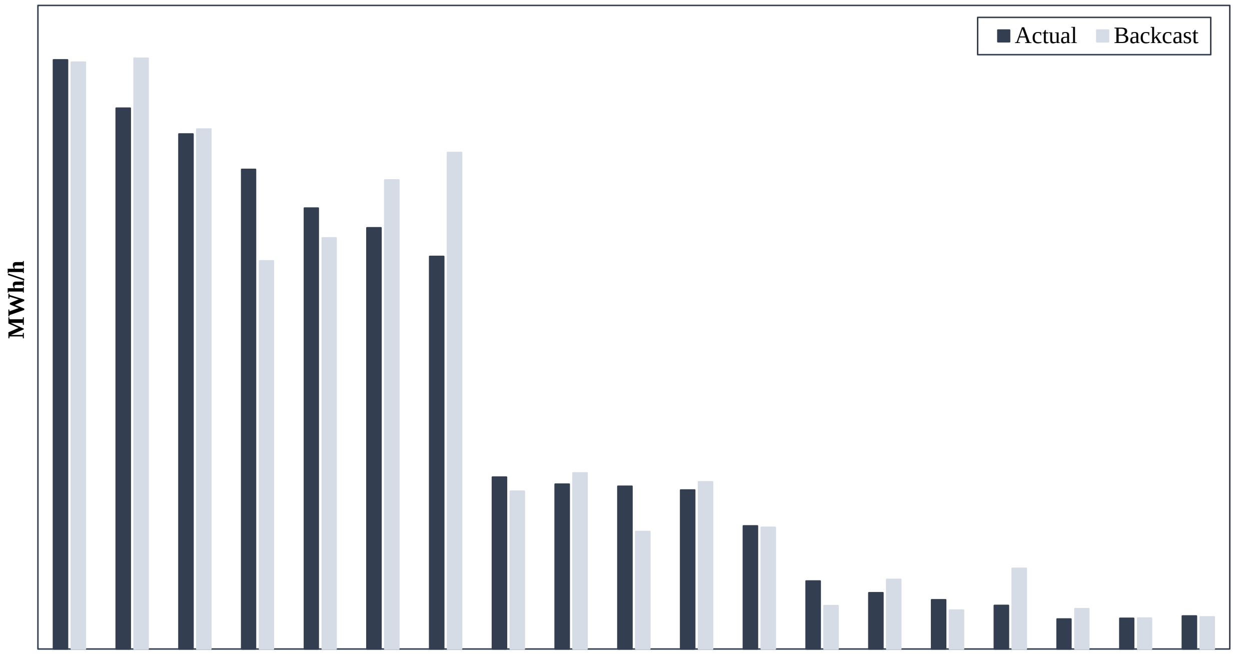
One possible explanation for the somewhat higher peak and somewhat lower off-peak prices is that generators may adjust their commercial strategies in very tight supply conditions versus very plentiful supply conditions. Yet, the SEM PLEXOS Model (in both forecast and backcast) does not attempt to recreate nuanced changes in generator commercial strategies throughout the day and

5 Table 2 reflects NERA's backcast run using metered demand.

year. There may be other real-world conditions that affect generators' offers that are not easily captured in the backcast. Overall, NERA conclude that the backcast shows good price calibration. Nonetheless, NERA discusses in this report various changes in approach that potentially could lead to better alignment between actual generator offers and how generator offers are modelled in PLEXOS, which potentially could improve peak and off-peak calibration. However, NERA cautions that such changes would likely increase the complexity of the PLEXOS Model, making it more difficult to maintain and update. Further, a more complex representation of generator offers in PLEXOS will not necessarily lead to better results, as detailed generator strategies a) may be hard to infer from historical data and b) will change over time. NERA do not recommend any of the more complex options NERA considered to model generator offers. Instead, NERA recommend maintaining the approach of prior SEM PLEXOS Models of modelling generator offers based on their variable costs and their stated VOMs and markups; this is a reasonable approach, aligned with economic and electricity market principles. (See Section 4.3 below.)

The backcast also showed that the SEM PLEXOS Model reproduced a reasonable representation of generator dispatch. The average generation of the generators in the historical data generally corresponds with the average generation levels in the PLEXOS backcast, as shown in Figure 2 below. NERA view this as a good result, considering that in practice generators' DAM strategies are likely more complex than as represented in PLEXOS.

Figure 2: Average Generation, Largest Generators, Backcast vs. History, Oct-2018 through Apr-2021[6]



Using the Backcast to Calibrate the SEM PLEXOS Model

The backcast allowed NERA to improve the forecast of the SEM PLEXOS Model. In particular, NERA noted any generators with material differences between average historical generation and average backcast generation. NERA checked these generators' technical and commercial input data. NERA made changes, where deemed appropriate, and where supported by data, including, for example, changing whether—or the extent to which—gas-fired generators incorporate short-term gas transportation capacity costs into their offers into the SEM market.

Furthermore, the backcast enabled NERA to test the effect of different PLEXOS parameter options, most importantly, Mixed Integer Programming ("MIP") vs. Rounded Relaxation ("RR") for unit commitment. NERA determined that both approaches produced reasonable results, and both could be used for the forecast SEM PLEXOS Model. Ultimately, NERA recommend using MIP for unit commitment. MIP pursues a direct optimisation of unit commitment, whereas RR determines unit commitment through a rounding approximation. MIP results in lower average price uplift and therefore also lower average wheeling charges than RR (wheeling charges are set to equal expected uplift). While uplift and wheeling charges are reasonable approaches to improve the accuracy of the SEM PLEXOS Model, nonetheless they are *ad hoc* approaches, and the fact that MIP relies

6 Figure 2 reflects NERA's backcast run using DAM demand and includes generators with the largest historical generation (excluding currently retired generators).

less on them than RR is an advantage for MIP. Further, MIP results in a somewhat better calibration to historical data than RR.

MIP, however, has significantly longer runtimes than RR. Thus, NERA also recommend that the use of MIP be tied to the use of one-state start costs. Prior SEM PLEXOS Models allowed for three start states—hot, warm, and cold—reflecting the fact that generators' start costs increase the longer a generator has been offline and the generator cools off. Modelling one start state simplifies the unit commitment optimization problem: a MIP model with one start state runs in about the same time as a RR model with three start states. NERA recommend running PLEXOS with one start state, using warm-state costs.[7] NERA conclude that the advantages of using MIP versus RR outweigh the advantages of using three-state starts versus one-state start costs. All MIP PLEXOS results in this report are for *warm-state* MIP (unless explicitly stated otherwise).

Notwithstanding, the backcast using RR was also accurate against historical data, so RR may also be used, particularly if runtime becomes a critical issue (even with warm states, using MIP may still take longer to run than RR). For any runs with RR, NERA recommend maintaining three start states.

As to other PLEXOS settings, NERA considered removing the look ahead period for the daily optimization, versus the 6 hour lookahead used in the 2019-2025 SEM PLEXOS Model. The SEM DAM does not optimize with a lookahead (the market prior to I-SEM Go Live did use a 6 hour lookahead). However, NERA recommend maintaining the 6 hour lookahead as using the lookahead produced better calibration with DAM prices, particularly in the first hour of the trading day (23:00). NERA recommend maintaining the so-called Korean uplift algorithm to determine prices that incorporate the recovery of generators' start-up and no-load costs.

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[7] Using warm start costs is a standard approach when needed to simplify models. NERA note that much earlier SEM PLEXOS Models used the one start state approach with RR (at that point in time runtimes for RR could be too long with three-state), e.g. see https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-08-062%20-%20SEM%20Plexos%20Validation%202008%2013.05.08.PDF.

1 Introduction

1.1 Scope of Work

NERA was engaged by the Regulatory Authorities (i.e. CRU & UREGNI) to update and validate their PLEXOS Model of the Single Electricity Market ("SEM") for the time period 2021-29

NERA's assignment included three principal steps:

1) Perform a backcast, starting with the 2019-2025 SEM PLEXOS Model, of historical I-SEM[8] data (starting with I-SEM Go-Live in October 2018).

2) Validate and update the input data (system input data and generator technical and commercial offer data) from the 2019-2025 SEM PLEXOS Model.[9] The resulting model is to be valid for 2021 through the end of 2029.

3) Review and update, as appropriate, the PLEXOS modelling settings from the 2019-2025 SEM PLEXOS Model.

NERA also notes that certain analysis were out of scope of this assignment:

- Determine a *de nouveau* approach to modelling the SEM arrangements post I-SEM Go Live in PLEXOS. For example, it would have been out of scope for NERA to redesign the SEM PLEXOS Model to explicitly mimic the offer structures in the SEM DAM, e.g. P-Q offer curves for generators and or complex offers. Both the design and calibration of such a model would be a major effort.

- Forecast commodity prices (NERA includes placeholders in PLEXOS).

- Perform a comprehensive validation of all generator technical and commercial data, e.g. investigating and then confirming every heat rate and VOM. Yet, NERA reviewed the generators' data for reasonableness, with a particular focus on changes in data since the prior validation.

- Independently verify system data provided by the TSOs (such as wind profiles and load forecasts).

[8] NERA use SEM to refer to the Single Electricity Market of Ireland and Northern Ireland, the market that exists today and has existed since November 2007. NERA write "I-SEM" to specifically refer to the updated SEM market that went live in October 2018, where "I" stands for integrated.

[9] The Information Paper for the prior SEM PLEXOS Model was published on the SEM Committee website on 24 January 2020. Economic Consulting Associates ("ECA") performed this most recent validation. See https://www.semcommittee.com/sites/semc/files/media-files/SEM-20-004%20SEM%20PLEXOS%20Validation%20%282019-2025%29%20and%20Backcast%20Report.pdf.

- Check that PLEXOS's dispatch and price algorithms worked correctly.

1.2 Approach and Methodology for Backcast and Validation

NERA's approach to the backcast was to focus on the core function of PLEXOS in the SEM PLEXOS Model: to determine hourly DAM prices and to determine the dispatch of dispatchable generation resources, given a set inputs including fuel and CO_2 costs, demand, generator availability, etc. NERA used the backcast to test the overall effectiveness of the SEM PLEXOS Model, to evaluate potential adjustments to PLEXOS settings, and to identify potential issues with underlying generator commercial and technical parameters. NERA views the backcast as an important part of the validation exercise.

The remainder of the validation exercise involved data gathering from key stakeholders: the generation companies, the TSOs, and the RAs (particularly the Market Monitoring Unit). NERA evaluated the data received from stakeholders for reasonableness and sought clarifications where needed. When deciding on PLEXOS settings, NERA considered primarily how well those settings performed in the backcast, but also reviewed the forecast results for 2021-2029. NERA also considered power sector modelling best-practices, alignment with the market structure of the SEM, and the requirement of delivering a practical model to the RAs, e.g. a model with acceptable runtimes and that is not overly burdensome to maintain.

1.3 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 importantly, every aspect of the 2021-2029 SEM PLEXOS Model has been independently checked by a different team member than the person who originally did the work. Furthermore, 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 1 for details of NERA's quality assurance process.

1.4 Report Structure

NERA has divided the remainder of this report into the following sections:

- Section 2 provides a background of the SEM;
- Section 3 presents NERA's initial backcast, prior to NERA's backcast test runs to evaluate potential PLEXOS settings;

- Section 4 describes NERA's backcast calibration process, and discusses why NERA chose certain PLEXOS settings;
- Section 5 presents NERA's updates to the generators and batteries in the SEM PLEXOS Model, including retirements and new additions;
- Section 6 discusses NERA's updates to the system data, e.g. demand data, in the SEM PLEXOS Model;
- Section 7 discusses the commodity prices NERA entered into the SEM PLEXOS Model;
- Section 8 summarizes the final PLEXOS model settings;
- Section 9 presents results from running the SEM PLEXOS model;
- Section 10 summarises the changes NERA made when putting together the 2021-2029 SEM PLEXOS Model; and
- Section 11 presents recommendations for future validations.

2 SEM Background

The RAs and their consultants originally produced the SEM PLEXOS Model prior to the original SEM Go-Live in 2007, and the model has since been incrementally updated at regular intervals. The original SEM PLEXOS Model closely mirrored several aspects of the market design of the original SEM, including how generators prepared their daily offers into the SEM. The original SEM PLEXOS Model also featured a PLEXOS recreation of the uplift algorithm specifically designed for the SEM. The I-SEM market that went live in October 2018 included several important fundamental changes in comparison to the structure of the original SEM. These changes included how generators bid into the market and how prices are formed. The various important changes are outlined in Table 3 below.

Table 3: Differences Between SEM and I-SEM

SEM	I-SEM
Generator offers included 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 included an uplift that allows for recovery of start costs and no-load costs[10]	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 were 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 provided 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
SEM used its own market settlement algorithm.	I-SEM DAM settled using EUPHEMIA algorithm, allowing more consistency with other European electricity markets

[10] In some markets, an uplift is added as part of the market price. The uplift is calculated after the market clears, and raises prices so generators may recover their start and no-load costs (if they did not recover those costs without the uplift).

Three SEM PLEXOS Models have been produced so far to model the SEM market since I-SEM Go-Live. Despite the differences in SEM post I-SEM Go Live, all three of these SEM PLEXOS Models have maintained the basic structure of the RAs' SEM PLEXOS Models prior to I-SEM (those three models are the 2018-2019 SEM PLEXOS Model, the 2018-2023 SEM PLEXOS Model, and the 2019-2025 SEM PLEXOS Model).[11] Similar to the SEM PLEXOS Models before the I-SEM, in the three versions of the *I-SEM* PLEXOS Model:

1) generator commercial offers are based on fuel, CO_2-emission, and Variable Operation and Maintenance ("VOM") costs;[12]

2) separately stated generator start, no-load, and incremental costs are inputs, along with explicit generator technical requirements such as minimum runtimes;

3) an explicit uplift algorithm determines prices that reflect recovery of start and no-load costs; and

4) no specific adjustments are made to the SEM PLEXOS Model to better align with the EUPHEMIA algorithm.

Effectively, by maintaining this structure, the prior 2019-2025 SEM PLEXOS 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 and stated VOMs; and

2) generators will seek to structure their offers so they only operate within their stated technical limits.

NERA maintain this basic structure – and the underlying assumptions behind this structure – in the current validation. This approach carried over from the pre-I-SEM SEM PLEXOS Model is a reasonable approach from an economic and power-sector-modelling perspective. NERA's backcast confirms that the current PLEXOS model structure reasonably predicts prices and generator generation levels.

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11 See https://www.semcommittee.com/publication/i-sem-plexos-model-validation-2018-2019-information-paper-0, https://www.semcommittee.com/publications/sem-18-175-sem-plexos-model-validation-2018-2023-information-paper, and https://www.semcommittee.com/publications/sem-19-044-sem-plexos-validation-2019-2025-information-note. NERA note that NERA also conducted the 2018-2023 SEM validation, which was also led by Willis Geffert.

12 Some generators also include markups, e.g. to reflect high bidding to limit generator for the purposes of adhering to contractual gas limitations.

3 Initial Backcast

3.1 Methodology

NERA adopted a two-staged approach to backcast the SEM PLEXOS Model against I-SEM data:

- Stage 1: Incorporate historical data into the current PLEXOS Model (i.e. 2019-2025 model), isolating as much as feasible the core function of PLEXOS in the SEM PLEXOS Model. NERA view the core function of PLEXOS as determining hourly prices (calibrated to the DAM) and the dispatch of dispatchable generation resources, given inputs of load, wind availability, fuel and CO_2 prices, and generator availabilities, among other key inputs. Essentially, this is a division of labour in the forecasting between: (a) determination of key inputs, such as fuel prices, which the PLEXOS user, rather than PLEXOS itself predicts, and (b) what PLEXOS does with that input data, i.e. dispatch generators, determine imports and exports, and determine prices.

- Stage 2: Having arrived at a satisfactory initial backcast model, NERA tested alternative PLEXOS settings. Such settings assessed how much better or worse these alternative settings were at enabling PLEXOS to accurately backcast historical prices, generation levels, and imports and exports.

In practice, the backcast was an iterative process. For example, in the test runs, having observed differences for generators between historical generation and generation in PLEXOS, NERA conducted investigations of these discrepancies. Occasionally, such investigations led to changes in generator inputs, for example changes to cost assumptions related to gas transportation capacity costs. Furthermore, the backcast occurred in parallel with updating the forecast model. As NERA gathered updated technical and commercial data from generators, NERA tested such updated data in the backcast.

3.1.1 Supply & Demand Approach in Backcast

It is important in any backcast to make sure that supply and demand are accounted for on a comparable basis. While this principle is likely obvious, its implementation in electricity markets can be complex. For example, the SEM has various behind-the-meter generators, including CHPs and small solar. Thus, appropriately, either both these resources *and* the load they serve should be included in the backcast model, or *both* should be excluded. Furthermore, while most load and most generation capacity in the SEM participates in the DAM, not all load and capacity does so.

NERA considered two backcast approaches: <u>Approach 1)</u> a backcast using historical demand in the SEM's DAM and <u>Approach 2)</u> a backcast using historical metered demand in the SEM. NERA notes that the SEM PLEXOS Model is calibrated to reproduce DAM prices. This first approach helps test PLEXOS settings in a controlled DAM environment. The second approach is also appropriate. While the SEM PLEXOS Model is calibrated to DAM prices, in practice the PLEXOS Model reflects all supply and demand in the SEM, whether or not it participates in the DAM. This second approach gives insight into how the SEM PLEXOS Model will predict DAM prices in the forecast. For simplicity, NERA performed most of the backcast analysis with DAM demand (Approach 1). NERA performed final reasonableness checks with the metered demand approach.

NERA carefully designed the backcast to have comparable supply and demand. A standard technique to determine demand for backcast modelling is to add up the historical generation from the resources relevant to your model (plus add in net imports). NERA followed this approach, and calculated demand for the backcast as outlined below. In each step below, NERA list first NERA's DAM demand approach (Approach 1) and then NERA's metered demand approach (Approach 2):

1) Determining, for every hour of the backcast period, the aggregate DAM awards for all dispatchable generators explicitly modelled in the SEM PLEXOS Model. (For the metered demand approach, NERA used the generators' metered demand instead of their DAM orders.)

2) Adding to the above net imports from Great Britain ("GB"), as represented in the DAM[13]. Starting in 2021, as a result of Brexit, the interconnectors with GB cannot trade in the DAM. During this period, NERA added actual net imports on an hourly basis. (For the metered demand approach, NERA used actual net imports for the entire backcast period.)

3) NERA then added the historical hourly day-ahead forecasts of wind in the SEM. (For simplicity, NERA used the same wind data in the metered demand approach. As wind is basically a pass through in the backcast, this choice had little if any effect on the backcast.[14])

The PLEXOS model was executed with the following supply resources, which ensured that supply and demand were aligned:

- The same dispatchable generators whose aggregate hourly DAM awards (or metered generation) were included in the calculation of hourly demand.

- Wind, with availability set to match the same day-ahead forecast of wind used to calculate demand.

As a result of NERA's approach, NERA excluded the following from the backcast:

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13 Specifically, NERA added the negative of the hourly "Net Position" data from the DAM, where NERA understand that "Net position" represents the difference between DAM supply and demand from resources and loads in the SEM, where the difference is due to trade with GB. NERA add the negative of "Net Position", as "Net Position" itself lines up with net exports.

14 NERA use the same hourly wind generation to build up the demand and to determine available wind generation. This allows PLEXOS to focus on modeling dispatchable units.

- DSUs (as well as the demand that they "serve");[15]

- Embedded generation (and the load it serves) – NERA did not have access to historical embedded generation in the SEM;[16] and

- Small scale wind that was not part of the DA forecast (and the load it serves). Historic information for small scale wind was not available to NERA.

3.1.2 Additional Historical Data Entered into Backcast Model

NERA entered the following additional data into the Backcast PLEXOS Model:

- Historical DA fuel and CO_2 prices.

- Historical generator forced and planned outages.

- Historical DAM awards for hydro generation. Specifically, NERA added to PLEXOS the daily totals of hydro generation for the four hydro plants (Ardnacrusha, Erne, Liffey and Lee). NERA added generation at the daily level as the SEM PLEXOS Model optimizes hydroelectric dispatch on a daily basis. This way, PLEXOS's hydroelectric generation optimization was tested as part of the backcast. Historical data for pumped storage plant (Turlough Hill) was not entered – rather, NERA allowed PLEXOS to optimise this plant in the backcast. The different treatment for Turlough Hill is because Turlough Hill is pumped storage, meaning that it can only generate after first pumping water uphill to an upper reservoir. An important aspect of the backcast is testing how PLEXOS dispatches the pumping and generation aspects of Turlough Hill.

- Hourly DAM awards for peat plants (West Offaly and Lough Ree). There is not a peat market with the same sort of liquidity and price transparency as natural gas. This fact makes it challenging to represent the offers of peat plants on both a forecast and backcast basis in the PLEXOS SEM Model. Hard coding their generation removed this complexity from the backcast, which was appropriate as these plants are retired and not part of the forecast model.

- Hourly prices in the GB market. This enabled the modelling of the interconnection with GB to be separated into two phases:

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[15] DSUs, or demand side units, serve demand not by generating electricity, but by reducing increasing levels of demand at certain price points. NERA excluded DSUs (and the demand they serve) to better isolate the testing of PLEXOS's ability to dispatch dispatchable generation. NERA separately ran an analysis of historical DSU dispatch to update the SEM PLEXOS Model.

[16] Furthermore, PLEXOS does not model embedded generation except by entering it as a free resource at the bottom of the supply stack, so excluding embedded generation also helps isolate the testing of PLEXOS's ability to dispatch dispatchable generation.

- o NERA used the Backcast SEM PLEXOS Model to test how well PLEXOS modelled imports and exports given the market price in GB; and
- o In a separate exercise (discussed in Section 8.10 below), NERA analysed historical GB data to determine a reasonable approach to forecast GB market prices in the 2021-2029 SEM PLEXOS Model.

3.1.3 Wheeling Charges

NERA include uplift in the 2021-2029 SEM PLEXOS Model and in the backcast model as a method to produce prices that reflect the recovery of start and no-load costs. Using uplift affects how NERA model the interconnectors. PLEXOS optimizes the interconnectors based on the *shadow prices* in the SEM and GB.[17] However, NERA model GB such that its shadow prices include recovery of start and no-load costs. In contrast, in *PLEXOS* the shadow prices of the 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.[18] NERA resolve this potential discrepancy with the addition of a wheeling charge to trade between the SEM and GB. The wheeling charge is set equal to the average uplift in PLEXOS for the SEM region, on an hour-of-day and monthly basis, with different wheeling charges each year.[19] Thus, January 2021 has 24 wheeling charges, one each for the 24 hours of the day. Every subsequent month also has 24 wheeling charges. Each wheeling charge is set separately, based on average uplift over the same period. The wheeling charge corrects for the presence of uplift by making trade relatively more attractive in the from-GB-to-SEM direction.

The inclusion of a wheeling charge is a change from the 2019-2025 SEM PLEXOS Model, which did not include a wheeling charge, but it is a return to the methodology of the 2018-2023 SEM PLEXOS Model. NERA consider the wheeling charge an essential aspect of a SEM PLEXOS Model so long as the SEM PLEXOS Model includes uplift.

Theoretically, one could re-design the SEM PLEXOS Model so that uplift was no longer needed, which would mean the wheeling charge is also no longer needed. All things equal, this would be an improvement. However, NERA did not identify an approach for eliminating uplift that was feasible, accurate, and conceptually appropriate.

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17 Shadow prices reflect the marginal cost of serving an increment of demand, as calculated by PLEXOS on an hourly basis. Total SEM price in PLEXOS equals shadow price plus uplift.

18 NERA emphasise that it is not a failing of PLEXOS that PLEXOS optimizes based on shadow prices. This is the standard way production cost models are designed. Uplift is an after-the-fact adder to prices, not a dynamic part of the optimization process in PLEXOS.

19 NERA 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.

3.1.4 Assetless Traders

Assetless traders participate in the DAM. A core function of assetless traders is arbitrage between the DAM and Intra-day markets ("IDM"). This function aligns with the reality that not all supply and demand in the SEM participates in the DAM. Thus, conceptually at least, assetless traders can help bring the DAM into line with the entire supply and demand situation in the SEM. For example, since January 2021, i.e. post-Brexit, the interconnectors with GB cannot participate in the DAM. Following communications with stakeholders, NERA understands that assetless traders, through their arbitrage activities in the various SEM energy markets, facilitate aligning the DAM with the reality that energy is still traded over the interconnectors, even if not in the DAM. NERA also understand that some assetless traders associate with wind generation, allowing an indirect avenue for wind generation to participate in the DAM.

As stated by the TSOs in a Guide to the I-SEM for industry: "An assetless trader arbitrages its position between the DAM and IDM. To ensure that it achieves a zero energy position before the BM gate closure, any trades cleared in the DAM must be reversed in the IDM."[20]

As a reference, NERA note that assetless traders are well established in the US energy markets. In the US, such trading is known as virtual transactions. As described in the 2020 State of the Market Report for MISO (the market covering much of the Midwest US):

> A large share of the liquidity that facilitates good day-ahead market performance is provided by virtual transactions. Virtual transactions are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources. As such, virtual day-ahead purchases or sales cannot perform in real time and, therefore, settle against the real-time price. <u>Virtual transactions are essential facilitators of price convergence because they are used to arbitrage price differences between the day-ahead and real-time markets.</u> (Emphasis added)[21]

From a fundamental perspective, assetless traders increase the accuracy of the SEM PLEXOS Model (this occurs even though NERA did not include assetless traders in the PLEXOS Model). The SEM PLEXOS Model considers (to the extent practicable) **all** supply and demand in the SEM. Yet, the purpose of the SEM PLEXOS Model is to produce *DAM* prices. Assetless traders help align the DAM with other energy markets in the SEM. Thus, the presence of assetless traders in the DAM help enable the SEM PLEXOS Model to do its task: produce reasonable forecasted DAM prices in a PLEXOS model that include all supply and demand, including supply and demand that does not participate in the DAM.

NERA did not explicitly include assetless traders in the backcast or in the 2021-2029 SEM PLEXOS Model, for both conceptual and practical reasons:

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20 https://www.sem-o.com/documents/training/Industry-Guide-to-the-I-SEM-Trading.pdf (page 17).

21 https://www.potomaceconomics.com/wp-content/uploads/2021/05/2020-MISO-SOM_Report_Body_Compiled_Final_rev-6-1-21.pdf (page 33).

- *Conceptually*, including assetless traders would potentially be counterproductive. The arbitrage of the assetless traders better aligns the DAM with the full supply and demand in the SEM. Explicitly incorporating them into the SEM PLEXOS Model might undo this alignment.

- *Practically*, it would be a substantial effort to simplify the offers of the assetless traders in a way that could be incorporated into PLEXOS, especially cognisant of the fact that the SEM PLEXOS Model's horizon runs from 2021 to 2029. The prices and quantities in the bids by assetless traders almost assuredly will change over time as market conditions change.

3.2 Observations on Market Behaviours

3.2.1 General Observations

The backcast model determined SEM prices with reasonable alignment on average, seasonally, and when tracked on a month-to-month basis. The backcast model also tracks price changes as supply and demand conditions change. However, NERA note that the backcast, on average, understated prices in peak periods and somewhat overstated prices in off-peak periods as shown in Table 4.

Table 4: Average Prices Backcast vs. Historical, Peak, Mid-Merit, and Off-Peak, Oct-2018 through April-2021[22]

Season	Backcast Average Price	Historical Average Price	Delta (€/MWh)	Delta (%)
Winter Peak	€76.71	€84.32	- €7.61	-9.0%
Mid-Merit	€52.32	€53.34	- €1.02	-1.9%
Off-Peak	€39.89	€35.85	€4.04	11.3%

NERA provide several thoughts on this issue:

1) NERA suspect that part of this phenomenon is due to generator commercial strategies, e.g. generators may have different DAM bidding strategies in tight supply conditions versus plentiful supply conditions. Since I-SEM Go Live, generators have more discretion (versus the pre-I-SEM arrangements) to submit offers that deviate from strict marginal costs, and

[22] Reflects NERA's final backcast run using MIP warm start costs and metered demand. NERA's backcast runs with RR produced a similar pattern of prices in the peak, mid-merit and off-peak.

commercial strategies may vary over time. In PLEXOS, by contrast, NERA apply VOM adders (on top of fuel costs) that do not change throughout the modelling horizon.

2) Another part of this phenomenon is related to price spikes. It is a classic problem with production cost models such as PLEXOS that they may not capture price spikes as extreme as those that occur in actual markets. PLEXOS may not capture generator commercial strategies in tight supply conditions, and PLEXOS cannot practically model all real world conditions that may cause prices to spike.

3) Similarly, I-SEM has experienced negative prices with some regularity. Over 500 instances of negative prices occur across the historical period from October 2018 to April 2021, whereas prices did not go negative in the NERA's backcast model. As with price spikes, production cost models often miss the lowest of low prices.

There may be options to better align the SEM PLEXOS Model with ranges of prices seen in the very tight and very plentiful supply conditions (and NERA explored some bidding behaviour options during the backcast exercise). That said, better alignment with changing bidding behaviour and extreme pricing conditions may come at the cost of a more complex model that is more involved to produce and update. Further, it is possible to "overfit" a model, where better backcast alignment does not necessarily mean better predictive power for the future.

3.2.2 Minimum Income Conditions

The I-SEM allows bidders to submit complex orders with minimum income conditions, where market participants specify a minimum income condition defined through a constant term (in euros) and variable term (in a €/MWh). Thus, a generator may specify X and Y, where minimum income equals: €X + €Y/MWh * MWh. In practice, NERA expect that generators use this tool, as well as other allowed bidding options such as block orders and linked blocks, to help ensure recovery of start costs and no-load costs, i.e. costs that may not be recovered with simple orders.

The SEM PLEXOS Model addresses this sort of cost recovery as well, though using a different approach. The PLEXOS Model includes start and no-load costs (both from fuel and non-fuel considerations) as parts of market optimization, and further the Model incorporates uplift, which allows generators to recover those start and no-load costs through the SEM market prices produced by the SEM PLEXOS Model. Given this and given the overall success of the backcast at replicating historical market outcomes, NERA did not explore alternative options that would mimic minimum income conditions.

3.3 Inputs

As detailed in Table 5, NERA sourced data for the backcast was as follows:

Table 5: Data Included in the Backcast

Type	Data Included	Source
Demand	Sum of DAM Orders for dispatchable resources in PLEXOS (or some of actual generation for same resources)	MMU
Demand	(+) *Pre-Brexit:* Net Position in DAM, reflecting net imports	MMU
Demand	(+) *Post-Brexit:* Actual Net Imports into SEM	MMU
Demand	DA Wind Forecast	MMU
Fuel & CO2 Prices	DA Prices for Gas, Coal, Gasoil, Fuel Oil, and CO_2	CRU and Bloomberg
GB Prices	Nordpool Exchange DA Prices	MMU
Generation	DAM Orders (or actual generation)	MMU
Generator Technical/ commercial parameters	Prior Validated PLEXOS Model, as updated by NERA during the current 2021-2029 PLEXOS Model validation exercise	Generators
Interconnector Flows	(+) *Pre-Brexit:* Net Position in DAM, reflecting net imports	MMU
Interconnector Flows	(+) *Post-Brexit:* Actual Net Imports into SEM	MMU
Outages	Historical forced and planned outages	TSOs
SEM Prices	DA Prices	MMU
Wind	DA Forecast	MMU

3.4 Generator Parameters Refinement

NERA evaluated how closely the average generation levels from the PLEXOS backcast aligned with historical data. NERA identified the units where PLEXOS performed the least well in initial backcast runs and investigated why. In many cases, NERA identified that updating fuel transportation costs improved the accuracy of generation levels, as discussed in Section 7.3 below.

NERA also updated generator technical and commercial parameters in the backcast model, based on updated data NERA received from the generators.

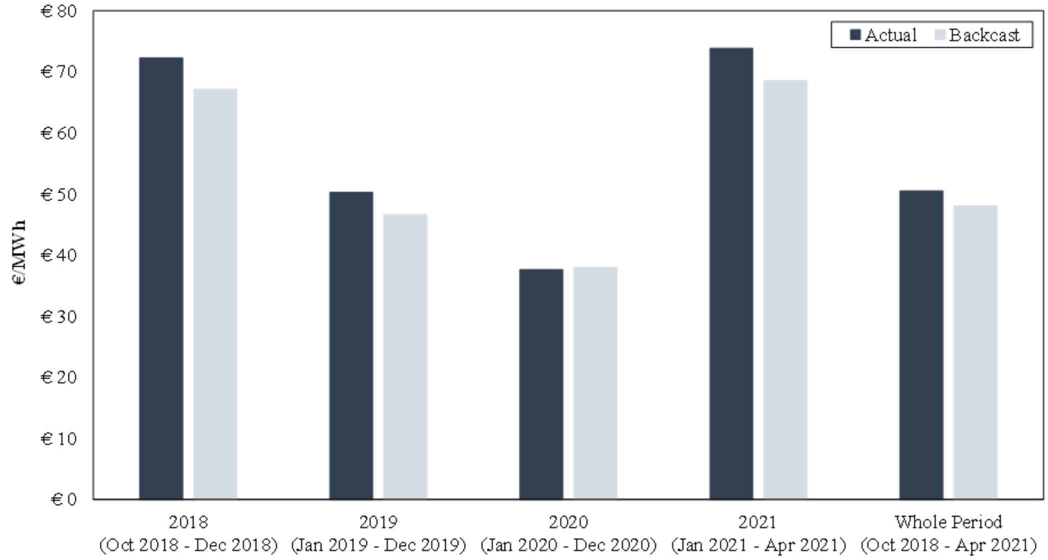
The backcast results presented in the next section include the results of NERA's generator parameter refinement process.

3.5 Outcomes

The backcast model – prior to any changes in PLEXOS settings – overall was successful at matching historical market prices. The charts below (Figure 3 to Figure 8) reflect an RR unit commitment approach. Ultimately, NERA recommends an MIP approach – NERA present the results of the MIP backcasts in Section 4.

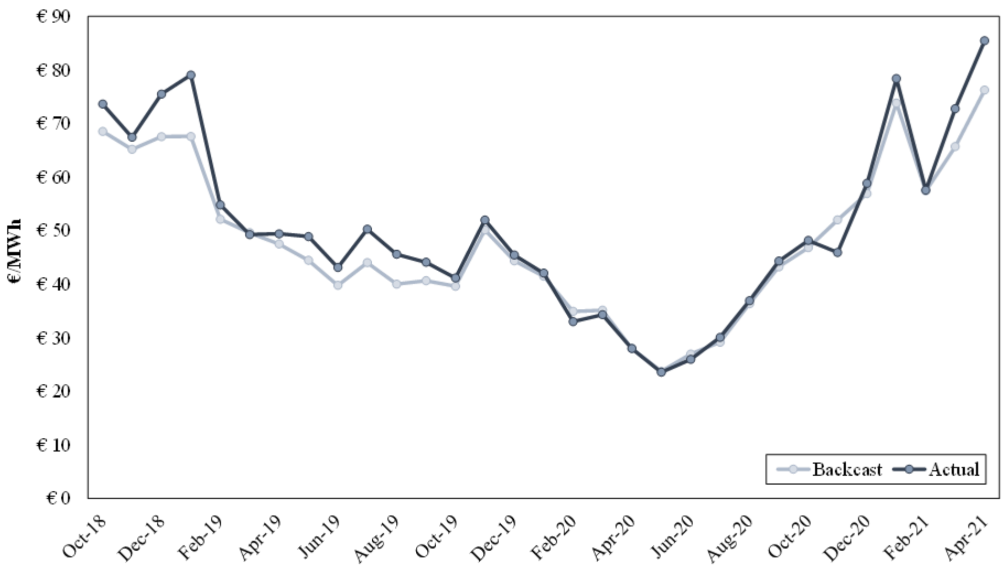
On an annual and whole period basis, the alignment (as indicated in Figure 3) is as follows:

Figure 3: Average SEM Price by Year (Backcast Using RR Approach)



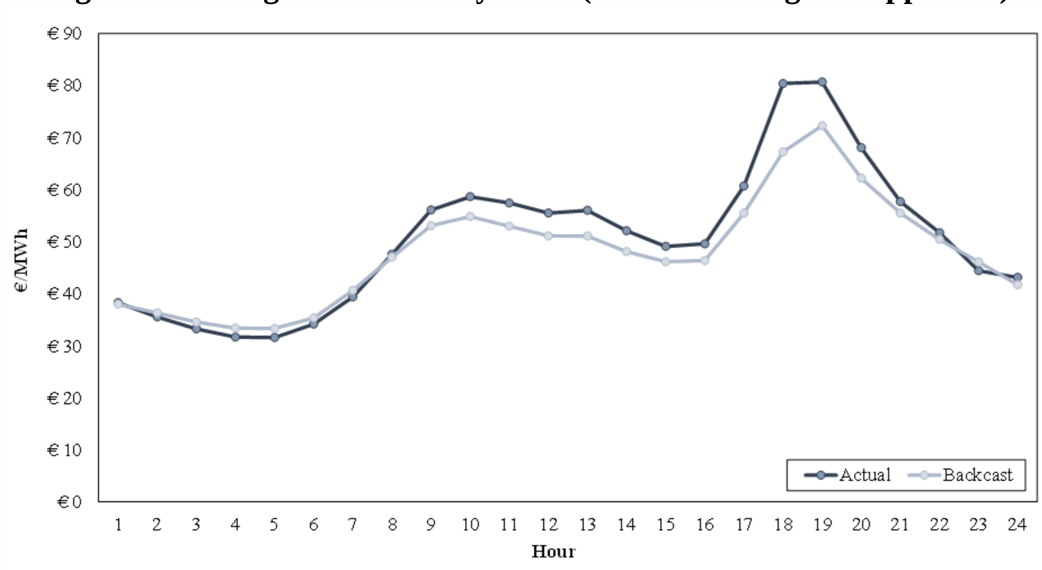
The backcast model tracks price changes by month reasonably well, as illustrated in Figure 4.

Figure 4: Average SEM Price by Month (Backcast Using RR Approach)



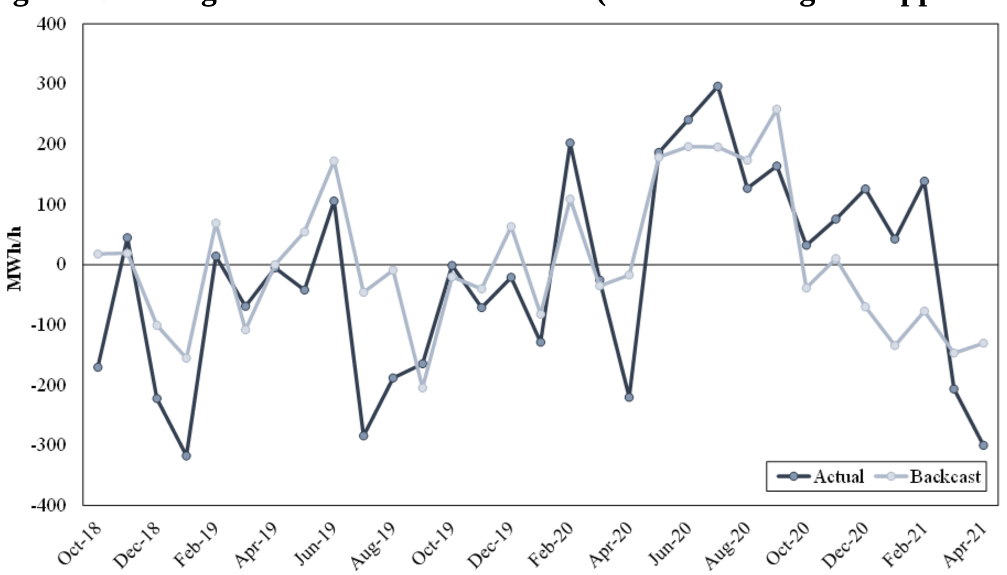
As illustrated in Figure 5, the model reasonably matches hourly variations in prices, though backcast prices are lower than SEM prices in the peak hours of the day and somewhat higher in off-peak hours.

Figure 5: Average SEM Price by Hour (Backcast Using RR Approach)



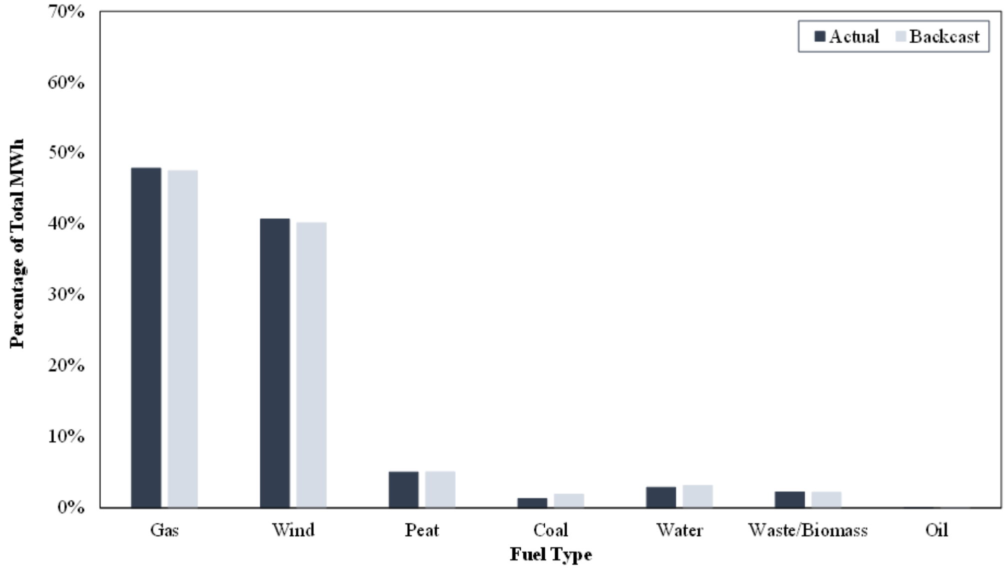
With respect to interconnector flows, and as illustrated in Figure 6, the model broadly matches the historical pattern.

Figure 6: Average Interconnector Net Flows (Backcast Using RR Approach)



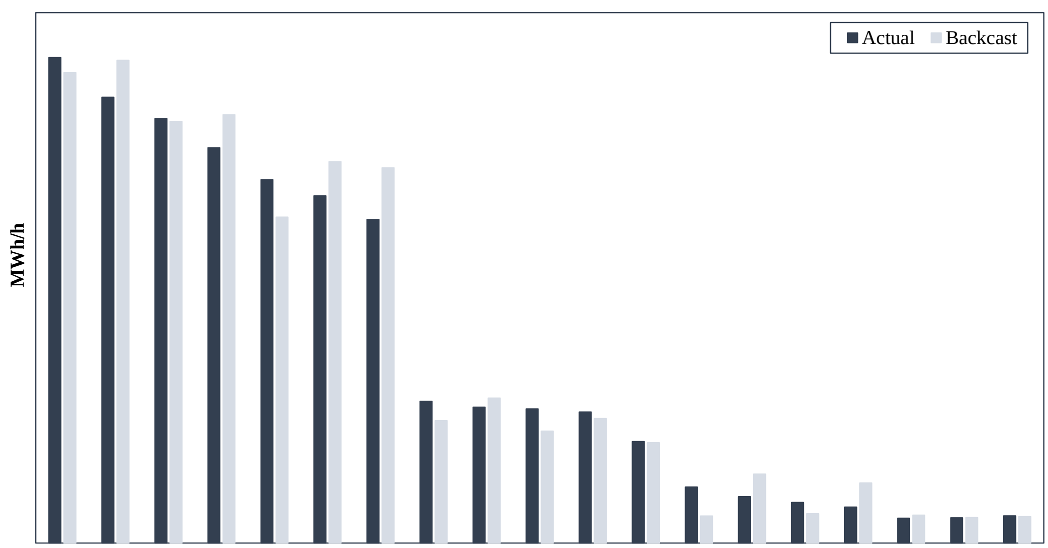
As to generators, as illustrated in Figure 7, the model generally matched generation by fuel type.

Figure 7: Average Hourly Generation Split by Fuel Type (Backcast Using RR Approach)[23]



The fact that gas generation far outweighs coal generation is not unexpected. Perhaps more importantly, NERA looked at the relative generation levels of the units with the largest generating levels in the SEM. For confidentiality reasons, NERA do not name the generators in Figure 8 below nor do NERA put labels on the axes. These results support that the SEM PLEXOS Model reasonably determines the generation level of the various dispatchable units in the SEM.

Figure 8: Average Hourly Generation by Generator (Backcast Using RR Approach)



23 NERA note that Moneypoint Unit 2 now runs on oil. NERA's charts keep all Moneypoint units (including 2) in the coal category, for historical reasons.

From this backcast starting point of good alignment, NERA considered various PLEXOS settings options, as discussed in Section 4, next.

4 Backcast calibration and refinement

4.1 Lookahead Period

The pre-I-SEM market explicitly incorporated a six-hour look-ahead period as part of its price formation, but the current SEM market does not. To date, all SEM PLEXOS Models of the post-I-SEM-Go-Live period have included the 6-hour lookahead. NERA's view is that the decision whether to use a look-ahead period should consider both the I-SEM market structure as well as how well using or not using a look-ahead aligns the PLEXOS results with actual market results. Even in a market without an official lookahead, 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, and in contrast, market participants may look as far into the future as they wish but with increasingly imperfect foresight.

NERA's test runs showed overall minimal differences in backcast results when executing PLEXOS with and without a six hour lookahead. Average prices were €0.20/MWh higher without the lookahead. Yet, the hourly pattern of prices did not match as well without the lookahead. Specifically, NERA noticed that the price for 11pm – the first hour of trading day – was significantly higher on average in backcast runs without lookahead versus historical prices for that hour, but the alignment was tighter with the 6-hour lookahead. Because of this improvement in hourly correlation, NERA recommends continuing the 6-hour lookahead.

4.2 MIP vs. RR

Determining unit-commitment is a classic problem of power sector modelling. Power plant units are either offline or online. Decisions to shut down an online plant or start up 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 start up tend to need to stay online for a minimum amount of time before they can be shut down; and
- The actual start-up 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, whereby if they are online they must generate at least at that level. In short, optimizing unit commitment is a *non-linear* problem, and optimizing non-linear problems poses particular 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.

3) **Mixed Integer Programming (MIP).** Under the MIP approach, PLEXOS attempts to find the optimal least-cost unit commitment decision by directly assessing different unit commitment possibilities.

NERA do not recommend the use of Linear Relaxation because NERA believe it is appropriate to use a unit commitment approach that reflects distinct online or offline states.

Considering RR vs. MIP, on a *prima facia* basis, NERA favour MIP as MIP theoretically results in lower-cost solutions than RR, and, from what NERA understand, MIP better aligns with the actual unit commitment algorithm used in the DAM in the SEM. In practice, NERA evaluated RR vs. MIP considering the relative performance of MIP and RR in the backcast and the practicality of using RR vs. MIP, where MIP typically has significantly longer runtimes than RR.

The MIP runtime issue is not trivial. On a comparable basis, NERA found that MIP runs took over 2.5 times longer in test backcast runs.[24] From discussions with the RAs, NERA understand that they would not prefer to adopt MIP without any other adjustments to reduce run time. Model settings can significantly reduce MIP runtime, for example:

1) <u>Reducing the number of samples of load, wind, and forced outages</u> – The 2019-2025 SEM PLEXOS Model (as well as several prior SEM PLEXOS Models) used five yearly samples of load patterns and wind availability from recent history.[25] PLEXOS runs each sample independently in the forecast model, and reports the average results of the five samples (as well as the individually sampled results). NERA do not recommend reducing the number of samples. Including several historical load and wind samples

[24] These run times reflect single samples of load and wind in the backcast. NERA ran RR with a 0.2 RR self-tune setting, and rounding up thresholds ranging from of 0.1 to 0.9, which are the default RR setting from the 2019-2025 SEM PLEXOS Model.

[25] The hourly load in the SEM PLEXOS Model is based on the TSOs' forecast of peak demand and total annual demand, shaped to match a historical year's hourly load pattern. Hourly wind generation is based on installed wind capacity and hourly availability percentages set equal to a historical year's actual hourly wind availability.

allows the results of the SEM PLEXOS Model to reflect more closely average-year conditions.

2) Use of a single start state versus three start states – The 2019-2025 SEM PLEXOS Model (as well as several prior SEM PLEXOS Models) incorporated three start states (hot, warm, and cold). However, switching from three start states to one start state significantly reduces runtime. *NERA recommends this approach (i.e., one start state – warm), as it significantly reduces runtime, but maintains good backcast calibration.*

3) Removing ramping constraints - Generation units are limited in how rapidly they can change their power output. However, the SEM PLEXOS Model is an hourly model. Ramp rate constraints often have relatively low importance in hourly models versus 15-minute or 5-minute models, for example. NERA do not recommend this approach, as it did not yield a significant runtime reduction. Notwithstanding, the RAs could consider removing ramping constraints if further runtime reduction were needed, as NERA found that the backcast maintained good calibration without ramping constraints.

4) Increasing the Relative Gap – This can reduce runtime with potentially little change in the PLEXOS model's results, depending on how much Relative Gap is increased.[26] NERA do not recommend this approach, as it did not yield a significant runtime reduction. Notwithstanding, the RAs could consider a higher Relative Gap if further runtime reduction were needed, assuming test runs show similar results.

Importantly, MIP produces noticeably different results versus RR in a few areas. The table below summarizes average prices in the backcast considering several variations of MIP versus the default RR option. NERA also show backcast run times.

[26] Relative Gap 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.

Table 6: Comparison of MIP and RR Backcast Runs with Historical Price (All Backcast Runs use DAM Demand Approach, except where noted)

Item	**Average Price (€/MWh)**	**Delta vs. Historical**	**Backcast Runtime (Minutes)**
Historical Average	**€ 50.51**	n/a	
RR (3-State Starts)	**€ 48.03**	**€ 2.48**	19
MIP (Warm starts), recommended approach[27]	**€ 48.96 [€ 50.82]**	**€ 1.55 [-€ 0.31]**	15
MIP (3-state starts)	**€ 48.78**	**€ 1.73**	49
MIP (Warm starts, without lookahead)	**€ 49.16**	**€ 1.35**	12

As per Table 6 above, each of the MIP options produce higher prices than the RR option.[28] In the DAM demand backcast runs, the historical average of prices is nonetheless still higher than the prices produced by RR and all MIP options, so the MIP options (with their higher prices than RR) show a better calibration with historical wholesale electricity prices. In the metered generation backcast run, while the backcast MIP price is higher on average than the historical price, the price gap is relatively small, about €0.30/MWh on average, further supporting the reasonableness of the MIP approach.

Average price is only one of several important results NERA analysed to test the accuracy of MIP vs. RR in the backcast. For the remainder of this section, NERA compare the RR option to the recommended MIP option of warm-state start costs.

Matching price changes over time is also important, and while both MIP and RR perform well, MIP performs partially better as illustrated in Figure 9 below:

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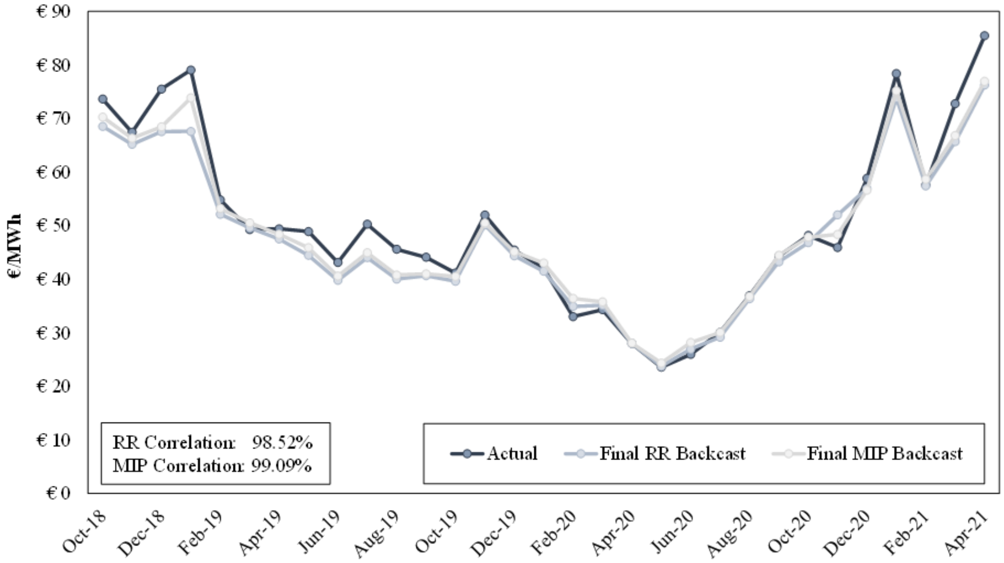
27 The bracketed average price of € 50.82/MWh (and -€ 0.31/MWh for the delta column) represents the backcast run using metered demand. The rest of the backcast results in Table 6 represent NERA backcast results using DAM demand.

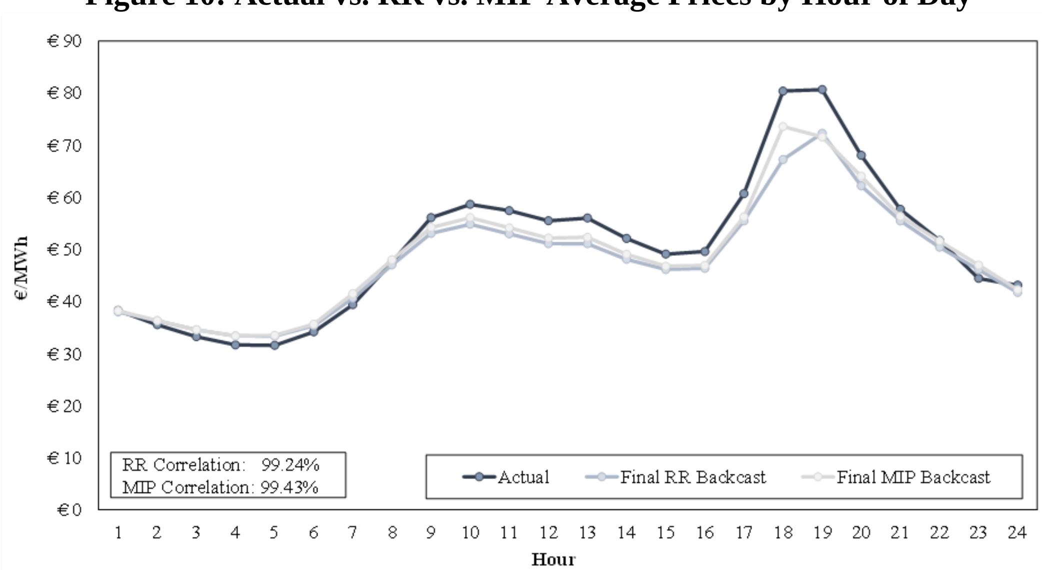
28 While MIP is typically more effective at minimizing system costs than RR, this does not necessarily mean that prices will be lower in MIP runs. A lower total cost solution may nonetheless result in a higher marginal cost unit setting the price.

Figure 9: Actual vs. RR vs. MIP Average SEM Price by Month



NERA also notes that MIP again partially improved upon the alignment of average price variations throughout the day, as illustrated in Figure 10.

Figure 10: Actual vs. RR vs. MIP Average Prices by Hour of Day



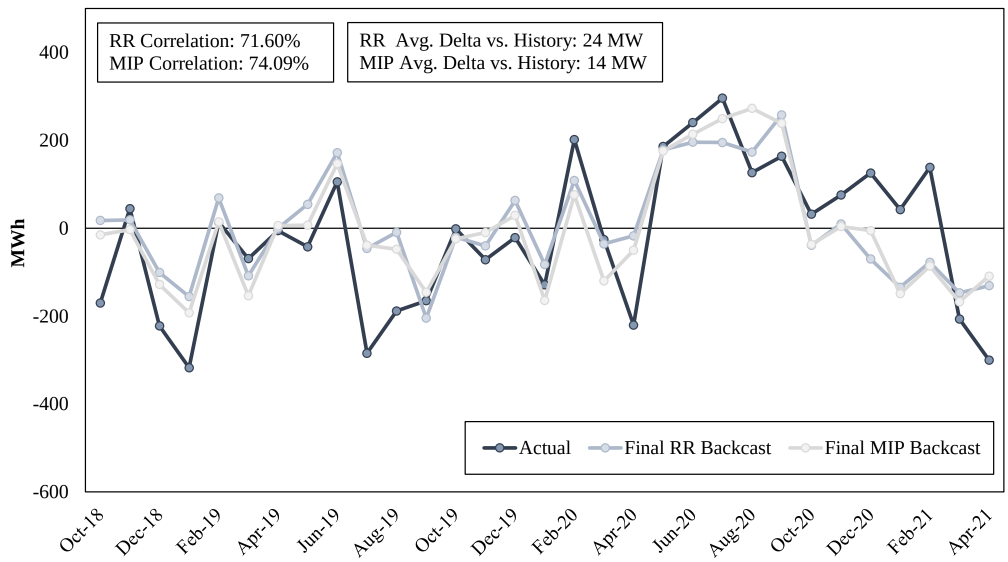
Notably, MIP and RR prices reflect different relative compositions of shadow price and uplift. NERA notes that MIP tends to have higher shadow prices and lower uplifts, on average, as shown in Table 7 below. All things equal, this is an advantage of MIP, as lower uplifts mean lower wheeling charges, and thus less need for adjustments by the PLEXOS user to put GB and SEM (or France and SEM) on equal footing for trade on the interconnectors—see Section 3.1.3.

Table 7: MIP vs RR, Backcast From Oct 2018 through April 2021

Run Type	Price (€/MWh)	Shadow Price (€/MWh)	Uplift (€/MWh)
MIP	50.0	48.6	0.3
RR	48.0	45.9	2.2
Delta	2.0	2.7	-2.5

As illustrated in Figure 11, both RR and MIP are broadly in line with historical interconnector patterns, with MIP having higher monthly corelation (74% vs. 72%) and a somewhat lower average difference versus history (MIP 24 MW off on average versus 14 MW for RR).

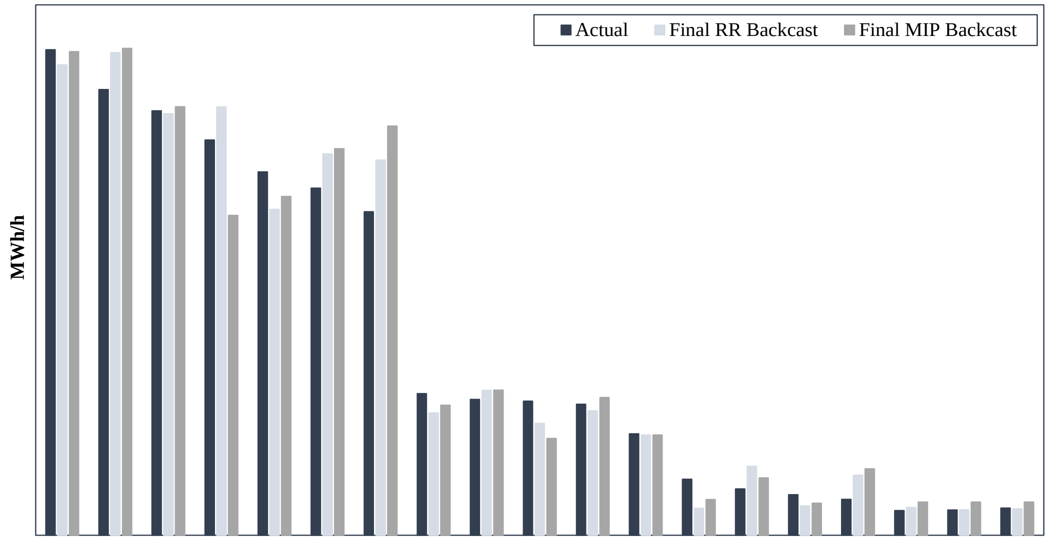
Figure 11: Actual vs. RR vs. MIP, Average Net Exports to GB, October 2018 through April 2021[29]



Both RR and MIP also matched the distribution of generation among the top generators in PLEXOS reasonably well. For confidentiality reasons, NERA do not name the generators nor do NERA put labels on the axes.

[29] 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 + *negative* 50)/2.

Figure 12: Actual v. RR v. MIP Average Hourly Generation by Generator



Overall, NERA recommend implementing the use of MIP instead of RR because:

- MIP produces prices on average that better align with historical prices over the period of the backcast;

- MIP somewhat better aligns with the monthly pattern of prices and interconnector flows over the period of the backcast;

- MIP results in a lower uplift, which reduces the wheeling charge adjustment in the model;

- MIP theoretically results in lower-cost solutions than RR;

- MIP better aligns (versus RR) with the actual unit commitment algorithm used in the SEM DAM; and

- MIP runtime can be reduced to an acceptable level with certain reasonable adjustments while maintaining accurate results.

Notwithstanding the above, both MIP and RR produced reasonable results in the backcast analysis, and RR does have the advantage of producing three-start-state PLEXOS Model results within a reasonable runtime. For this reason, NERA ultimately includes both a 3-state RR and warm-state MIP option in the SEM PLEXOS Model.

4.3 Generator Offers

In the 2019-2025 SEM PLEXOS Model—and, as far as NERA are aware, in all previous SEM PLEXOS Models going back to the beginning of the original SEM in 2008—generator offers in PLEXOS were based on marginal fuel and CO_2 costs plus VOMs/MWh, plus any applicable markups. Further, in all SEM PLEXOS Models to date, start and no-load costs affect SEM PLEXOS Model results in two ways. First, PLEXOS incorporates no-load and start costs in its least-cost optimization. Second, PLEXOS adds an uplift that (within certain limits) guarantees recovery of start and no-load costs.

While the above approach has worked to the RAs' satisfaction to date, there are other potential approaches to modelling generator offers in PLEXOS. NERA reviewed several approaches below and, where practical, tested the approaches in the backcast.

<u>Option One: Redesign of SEM PLEXOS Model to reflect P-Q offers calibrated to historical generation offers in the I-SEM, i.e. a "bid-based" approach.[30]</u>

- **Advantages**: Potentially would remove the need for uplift and would theoretically offer better alignment with DA Market results in SEM.

- **Disadvantages:** Would require significant effort to build this new model structure and calibrate the model to historical data, and would require significant ongoing effort to re-calibrate model with each new Validation. There is a risk that such a model would perform no better than the current approach and may perform worse if the tailored-offer approach for generators became outdated.

- **Decision:** Not recommended.

<u>Option Two: Use the pre-set PLEXOS algorithm that adjusts generator offers to reflect no-load and or start costs.</u>

- **Advantages**: Potentially would remove the need for uplift and would offer better alignment with DA Market results in I-SEM.

- **Disadvantages:** PLEXOS has settings that automatically adjust generator energy offers to reflect no-load or start costs or both in generator offers. NERA found that adjusting generator energy offers to reflect start costs resulted in excessive run times. The runtimes for reflecting no-load costs in energy offers were more reasonable, but the calibration was poorer. Prices were too high on average in the backcast, and the monthly pattern aligned poorly with history.

[30] Some stakeholders, in response to the RAs' request for initial comments on this backcast/validation exercise (refer to SEM-21-041) have requested such a "bid-based" approach.

- **Decision:** NERA recommend remaining with the traditional generator offer approach, given the poor fit and or long run times of the PLEXOS algorithm that adjusts generator offers to reflect no-load and or start costs.

<u>Option Three: Use a pre-set PLEXOS algorithm that allows for bidding above marginal costs.</u>

- **Advantages**: Potentially would capture more realistic bidding and improve alignment of the backcast and actual data.

- **Disadvantages:** NERA considered the two algorithms:

  - *Bertrand competition, without company coordination.*[31] Bertrand competition has generators increasing their offers up to the marginal costs of the next generator in the supply stack. In practice, the effect of this was relatively muted (about an €0.55/MWh increase in average prices), as presumably the gaps between generators in the supply stack in the SEM are generally relatively small. Attempting to demonstrate that generators actually offer this way would require significant analysis and still may be inconclusive.

  - *Residual Supply Index (RSI) Bid Cost Markup.* RSI Bid Cost Markup could be an effective tool to represent in the PLEXOS Model historical markup behaviour when supply conditions are tight. However, implementing this competition algorithm requires an econometric analysis of prices under cost-based bidding versus actual outturn prices. Such an approach in the SEM PLEXOS Model would be complex to maintain. NERA also suggest caution when considering adding empirically-derived markup methods. Suh a change would represent a deviation from the cost-plus-VOM approach the SEM Validated Model has employed since the model was built nearly 15 years ago, where the latter is a standard approach in power market modelling.

- **Decision:**

  - NERA do not recommend either Bertrand competition or the Residual Supply Index approach for the SEM PLEXOS Model.

<u>Option Four: Use the standard approach to generator offers, but have VOMs that vary in peak and off-peak periods and or seasonally.</u>

- **Advantages**: Potentially would improve the calibration of the model in peak vs. off-peak times of day and in the summer vs. winter. For example, one might employ four sets of VOMs (summer peak, summer off-peak, winter peak and winter off-peak).

[31] PLEXOS can also run with Bertrand competition with coordination among generators within a company, but NERA did not consider this as an option for the Validated PLEXOS Model.

- **Disadvantages:** Establishing VOMs that change by season or in peak and off-peak hours could happen if: 1) the generators provide different sets of VOMs; or 2) the RAs or its consultants perform a statistical analysis of historical offers for each generator to establish different VOMs. Yet, either option could have implementation challenges, and may require more frequent model updates as generator commercial strategies change.

- **Decision:** NERA did not attempt to implement VOMs that vary, given the substantial challenges posed by such an approach. NERA note it would be important to assess and gain comfort with the fundamental reasons behind varying VOMs before adopting such an approach in the SEM PLEXOS Model.

Summary

NERA do not recommend any of the four options presented above. NERA recommend maintaining the standard approach of incremental-cost based generation offers, based on fuel, CO_2, and VOMs. Notwithstanding, NERA do not consider this standard PLEXOS approach as immutable. Rather, NERA recommend that any potential future changes to the SEM PLEXOS Model should be judged by their accuracy, conceptual reasonableness, and practicality for the RAs to maintain and update.

4.4 Final Backcast Calibration Results

This section summarizes the results of NERA's backcast using NERA's recommended approach of MIP with warm-state starts. The backcast model reasonably replicates average SEM prices and the seasonal pattern of these prices. As shown in Table 8 below, NERA's backcast using DAM demand produced prices only €1.55/MWh below historical SEM DAM prices (a difference of 3.1%), over the backcast period of October 2018 through April 2021. NERA's backcast using metered demand produced prices €0.31/MWh above historical SEM DAM prices (a difference of 0.6%).[32]

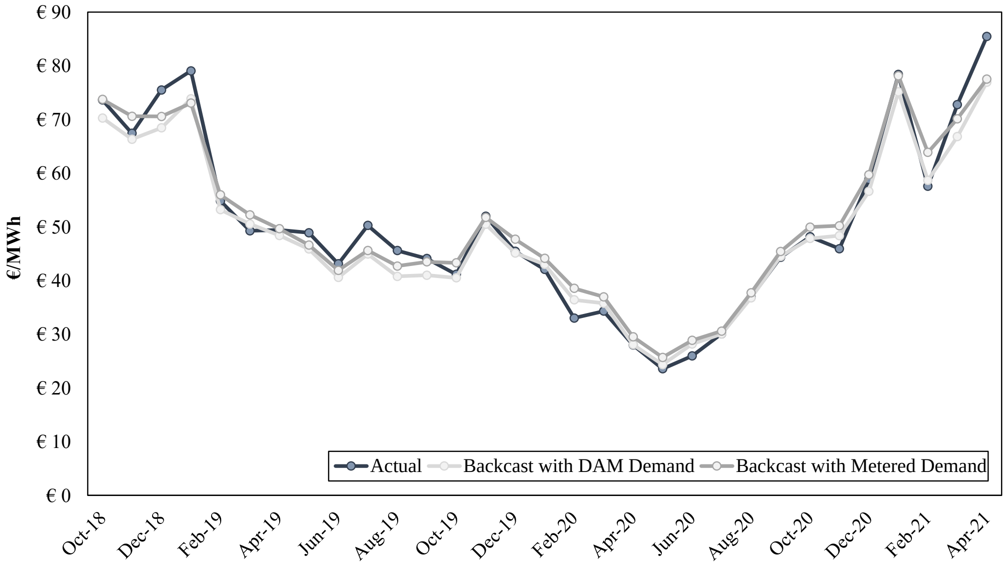
Table 8: Average Prices Backcast vs. Historical, Oct-2018 through April-2021

Backcast Run	Backcast Average Price	Historical Average Price	Delta (€/MWh)	Delta (%)
DAM Demand	€48.96	€50.51	- €1.55	-3.1%
Metered Demand	€50.82	€50.51	€0.31	0.6%

32 See Section 3.1.1 above for further information about the two demand approaches in NERA's backcast.

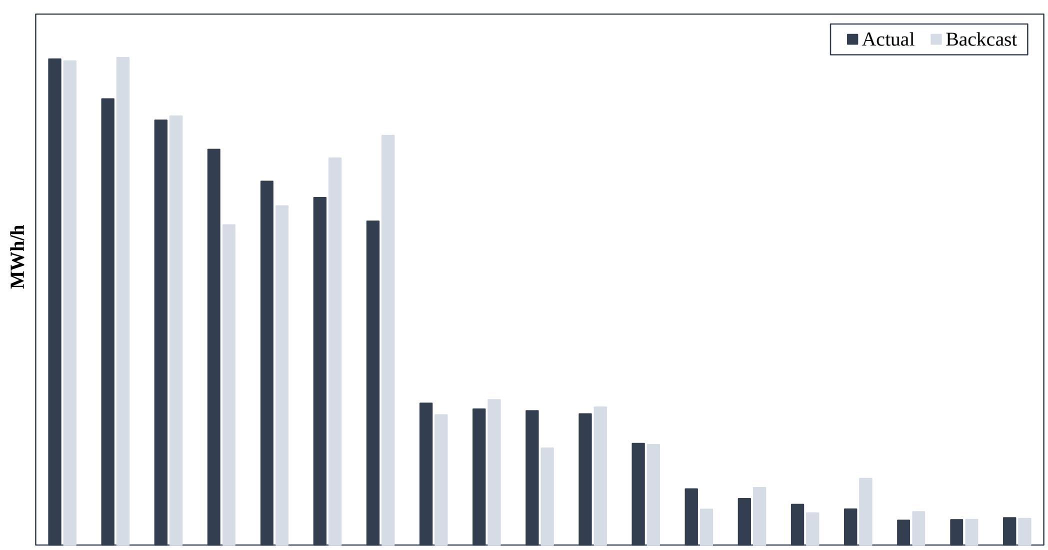
Figure 13 below shows significant alignment of monthly backcast and historical prices.

Figure 13: Average Monthly Backcast and Historical SEM Prices, Oct-2018 through April-2021



The backcast also resulted in a reasonable representation of generator dispatch, as shown in Figure 14 below.

Figure 14: Average Generation, Largest Generators, Backcast vs. History, Oct-2018 through Apr-2021[33]



[33] Reflects NERA's backcast run using DAM demand.

The closeness of these backcast prices results to historical prices give NERA confidence in the reasonableness of the SEM PLEXOS Model.

5 Generator Plants and Batteries

5.1 Generator Commissioning and retirements

NERA include several new generation plants in the 2021-2029 SEM PLEXOS Model, as listed in Table 9 below:

Table 9: New Generation Plants[34]

Unit	Jurisdiction	Fuel	Capacity (MW)	Assumed Online Date
Data and Power Hub Services Limited Gas Turbine 1	ROI	Gas	58	1-Oct-2023
Data and Power Hub Services Limited Gas Turbine 2	ROI	Gas	58	1-Oct-2023
Grange Backup Power Limited Gas Turbine	ROI	Gas	115	1-Jan-2024
EP Kilroot 1	NI	Gas	350	1-Oct-2023
EP Kilroot 2	NI	Gas	298	1-Oct-2023

The 2021 GCS assumed several other new generation units in its 2023 to 2025 adequacy studies (Table 5 of the 2021 GCS) which are not included in the 2021-2029 SEM PLEXOS Model, as these units have subsequently been cancelled: three ESB Gas Flexgen units; (1) Ringsend, (2) Poolbeg and (3) Corduff (210 MW in total), as well as Statkraft Gas Turbine (48 MW). A 13 MW "ESB Gas Turbine" with a 2024 online date from Table 15 of the 2021 GCS is not included, as NERA understand this is associated with the cancelled ESB gas turbines. Finally, a 2 MW Ronaver Gas Turbine with a 2024 online date from Table 15 of the 2021 GCS is not included. Not only is Ronaver small enough at 2 MW to be nearly *de minimis* for the purposes of the SEM PLEXOS Model, but NERA also understand that this entry in the 2021 GCS represents a capacity award that is associated not with a new build turbine, but with an existing, small diesel powered generator that rarely, if ever, runs.

For the two new EP Kilroot units, NERA entered the technical and commercial parameters provided by EP into PLEXOS. The specific technical and commercial parameters for the Data and Power Hub Services and Grange gas turbines were not available. As a result, NERA entered the reasonable assumptions of technical and commercial parameters into PLEXOS. The most critical assumption is the heat rate, which NERA derived from an assumed average low-heating value efficiency of 42%, which comes from a Pöyry report to the RAs on the costs of new entry power

34 Grange GT is included as a single generation unit. NERA is not aware if Grange GT will be a single unit or multiple units – if it is the latter, NERA recommends the RAs update the model accordingly. Further, in the 2021 GCS, the two EP Kilroot GTs are listed as 406 MW and 263 MW, respectively. NERA include these units at 350 MW and 298 MW, as these are the capacities provided to NERA by EP. For the Data and Power Hub Services and EP Kilroot units, NERA used the online dates provided by the owners, which differ somewhat for the online dates assumed in the 2021 GCS.

plants.[35] NERA recommend updating the Data and Power Hub Services and Grange gas turbines in PLEXOS when unit-specific technical and commercial parameters become available.

The 2021-2029 SEM PLEXOS Model retires the following generation plants, based on the assumptions stated in the 2021 GCS (see Tables A-4 and A-7):

Table 10: Retired Generation Plants Based on 2021 GCS

Generator	Jurisdiction	Capacity (MW)	Fuel	Retirement Date Assumed
Kilroot Coal (Both Units)*	NI	476	Coal	1-Oct-2023
Tarbert (All units)*	ROI	592	Heavy Fuel Oil	1-Oct-2023
Aghada (AT1)	ROI	90	Gas	1-Jan-2024
Edenderry (ED1)**	ROI	118	Peat/Biomass	1-Jan-2024
Moneypoint (All Units)	ROI	855	Coal	1-Oct-2025

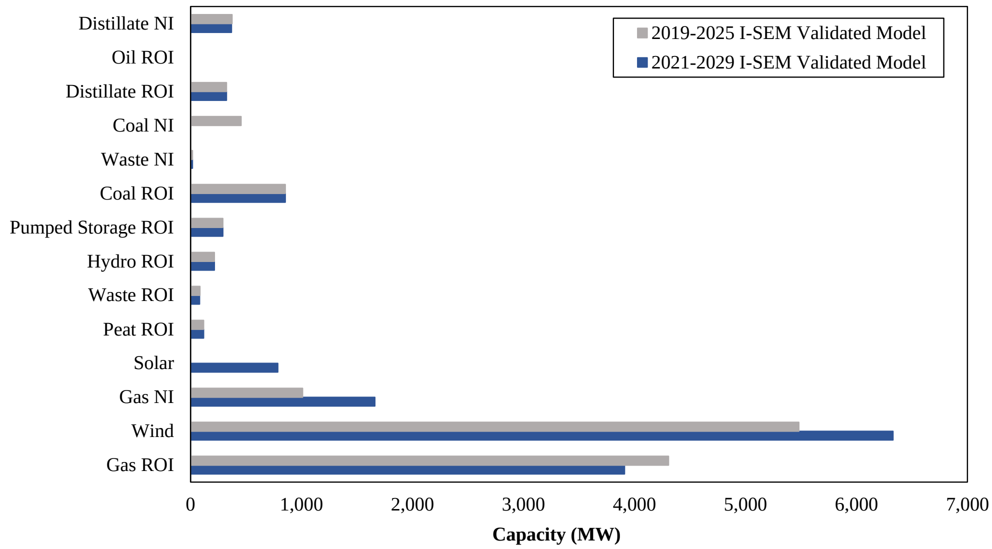
* The 2021 GCS stated Kilroot "Ceases operation in 2023" (Table A-7), which for modelling purposes NERA align with the market year, i.e. retirement on 1-Oct-2023. Similarly, NERA aligns Tarbert's retirement with the market year.

** As stated in the 2021 GCS, the planning permission for Edenderry peat/biomass unit will expire at the end of 2023, though NERA understand Bord na Móna is applying for a planning permission extension. Users of the 2021-2029 SEM PLEXOS Model may negate that retirement in the SEM PLEXOS Model if the planning permission for Edenderry is extended or if they wish to run scenarios assuming Edenderry peat/biomass continues to operate beyond 2023. NERA make no judgment as to whether Edenderry will actually retire at the end of 2023, but have instead aligned the 2021-2029 SEM PLEXOS Model with current planning permissions.

Figure 15 below shows total generation capacity by fuel in the 2021-2029 SEM PLEXOS Model and compared with the 2019-2025 SEM PLEXOS Model.

[35] Updated Cost of New Entrant Peaking Plant and Combined Cycle Plant in the I-SEM, A report to the Utility Regulator and the Commission for Regulation of Utilities, Pöyry, September 2018 (page 11). Specifically, 42% represents the efficiency of aeroderivative gas turbines, a standard technology for high efficiency new gas turbines. Link: https://www.semcommittee.com/sites/semc/files/media-files/SEM-18-156a%20Poyry%20Report%20-%20Cost%20of%20New%20Entrant%20Peaking%20Plant%20and%20Combined%20Cycle%20Plant%20in%20I-SEM.pdf.

Figure 15: Generation Capacity in 2021-2029 SEM PLEXOS Model vs. 2019-2025 SEM PLEXOS Model (End of 2023)[36]



5.2 Battery Commissioning and Modelling Approach

5.2.1 Battery Units in SEM PLEXOS Model

The SEM already has several batteries registered in the market, and several more are planned for the coming years. NERA included the existing and planned batteries in the 2021-2029 SEM PLEXOS Model, as shown in Table 11.

Table 11: Existing and Planned Batteries

Battery	Jurisdiction	Capacity (MW)	Online Date
Beenanaspuck and Tobertoreen Battery	ROI	11	1-Apr-2020
Avolta 1	ROI	8.5	30-Mar-2021
Drumkee Battery	NI	50	1-Apr-2021
Gardnershill Battery	ROI	8.5	1-Apr-2021
Kelwin Battery	ROI	26.6	1-Apr-2021
Mullavilly Battery	NI	50	1-Apr-2021
Barnesmore	ROI	3	1-Mar-2022
Avolta 2	ROI	60	1-Apr-2022
Aghada Battery Storage	ROI	19	1-Oct-2022

36 The capacities in the table do not include embedded generation. The 2021-2029 PLEXOS SEM Model includes direct representation of solar in the SEM and small-scale wind in NI (and so they show up in Figure 15), whereas the 2019-2025 SEM PLEXOS Model includes these as part of embedded generation. This explains part of the wind capacity discrepancy between the models.

Battery	Jurisdiction	Capacity (MW)	Online Date
Inchicore Battery Storage	ROI	30	1-Oct-2022
Poolbeg Battery Storage	ROI	75	1-Oct-2022
Southwall Battery Storage	ROI	30	1-Oct-2022
Castlereagh	NI	50	1-Oct-2022

The 2021 GCS lists new batteries in Tables 5 and 15. With respect to batteries, the 2021-2029 SEM PLEXOS Model differs in some instances from the 2021 GCS, as a result of NERA's research and communications with stakeholders. These differences occur for various reasons. Some generation and battery units are developed by one affiliate of a company; however, as they near commercial operation, they are deregistered and reregistered in the SEM to a different affiliate. Also, many of the online dates that NERA assume in the 2021-2029 SEM PLEXOS Model are different from those in the 2021 GCS. NERA understands the 2021 GCS in general lists online dates for a battery based on the date when the battery's capacity obligation begins. However, capacity obligations may begin well after commercial operation, depending on a battery or generator's strategy in the capacity market. For the 2021-2029 SEM PLEXOS Model, NERA use actual online dates. In general, where the battery (or generation) companies provided different data for new units than as presented in the 2021 GCS, NERA utilised the data provided by the companies. NERA note the following differences versus the 2021 GCS:

- Aghada Battery Storage is listed as a 1 hour battery in the 2021 GCS, but ESB informed NERA it is a two hour battery.

- The 2021 GCS lists a 40 MW Scottish Power Battery available from 2024 (Tables 5 and 15). From NERA's communication with Scottish Power, this reference corresponds to two batteries, Gorman (50 MW online Dec-2021) and Barnesmore (3 MW online Mar-2022). NERA include Barnesmore in the SEM PLEXOS Model. NERA do not include Gorman, however, as it has a Capped DS3 contract, which commits its capacity to providing DS3 services. If and when Gorman switches to participate significantly in the SEM energy markets, NERA recommend including it in the SEM PLEXOS Model.[37]

- The 2021 GCS lists a 9 MW Winter Winds Battery available from 2024 (Tables 5 and 15). From NERA's communication with Statkraft, this reference actually relates to existing battery BT&2 (Kilathmoy) Battery (11 MW online April-2020).

- The 2021 GCS lists a 60 MW Energia Battery available from 2024 (Tables 5 and 15). From NERA's communication with Energia, NERA understand this refers to two batteries planned for ROI: (1) a 10 MW battery planned for Oct-2022, and (2) a 50 MW battery planned for Oct-2023. However, NERA understand that it is uncertain if either or both of these battery projects will be built, as a result, NERA do not include those units in the

[37] As a courtesy to Model users, NERA include technical information for this battery in PLEXOS, though the battery is turned off in the Model.

2021-2029 SEM PLEXOS Model. Energia did provide information for the 10 MW battery (planned for Oct-2022), which is included in the 2021-2029 SEM PLEXOS Model as a courtesy to the RAs and the public, but NERA set the battery to offline status. However, the model user may simply turn on this battery if they wish to model the SEM with it online.[38] NERA do not have the technical or commercial data for the potential 50 MW battery (planned for Oct-2023). Thus, the 50 MW battery is not in the 2021-2029 SEM PLEXOS Model.

- The 2021 GCS lists 73 MW of "Various Battery project[s]" available from 2025 (Tables 5 and 15). From NERA's research and engagement with stakeholders, NERA understands that this aligns with the following batteries:
    - Beenanaspuck and Tobertoreen (11 MW online from Apr-2020)
    - The two Avolta batteries (8.5 MW and 60 MW, online from Mar-2021)
    - Kelwin Battery (26.6 MW online from Apr-2021)
    - Gorman (50 MW online from Dec-2021)
    - Barnesmore (3 MW online from Mar-2022)
- In the text below Table 15, the 2021 GCS references Drumkee and Mullavilly, each 50 MW batteries in NI. NERA includes both in PLEXOS (see Table 11 above), however, NERA lists the online dates as April 2021, as this was the date provided during the data gathering process from the generation and battery companies – a slight contrast with the dates listed in the 2021 GCS of November and December 2020 for Drumkee and Mullavilly, respectively.
- The text below Table 15 in the 2021 GCS also references two planned 50 MW batteries for NI, Kells and Castlereagh. While NERA includes Castlereagh, NERA do not include Kells, as based on engagement with the owner of Kells, NERA understands that this battery is not anticipated to participate significantly in the energy markets, at least not at first once it is online, and the SEM PLEXOS Model only models the energy market in the SEM.

Our principle was to consider for inclusion in the SEM PLEXOS Model only batteries referenced in the 2021 GCS and or where market participants provide information to NERA about their batteries. NERA exclude batteries if NERA understood that a) they would have little to no participation in energy markets or b) their future status was uncertain.[39]

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[38] As PLEXOS users will know, a unit is turned off or on via the "units" property.

[39] For example, NERA identified Shannonbridge BESS and Lumcloon Battery (each 100 MW and each with stated 2021 online dates), but at least according to trade press, it appears these batteries will provide system services to support

NERA recommend that the RAs continue to review the appropriate battery capacity to include in the SEM PLEXOS Model in future validations.

5.2.2 Battery Modelling Approach

Grid-connected batteries serve many functions in energy markets, which can be simplified into three categories:

1) Energy. A battery's ability to charge, store energy, and discharge allows a battery to arbitrage between low-price hours and high-price hours, similar to pumped storage hydro.

2) Capacity. With effective planning, batteries can store enough energy to provide power during peak hours where capacity supply is tight. In practice in the SEM, resources with capacity awards take on a Reliability Option, where the resources must pay the difference between the market price and a €500/MWh strike price, when prices exceed €500/MWh.

3) System services and renewables support. Batteries can provide numerous ancillary services, and batteries can be effective at enabling the integration of intermittent renewable resources such as wind. In the SEM, the DS3 regulatory program provides contracts and revenues to batteries and other resources for supporting renewables integration.

The SEM PLEXOS Model only incorporates item 1) above, energy. Yet, as of the writing of this report, in the SEM and in markets more broadly, energy market participation by batteries has been relatively limited, for at least three reasons:

a) Charging and discharging losses as well as the wear and tear on batteries from cycling are costs that reduce incentives to arbitrage between high and low market energy prices.

b) Revenues from system services and renewables integration are often higher than merchant activity in energy markets. Batteries may also have contracts requiring they provide such services.

c) Energy market rules, and market and system operations may not be optimized for battery participation.

These facts make it challenging to determine the most accurate battery representation in the SEM PLEXOS Model. On one extreme, one could ignore all batteries, based on the theory that energy market participation will be minimal. On the other extreme, one could allow full participation in the energy markets, limited only by battery charging and discharging efficiency, any operational

renewables. See https://www.energy-storage.news/100mw-battery-project-in-ireland-energised-and-ready-to-go-operational-in-q1-2021/.

costs, and any cycling limits. This latter approach, however, would likely lead to a significant overstatement in the SEM PLEXOS Model of battery participation in energy markets. NERA decided to include batteries, and considered two methods for appropriately limiting participation in the energy markets:

1) Adding a VOM charge that represents the opportunity cost of participating in the energy markets, i.e. the lost revenue from DS3.

2) Identifying a subset of a battery's capacity that would participate in energy markets, e.g. 20% for energy markets.

Through engagement with stakeholders, NERA found there was no consensus as to the best approach for modelling battery energy market participation. Ultimately, a historical analysis of battery data may help inform the best way to model batteries, yet there are only a few batteries online and participating in the SEM energy markets today, and even these have not been online for very long. Further, the factors that limit battery participation in energy markets referenced above are not static.[40]

For simplicity and transparency, NERA decided to utilise the second option above, identifying a subset of battery capacity that would participate in the energy markets. As a reasonable placeholder, NERA assumes 10% energy market participation through 2023 and 50% energy market participation starting in 2024. NERA received feedback from multiple stakeholders that battery participation in the energy market is likely to be relatively low for the next few years but may increase thereafter as regulations and market structures evolve in the SEM. Based on that feedback, NERA adopted the lower 10% participation ratio through 2023.

The 10% and 50% proportions were chosen considering specific feedback from various battery owners, though the precise percentages provided by battery owners varied. NERA recommends the RAs monitor the effect of batteries on the SEM energy market—particularly on the DAM. As more historical data becomes available, the RAs may refine this approach to modelling batteries in the SEM PLEXOS Model, when completing future backcast/validation exercises.

5.3 Generator and Battery Technical and Commercial data

NERA contacted all of the generation and battery companies in Ireland and Northern Ireland, requesting them to review and update the technical and commercial data for their generation plants as represented in the RAs' I-SEM PLEXOS model. NERA asked for any updates that would apply going forward, and asked for data on planned generators and batteries.

[40] For example, as battery costs go down, the "cost" of wear-and-tear on a battery from cycling, e.g. the cost of replacing the battery earlier than anticipated, also goes down, which may make energy market participation more feasible.

While NERA performed a high-level review of the generators' data for reasonableness, NERA did not perform a comprehensive "from-scratch" validation of all generator commercial offer data. The RAs may wish to conduct such a comprehensive review in future validation, exercises.

NERA focused the review on the data changes that generators proposed. NERA reviewed the proposed changes to generator data for reasonableness, and also reviewed the changes with the RAs. As required, NERA followed up with the generation companies to clarify the changes they suggested, which in some instances led to adjustments to the proposed changes. While NERA obtained start costs for the biomass and waste generators, NERA set their start costs to zero in the Validated SEM Model – this has been the standard for recent PLEXOS Validations. Setting these units' start costs to zero helps ensure these units to run when available, which NERA understand is their operational pattern.[41]

The public version of the 2021-2029 SEM PLEXOS Model, and the accompanying Excel generator dataset (PUBLIC--GEN DATA 2021-29.xlsx), reflect the updated generator data, with the exception of generator and battery VOM costs and markups and battery cycling limits, which are included neither in the public SEM PLEXOS Model nor in the public Excel generator dataset. However, NERA delivered to the RAs a confidential 2021-2029 SEM PLEXOS Model which includes VOM costs and markups and cycling limits.

5.4 Hydro and pumped storage data

NERA have maintained the hydro and pumped storage data from the 2019-2025 SEM PLEXOS Model in the 2021-2029 SEM PLEXOS Model, as deemed a reasonable approach based on discussions with the RAs and the TSOs, and based on the information provided by the owners of these units.

5.5 Outages

5.5.1 Scheduled outages

NERA updated scheduled outages in the 2021-2029 SEM PLEXOS Model to reflect the latest updated projections of outage schedules from 2020 to 2022, as provided to NERA by the TSOs. The outage schedules also include outages on the interconnectors between GB and the SEM. NERA adds a maintenance rate to the Celtic an Greenlink interconnectors, as they are not yet included in the TSOs outage schedules.

[41] The relevant units are Dublin Waste, Indaver Waste, and Lisahally.

For the years 2023 to 2029, for the existing generators and interconnectors, NERA utilized an average-year outage schedule, by averaging the 2020 to 2022 (inclusive) outage plan.[42]

For the new gas turbines, NERA assumed two weeks of outages per year (the same assumption from Table 16 of the 2021 GCS), which translates to a 3.8% maintenance rate ("MR").

For all batteries, NERA assumed a 95% availability, implemented as a 4% maintenance rate and a 1% forced outage rate. These are placeholder assumptions that reflect the high availability batteries often have, and are reasonable for the PLEXOS Validated Model. These placeholders can be adjusted once sufficient Forced Outage Rates ("FOR") and MR historical data are available for batteries.

Using maintenance rates is new for the 2021-2029 SEM PLEXOS Model. For existing units, a maintenance rate is not required, and instead precise planned outage schedules from the TSOs were utilised. PLEXOS has a modelling process called "PASA" (Projected Assessment of System Adequacy), whose purpose is to develop a reasonable schedule of maintenance outages for each year based on user-entered maintenance rates.[43] Once the new units and interconnectors are part of the TSOs' outage schedules, the RAs may wish to swich to precise outage modelling for these entities.

NERA understands the standard outage schedules produced by the TSOs do not include planned battery maintenance. If this changes in the future, the RAs may also update the modelling of planned outages for batteries.

5.5.2 Forced outages

FORs were calculated using reported *ex post* FORs, annually, from 2016 through 2020. For each year and each category from the below, NERA calculated a weighted average FOR (weighted by generator capacity); NERA then averaged across the five years. Each unit in a generator category is attributed the same FOR.[44]

The 2021-2029 SEM PLEXOS Model include the forced outages rates in Table 12 below.

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[42] Basically, for each year in 2023 and beyond, NERA applies all the outages from 2020 to 2022, but divides the length of those outages by a factor of three. This is a placeholder approach until the precise outage schedule is available.

[43] A reasonable outage schedule spreads out maintenance events and focuses maintenance in periods of higher capacity reserves.

[44] 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.

Table 12: Forced Outage Rates by Generator Type

Generator Type	Updated FORs	FORs Prior Validation[45]
Gas	5.5%	5.8%
Oil	5.0%	2.2%
Coal	23.4%	7.9%
Peat/Biomass	3.7%	7.9%
Hydro	4.1%	4.5%
Pumped Storage	6.3%	6.0%
Distillate	3.4%	2.2%
Waste/Biomass	6.7%	6.7%

Three changes are of particular note:

- Coal outage rates increased to 23.4%. Both Moneypoint and Kilroot had significant time offline due to forced outages from 2018 to 2020, leading to this high FOR.

- Peat/Biomass FOR dropped to 3.7% from 7.9%. The main driver of this is due to the two peat units – Lough Ree and West Offaly, retiring at the end of 2020. Those two units have had relatively high FORs in recent years, while the remaining peat unit (now a peat/biomass unit), Edenderry, has had relatively low FORs. NERA decided to switch to the peat FOR for Edenderry specifically.

- Separate FORs were determined for oil and distillate generation units. NERA consider this is appropriate given the different technologies of oil steam turbines versus distillate peakers. Also, note both oil and distillate FORs are higher than the FORs in the prior SEM PLEXOS Model. This simply falls out from the averaging of the performance of the underlying units in the last five years.

For the interconnectors between GB and the SEM and France and the SEM, NERA uses a 7.5% forced outage rate, as recommended by the TSOs, an update versus the 6.9% FOR assumed in the 2019-2025 SEM PLEXOS Model.

For batteries, as already mentioned, a 1% FOR is assumed as a reasonable placeholder assumption.

45 2019-2025 Validation Report, Figure 5.

6 System Data

6.1 Demand

NERA uses an hourly demand forecast covering the years 2021 through 2029 in the 2021-2029 SEM PLEXOS Model. The demand forecast reflects the peak demand and the total annual energy requirements (TER) forecast from the 2021 GCS. Specifically, the "median" forecasts from the 2021 GCS are used, shown in Table 13.

Table 13: Demand Forecast for the All-Island Market

Year	Peak Demand (GW)	Total Energy Requirement (TWh)
2021	6.98	39.1
2022	7.14	40.5
2023	7.33	41.8
2024	7.45	43.2
2025	7.57	44.3
2026	7.67	45.0
2027	7.77	46.1
2028	7.87	47.0
2029	7.97	48.0

Historical hourly demand profiles were used to shape the GCS forecasts of the peak demand and the total annual energy to hourly forecasts. Five versions of the 2021 through 2029 hourly demand forecast were produced, each based on a different base year demand profile. Historical hourly demand from 2014 to 2018 was used to produce five different demand shaping patterns.[46] Each of the five versions of the demand forecasts from 2021 through 2029 correlate with the forecast from Table 13. The only difference among the five forecasts is how the total annual energy from Table 13 is distributed within each year of the forecast (where the different in-year distributions are based on the five historical hourly demand patterns from 2014 to 2018).

[46] 2020 historical hourly demand was not used out of concern that the demand profile would be an outlier as a result of the Covid-19 pandemic. While NERA had access to the 2019 demand profile, access to the 2019 wind profile was unavailable when NERA updated the SEM PLEXOS Model. As a result, the five years of data ending in 2018 was used resulting in the continuation of correlated wind and demand profiles.

6.2 Wind

The wind forecast is based on the 2021 GCS's forecast of wind capacity in Ireland and Northern Ireland, shown in Table 14 below.[47]

Table 14: Wind Capacity Forecast

At Year End	ROI Onshore Capacity (MW)	ROI Offshore Capacity (MW)	NI Large Scale Wind Capacity (MW)	NI Small Scale Wind Capacity (MW)
2021	4,500	25	1,095	176
2022	4,700	25	1,196	176
2023	4,900	25	1,251	176
2024	5,100	25	1,274	176
2025	5,300	25	1,405	176
2026	5,420	395	1,405	176
2027	5,540	1,445	1,405	176
2028	5,660	2,745	1,405	176
2029	5,780	3,345	1,405	176

In Ireland, the wind forecast is split between onshore and offshore wind, however, offshore wind is not forecasted to increase above its current level of 25 MW until 2026. In all prior SEM PLEXOS Models, all wind in the ROI was represented by a single PLEXOS generation object – essentially an onshore wind object – and this approach was appropriate, as long as offshore wind was only at 25 MW. As the current Validation extends to 2029, offshore wind is included as separate generation object. Having separate generation objects in PLEXOS makes it easy to model different wind profiles. Specifically, offshore wind is split into two objects: the 25 MW of existing offshore wind (Arklow Phase 1) and the new offshore wind greater than 25 MW. NERA learned from the TSOs that the typical capacity factors at Arklow Phase 1 are closer to onshore wind than to what is expected for new offshore wind.

In Northern Ireland, the wind forecast is split between small- and large-scale wind. In previous PLEXOS Model Validations, small scale wind was accounted for in the embedded generation profiles. NERA have updated the PLEXOS model to include a separate PLEXOS generation object for small scale wind. This way, one can easily update the SEM PLEXOS Model should the small-scale wind capacity in Northern Ireland change.

Historical wind profiles are used to determine wind availability in PLEXOS on an hourly basis. For onshore wind in ROI and large scale wind in NI, wind profiles from 2014 to 2018 are used. Load profiles are used from the same period also. Previous SEM PLEXOS Models incorporated five correlated wind and demand profiles. This means that the 2015 wind profile is linked to the

[47] The GCS publishes a forecast of *annual* wind capacity; in PLEXOS wind is added on a monthly basis, extrapolating between the annual capacities.

2015 demand profile and so on. NERA maintain such method. Using five years' worth of wind data is particularly important because wind availability may change significantly from year to year, but over five years wind availability will be more stable. Correlating wind and demand profiles allows the model to face historical conditions as they were, over five years, e.g. including constrained historical supply conditions (low wind and high demand) as well as the reverse.

For the 25 MW Arklow Phase 1 offshore unit, the same profiles as onshore wind in ROI are used.

For the planned new offshore wind in ROI, NERA use a 45% capacity factor, the same assumption stated in the 2021 GCS (2021 GCS, Table 12) – onshore wind has approximately a 30% capacity factor in the PLEXOS Model, by comparison. NERA developed a new wind profile for the new planned offshore as follows: NERA started with the ROI onshore wind profile, and increase the wind availability to match an average capacity factor of 45%.[48] NERA recommend the RAs refine the profile for offshore wind in further validations, as the online dates for new offshore wind capacity becomes less far in the future.

For small-scale wind in NI, a single year's profile was used, as provided by the TSOs. Using a single year's profile is reasonable for NI small-scale wind given its relatively small size (176 MW) versus the rest of wind in the SEM. NERA note that NI small-scale wind has a lower capacity factor (about 20%) than large-scale wind (about 30%).

SNSP Limits

While in practice the SEM operates with System Non-Synchronous Penetration ("SNSP") limits, historically the SEM PLEXOS Model has not had such limits. NERA do not adjust this aspect of the SEM PLEXOS Model. All things equal, SNSP limits will bind in the highest wind and lowest load hours, when prices are likely to be low no matter what, so the effect of a potential SNSP modelling approach in PLEXOS is likely to be relatively small. NERA also note the stakeholder workshop in the prior validation led to the conclusion not to reflect SNSP limits in the SEM PLEXOS Model.[49]

6.3 Solar

Solar generation forms a small percentage of generation in the SEM today (~1%). Yet, solar capacity is expected to increase significantly versus current levels, up to 1.2 GW by 2029. While

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48 Each historical hourly wind availability factor from the chosen 2014 to 2018 data period was multiplied by a factor X, such that the average capacity factor over those five years, after this multiplication, was 45%. A rule was also included such that no hourly availability factor could exceed 100%. The X factor was large enough that some historical hours would exceed 100%, without that rule. Excel's goal-seek functionality was utilized to arrive at the appropriate X factor. The resulting adjusted 5 years of wind profiles (now with an average capacity factor of 45%) for offshore wind was used.

49 See page 31 of the PLEXOS Validation 2019-25 and Backcast, Input Validation and Backcast Report.

annual capacity factors are small (about 11%), at peak sun times solar will form a significant portion of generation by 2029. For these reasons, NERA model solar explicitly in the 2021-2029 SEM PLEXOS Model. Previously, solar was a part of embedded generation in PLEXOS.

The solar forecast is based on the 2021 GCS's forecast of solar capacity in Ireland and Northern Ireland, shown in Table 15 below.[50] While the 2021 GCS lists small-scale and large-scale solar separately for NI, they are combined within the model, as NERA understand from the TSOs that the capacity factors are relatively similar for large- and small-scale solar. If small-scale solar grows substantially, it may be worthwhile to determine a separate profile for small-scale solar in future validations.

Table 15: Solar Capacity Forecast

At Year End	ROI Solar (MW)	NI Solar (MW)
2021	261	268
2022	384	289
2023	507	289
2024	630	289
2025	692	289
2026	753	289
2027	815	289
2028	877	289
2029	938	289

A single year's solar profile for solar is used for each of Ireland and N. Ireland – as provided by the TSOs. NERA note that solar patterns are relatively more stable from year-to-year in comparison to wind patterns, as a result, NERA are satisfied in using a single solar profile for the 2021-2029 SEM PLEXOS Model. In future validations, as solar generation increases, the RAs may consider using more solar profiles.

6.4 Demand side units

Demand participation is growing in the SEM. Demand Side Units ("DSUs") represent demand that effectively participate in the market as generators, except that a DSU's "generation" is negative load. The 2021 GCS lists a total of 658 MW of DSUs across Ireland and Northern Ireland. DSUs participate in both the DAM and the Intra-Day markets and Balancing market. The established standard in the SEM PLEXOS Model is to represent the DSUs in aggregate as P-Q pairs – the 2019-2025 SEM PLEXOS Model had 6 P-Q pairs. In effect, this creates a demand curve, representing a subset of demand in the SEM that is price sensitive. While DSU capacity is growing

50 As with wind, the annual solar capacity growth forecast is converted into a monthly growth forecast, using extrapolation.

in the SEM, the average "generation" (really avoided demand) from DSU resources is still relatively small, so it is reasonable to continue this simplified aggregation into P-Q pairs. If average DSU "generation" expands significantly, NERA recommends that the RAs may consider enhancing the modelling of DSUs in future validations.

In line with historical data, DSUs are rarely dispatched in the test runs of the 2021-2029 SEM PLEXOS Model, with the exception of certain low-priced DSUs. NERA understand that many of the low-priced DSUs are industrial loads with Combined Heat and Power ("CHP") plants, where the loads do not want to turn off their CHPs. Basically, these industrial customers put their full load into the market, assuming that their CHP is not generating. The DSUs then bid a low price (sometimes a negative price) as a DSU to "reduce" that load. In reality, by "reducing" its load these DSUs are simply maintaining their generation at their CHP (and the lower net load that results). These DSU "generators" are excluded from the embedded generation determined by the TSOs, to avoid double counting.

The 2019-2025 SEM PLEXOS Model included the DSU values from Table 16:

Table 16: Demand P-Q Pairs, 2019-2025 I-SEM PLEXOS Model

DSU Blocks	Quantity (MW)[51]	Price (€/MWh)
1	19	-100
2	15	125
3	22	302
4	130	656
5	90	1,983
6	264	8,100

In the 2021-2029 SEM PLEXOS Model includes five demand P-Q, as shown in Table 17.

Table 17: Demand P-Q Pairs, 2021-2029 SEM PLEXOS Model

DSU Blocks	Quantity (MW)	Price (€/MWh)
1	6.1	0
2	4.5	20
3	4.6	30
4	2.3	100
5	7.1	250

[51] This represents initial quantities in the prior SEM PLEXOS Model – these quantities increase over time in that model.

Table 17 makes apparent three changes versus the DSU P-Q pairs from the previous PLEXOS Model:

1) the quantities at each DSU block are lower,

2) there are no longer very high price points (Table 17 does not go above €250/MWh whereas Table 16 has prices as high as €8,100/MWh), and

3) there are more relatively lower price points in the updated PLEXOS Model (e.g. €100/MWh and lower).

Before discussing the updated approach to determining P-Q pairs, NERA present background information. The final three price points from the prior PLEXOS Model are €656/MWh, €1,983/MWh and €8,100/MWh. Each are above the €500/MWh strike price in the SEM's Capacity Remuneration Mechanism ("CRM") contracts. At least through Sept 2021, DAM prices have not exceeded €500/MWh since I-SEM Go Live, and prices rarely (less than 1% of hours) have exceeded €250/MWh (the latter being the highest price point in the updated SEM PLEXOS Model). In summary, it remains untested how DSUs will respond at the highest price points.

Further, the DSU modelling in PLEXOS simplifies how DSUs actually offer into SEM markets. In PLEXOS, DSUs may be dispatched with full flexibility within the specified P-Q pairs. For example, using the P-Q pairs from Table 16, PLEXOS may use 2 MW of Block 4 at a price of €656/MWh, a total cost of €1,312. While €656/MWh is expensive compared to typical marginal costs in the SEM, it still might be a lower-cost solution in PLEXOS to use the €656/MWh DSU, if using the DSU means avoiding starting up a new unit (start costs can be several thousands of euros and over €100,000 for large units). In reality, DSU offers are more complicated because:

1) DSUs often participate in the DAM and the BM, where in the BM they offer both incremental and decremental bids, where the acceptance BM bids will adjust dispatch from DAM orders – these multiple tiers of offers complicates the creation a simple P-Q curve; and

2) DSU offers sometimes include shutdown costs, where DSUs are paid a fixed euro amount in addition to a variable amount per MWh for reducing load.

The second point in particular is relevant here. In past SEM PLEXOS Models the shutdown costs have been averaged into the prices in the P-Q curves. Yet, an explicit accounting of shutdown costs might prevent situations like the example above, where PLEXOS draws on 2 MW of Block 4, only paying €656/MWh, a total cost of €1,312. Explicit accounting of shutdown costs might have made it cost prohibitive to rely on a Block 4 DSU (at €656/MWh), and instead PLEXOS might have rearranged dispatch to use generation resources instead. Perhaps ironically, using the €656/MWh may be a lower-cost solution but one that leads to higher prices. When the €656/MWh DSU is used, the market price will be (at least) €656/MWh, even if just 2 MW of that Block 4 DSU are used. Yet, in the alternative of using generation (and or battery) resources instead, the market price is likely to be far lower, even if overall system costs might go up somewhat.

In summary, NERA find that conceptually it is not clear whether the dispatch of high-price DSUs in PLEXOS aligns with the same way DSUs are dispatched (and affect prices) in the SEM, due in particular to the issue of DSU shutdown costs. Further, NERA find that there have not been historical periods of DAM prices high-enough to test whether such high-price DSUs will actually be dispatched. Thus, to the extent that high-priced DSUs could be dispatched in PLEXOS, there is at least some risk of PLEXOS producing high prices unlikely to be reproduced in the actual DAM.

In practice, the high-priced, e.g. >€500/MWh, DSUs very rarely are dispatched in PLEXOS. Thus, in practice, the inclusion or exclusion of them is unlikely to have a significant effect on resulting prices. Nonetheless, the risk of PLEXOS producing high prices unlikely to be reproduced in the actual DAM remains.[52] Therefore, given this possibility, NERA recommend the following different approach, which by design does not include DSUs with prices higher than have been observed historically in the DAM.

NERA analysed a recent period of actual DSU dispatch and DAM prices.[53] NERA constructed the P-Q pairs from Table 17 by testing what set of P-Q pairs reproduced actual SEM DSU dispatch, on average. NERA did this through a backcast exercise.[54]

As seen in Table 17, the quantities are far lower than those in the prior PLEXOS Model (Table 16). This change is because, in practice, DSU dispatch quantities have been relatively low in the SEM – about 15 MW on average in the historical period NERA assessed.

In summary, there are three primary options for DSUs in PLEXOS:

1) An offer-based approach, with simple P-Q pairs, which has been used in prior PLEXOS Validations. This approach has the advantage of modelling the offers of all DSUs, but has the disadvantage of the possibility of causing high-prices that may not reflect actual DSU dispatch in the SEM.

2) A detailed representation of DSU offers, including shutdown cost offers. This approach could lead to DSU dispatch more in line with the SEM while at the same time capturing all DSUs in the SEM, but it would be complicated to develop.

3) A backcast-based approach to infer dispatch quantities and prices. This approach is designed to align with actual DSU dispatch, but has the disadvantage of excluding the rarely dispatched high-price DSUs.

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[52] NERA did observe some dispatch of higher price DSUs in test PLEXOS Model tuns.

[53] NERA was provided with DSU dispatch data from 1 Aug 2020 to 14 Sep 20221, a total of 13.5 months.

[54] NERA dispatched the P-Q pairs from Table 17 against actual DAM prices. Specifically, NERA set the DSU quantities from Table 17 such that average DSU dispatch in NERA’s backcast matched precisely average actual DSU dispatch for each level of prices in Table 17. For example, DSU dispatch for prices between €30/MWh and €100/MWh in NERA’s backcast matched exactly average historical DSU in that price range.

NERA recommend option 3, but suggest the RAs continue to evaluate the best DSU approach in future validations.

Finally, NERA note that the 2021 GCS references an increase of 260 MW of DSUs in 2025 (2021 GCS Table 5), and NERA increases proportionally all DSU quantities in 2025 to reflect this addition.

6.5 Interconnectors

SEM has two interconnectors with GB: Moyle and the East-West Interconnector. Two additional interconnectors are also planned. Another interconnector to GB, Greenlink, is expected to commence regular operation in November 2024 (that date is per discussions with the CRU), and the proposed Celtic Interconnector, between Ireland and France, is expected to come online in 2027 (per the 2021 GCS).

NERA made the following updates to the technical parameters of the existing interconnectors vs. the parameters in the 2019-2025 SEM PLEXOS Model:

- For Moyle, the losses rate was updated from 1.9% to 2.4%, as suggested by the TSOs.
- For the East-West Interconnector (“EWIC”), the losses rate was updated from 4.9% to 4.7%, as suggested by the TSOs.
- It was noted in the 2019-2025 SEM PLEXOS Model, losses only occurred on Moyle and EWIC when exporting to GB, but not when importing to SEM. Losses are now applied in both directions.
- The FORs for Moyle and EWIC were also updated from 6.9% to 7.5%, as suggested by the TSOs.

As per the previously SEM PLEXOS Models, Moyle’s contract capacity is reflected in the 2021-2029 SEM PLEXOS Model. See Table 18 below (values from Table 10 of 2021 GCS).

Table 18: Moyle Capacity, West to East, in 2021-2029 SEM PLEXOS Model

Dates	West to East Capacity (MW)
June 2020 – 31 October 2021	250
November 2021 – 31 March 2022	160
April 2022 – Onwards	500

NERA note the contract capacity on Moyle is lower than the maximum transfer capacity on Moyle, so potentially more capacity could flow from SEM to GB. Yet, given the relatively good alignment of the PLEXOS Model with historical data in the backcast, NERA believe that maintaining the assumption of limiting exports to the contract capacity is reasonable.

In the East to West direction, Moyle's capacity in the SEM PLEXOS Model is 450 MW from November to March and 410 MW from April to October. While imports over Moyle in April to October may be up to 450 MW, for consistency, NERA maintain the 410 MW limit assumed in prior SEM PLEXOS Models.

For the East-West interconnector, in the 2021-2029 SEM PLEXOS Model, the same assumptions as in prior models are maintained, namely that a max flow to GB from the SEM is 500 MW and a max flow in the reverse direction is 530 MW.

The new interconnectors have capacities of 500 MW for Greenlink and 700 MW for Celtic. Per the TSOs, NERA assume FORs of 7.5% for both and loss rates of 7.5% for Celtic and 5% for Greenlink.

NERA set the ramp rates for both new interconnectors to 10 MW/min, per information provided by the CRU. Similarly, NERA increased the ramp rates to 10 MW/min for both Moyle and EWIC (effective as of the online date for Greenlink), per information provided by the CRU.[55] This adds up to a future total ramping capability of the interconnectors of 40 MW/min (10 MW/min per interconnector). In future validations, NERA recommend the RAs review the current and estimated future ramp rates for the interconnectors, to ensure any future ramp rate updates are reflected in the PLEXOS Model.

6.6 Transmission loss adjustment factors ("TLAFs")

As of the writing of this report, the most up to date 2021 to 2022 TLAFs are used (as published by EirGrid).[56] New generation units and batteries do not appear in those TLAFs. NERA nonetheless link in PLEXOS all batteries and generation units to the active TLAF file, in anticipation of future published TLAFs that will include these resources.

6.7 Embedded generation

Consistent with prior SEM PLEXOS Model validations, generators in PLEXOS are represented in one of three ways:

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55 In PLEXOS, prior to the Greenlink coming online, the existing interconnectors are modeled with a ramp rate of 5 MW per min.

56 *See* http://www.eirgridgroup.com/customer-and-industry/general-customer-information/tlafs/.

1) Dispatchable thermal, hydroelectric, and pumped storage generators are modelled as individual units, with their own properties;

2) Wind (and now solar) are modelled as individual regional generation units in PLEXOS, where each PLEXOS wind "unit" is actually an aggregation of *all* the wind generators in a certain geographical area; and

3) Non- (or partially-) dispatchable generators are modelled as embedded generation, whose output is fixed in advance as an input to the model.

Previously small-scale wind in NI and all-island solar was included in embedded generation. Without such intermittent resources, the modelling of embedded generation is less complex. Based on analysis provided to NERA by the TSOs, average embedded generation is 164 MW for the entire forecast period. The TSOs recommended using a flat generation amount every hour. NERA calculated this value based on an assumed average capacity factor for each category of partially / non-dispatchable generation (provided the TSOs) and multiplying that capacity factor by the total capacity for each category of partially / non-dispatchable generation. The relevant categories, as listed in the 2021 GCS, are:

- For ROI: Small Scale Hydro, Biomass and Biogas, Biomass CHP, Industrial, and Conventional CHP – see Table A-5 of the 2021 GCS.

- For NI: Small Scale Biogas, Landfill Gas, Small Scale Biomass, Renewable CHP, Other CHP, Small Scale Hydro, and Waste To Energy – see Table A-8 of the 2021 GCS.

In summary, 164 MW of embedded generation is included in every hour of the 2021-2029 SEM PLEXOS Model.

7 Commodities

7.1 Fuels and CO_2 Prices in the All-Island Market

The indicative fuel and CO_2 prices from Table 19 below are included in the 2021-2029 SEM PLEXOS Model. It was outside the scope of the current validation project to provide a precise forecast of commodity prices, but nonetheless NERA put placeholder fuel prices into the SEM PLEXOS Model roughly in line with current market expectations. However, NERA caution that fuel prices were in flux during the period of NERA's analysis, so these prices may quickly become obsolete. NERA use the same prices each year from 2021 through 2029. When the RAs (or any user) use the model for forecast purposes, NERA recommend that they update the fuel price input data.

Table 19: Indicative Commodity Prices used in 2021-2029 SEM PLEXOS Model

Commodity	Q1	Q2	Q3	Q4
Gas (p/th)	114	69	67	75
LSFO ($/t)	450	450	450	450
Gasoil ($/t)	650	650	650	650
Coal ARA ($/t)	150	150	150	150
Carbon (€/t)	60	60	60	60

For Edenderry, NERA include in the model a consensus peat/biomass price of €2.50/GJ, which reflects a NERA analysis of different fuel price ranges provided by BnM for Edenderry. NERA also reflect a consensus CO_2 production rate for Edenderry of 63 kg/GJ.

7.2 Carbon pricing in Great Britain

The carbon pricing scheme in the UK only affects prices in the SEM indirectly, through trade between the SEM and the GB market. This is because the specifics of the UK carbon pricing scheme do not apply to generation units in Northern Ireland, even though Northern Ireland is part of the UK. Rather, the generation units in Northern Ireland face the same carbon pricing as in Ireland, namely, the EU ETS carbon prices.

The UK carbon pricing, as it applies to electric generation plants, is the sum of two components:

1) the prices from the carbon trading scheme in the UK, known as UK ETS; plus

2) The UK Government's carbon price support scheme, known as CPS.

The UK ETS was implemented as a result of Brexit. For simplicity, the UK ETS prices are incorporated into PLEXOS by taking the EU ETS prices, and adding a premium (or discount) that reflects average historical differences between the UK ETS and the EU ETS. This method is used for a very specific practical reason, given how the RAs use the SEM PLEXOS Model. The RAs use the SEM PLEXOS Model to develop an econometric formula for SEM prices, which then is used for pricing the regulated Directed Contracts ("DCs") in the SEM.[57] Importantly, for that model to be accurate, all of the commodity data used in the SEM PLEXOS Model must appear in the econometric model that the RAs develop. Already, that econometric model considers price variations of gas, coal, and EU ETS CO_2. (and potentially could include Gasoil and LSFO). Adding the UK ETS price to the list of needed prices to incorporate in the econometrics would increase the complexity of the analysis by at least a factor of two. Following interactions with the RAs, it was agreed to produce a SEM PLEXOS Model that does not require the explicit use of UK ETS data, but rather a proxy that represents UK ETS prices, based on the historical relationship between the two carbon markets, which NERA found to be reasonably well correlated, but with the UK ETS price trading at roughly on average a 5% premium to the EU ETS price. NERA adopt a 5% premium in the SEM PLEXOS Model. Given how new the UK ETS is and how limited the historical data available to NERA was, NERA recommend the RAs' monitor the relationship between UK and EU carbon prices and update as needed in future validations.

NERA note that the CPS in the UK is £18/t.[58] The CPS has been at this price level for many years,[59] and NERA keep the GCS price at this level for 2021-2029 forecast period. If this CPS price changes in the future, NERA recommends that the RAs or their consultants update it in the SEM PLEXOS Model.

7.3 Fuel Adders

In general, the 2021-2029 SEM PLEXOS Model uses the same fuel transportation costs used in the 2019-2025 SEM PLEXOS Model.

Gas transportation costs deserve special comment. Gas generators generally pay both a capacity and a commodity (or variable) charge to transport gas to their units. Generators may procure gas transportation capacity on a long-term or short-term basis, or use a combination of such approaches. From an economics perspective, long-term gas capacity costs are sunk costs, so the marginal gas transportation costs for a generator with long-term gas transport capacity arrangements will only be its variable gas transport costs. In contrast, gas generators that buy gas capacity on a short-term basis potentially can secure gas transport capacity after they secure an award to generate in the DA

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57 A recent information paper on DC Prices may be found here: https://www.semcommittee.com/publications/sem-21-072-round-16-quarterly-directed-contracts-q1-2022-q4-2022.

58 See, for example, https://uk.practicallaw.thomsonreuters.com/w-029-9484?transitionType=Default&contextData=(sc.Default).

59 See for example the 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, which announced a freeze of the CPS at £18/t starting from the 2016-17 UK fiscal year.

Market. In that case, a generator's marginal gas transport costs will reflect both variable transport costs and short-term capacity costs.

In prior SEM PLEXOS Models, the gas generators in ROI were split into two groups:[60] gas generators that offered short-term gas transportation capacity costs into the DA energy market, and those that did not. The difference in marginal gas costs is not insignificant between the two groups, particularly in colder months when short-term gas capacity charges are relatively high. Appropriately determining which generators include short-term gas capacity charges in their offers is therefore important for the accuracy of the SEM PLEXOS Model. Yet, generators typically keep their gas procurement arrangements confidential. There is not a public record of which gas generators procure long-term and which gas generators procure short-term gas capacity. Further complicating the situation, generators may have a blended approach: procuring some gas transport capacity long-term and some short-term. Generators may also change their gas transportation strategies over time. The help determine how to represent gas transport costs:

- NERA asked various owners of gas generators in the ROI what strategy they used for gas transport capacity;

- NERA tested the effect of switching generators between the 'yes-ST-gas-capacity' and the 'no-ST-gas-capacity' in the backcast.

Taking into consideration the following goals: producing an accurate model for the RAs, producing a helpful public version of the model, and protecting the confidentiality of generators commercial strategies, NERA and the RAs agreed on this approach:

- Continue to include the option in the SEM PLEXOS Model to assign ROI generators to one of two categories: 'yes-ST-gas-capacity' and 'no-ST-gas-capacity'.

- Pre-populate the **public** version of the PLEXOS model as follows: all gas-fired gas turbine generators in ROI will be assigned to the yes-ST-gas-capacity and all CCGTs in ROI will be assigned to the no-ST-gas-capacity. Given that CCGTs generally run more often than gas turbines, such an allocation is reasonable as a placeholder.

- For the **confidential** version of the 2021-2029 SEM PLEXOS Model, include NERA's assignment of generators to categories of gas transport capacity costs, based on NERA's best judgement. NERA have also developed a 50-50 blend of the yes-ST-gas-capacity and the no-ST-gas-capacity, which is assigned to ROI gas generators if determined by NERA that a 50-50 blend is most appropriate. NERA include the 50-50 blend prices in the Public PLEXOS Model as well, but do not assign 50-50 blend prices to generators in the Public version.

60 Gas generators in NI were not similarly split up. NI gas generators are discussed later in this section.

Users of the public model are free of course to make their own decision as to how to assign generators to the gas costs options in the SEM PLEXOS Model.

NERA caution that the generators' gas procurement strategies may change in the future versus what is represented in the 2021-2029 SEM PLEXOS Model. NERA recommend that the RAs continue to evaluate the best approach to modelling short-term gas capacity costs in the SEM as part of future validations.

NERA reflects the most recent (2021-2022) gas year ST Gas Capacity tariffs for ROI in the SEM PLEXOS Model.[61]

NERA also created a NI ST Gas Transportation Capacity fuel object in PLEXOS, incorporating the most recent forecast of daily entry capacity costs.[62] (NERA understands that Exit capacity in NI is only available as an annual product, though this may change in the future.) For confidentiality reasons, NERA has not made any assignments to this NI ST Gas Transportation Capacity transportation cost in the Public PLEXOS Model. NERA has made assignments to the NI ST Gas Transportation Capacity cost option in the confidential PLEXOS Model, as appropriate.

NERA also notes that it uses markups to mimic fuel transport costs for certain generators, where this was deemed most appropriate. These markups are treated confidentially and are not in the Public PLEXOS Model.

NERA used indicative foreign exchange rates of 1.16 $/€ and 0.85 £/€ to convert non-euro denominated commodity prices to euros, and NERA expect the RAs to update these exchange rate for their future PLEXOS runs.

Otherwise, NERA did not change the fuel adders in the SEM PLEXOS Model. NERA understands that most, if not all, of fuel adders in the SEM PLEXOS Model reflect averages of surveys of the generation companies in the SEM (excepting certain tariffs such as for ROI and NI ST Gas Capacity, which come directly from published tariffs). While NERA received suggestions from generators for updating certain tariffs, NERA's opinion was that there was not enough new data to merit a wholesale replacement of the prior transportation adders. That said, it may be appropriate in future validations to reconsider the most appropriate fuel transport adders.

7.4 Input Sheet

NERA have produced a spreadsheet that calculates the fuel price inputs to the 2021-2029 SEM PLEXOS Model. NERA have provided this spreadsheet to the RAs (PUBLIC--SEM commodity setup file 2021-29.xlsx), and understand it will be published alongside the public version of the

61 See Gas Networks Ireland tariffs: https://www.gasnetworks.ie/corporate/gas-regulation/tariffs/transmission-tariffs.

62 See http://gmo-ni.com/assets/documents/NI-Forecast-Tariff-Publication-GY2122.pdf.

2021-2029 SEM PLEXOS Model. NERA updated the fuel spreadsheet associated with the 2019-2025 SEM PLEXOS Model to produce PLEXOS inputs through to Q4 2029.

The updates from the prior SEM PLEXOS Model include:

- Updating ST-Capacity costs to reflect the latest published tariffs.
- Adding in an option for a 50-50 blend of ST Gas Capacity and regular ROI Gas.
- Adding NI ST Gas Capacity fuel costs.

8 Model parameters and sensitivities

8.1 Daily market optimisation parameters

The previous SEM PLEXOS Models utilized a daily optimization step, a 6-hour lookahead, and trading day starting at 11pm. NERA maintain all these assumptions.

8.2 PLEXOS Version

NERA recommend updating to PLEXOS Version 8.300 R08. In the waterfall analysis presented below, NERA found a total effect of €1.40/MWh when switching versions. Upon NERA's investigation, it was determined that most of this was due to a somewhat higher prevalence in version 8.3 of price spikes when PLEXOS calls upon very high priced DSUs. NERA notes that it updated the DSU modelling in PLEXOS to eliminate these very high DSU price points, as there is not sufficient historical dispatch data in the SEM to determine whether it is realistic to include them – see Section 6.4 above. NERA performed a separate comparison of versions 8.1 and 8.3, controlled for the DSU-effect, which showed only a €0.20/MWh increase with the new version, which NERA considers a reasonable price change when changing PLEXOS versions.

8.3 Uplift Algorithm

The various SEM PLEXOS Models of the I-SEM utilize an uplift algorithm, to reflect compensation for start and no-load costs in the SEM price. While there has been no uplift since I-SEM Go Live, the use of uplift is a practical approach to reflect compensation for start and no-load costs. Given the relatively good fit for back cast prices to historical prices, NERA view the uplift approach as a reasonable approach.

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. Since I-SEM Go Live, all SEM PLEXOS Models have used the Korean Uplift, and NERA recommend maintaining that choice. As NERA recommend a 1-start-state approach (tied to a MIP recommendation), the choice of uplift is less important. NERA understand that the main difference in practice between the SEM and Korean uplift is in the treatment of different start states.

8.4 Scarcity Pricing

The SEM today does not have the same cost-based day-ahead bidding constraints on generators that the SEM did before I-SEM Go Live. Thus, in theory, generators could extract scarcity rents when the supply-demand balance is tight. As noted already, the backcast model runs produced lower prices on average in most peak periods versus the prices that occurred historically. Nonetheless, backcast prices correlated well on average, seasonally, and within the day. NERA explored various options for scarcity pricing or other bidding above strict marginal costs, as discussed in Section 4.3 above. Ultimately NERA did not identify an option that was practical and effective for use in the SEM PLEXOS Model. NERA recommend the RAs continue to evaluate possible options in PLEXOS to reflect scarcity pricing in future validations.

8.5 MIP vs. RR

In Section 8.5 above, NERA compared the MIP versus RR unit commitment approach in detail. The result of the backcast analysis showed the use of MIP (with warm-state start costs) produced results that better aligned with history than the use of RR (RR used with three-state start costs). NERA recommends a MIP, with a warm-state start.

NERA also include a RR model option in the SEM PLEXOS Model, where the key assumptions for a RR solver from the prior SEM PLEXOS Model are maintained. These assumptions include; utilization of the RR self-tune feature, with the self-tuning increment set to 0.2, with the lowest RR threshold set to 0.1 and the highest to 0.90.

8.6 Start States

NERA recommend switching to a single-state start cost approach tied to the MIP unit commitment approach for the 2021-2029 SEM PLEXOS Model. Each generator is assigned its warm-state start cost. The three-start-state approach is maintained in the RR option that is also included in the SEM PLEXOS Model.

8.7 PLEXOS Solver

PLEXOS offers various solvers. While NERA conducted its backcast with the Xpress-MP solver, NERA notes that PLEXOS is in the process of transitioning away from Xpress-MP. NERA tested the effect of using the Gurobi solver and found it produced similar results, and could be used as well for the 2021-2029 SEM PLEXOS Model. NERA has not tested the CPLEX solver, but NERA understands it is also a powerful solver like Xpress-MP and CPLEX. NERA do not expect that the solver chosen will have a material effect on the results of the SEM PLEXOS Model. NERA understand that Energy Exemplar (the company that runs the PLEXOS solver) is ready and able to work with clients on any issues they face in the transition away from Xpress-MP.

8.8 Price caps and floors

The -€500/MWh price floor has not changed, as NERA understand this will continue to be the value in the I-SEM. NERA changed the price cap to €500/MWh in the SEM PLEXOS Model. While the actual market price cap is $3,000/MWh, NERA recommend the lower price cap of €500/MWh, due to the possibility of unserved energy in PLEXOS Model Results, as discussed in the next section. Potentially, USE pricing could be addressed with a different PLEXOS property in the next validation, in which case the price cap could be restored to €3,000/MWh, but this is not an option presently as the other possible property is currently under review by Energy Exemplar, as explained in footnote 65.

8.9 Unserved Energy and Value of Lost Load

Unserved Energy

Unserved energy ("USE") occurs when supply cannot meet demand in a power system. The SEM (like other global power markets) are designed to limit the possibility of USE to an acceptable very low minimum. In PLEXOS, USE is possible but very rare. If USE occurs in PLEXOS, the price defaults to the price cap, which was €3,000/MWh in prior validated PLEXOS Models. NERA suggest that the RAs track whether any USE occurs in their runs of the SEM PLEXOS Model. If USE does occur, NERA do not recommend accepting €3,000/MWh prices. NERA recommend this because of the likelihood that in practice USE can be avoided in the SEM. During actual system operation, reserve capacity is secured to help prevent USE, plus proactive steps can be taken to prevent a potential USE situation from occurring. For example, flexible maintenance outages might be rescheduled if a temporary very tight supply situation is anticipated.

Options for excluding the €3,000/MWh prices in cases of USE in PLEXOS results include:

A. ignoring those prices;

B. substituting the average price from the hour before and after the €3,000/MWh price; and

C. using a standard substitute price in any hours with USE, such as the marginal cost of an expensive peaker or the strike price of the CRM option (€500/MWh).

Assuming there are very few USE hours, the choice among these options is unlikely to make a material difference when assessing average SEM prices. As a default option, NERA includes Option C in the SEM PLEXOS Model, and sets the default substitute price in cases of USE to

€500/MWh, which is the CRM contract strike price.[63] A lower default price would also be reasonable, e.g. NERA note that in earlier versions of the SEM PLEXOS Model the default price was €300/MWh,[64] and such a value would also be reasonable now as well, as this roughly corresponds to the marginal costs of an expensive peaker.

NERA recommend that the RAs use one of Options A, B, or C above. If the RAs continue the use of the current default in the model (Option C), NERA recommend a default price in cases of USE in the range of €300/MWh to €500/MWh. In the SEM PLEXOS Model, NERA include a scenario that turns on Option C, and this scenario is active by default, but it can be turned off. In practice, NERA sets the default price of €500/MWh using the price cap parameter in PLEXOS. Aside from hours of unserved energy, it is very rare to have prices about €500/MWh so this is viewed as a reasonable approach.[65]

Internal VOLL in PLEXOS Optimization

PLEXOS places a cost on unserved energy, which is called the Internal Value of Lost Load ("Internal VOLL"). Internal VOLL is set to €12,533/MWh in the 2021-2029 SEM PLEXOS Model. PLEXOS therefore will chose to shed load if costs are more than €12,533/MWh to prevent shedding load. The €12,533/MWh is a SEM official VOLL, set originally at €10,000/MWh in 2007, plus indexing.[66] A higher Internal VOLL potentially would reduce the prevalence of USE in the SEM PLEXOS Model (though USE would still be possible). The RAs may wish to consider a higher Internal VOLL in future validations. NERA recommends judging whether the Internal VOLL in PLEXOS is reasonable based the USE levels that result, even if PLEXOS uses an Internal VOLL higher than the official VOLL used in the SEM.

[63] This is new for the 2021-2029 SEM PLEXOS Model – in the prior PLEXOS Model there was not a default substitute price in cases of USE.

[64] For example see page 11 of the report on the very first SEM PLEXOS Model, available here https://www.semcommittee.com/sites/semcommittee.com/files/media-files/AIP-SEM-07-128%20Model%20Validation%20Report%2030.04.07.pdf.

[65] In theory, PLEXOS can set the default price for USE using the Regional property "VOLL". The RAs may consider this approach in the next validation. As of the writing of this report NERA understand that Energy Exemplar is adjusting PLEXOS to address a reporting issue related to the Regional property "VOLL".

[66] Specifically this is the value for the T-4 2024/2025 Capacity Auction – see page 11 of https://www.semcommittee.com/sites/semc/files/media-files/SEM-21-083%20Information%20Paper%20on%20Scarcity%20Pricing%20and%20Demand%20Response.pdf.

8.10 Great Britain and France

8.10.1 Great Britain

Similar to previous SEM PLEXOS Models, the 2021-2029 SEM PLEXOS Model includes a representation of GB in order to model the trade between the SEM 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. This choice was not adopted. It would require great expense and time to develop an entire GB model. Further, the goal of the SEM PLEXOS 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. This approach was adopted, as per the last several SEM PLEXOS Models. In this approach, the GB "market" is far smaller than the SEM market, so PLEXOS will focus on optimizing the SEM.

Within approach 3), there are several options, however, NERA's preferred option is to model GB as a single gas-fired generator with a heat rate that varies seasonally, within the day, and with a VOM cost. It is important to stress that the purpose of this approach is to recreate prices in GB as accurately as possible, specifically the purpose is to estimate the GB price as a function of the gas and CO_2 prices prevailing in GB. This approach is naturally achieved through a historical regression. Such a regression automatically calibrates the GB model to historical GB prices. This approach is also forward looking, as GB prices automatically update when the model user changes the input fuel and CO_2 prices.

This approach calculates market heat rates for GB. While market heat rates may change over time, the question is whether there is a practical approach that would incorporate a forecast of anticipated future changes in market heat rates, while also still providing the RAs with a model of GB that is easy to maintain. While a full representation of the GB Market including full forecasts for changes all supply and demand would serve the purpose of forecasting future changes in market heat rates, such an approach would not result in a SEM PLEXOS Model that is easy for the RAs to maintain. A simpler approach could be to calibrate GB prices in the SEM PLEXOS Model to the market heat rates implied by forward GB gas, and CO_2 prices, but this approach nonetheless adds another layer of complexity to the SEM PLEXOS Model, and furthermore, this approach will become outdated over time as the forward markets change.

The 2019-2025 SEM PLEXOS Model used a simplified model of GB, one based on a hybrid of a regression-based approach to determine market heat rates and a pseudo-fundamental based approach incorporating a GB peaking plant and GB wind plant into the model. This is the "Heat-rate regression (with fixed component) against GB gas prices with horizontal segmentation and intermittent generation", from the 2019-2025 PLEXOS Validation Report (page 70). First, NERA note that much of the GB model from the 2019-2025 PLEXOS Validation Report is similar to the GB model NERA suggest, as both have a regression-based approach to determining heat rates. The key differences between the models occurred in the summer months, where in those months only, the GB model from 2019-2025 SEM PLEXOS Model adds in a peaking GB unit and wind GB unit. NERA is not opposed to such an approach. However, NERA note that in practice the triple calibration of a peaking unit, wind unit and regression-based to historical GB prices may prove complex. NERA in particular is concerned as to whether such calibration would grow stale over time. In contrast, a single GB unit (with hourly and seasonally varying heat rates and VOMs) is straightforward to calibrate and update. Such calibration is essentially automatic as the single-GB-unit approach is 100% regression based.

NERA's process to develop its GB approach is as follows.

- NERA regressed five years of historical GB prices as the dependent variable with the total GB gas/CO_2 price as the independent variable, where the total GB gas/CO_2 price is the sum of:

    - The NBP GB Spot Price (converted to LHV, so that the resulting heat rates are consistent with the LHV standard in the SEM PLEXOS Model); plus

    - The carbon price associated with burning natural gas in power plants, based on the prevailing EU ETS (or UK ETS) carbon plus the CPS support carbon price, again expressed in relation to LHV-measured gas heat content; plus

    - The gas transport added assumed for gas generators in the GB in the SEM PLEXOS Model (expressed in terms of LHV gas).

    - The total GB gas/CO_2 price was interacted with dummy quarterly variables and, separately, the total GB gas/CO_2 price was interacted with the hour of the day and separately with the quarter of the year. Thus, the resulting coefficients were aggregated to produce market heat rates that varied by quarter and by hour.

    - The constant term of the regression is then the VOM/MWh for the GB Market in PLEXOS, and the constant varies by quarter.

Despite the differences in approach, the net results of the GB model as recommended by NERA and the GB model used in the prior validation are relatively close. Figure 16 and Figure 17 below show the derived average market heat rates for each model. For the purposes of these charts, a simple market heart rate is calculated, taking the resulting GB prices from a test run of each model and dividing by the total GB gas/CO_2 price. The principle difference is that the current GB approach has a higher market heat rate in the summer peak hours than the prior model. NERA assume this is an improvement, as NERA's results is based on the most recent five years of market results as directly summarized by NERA's regression. The early evening summer peak is at least partially explained by the growing prevenance of solar in GB, where after the sum weekends in the early evening prices tend to go up as solar generation dramatically goes down.

Figure 16: GB Heat Rates, 2019-2025 vs. 2021-2029 SEM PLEXOS Models, Summer (2023 Sample Year)[67]

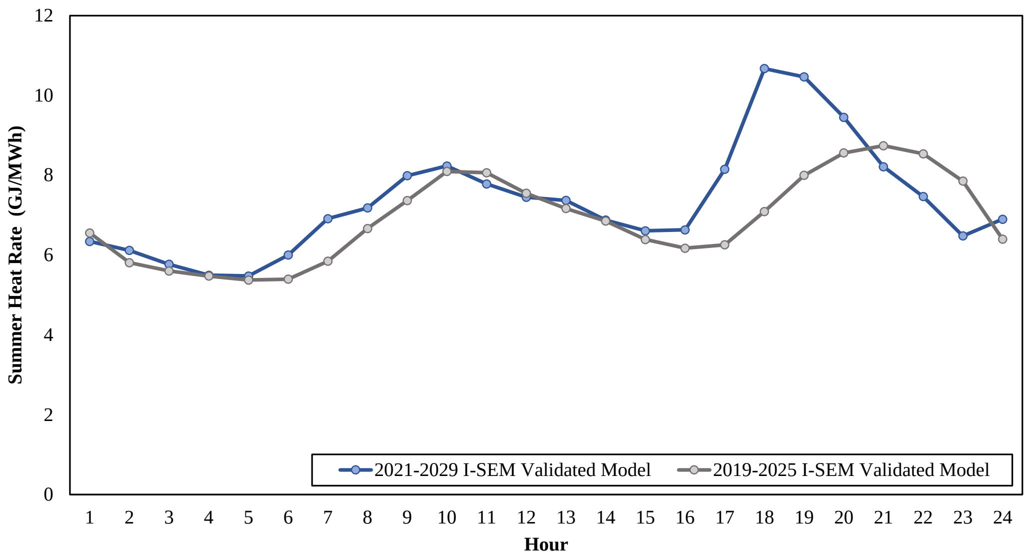
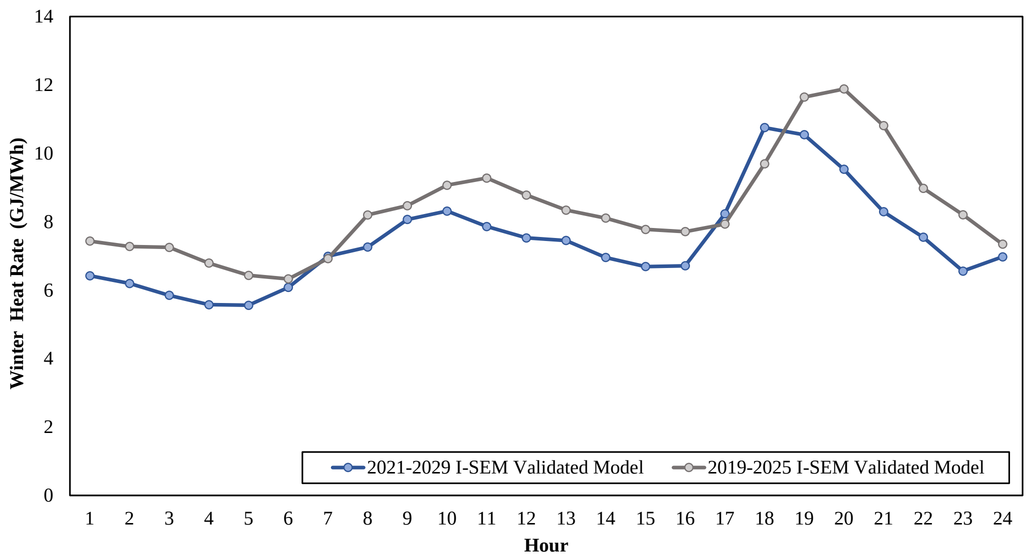


Figure 17: GB Heat Rates, 2019-025 vs. 2021-2029 SEM PLEXOS Models, Winter (2023 Sample Year)



67 Calculated average market heat from sample forecast run of 2023.

The principal downside to a regression based approach is that it uses average market heat rates in VOMs, where in practice there will be daily variations due to unique daily conditions (particularly cold or warm days, unit outages, high or low renewables output, etc.), where some of these changing daily conditions will be correlated between GB and the SEM and others will be unique to GB. NERA have yet to identify an easy-to-maintain approach for GB that nonetheless solves these issues, and that does so in a principled way that will maintain accuracy in a forecast model. NERA recommend the RAs continue to consider options for representing GB in future validations.

8.10.2 France

For France, NERA utilized a nearly identical regression-based approach as the one NERA utilized for GB. NERA found a high correlation between NBP spot gas prices and French DAM spot electricity prices, even though France itself is mostly nuclear generation and has very little gas generation. However, France does have some gas generation, which may be marginal in some hours. Furthermore, France is integrated electrically with the rest of Europe, where gas generation is more prominent. As a result of this correlation with NBP prices, for modelling purposes, NERA triggers the French market prices off of the GB gas prices. The electricity price in France in PLEXOS is as follows: the prevailing heat rate from NERA's France regression multiplied by the prevailing *GB* gas price, plus the prevailing VOM from NERA's France regression.[68] This approach of using GB prices benefits the RAs, as otherwise the RAs' DC modelling would be made significantly more complex, as the DCs would need to consider two gas prices: UK NBP and a European gas price for France. NERA found however that NBP and major continental European gas prices were well correlated historically. If the correlation between NBP and major continental European gas prices goes away, the RAs may consider updating the modelling of France in the SEM PLEXOS Model so that France prices are tied to a continental European gas price index, such as TTF ("Transfer Title Facility"), from the Netherlands. Changing the fuel price would require redoing the French power price regression and putting the new regression coefficients into PLEXOS.

8.10.3 Interconnectors

As discussed in Section 3.1.3, a wheeling charge is included on the interconnectors to ensure that prices in the SEM are compared with prices in GB and France on a comparable basis.

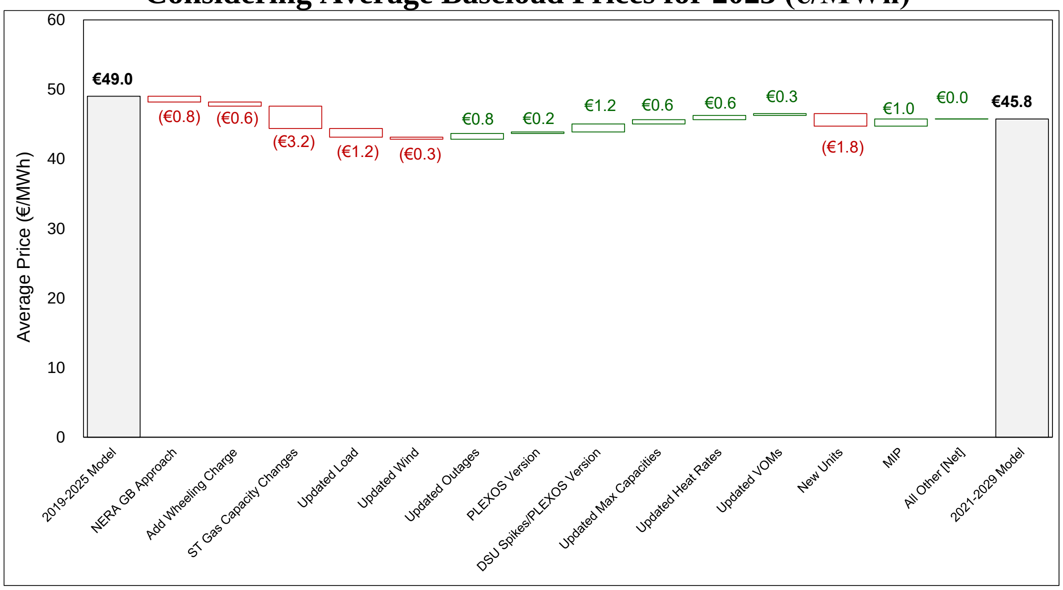
[68] The heat rates and VOMs came from NERA's regression analysis, which, for consistency with the planned approach for PLEXOS, compared historical GB gas prices to historical France electricity prices. As regards CO_2, the French prices in PLEXOS appropriately are based on EU ETS CO_2 prices.

9 Summary of Results of the 2021-2029 SEM PLEXOS Model

9.1 Average Power Prices

NERA compared prices from the 2021-2029 SEM PLEXOS Model (which uses MIP and warm-state start costs) to the previous 2019-2024 I-SEM PLEXOS Model (which uses RR and three-state start costs), using 2023 as a sample year. Average baseload prices are about €3/MWh lower in 2023 in the 2021-2029 SEM PLEXOS Model as compared to the 2019-2025 SEM PLEXOS Model, holding fuel costs constant. Figure 18 shows the several changes between the prior Validated Model and the 2021-2029 SEM Validated Model.

Figure 18: Drivers of Changes Between 2019-2025 and 2021-2029 SEM PLEXOS Models, Considering Average Baseload Prices for 2023 (€/MWh)



NERA note that the order in which these changes are evaluated affects the relative size of the adjustments, but not the total sum of all adjustments. NERA comment briefly on the differences:

1) NERA GB Approach (€0.8/MWh reduction)[69]: NERA's updated regression leads to lower market heat rates overall in GB, particularly lower in the winter (with summer relatively higher).

2) Add Wheeling Charge (€0.6/MWh reduction): Appropriately, the wheeling charge lowers prices. Without the wheeling charge, exports from the SEM into GB are artificially supported, raising SEM prices.

[69] To avoid a perception of too much precision, NERA shows the various price effects rounded to the nearest €0.10/MWh.

3) ST Gas Capacity Changes (€3.2/MWh reduction). NERA adjusted the assignment of ST Gas Capacity costs to generators, the net effect of which was to reduced SEM prices.

4) Updated Load (€1.2/MWh reduction): The 2021 GCS reflects a lower load forecast for 2023 than the 2019 GCS forecast relied upon in the 2019-2025 SEM PLEXOS Model.

5) Updated Wind (€0.3/MWh reduction): The 2021 GCS reflects more wind forecasted for 2023 than the 2019 GCS forecast.

6) Updated Outages (€0.8/MWh increase): NERA's updated FORs produce relatively higher prices, and NERA's forecast of outages for 2023 also increase prices. NERA caution that its planned outage forecasts for 2023 (and for 2024-2029) are placeholders, to be replaced by a precise outage schedule when available.[70]

7) PLEXOS Version (€0.2/MWh increase) and DSU Price Spikes related to PLEXOS Version (€1.2/MWh increase): NERA observed a €1.4/MWh increase overall when changing from version 8.1 to 8.3. However, much of this increase appears to be due to a higher propensity of peak prices in the SEM PLEXOS Model in version 8.3 versus 8.1 related to a DSU modelling approach which NERA ultimately changed – a €1.2/MWh increase.[71] NERA found a €0.2/MWh increase after NERA controlled for the high-price DSU issue.

8) Updated Max Capacities (€0.6/MWh increase): The 2021 GCS had different capacities for various units versus those in the 2019-2025 SEM PLEXOS Model, often lower capacities.

9) Updated Heat Rates (€0.6/MWh increase): The net effect of heat rate changes since the prior PLEXOS Model is a slight increase in prices.

10) Updated VOMs (€0.3/MWh increase): The net effect of VOM changes since the prior PLEXOS Model is a slight increase in prices.[72]

11) New Units (€1.8/MWh reduction): Generally, the forecasted new generation additions in the 2021-2029 SEM PLEXOS Model have lower operating costs than those forecasted to come online in the prior SEM PLEXOS Model.

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70 NERA understand that a 2023 outage schedule is available from the TSOs as of the writing of this report, but NERA did not have such outage schedule when it conducted its analysis.

71 Specifically, this appears to be due to price spikes when a high-price DSU P-Q pair is dispatched. However, as discussed in Section 6.4 above, in the final version of the 2021-2029 SEM PLEXOS Model, NERA adjusted the DSU methodology to better ensure that PLEXOS DSU dispatch aligns with historical DSU dispatch.

72 For simplicity, NERA targeted its VOM analysis on the largest changes in VOMs. Smaller changes in VOMs are subsumed in the "All Other" category.

12) MIP (€1.0/MWh increase): MIP has been found, in the SEM PLEXOS Model, to produce somewhat higher prices.[73]

13) All Other [Net]: (€0.0/MWh increase): the additional smaller changes balance each other out.

Figure 19 shows the monthly price pattern. Overall, the price pattern is similar, but with some pattern differences in many cases explained by differing planned outages forecasts.[74]

Figure 19: Comparison of Average Price in SEM PLEXOS Models (Year 2023)

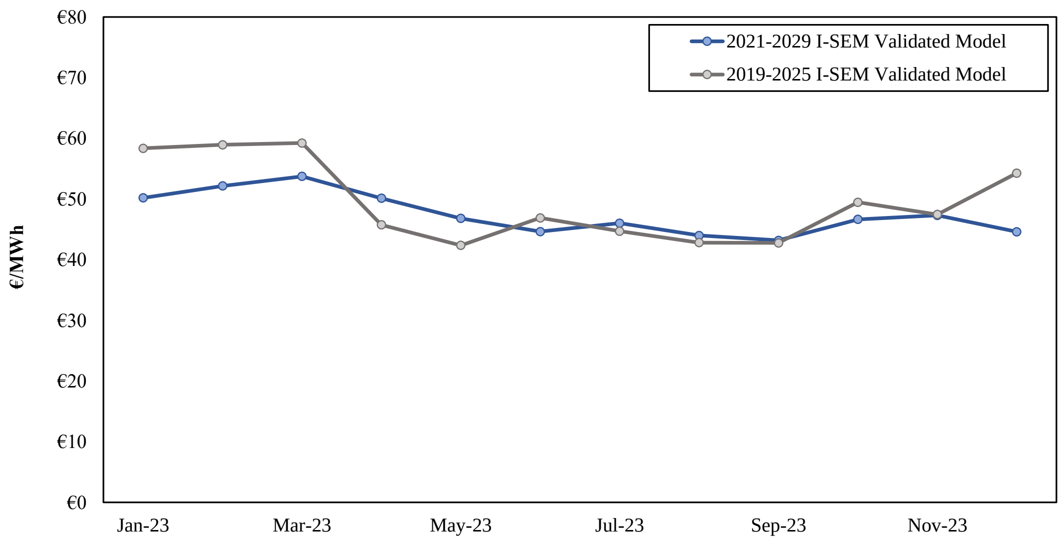


Figure 20 and Figure 21 below show by month the shadow price and uplift components of the price in the I-SEM PLEXOS Models, comparing the 2021-2029 PLEXOS Model to the 2019-2025 version. In the 2021-2029 PLEXOS Model, the drop in uplift is significant, and this is driven by the change from RR to MIP. Shadow prices are higher in the new PLEXOS model, also related to the change to MIP.

73 This category also includes the change from three-state to warm state, but the driver of the change appears to be the switch to MIP.

74 Planned outages forecasts explain part of the differences. For example, the drop in price from November to December for the 2021-2029 Validated Model reflects that planned outage forecast includes several November planned outages and almost no December planned outages among the highest generating plants in the SEM. NERA's approach to forecast planned outages carries forward the average of the 2020-2022 outages plans from the TSOs. Once available, the forecasts should be replaced with the actual TSOs' schedule of planned outages.

Figure 20: Total and Shadow Prices in 2021-2029 and 2019-2025 I-SEM PLEXOS Models (Year 2023)

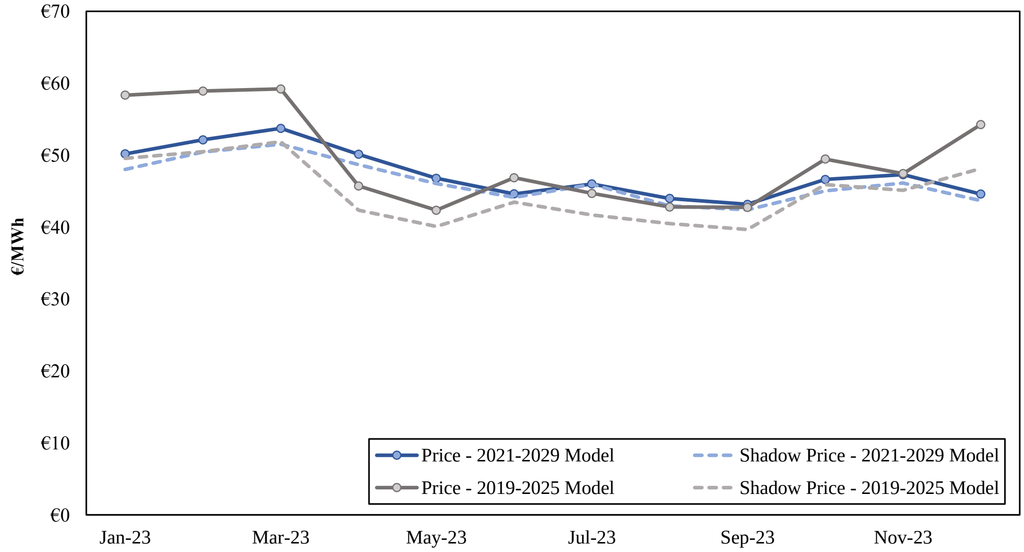


Figure 21: Uplift in 2021-2029 and 2019-2025 I-SEM PLEXOS Models (Year 2023)

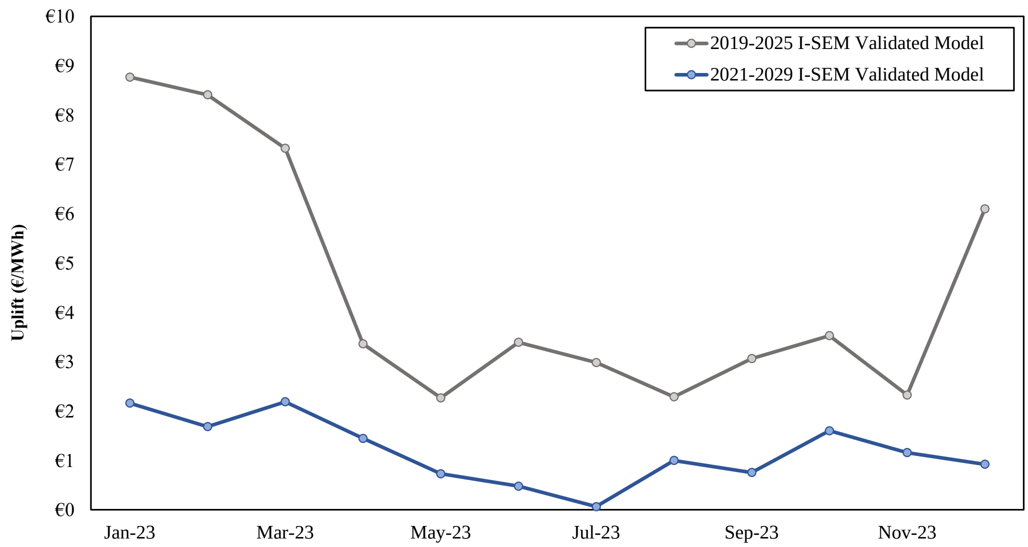


Figure 22 shows that the current and prior PLEXOS Models have similar hourly patterns.

Figure 22: Hourly Prices in 2021-2029 and 2019-2025 I-SEM PLEXOS Models (Year 2023)

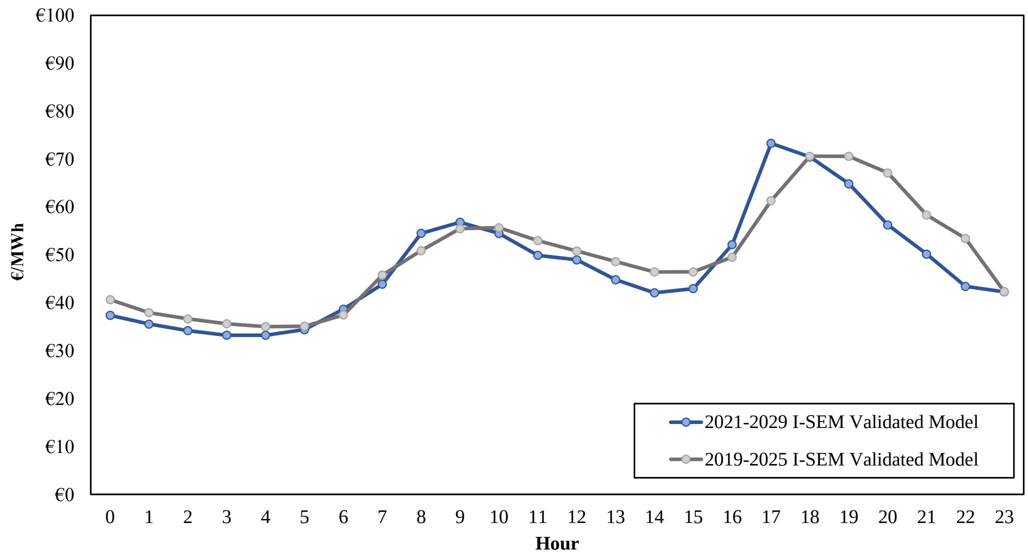
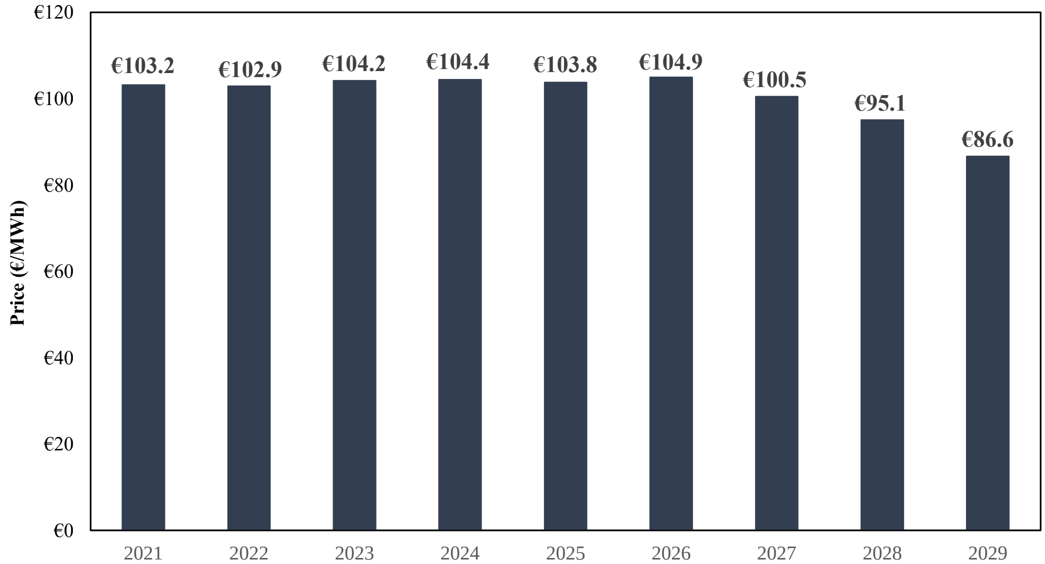


Figure 23 shows the annual average prices from 2021 to 2029, shown with same fuel prices each year for comparison purposes. The prices reflect updated fuel prices from Table 19 – as the updated commodity prices are higher, the prices in Figure 23 are higher versus PLEXOS Model runs based on the prices from the prior SEM PLEXOS Model. As seen in Figure 23, prices are relatively stable from year to year through 2026 – in this period new renewable capacity appears to balance out load increases. The drop in prices from 2026 to 2029 is spurred mostly by the rapid increase in renewable generation in those years (driven by offshore wind), balanced against more modest increases in load. Further, the addition of the interconnector to France is part of the reason for the price decline in 2027, as prices tend to be lower in France.

Figure 23: Annual Average Prices, 2021-2029 SEM PLEXOS Model



9.2 Generation and Interconnector Flows

Figure 24 shows average interconnector flows. Net flows out of the SEM into GB show a similar pattern in the 2021-2029 SEM PLEXOS Model and the prior PLEXOS Model: a tendency to import in the first half of the year and export in the second.

Figure 24: Net Exports, in 2021-2029 and 2019-2025 SEM PLEXOS Models (Year 2023)

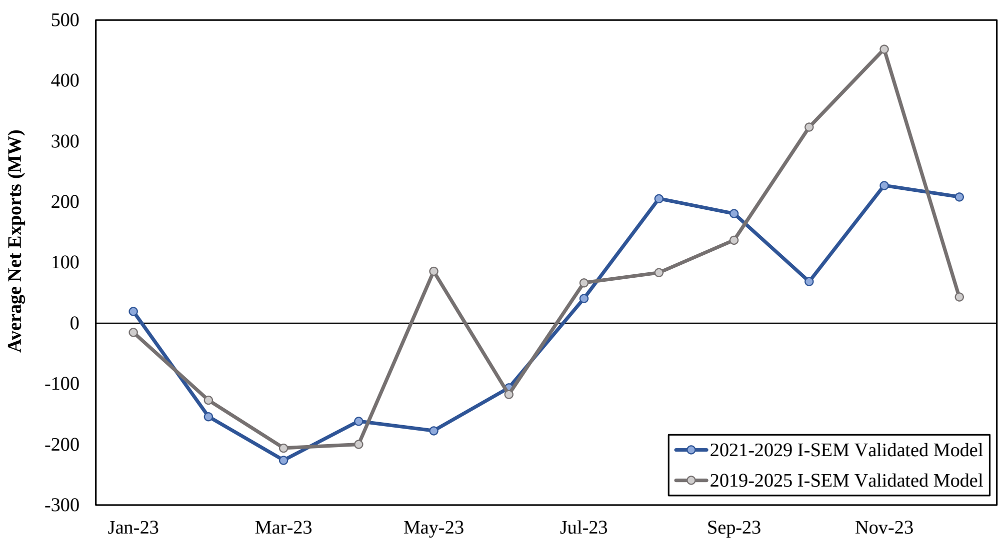
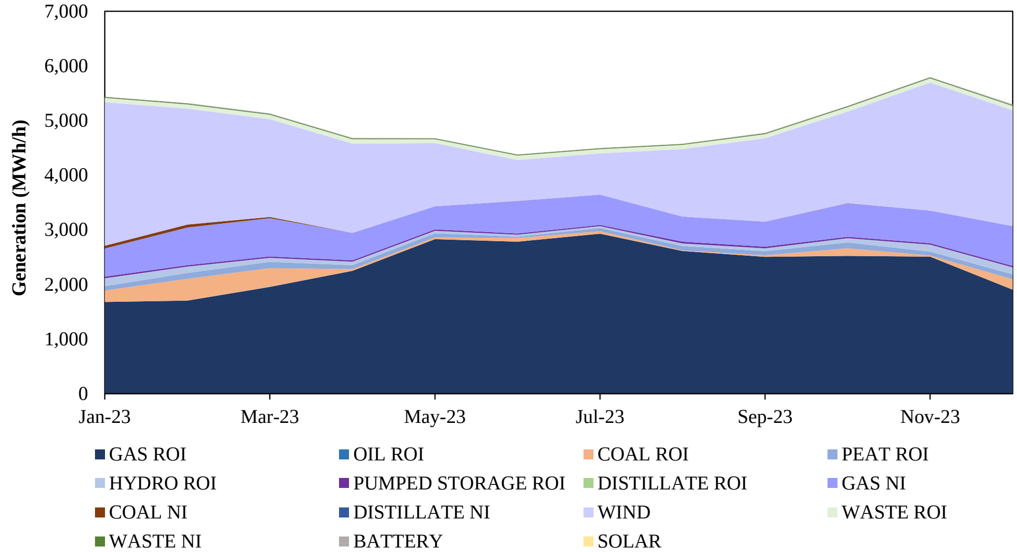


Figure 25 shows average hourly generation by plant type by month for the 2019-2025 SEM PLEXOS Model (Part A) and the 2021-2029 SEM PLEXOS Model (Part B). The patterns are similar, though one noticeable change that the 2021-2029 SEM PLEXOS Model has even less coal generation than the previous model (though coal generation is low in both models).

Figure 25: Average Generation (MWh/h) by Plant Type

Part A: 2019-2025 SEM PLEXOS Model (Year 2023)



Part B: 2021-2029 SEM PLEXOS Model (Year 2023)

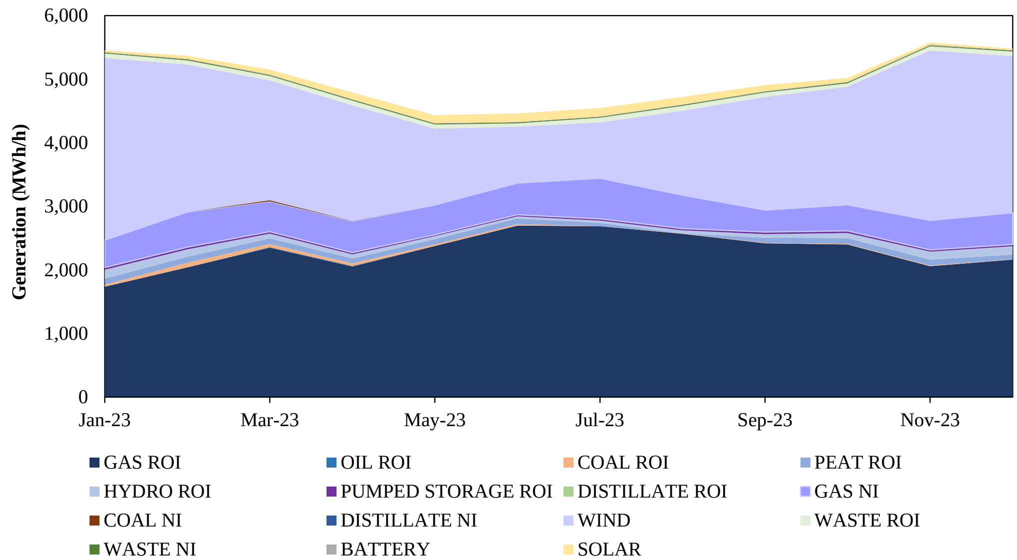
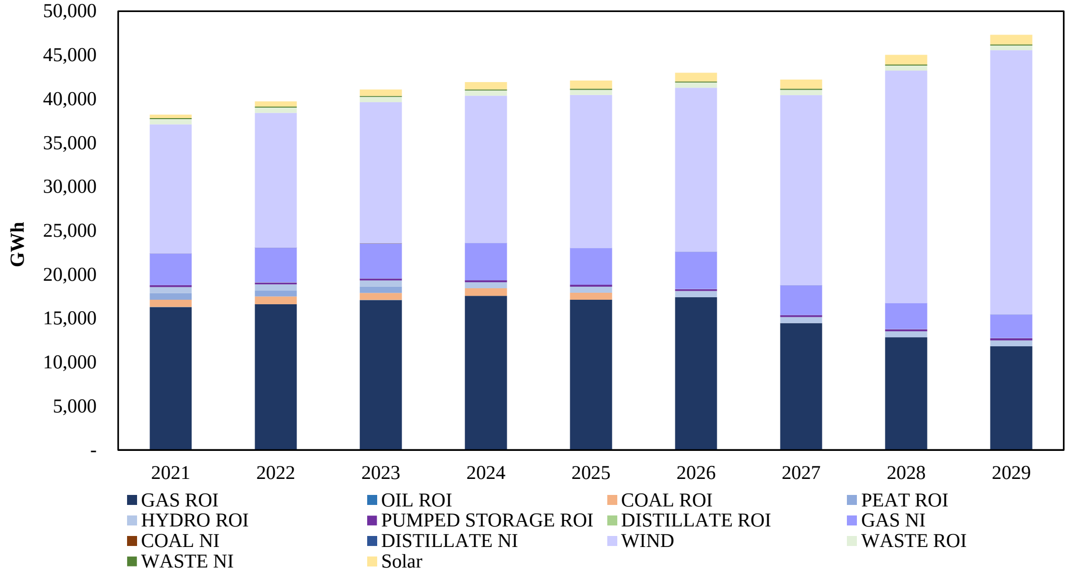


Figure 26 shows the forecast of generation by plant type in the 2021-2029 SEM PLEXOS Model, showing a long term reduction in gas and increase in wind and solar, though solar remains relatively small.

Figure 26: Total Generation by Plant Type by Year, 2021-2029 SEM PLEXOS Models



10 Changes to SEM PLEXOS Model

NERA implemented the following key changes in the 2021-2029 SEM PLEXOS Model (versus the previous 2019-2025 SEM PLEXOS Model).

Table 20: Key Changes in 2021-2029 SEM PLEXOS Model vs. Prior SEM PLEXOS Model

Item	2021-2029 SEM PLEXOS Model	Prior SEM PLEXOS Model
Unit Commitment Approach	MIP	RR
Start-States Modelled	Warm	Hot, War, and Cold
Wheeling Charge	Included and set equal to anticipated uplift	Not Included
Interconnectors	Added Greenlink and Celtic	
Trade with France	Added	
ST Gas Transport Capacity	NI ST Gas Capacity, ROI ST Gas Capacity, and ROI 50% of ST Gas Capacity	ROI ST Gas Capacity
Offshore Wind	Explicitly modelled as PLEXOS generation object (higher capacity factor than onshore wind)[75]	n/a (no significant offshore wind during 2019-2025 modelling horizon)
GB Modelling	Regression based approach	Regression approach with, in summer, horizontal segmentation and intermittent generation
Default Price in Case of USE and Price Cap	€500/MWh (strike price for CRM contract), set via a €500/MWh Price Cap	None (price goes to price cap of €3,000/MWh)

[75] NERA includes two generation objects: one for the existing 25 MW offshore wind plant and the other for all new offshore wind (where new offshore wind is expected to have significantly higher capacity factors than the existing offshore wind capacity).

Table 21: Additional Minor Changes in 2021-2029 SEM PLEXOS Model vs. Prior SEM PLEXOS Model

Item	2021-2029 SEM PLEXOS Model	Prior SEM PLEXOS Model
PLEXOS Version	8.3	8.1
Batteries	Modelled as PLEXOS Battery Objects	Modelled as Pumped Storage
ROI & NI Solar and NI Small Scale Wind	Explicitly modelled as PLEXOS generation objects	Included in embedded generation
Embedded Generation	Modelled as negative Fixed Load [change due to different PLEXOS version][76]	Modelled as Fixed Generation
Partial Outages on Interconnectors	Modelled using combination of the Units Out, Outage Max Rating, and Outage Min Rating properties	Modelled by adjusting Max Flow and Min Flow properties[77]
Internal VOLL	€10,988.90/MWh	€12,533/MWh
Forced Outages and Lookahead	Forced outages included in lookahead[78]	Forced outages not included in lookahead

[76] This is a minor change which has no effect on results (not discussed elsewhere in this report). Fixed Load and Fixed Generation are PLEXOS properties. The prior PLEXOS Model used PLEXOS version 8.1, which treated Fixed Generation as an injection of generation into the grid. This was appropriate as the demand the Model uses is the total energy requirements demand (which includes behind the meter demand served by embedded generation). PLEXOS version 8.3 (used for 2021-2029 SEM PLEXOS Model) treats Fixed Generation as both load and generation (behind the meter) and provides no net injection to the grid. For this reason, NERA now represents embedded generation as negative Fixed Load, which has the effect of assuming the embedded generation serves demand behind the meter (also an appropriate approach).

[77] This is a minor change which has no effect on results (not discussed elsewhere in this report). The Outage Max Rating and Outage Min Rating properties are newly available in PLEXOS, and they are a more natural way to model partial outages in interconnectors. The previous approach of changing the max (and min) flow of the interconnectors worked, but it is more intuitive to keep the max (and min) flow unchanging (similar to how a generator outage does not change its max capacity).

[78] This is a property in the Stochastic object. NERA noticed some instances of infeasibility which appeared to be related to interconnector ramp rate limits and forced outages on the lines. These instances appeared to occur in the first hour of the trading day (11 p.m.). Including forced outages in the lookahead appears to have eliminated this issue.

Item	2021-2029 SEM PLEXOS Model	Prior SEM PLEXOS Model
Planning Horizon (affects MT Schedule and PASA)	Set to 1 year increments[79]	Set to precisely match ST modelling horizon
Markups at Min Stable Level	Included as certain markups should apply over whole price offer range[80]	Not Included

79 This is done so that all MT Schedule (MT refers to a medium-term) and PASA running steps are for full years, which is their default increment. The MT Schedule and PASA run ahead of the detailed ST Schedule in PLEXOS.

80 Set using a property in PLEXOS's Competition Object.

11 Recommendation for Future Validations

NERA provide the following recommendations for future validations.

Table 22: Recommendation for Future SEM PLEXOS Validations

Area	Recommendation	Preconditions	Priority	Notes
New Additions and Retirement	Monitor changes in retirement plans and planned new additions		High	
ST Gas Capacity Charges[81]	Review designation of which generators include ST Gas Capacity charges in offers; explore whether systematic way to make assignments	May require more information from generators	Medium / High	Gas transportation capacity procurement strategies may be viewed as commercially sensitive; nonetheless proper representation in PLEXOS of ST Capacity charges improves model accuracy
Scarcity Pricing / Refinement of Generator Offers	Continue to assess whether refinements to generator offers or explicit scarcity pricing is appropriate in SEM PLEXOS Model	None	Medium	Present method aligns well with history in backcast, and NERA suggest that a more complex approach be judged based on its accuracy (more complex is not always more accurate), practicality, and alignment with economic and power market modelling best practices

81 As a precaution, NERA does not disclose the specific assignments it made in this report or in the public version of the SEM PLEXOS Model – rather NERA makes a generate assignment in the public PLEXOS Model as discussed in Section 7.3 above.

Area	Recommendation	Preconditions	Priority	Notes
Uplift	Assess whether a feasible, accurate, and conceptually reasonable approach can be employed to eliminate need for uplift	None	Low/ Medium	Present method aligns well with history in backcast; use of MIP already has reduced uplift substantially; getting rid of uplift would allow removing wheeling charge
Offshore Wind Profile	Develop or obtain an offshore wind profile appropriate for Ireland	None, but cannot use historical data from large offshore wind farms until those farms are online	Low then High	With new offshore not due until 2026, not an urgent priority; until actual generation data are available, possibilities include using UK offshore data or having the TSOs or a 3rd party develop a profile
Batteries	Review energy market participation (and refine PLEXOS settings appropriately)	Sufficient historical data	Medium	Recommend assessing each Validation – may be a few years before significant increase in battery energy market participation
DSUs	Review DSU P-Q Pairs	None	Medium	Recommend assessing each Validation – a lower priority so long as only small quantities are regularly dispatched
Outages	Add planned outages for new capacity in the PLEXOS Model	TSOs adding new generators to outage plan	Medium	As a place holder, NERA include a maintenance rate and include the PASA modelling processes in PLEXOS – the PASA can be removed once no generators (or batteries) use a maintenance rate

Area	Recommendation	Preconditions	Priority	Notes
Batteries	Refine forced and maintenance outage rates, or if available use planned outages from TSOs	Availability of battery outage rates or batteries in outage plans from TSOs	Low	Batteries tend to have a high availability, so the 95% availability assumed in PLEXOS is likely reasonable, but information specific to the batteries in the SEM would be better to use

Appendix I: NERA Quality Assurance

This appendix provides the details of the checks NERA performed to ensure the accuracy and quality of the 2021-2029 SEM PLEXOS Model.

Generator data. A critical quality assurance ("QA") step is to assure that the underlying data are reasonable and apt for the PLEXOS model. NERA asked every generation company to review, and update as needed, the PLEXOS data for their generators as represented in the previous 2019-2025 SEM PLEXOS Model.

- NERA asked the generation companies to explain the changes in data; where the explanations were not satisfactory, NERA 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.

- NERA independently reviewed the proposed new data for reasonableness. NERA also provided all proposed new data to the RAs, for their review.

- NERA also reviewed the generator data that the generation companies did *not* update, i.e. the data that was unchanged since the 2019-2025 SEM PLEXOS Model. NERA did not perform a comprehensive validation of this unchanged data, as NERA agreed with the RAs this was out of scope. Rather, NERA reviewed the unchanged generator data for reasonableness, looking for any outliers or inconsistent data, for example, a CCGT with a very low minimum downtime setting. NERA discussed any possible inconsistencies with the relevant generation company, and made appropriate changes based on the results of those discussions.

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

After NERA initially populated 2021-2029 SEM PLEXOS Model with data, NERA performed a comprehensive check to assure that the actual data was what NERA intended that data to be.

Updates to the SEM PLEXOS Model initially performed by one project team member was independently checked by a different team member.

NERA checked data in multiple ways. For example, the PLEXOS model uses five different *hourly* load forecasts from 2021 to 2029, each based on a different historical profile and each reflecting the 2021 GCS demand forecast. After creating that file, NERA checked that:

- The peak demand in each year (2021 to 2029) indeed matched the target peak demand from the 2021 GCS (and matched the target total energy requirement from the 2021 GCS).

NERA ensured that this was the case for all five forecasts based on the different historical profiles.

- That the shape of demand from the five 2021 to 2029 forecasts indeed lined up with the historical years upon which they were based.

NERA also performed various checks on the outputs of the 2021-2029 SEM PLEXOS Model. NERA confirmed that the wind and solar from the model outputs matched what was expected based on the model inputs. NERA also confirmed that the total generation in the SEM lined up with the forecast for total energy requirements that produced the inputs to the model (adjusting for trade over the interconnectors).

Finally, NERA reviewed various aggregate outputs of the model, including the level of dispatch for the various generation units and market prices. It was beyond scope to check that PLEXOS's dispatch and price algorithms worked correctly. But NERA 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.

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