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SEM PLEXOS Backcast and Validation, 2024-2032

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

12 March 2025

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List of Acronyms Used in Report

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
EWIC	East-West Interconnector
FOR	Forced Outage Rate
GB	Great Britain
GCS	Generation Capacity Statement
GJ	Gigajoule
HVO	Hydrotreated Vegetable Oil
I-SEM	Integrated Single Electricity Market
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
SEMOpx	SEMO Power Exchange
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

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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. 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 2024 to 2032 period ("2024-2032 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.

Basic Approach of 2024-2032 SEM PLEXOS Model

The basic approach of 2024-2032 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.

This basic approach in the SEM PLEXOS Model differs from the SEM rules since I-SEM Go-Live (1 Oct. 2018). Since I-SEM Go-Live, generators do not explicitly declare their start and no-load costs as part of their offers into the Day Ahead Market ("DAM" or "DA Market") (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). The SEM rules since I-SEM Go-Live also do not include Uplift (Uplift is discussed in detail later in this summary and in the main section of this report).

NERA maintains 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 the 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 2021 through 2029 ("2021-2029 SEM PLEXOS Model"). To extend the model to 2032, NERA extended the forecasts for load, renewables capacity, embedded generation, and generator outages to 2032, 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 2032 and what units may retire.

NERA added 16 new generators coming online in the forecast timeframe (2024 to 2032) which were not in the prior Validated SEM PLEXOS Model, a total of about 2,700 MW of new generation capacity.

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The 2024-2032 SEM PLEXOS Model reflects the retirement of the Tarbert plant and the Kilroot coal units prior to the start of the modelling horizon in 2024 and reflects the planned transition of Moneypoint to emergency use status starting in July 2025 (in practice Moneypoint is turned off in the PLEXOS Model , as NERA understands that Moneypoint will not participate in the SEM energy markets once it switches to emergency use). Load growth in the SEM PLEXOS Model is served by new renewable capacity (wind and solar), new thermal generation units and increased import capability.

The 2024-2032 SEM PLEXOS Model includes Greenlink (2025) and Celtic (2027) interconnectors. The proposed Celtic interconnector connects the French electricity market to the SEM, and, as a result, NERA also includes a representation of the French market in the 2024-2032 SEM PLEXOS Model.

NERA also added several new batteries since the last published Validated Model, bringing total battery generating capacity to approximately 1,000 MW by 2026. NERA understands that existing (and planned) batteries in the SEM have contributed (and will increasingly contribute in the future) to DS3 and system services[1]. Furthermore, batteries provide system reliability in peak load conditions. Notwithstanding the fast pace of battery growth, currently planned battery capacity still is small relative to renewable and thermal capacity. However, NERA expects the importance of batteries in SEM energy markets to continue to increase as more battery capacity comes online to assist with meeting the renewable targets within Northern Ireland and Republic of Ireland.

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 Demand Side Units ("DSUs") in the Validated PLEXOS Model. NERA notes that total DSU capacity is now over 750 MW, growing to nearly 1,000 MW by the end of 2027 according to the 2023 GCS[2]. While 750 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's approach in PLEXOS is to dispatch DSUs at levels consistent with their historical dispatch quantities at different price points.

To update the model, NERA relies on assumptions and data from the 2023 GCS, which is the latest version of the GCS as of the date of publication of this report. The GCS is published annually by the TSO, and model users will be able to update GCS-derived inputs as future TSO capacity statements or other sources are published.

As with all prior models, the 2024-2032 SEM PLEXOS Model does not include assetless traders. Assetless traders offer into SEM energy markets (offers to buy or sell energy), but their offers are not associated with assets (generation assets or assets that consume electricity). Thus, assetless traders must close out their positions prior to real-time electricity delivery. Nonetheless, assetless traders have significant volumes in the DAM and can affect prices. Assetless traders perform an arbitrage function, where they can help align DAM prices with the prices in other SEM energy markets closer

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

2 2023 GCS refers to the Ten-Year Generation Capacity Statement, 2023–2032, January 2024, available here: https://cms.eirgrid.ie/sites/default/files/publications/19035-EirGrid-Generation-Capacity-Statement-Combined-2023-V5-Jan-2024.pdf. (Links in this report valid as of 8 December 2024.)

to real-time delivery. NERA notes that prices can diverge between DAM and shorter-term energy markets for various reasons, including among others: differences in market participants which participate, different offer strategies in different markets, and differences in the details of market rules. Those differences can lead to arbitrage opportunities for assetless traders. NERA's *a priori* view is that the potential for assetless traders in the DAM to arbitrage between the DAM and shorter-horizon markets increases the accuracy of the SEM PLEXOS Model. The assetless traders may help align DAM market prices (where the DAM has a particular process and where not all resources participate in the DAM market), to prices similar to what the SEM PLEXOS Model produces, where the SEM PLEXOS Model covers all supply and demand in the SEM, using the basic approach outlined above.

Backcast Against Historical SEM Data

NERA performed a detailed iterative backcast of the PLEXOS Model against outturn results of the SEM market and focused on the four most recent full years of data (2020 to 2023), a period with a wide range of market conditions, which helped test the resilience of the SEM PLEXOS Model. NERA ran the backcast using actual historical demand, wind and solar data, fuel prices, and generator availability. Actual historical data allowed NERA to evaluate PLEXOS's ability to predict DAM 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 DAM prices and generator operations, under various fuel market 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 to the PLEXOS model, most critically future demand, fuel prices, unit outages, wind and renewable expansion, and generator retirements and additions.

NERA ultimately produced three final backcast SEM PLEXOS Model runs, reflecting an Option A (based on available wind generation, uplift, and a wheeling charge) and an Option B (based on actual wind generation, no uplift and no wheeling charge). NERA also ran an Option A2 (based on available wind generation, no uplift and no wheeling charge). Given the challenges of predicting how the SEM and international fuel and CO_2 markets will evolve over the next years and decade, having these options provides flexibility to the RAs and other users in terms of some of the key aspects of the PLEXOS Model. NERA's backcast runs for the three options each reasonably replicate average SEM prices and the seasonal pattern of these prices. NERA's backcast using Option A produced prices €0.09/MWh above historical SEM DAM prices (a difference of 0.1%), over the backcast period of January 2020 through December 2023, with option A2 having prices €1.25/MWh below historical (1.0% difference). NERA's backcast using Option B produced prices €1.89/MWh above historical SEM DAM prices (a difference of 1.4%). See Table 1 below. The closeness of these backcast prices to historical prices gives NERA confidence in the reasonableness of the SEM PLEXOS Model.

Backcast Run	Backcast Average Price	Historical Average Price	Delta (€/MWh)	Delta (%)
Option A: Available Wind, Uplift & Wheeling Charge	€130.31	€130.22	€0.09	0.1%
Option A2: Available Wind, No Uplift, No Wheeling Charge	€128.97	€130.22	- €1.25	-1.0%
Option B: Actual Wind, No Uplift, No Wheeling Charge	€132.11	€130.22	€1.89	1.4%

Table 1: Average Prices Backcast vs. Historical, January 2020 through December 2023

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

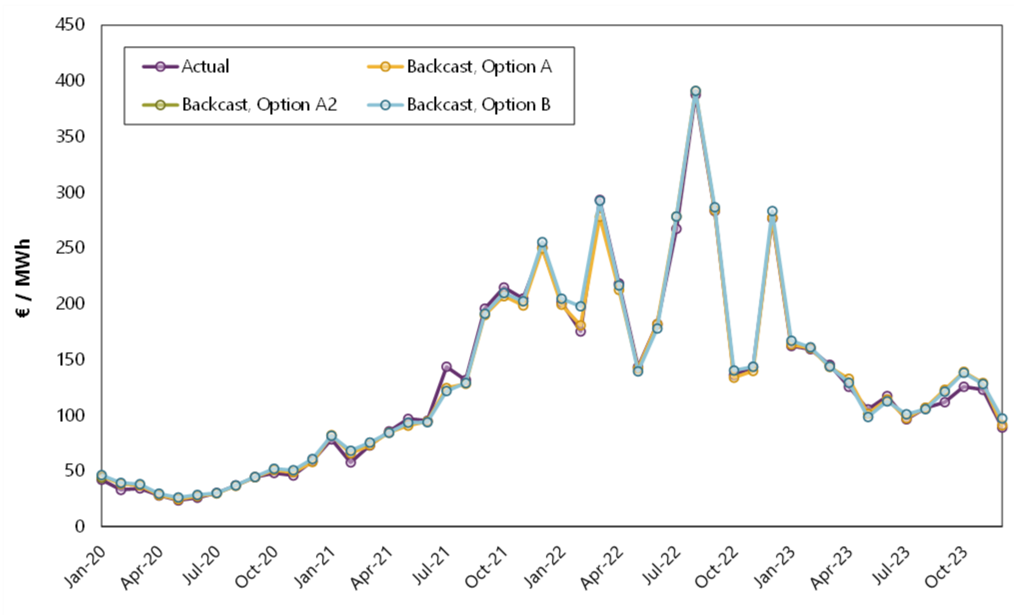

Figure 1: Average Monthly Backcast and Historical SEM Prices, January 2020 through December 2023

While there is no one universal standard for what is or is not acceptable accuracy of a backcast, the high level of correlation in the patterns of prices over time and the low overall percentage difference in prices gives NERA confidence that the SEM PLEXOS Model is fit for purpose for the RAs to use for their regulatory purposes.

The backcast showed good alignment as well in peak prices, mid-merit and baseload prices specifically. For simplicity, NERA shows Option A (available wind with uplift and wheeling charge) in

Table 2 below. Similarly, by default all tables and figures in this report show Option A results, unless explicitly stated otherwise. All three options similarly show good fits – the choice between models is discussed further below.

Time/Season	Backcast Average Price	Historical Average Price	Delta (€/MWh)	Delta (%)
Winter Peak	€178.25	€173.84	€4.41	2.5%
Mid-Merit	€140.10	€139.26	€0.84	0.6%
Off-Peak	€101.57	€103.59	- €2.02	-2.0%

Table 2: Average Prices Backcast vs. Historical, Peak, Mid-Merit, and Off-Peak, January 2020 through December 2023

While prices from PLEXOS match quite well with historical prices overall, there is a slight effect where PLEXOS somewhat overstated prices in the Winter Peak and slightly understated prices in off-peak hours in the backcast. The differences are small enough (2.5% is the largest difference) that it is challenging to know how much of this is a coincidence versus how much is due to a trend in the SEM PLEXOS Modelling. NERA notes that the trend was the reverse according to the prior backcast (with PLEXOS overstating prices in winter peak hours and understating prices in off-peak hours)[3]. Given that different backcasts have had different peak versus off-peak trends and given the very small percentage differences observed, NERA is satisfied with the reasonableness of the backcast considering peak versus off-peak prices.

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 views this as a good result, considering that in practice generators' DAM strategies are likely more complex than as represented in PLEXOS[4].

However, NERA cautions that the very high accuracy of the backcast does not imply a similar level of accuracy to the forecast. In the backcast model, important variables including fuel prices, renewable output, and system load are known precisely; in the forecast model, however, these variables are highly uncertain and could be substantially different than the projections assumed for the 2024 Validated model (potentially leading to substantially different prices than those presented in this report).

3 The prior SEM PLEXOS Model and Report were published on the SEM Committee website on 3 December 2021. NERA performed this most recent validation. See https://www.semcommittee.com/publications/sem-21-086-sem-plexos-model-validation-2021-2029-and-backcast-report. (2021-2029 Validation Report) See Table 2 of that report.

4 The potential complexities of generators DAM strategies relate to: the various offer types available (e.g. simple and complex DAM bids), the flexibility generators have in the costs they seek to recover in their offers (e.g. VOMs may vary), and the ability of generators to change strategies over time, throughout the day or seasonally.

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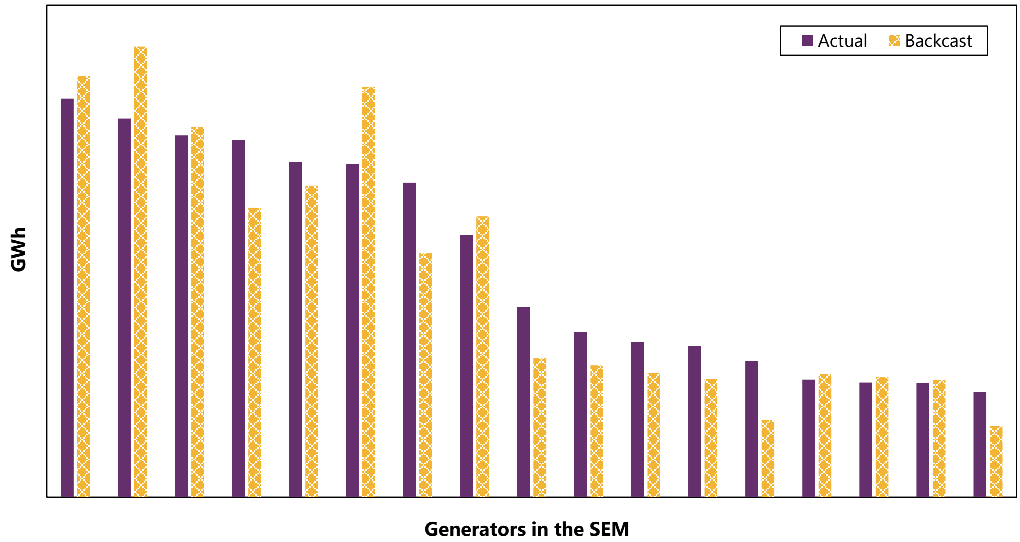

Figure 2: Average Generation, Largest Generators, Backcast vs. History, January 2020 through December 2023[5]

Using the Backcast to Calibrate the SEM PLEXOS Model

The backcast allowed NERA to test potential changes to the SEM PLEXOS Model. NERA tested the effect of different PLEXOS parameter options, including Mixed Integer Programming ("MIP") vs. Rounded Relaxation ("RR") for unit commitment. The MIP approach mimics how actual unit commitment decisions are typically made in power models like the SEM. Basically, MIP is an iterative, process to arrive at unit commitment as close to optimal as feasible given modelling limitations. RR is essentially a rounding approximation for unit commitment, which is faster to run. Until 2021, all SEM PLEXOS Models used RR, whereas MIP has been used since 2021. NERA discusses MIP and RR further in the main section of this report. NERA determined that both approaches produced reasonable results, and both could be used for the forecast SEM PLEXOS Model. Ultimately, NERA recommends using MIP for unit commitment, the same approach recommended in the prior validation. Also as with the prior validation, NERA recommends modelling one generator start state when running the MIP algorithm (based on warm-state start costs) and three-start states when running the RR algorithm (hot, warm and cold start costs). The MIP approach has advantages over the RR approach, advantages which NERA's view outweigh the drawback of approximating start costs with a warm-costs-only approach. The reason we recommend that MIP be run with one start state is to reduce runtime. All things equal, MIP takes significantly longer than RR to run in PLEXOS but limiting to one start state for the MIP runs makes the runtimes when using MIP acceptable Three-start-state runtimes significantly exceed one-start-state runtimes. That said, users may choose to run MIP with three start states if they can tolerate the longer runtimes. Within the RR options, however,

5 Reflects NERA's backcast run with demand aligned with DAM results and includes generators with the largest historical generation (excluding currently retired generators). Metered generation can differ from DAM generation for various reasons. Each pairing of bars represents one generator.

NERA notes that Option B produced somewhat more variation versus historical prices, compared to RR with Option A, suggesting that when using RR, Option A may be more accurate[6].

NERA also reviewed its backcast runs for generators with material differences between average historical generation and average backcast generation. NERA then reviewed these generators' technical and commercial input data and made changes as appropriate, where NERA found support for such a change.

As to other PLEXOS settings, NERA considered removing the look ahead period for the daily optimization, versus the 6 hour lookahead used in the 2021-2029 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. NERA recommend maintaining the so-called Korean uplift algorithm for runs where uplift is enabled.

Treatment of Wind, Solar, Uplift, and Wheeling Charges on Interconnectors

The SEM PLEXOS Model allows wind and solar to generate up to available wind levels (*availability factors*), yet the 2024-2032 SEM PLEXOS Model has an optional feature that sets wind and solar generation in line with historical actual wind generation levels (*capacity factors*)[7]. In the SEM, a material amount of wind that is available to generate does not actually generate, primarily due to a) transmission constraints (grid congestion prevents the wind generation getting to load) and b) curtailments (reductions in wind generation to prevent wind from exceeding limits based on system-wide reliability)[8]. The SEM DA market is an unconstrained market (no transmission constraints apply) and wind has priority dispatch in the DA market. Thus, wind generation that might be constrained off or curtailed may nonetheless receive dispatch instructions in the DA market. However, higher levels of wind lead to lower prices, all else equal. PLEXOS produces lower prices when wind generation matches available wind generation versus when wind generation is in line with actual generation, as affected by constraints and curtailments.

NERA tested how well the SEM PLEXOS Model matched historical SEM prices, considering available wind (Options A and A2) and actual wind (Option B) in the backcast. NERA found good alignment with all options. Considering Option B, NERA notes that by the real time (and in real time markets), wind generation would reflect dispatch down. Even though that same dispatch down is not reflected in the DAM, there may be some interplay between the different SEM energy markets where the effects of real time operations may affect the DAM, providing some conceptual support for Option B.

6 An approach using RR and one start state was not considered. NERA views this option as the least precise of the various MIP, RR, and start-state options.

7 Availability factors reflect average *available generation* over a period of time as a percentage of maximum capacity. Capacity factors reflect average *actual generation* over a period of time as a percentage of maximum capacity.

8 More information on constraints and curtailments is available on the EirGrid website: https://www.eirgrid.ie/grid/system-and-renewable-data-reports.

Separately, as in the 2021-2029 SEM PLEXOS Model, NERA recommends the use of a wheeling charge on the interconnectors when uplift is enabled in order to prevent erroneously low net imports into the SEM.

Given the high importance of price and import/export alignment, NERA recommends running the SEM PLEXOS Model with either:

> Option A: allowing wind and solar generation at available wind and solar generation levels (availability factor) and Uplift and wheeling charges turned on;
>
> Option A2: allowing wind and solar generation at available wind and solar generation levels (availability factor) but without Uplift and without wheeling charges; or
>
> Option B: limiting wind and solar generation to actual generation levels (capacity factor) and uplift and wheeling charges turned off.

Note on treatment of solar: For clarity, in the 2024-2032 SEM PLEXOS Model, Options A and A2 versus Option B have different treatment of both wind and solar, considering availability versus capacity factors. However, for simplicity, the backcast runs focus on the difference between available wind generation and actual wind generation. In the backcast period, installed solar capacity is low enough that the difference between available and actual solar generation has a minimal effect on results. In the forecast period (2024-2032) there is sufficient solar capacity such that the difference between modeling solar using availability versus capacity factors will have somewhat more effect on results than in the backcast (particularly in the later period of the forecast). Thus, NERA considers both wind and solar in defining the Options above. For simplicity, the discussions in the rest of this report tend to focus on the difference between available and actual wind generation, where 2023 GCS forecasts show that wind will continue to be by far the largest source of renewables generation. Nonetheless, the 2024-2032 SEM PLEXOS Model Options consider both wind and solar.

Options A and A2 have the advantage of conceptually aligning wind generation in PLEXOS with the treatment of wind in the DA market, which consequently leads to better alignment for thermal units between their SEM PLEXOS Model dispatch levels and SEM DA market dispatch instructions. Option A specifically has the disadvantage that neither uplift nor wheeling charges are present in the actual SEM market; rather, they are used for practical purposes in PLEXOS Option A to improve alignment with the SEM market. Further, the wheeling charges present in the 2024-2032 SEM PLEXOS Model Option A could become obsolete if SEM market prices change significantly from current expectations due to unanticipated changes in supply and demand or in fuel markets.

Option B's advantage is that it does not require uplift and wheeling; while Option B conceptually differs from treatment of wind in the DA market, as stated above interactions between the various energy markets may mitigate this effect. Further, Option B will tend to result in aggregate renewable and aggregate thermal generation levels that are more in line with actual aggregate metered generation levels of the same, respectively. Option A2 is in between Options A and B: it aligns conceptually with DA treatment of wind generation but does not have uplift and wheeling charges. In contrast, Options A and A2 are more in line with historical DA market dispatch instructions. NERA recommends the user of the model choose the model option that best fits the user's modelling needs.

NERA stresses that all 3 options run in PLEXOS as unconstrained models - the only difference is the target for wind generation in PLEXOS. In Options A and A2, the targets for wind are historical wind availability factors. In Option B, the targets for wind are historical wind capacity factors. The difference between capacity and availability factors is that capacity factors reflect dispatch down of the wind. Historical capacity and availability factors reflect targets for wind generation in PLEXOS because PLEXOS in some circumstances will dispatch down wind below the targets. PLEXOS does not have any transmission constraints in the SEM nor does PLEXOS impose non-synchronous limits[9], but in some cases there is more wind than can be absorbed by load and/or exports in PLEXOS[10].

Uplift background: All prior SEM PLEXOS Models add uplift to the resulting market price, as needed, to ensure the final market price compensates generators for their start and no-load costs. Prior to I-SEM Go-Live, the SEM market itself included an uplift adder to prices; however, since I-SEM Go-Live there has not been an uplift added to SEM prices.

Wheeling charge background: The use of uplift necessitates the use of a wheeling charge in PLEXOS modelling. This is because PLEXOS determines imports to and exports from the SEM prior to when uplift is added to the SEM price. NERA adds a wheeling charge equal to expected uplift, allowing import and export levels to align with anticipated SEM prices. When using uplift, the wheeling charge improves the accuracy of the SEM PLEXOS Model, even though the wheeling charge does not reflect any actual tariff imposed on interconnector trade.

Historical Alignment of Different PLEXOS Options

NERA notes that each option had advantages and disadvantages in different historical periods. NERA reviewed:

- Jan 2020 through June 2021: a period of very low natural gas prices and power prices, plus the beginning of the transition to higher prices – this period includes the effects of the worst of the Covid-19 pandemic;
- July 2021 through September 2022: a period marked by very high natural gas and power prices;
- October 2022 through December 2023: a period where natural gas and power prices return to prices closer aligned with historical norms.

9 For example, EirGrid references the non-synchronous limit here https://www.eirgrid.ie/news/solar-power-reaches-new-monthly-peak-may.

10 At present levels of wind (and solar) it is very rare for any dispatch down in PLEXOS versus the targets, but by the later years of the current model's nine-year horizon, the level of wind and solar in PLEXOS (based on the 2023 GCS) is high enough that PLEXOS further dispatches down wind.

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Time Period	Price Diff. to Actual (€/MWh) Opt A	Opt A2	Opt B	Net Exports Diff. to Actual (GWh/mo) Opt A	Opt A2	Opt B
Jan 2020 – Jun 2021	1.22	0.63	2.34	-97	-65	-122
Jul 2021 – Sep 2022	-3.14	-4.14	0.09	24	52	32
Oct 2022 – Dec 2023	1.96	-0.60	3.13	-24	17	-50
Whole Backcast	*0.09*	*-1.25*	*1.89*	*-36*	*-3*	*-51*

Table 3: Price and Net Export Differences to Actual Across Backcast Periods

As shown in **Table 3**, all options performed well overall but with different levels of success in different periods:

- Option A: The best average price match and in the middle in terms of average interconnector flow match.
- Option A2: Did particularly well in the Jan-2020 to Jun-2021 and Oct-2022 to Dec-2023 periods, plus has the best average interconnector flow match, though not as good an overall price match as Option A. This option also did not do as well in the July-2021 to Sept-2022 period.
- Option B: While this option had the lowest fit in terms of average price and interconnector flow match, it performed the best in the July-2021 to Sep-2022 period.

Which Option to Choose in SEM PLEXOS Model

The 2024-2032 SEM PLEXOS Model makes Option A, Option A2 and Option B available. While different options do appear to have different advantages and disadvantages based on historical alignment, NERA cautions against an over reliance on historical calibration. History does not always repeat. Further, there is uncertainty and variability in models like the SEM PLEXOS Model: a seemingly near perfect historical alignment could be somewhat coincidental and somewhat due to random historical and modelling effects. Thus, NERA recommends consideration of historical alignment, the conceptual basis for each option, as well as current market conditions.

In NERA's view, any of Option A, Option A2, and Option B would be reasonable. That said, NERA notes that the somewhat better alignment of Options A and A2 along with their conceptual alignment with DA market treatment of wind may favor use of either Option A over Option B. If a user chooses Option A, NERA suggests that the choice between Options A and A2 depends mostly on the user's view as to whether to include uplift and wheeling charges (Option A) or not (Option A2). NERA also notes the following:

- To the extent electricity and gas market conditions tighten versus current conditions, Option B may have an advantage, given how Option B performed during very high period gas and power prices in the backcast[11].
- If the energy market and electricity conditions change significantly versus current conditions (whether higher or lower prices), then uplift in Option A may also change. NERA reminds the reader that in Option A, wheeling charges should approximately match uplift. Thus, wheeling charges may become outdated (too low or too high) if the overall market moves significantly. In this situation, model users may wish to switch to Option A2 or to Option B, which have neither uplift nor wheeling charges. Alternatively, the user could update the wheeling charges in Option A[12].
- As renewable capacity increases in the SEM, the difference between Options A and A2 (which use available renewable generation) and Option B (which uses estimated actual renewable generation) will become more stark. NERA does not prejudge whether Options A, A2 or B will perform better in a high renewables environment. This issue may also be reassessed in the next validation of the SEM PLEXOS Model.

Great Britain and France Modelling (Calibration with Forwards)

The SEM will become more interconnected with the power markets in Great Britian and the rest of Europe as a result of the Greenlink and Celtic Interconnectors. The 2021-2029 SEM PLEXOS Model represented Great Britain and France with market heat rates. Market heat rates represent the ratio between the electricity price and the price of natural gas. Generally, natural gas power plants are marginal, and thus set the electricity price in the SEM, Great Britian, and France[13]. This approach allows the electricity prices for Great Britan and France to update in PLEXOS automatically with changes in the natural gas market (as well as with changes in CO_2 prices). In the 2021-2029 SEM PLEXOS Model (and in several other prior SEM PLEXOS models), the market heat rates for Great Britain and France in PLEXOS reflected the historical relationship between electricity and natural gas prices.

The 2024-2032 SEM PLEXOS Model uses market heat rates for Great Britain and France that are calibrated to the forward prices for electricity, natural gas prices and CO_2 prices in those markets. So-called "forwards" are traded products where the price is set today for delivery of a product (like

11 While NERA has not assessed what precise conditions might suggest switching to Option B, NERA notes Option B did well in the high energy price environment of the second half of 2021 and most 2022.

12 Again, NERA has not assessed what specific price conditions might merit a switch away from using uplift. That said, model users can track the difference between average uplift (€/MWh) in PLEXOS Model output versus the average wheeling charges in the PLEXOS Model inputs (€/MWh). If the difference exceeds more than a couple €/MWh, users may consider either updating the wheeling charges or switching to a PLEXOS Model option that does not have uplift and wheeling. €2/MWh of difference is not a precise threshold, rather it is a suggestion as to indicate the approximate scale of differences that might be deemed significant. All things equal, considering Option A exclusively, updating wheeling charges to match average uplift should enhance PLEXOS Model accuracy, even if the difference is less than €2/MWh.

13 Even as natural gas generation has declined with increased renewables generation, the strong relationship between natural gas and electricity prices still exists. While France has relatively little internal natural gas generation (given its high portion of nuclear generation), France is interconnected with the rest of Europe, where natural gas generation is relatively more prevalent.

electricity or natural gas) in the future. Forwards can settle financially or with physical delivery of the product.

NERA started by determining market heat rates for GB and France based on historical electricity, natural gas and CO_2 prices. NERA then adjusted the historical market heat rates such that they result in forecasted electricity prices in GB and France that align with forward electricity prices. NERA recommends this approach for two reasons.

- First, in recent years extreme variation in electricity and natural gas prices has occurred – this creates uncertainty as to whether market heat rates implied by this historical period are reasonable for use in a forecast model (NERA considered historical prices back to 2019).
- Second, European power markets are rapidly decarbonizing, which may lead to lower energy-market power prices all else equal, thus lowering market heat rates.

NERA believes that the calibration of heat rates for Great Britain and France to forward prices will give users of the SEM PLEXOS Model more confidence in its results. Yet, NERA notes that the forward power prices NERA relied upon show forecast prices only going three years into the future, whereas the current SEM PLEXOS Model forecasts to 2032. There is uncertainty as to long-term electricity and natural gas prices and the relationship between the two. SEM PLEXOS Model users may take their own view as to how market heat rates in Britain and France will change over the longer-term horizon (especially the period from approximately 2028 and beyond, i.e. the period after the last forward electricity prices were used for Great Britian and France calibration within the 2024-2032 SEM PLEXOS Model).

NERA notes that the 2024-2032 SEM PLEXOS Model reflects approximately 14,800 MW of new wind and solar capacity coming online in the SEM during the five-year period from 2028 through 2032. This results in a total of 27,200 MW of wind and solar by the end of 2032, very large amounts as compared to a peak SEM load of about 9,000 MW in 2032 (all based on the 2023 GCS). Holding fuel prices and CO_2 prices constant[14], this increase in renewable capacity results in declining prices in the SEM, especially post-2028. It is possible that similar declines in prices and market heat rates could occur in Great Britain and France over that period as decarbonization progresses. In light of this, NERA makes a default assumption that market heat rates in Great Britain and France decline in line with the decline in SEM prices observed in preliminary runs of the SEM PLEXOS Model.

NERA notes that this is a placeholder assumption, if a reasonable one on an *a priori* basis. It was outside of NERA's scope to perform a detailed long-term forecast of prices in France and GB. The decline in GB and France market heat rates in the PLEXOS Model is accomplished with PLEXOS variable objects. Those variables state ratios for every year of the model, PLEXOS multiplies the market heat rates for France and GB by those ratios, with the decline in market heat rates starting

14 NERA emphasizes that holding fuel and CO_2 prices constant for NERA's test runs of the 2024-2032 SEM PLEXOS Model is done so that NERA can show the isolated effect on SEM prices of changes in the supply and demand balance in the SEM over the 2024-2032 period. To forecast SEM prices or any other SEM result, the RAs (and any model user) should put into PLEXOS a reasonable forecast of fuel and CO_2 prices including how those prices may change over the modelling horizon.

after the end of the forward curve. Users are encouraged to enter their own ratios that reflect their view about how market heat rates in France and GB will evolve over the longer term[15].

During NERA's engagement with stakeholders, some generation companies recommended NERA update the SEM PLEXOS Model to include fundamental models of Great Britian and France, i.e. models that include the specific generators and loads of those markets, with forecasts of new capacity additions, retirements, and load growth to 2032, including specific forecasts of growth of renewables in those markets. Such an approach has the advantage that, at least conceptually, it would naturally forecast the interrelated effects of renewables growth in SEM, Great Britian, and France on prices in those markets. However, NERA and the RAs agreed that such an approach was out of scope for NERA in its instant assignment, given the high level of complexity of building, calibrating and maintaining fundamental models of Great Britian and France, particularly since each market is significantly larger than the SEM. Further, given the complexity of such a task, it is unclear whether the end result would be more reliable than the current approach.

Further Comments on Forecasted Decline in Prices Long-Term in the SEM PLEXOS Model

The large level of new renewables capacity installed in the SEM per the 2023 GCS (an especially large amount between 2029 and 2032) naturally results in declining prices from the SEM PLEXOS Model, even when holding fuel and CO_2 prices constant. See Figure 3 below. In many hours in those years, available renewable energy exceeds load, resulting in zero prices in the SEM per the SEM PLEXOS Model.

While such a trend makes sense conceptually, NERA recognizes that there is uncertainty as to how precisely prices in the SEM will react once renewables penetration reaches the levels forecasted by the early 2030s. Additionally, NERA reiterates that there is significant uncertainty as to future SEM prices. The forecasted prices presented in this report are based on uncertain inputs including projected renewable capacity, system load, capacity retirements and additions, and fuel prices, among others. NERA notes that Table 16 below presents the indicative fuel prices assumed for test runs of the SEM PLEXOS Model (including the run that produced Figure 3 below) – actual fuel prices will presumably differ from those prices, and PLEXOS Model users are encouraged to update fuel prices to contemporaneous forecasts when running PLEXOS.

15 By default, the ratios are 1.00 through 2027 in France and through 2028 in GB, meaning that there is no adjustment to forward-calibrated heat rates through those years. Those years reflect the last years with forward prices available to NERA, for each market, respectively, as of the time of NERA performed its validation. Ratios are less than one and decline over time post-2027 in France and post-2028 in GB.

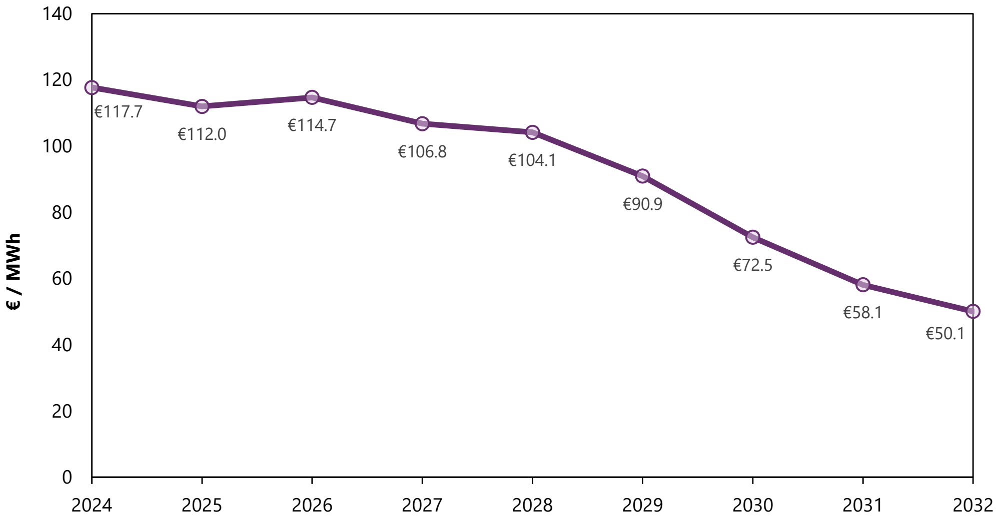

Figure 3: Annual Average Prices, 2024-2032 SEM PLEXOS Model

NERA raises several options for the RAs to consider going forward. Each of these was out of NERA's scope for the instant assignment, however:

1) Explicitly model the system services market in the SEM, which NERA understands will be co-optimized on a day-ahead basis with the energy market starting in 2026. This would presumably affect dispatch decisions, especially in a high renewables-penetration environment.

2) Adjust how PLEXOS models generation offers, with the goal of aligning PLEXOS with the best expectations of how the actual SEM DA Market will handle generation offers and price formation with the very high levels of renewables penetration forecasted, especially by the early 2030s.

3) Consider potential changes to the supply mix in the SEM by the 2030s. If energy prices are anticipated to go very low, some units may retire, which could raise prices. Further the very high levels of intermittent generation by the early 2030s may correspond with increasing amounts of storage capacity including (if feasible) longer-term storage, which could potentially affect prices as well[16].

4) Potentially make updates to Great Britain and France modelling in PLEXOS to explicitly account for renewables growth in those markets.

5) Potentially develop a more complex statistical approach for France and GB addressing wind and solar generation uncertainty (that uncertainty being more important with the very high levels of renewables penetration anticipated by about 2030 and beyond).

[16] NERA clarifies that, in line with its instructions from the RAs, the 2024-2032 SEM PLEXOS Model does not speculate as to changes in the supply mix beyond those announced and confirmed as reasonable based on NERA's and the RAs review, including review of the capacity contract awards. Nonetheless, 2032 is sufficiently

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Future of SEM and SEM PLEXOS Model

Looking more broadly, the next decade will be an exciting time of change in the SEM, with the potential arrival of significant new quantities of renewables as Ireland and Northern Ireland decarbonize. There presumably will be engineering, regulatory, and/or market challenges as such large quantities of intermittent renewables come online. In parallel, there may be modelling challenges considering the SEM PLEXOS Model. NERA has made initial efforts to prepare the model for such challenges, including implementing a methodology to calibrate the modelling of France and Great Britian to forward prices that presumably anticipate the installation of new renewables. Given the potential for changes in power markets beyond the current forward curve, NERA also provides the modelling infrastructure to lower market heat rates in Great Britain and France in PLEXOS in anticipation of potential significant increases in the future of renewables penetration in those markets. Finally, per the list above, NERA provides several modelling ideas that may help future validations appropriately model SEM prices in a world with very high levels of intermittent generation.

far in the future that there is significant uncertainty as to what changes in SEM generation and storage resources will occur by that year.

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1. Introduction

1.1. Scope of Work

NERA was engaged by the Regulatory Authorities (CRU & UREGNI) to update and validate their PLEXOS Model of the Single Electricity Market ("SEM") for the time period 2024-32.

NERA's assignment included three principal steps:

1) Perform a backcast, starting with the 2021-2029 SEM PLEXOS Model, of historical SEM data.

2) Validate and update the input data (system input data and generator technical and commercial offer data) from the 2021-2029 SEM PLEXOS Model[17]. The resulting model is to be valid for 2024 through the end of 2032.

3) Review and update, as appropriate, the PLEXOS modelling settings in the 2021-2029 SEM PLEXOS Model.

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

- Determine a *de novo* 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.

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

- Perform a comprehensive validation of all generators' 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 renewables and load forecasts).

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

- Perform a detailed forecast of France and GB prices beyond the end of the current forward curve.

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

17 See https://www.semcommittee.com/publications/sem-21-086-sem-plexos-model-validation-2021-2029-and-backcast-report.

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 (MMU)). 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 2024-2032. 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 (a model with acceptable runtimes 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 2024-2032 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 core 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 introduces NERA's backcast;
- 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 2024-2032 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 4 below.

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 that can allow for recovery of those costs
Market prices included an uplift that allows for recovery of start costs and no-load costs[18]	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

Table 4: Differences Between SEM and I-SEM

The various SEM PLEXOS Models produced post I-SEM Go Live maintain the basic structure of the SEM PLEXOS Models prior to I-SEM Go Live. This basic structure aligns with traditional production-cost modelling of power systems, a common approach to modelling electricity markets even if it may not precisely mimic all details of offers and bids and how market operators perform their optimization. The support for such an approach is two-fold: a) markets such as the SEM align with

[18] 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).

the core economics behind production cost modelling (minimizing costs to serve load); and b) backcast modelling supports the reasonableness of the structure of the SEM PLEXOS Model.

3. Backcast – Introduction

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. 2021-2029 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.

- Stage 2: Having arrived at a satisfactory initial backcast model, NERA tested alternative PLEXOS settings and approaches. NERA's testing considered how much better, or worse such alternatives 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, e.g. CHPs. Thus, appropriately, either both these resources *and* the load they serve should be included in the backcast model, or *both* should be excluded. NERA followed a standard technique to determine demand for backcast modelling. The technique involved adding up the historical generation from the resources relevant to the model (plus adding in net imports). This approach automatically ensures that generation and demand are comparable.

NERA primarily relied on historical metered generation to calculate historical demand, but NERA also considered historical DA market instructions. Often, the DA instructions and metered generation are similar and sometimes they match. Yet, DA market instructions can differ from metered generation for individual generators and, importantly, in aggregate across all generators. This occurs for a variety of reasons, including: a) generators may choose not to participate in the DA market but nonetheless generate due to their participation in shorter-term SEM markets; b) the DA market does not include imports from and exports to Great Britan (though assetless traders to some extent counteract this effect by mimicking interconnector trade); and c) assetless traders' participation in the DA market (aside from their mimicking of interconnector trades) may result in different dispatch levels for physical generators than their expected actual generation levels (e.g. due to anticipated wind curtailments and constraints or unexpected operational events to ensure network stability).

NERA determined demand for the backcast based on historical metered generation to align with demand in the forecast SEM PLEXOS Model. Forecast demand for PLEXOS is set equal to forecasted total energy requirement (TER) of the SEM, which (after accounting for imports and exports) necessarily aligns with total metered generation, because generation (plus net imports) consequently matches demand in electricity markets. Specifically, NERA:

1) Determined, for every hour of the backcast period, the aggregate metered generation of all dispatchable generators explicitly modelled in the SEM PLEXOS Model.

2) Added to the above metered net imports from Great Britain ("GB");

3) Added the historical hourly metered wind and metered solar generation in the SEM.

The PLEXOS model was executed with the following supply resources, which ensured that supply and demand were aligned. NERA considered two wind generation options in the backcast (discussed below) and included in the backcast:

- The same dispatchable generators whose aggregate hourly metered generation were included in the calculation of hourly demand; and

- Wind and solar, based on their historical actual generation. <u>For wind, both available and actual generation were analysed.</u>

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

- DSUs (as well as the demand that they "serve"): NERA excluded DSUs (and the demand they serve) to better isolate the testing of PLEXOS's ability to dispatch dispatchable generation. NERA separately analysed historical DSU dispatch to update the SEM PLEXOS Model.

- Embedded generation (and the load it serves): NERA did not have access to historical embedded generation in the SEM. This has little to no effect on the backcast. NERA notes that embedded generation (specifically non-wind and non-solar embedded generation) is very small in the SEM compared to total SEM load. To be consistent, NERA also does not include in the backcast the load that historically was served by non-wind and non-solar embedded generation.

- Batteries: while battery participation in the SEM energy markets will likely grow rapidly, NERA understands that battery participation in the energy markets over the historical backcast was relatively low. Depending on how fast battery participation in the energy markets grows, future validation exercises may benefit from explicitly addressing batteries in backcast runs. Further, NERA notes that the historical output from dispatchable generators reflects the historical generation and charging from batteries and, therefore, the effect of batteries is in the backcast indirectly.

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 generation for 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. For the pumped storage plant, Turlough Hill, NERA did not force PLEXOS to set Turlough Hill generation equal to its historical generation. Rather, NERA allowed PLEXOS to optimise this plant in the backcast.

- Hourly generation for the Lough Ree and West Offaly peat plants. Such plants are now retired. When online, they tended to generate when available, rather than respond to the dynamics in electricity, fuel, and emissions markets. Hard coding their generation in the backcast allows PLEXOS to focus on backcasting the traditional thermal and hydro generators.

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

  - NERA used the Backcast SEM PLEXOS Model to test how well PLEXOS modelled imports and exports given the market price in GB; and

  - In a separate exercise (discussed in Section 8.11 below), NERA analysed historical GB data to determine a reasonable approach to forecast GB market prices in the 2024-2032 SEM PLEXOS Model.

3.1.3. Wheeling Charges

As discussed, the 2024-2032 SEM PLEXOS Model includes three options, two with wind based on historical wind generation as available (called Options A and A2 above) and one with wind based on historical wind generation reflecting actual generation - i.e. wind after any historical dispatch down (called Option B above). In Option A, NERA includes uplift; in contrast, NERA does not include uplift in Option B or in Option A2. Uplift produces higher prices, because uplift explicitly reflects needed price increases for recovery of start and no-load costs in the output SEM price. Using uplift affects how NERA models the interconnectors. PLEXOS optimizes the interconnectors based on the *shadow prices* in the SEM and GB[19].

[19] 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.

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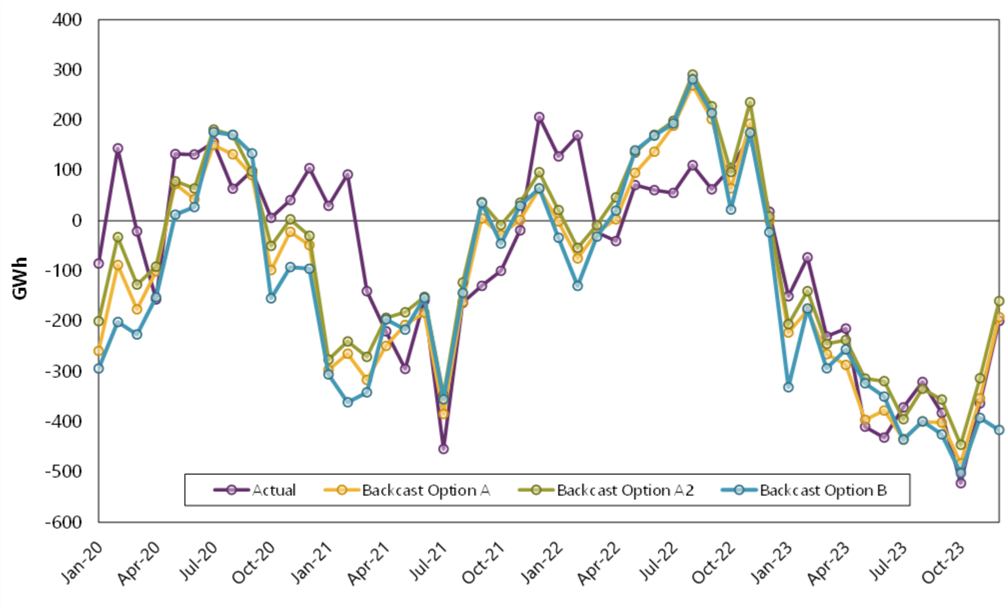

Figure 4: Interconnector Net Flows by Month

However, NERA models GB without uplift, so GB shadow prices are the full GB prices. In contrast, when PLEXOS runs with uplift enabled, the shadow prices of the SEM do not match the full SEM prices. Thus, the shadow prices in the two markets are not comparable on a consistent basis. NERA resolves 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[20]. Each wheeling charge is set separately, based on average uplift over the same period. The wheeling charge accounts for the presence of uplift by (appropriately) making trade relatively more attractive in the from-GB-to-SEM direction. Thus, NERA adds a wheeling charge to Option A, setting that wheeling charge equal to anticipated uplift.

NERA also finds good alignment when uplift is not utilized (and therefore wheeling charges are also not utilized). Thus, NERA developed Option A2 (based on available wind generation) and Option B (based on actual wind generation), both of which do not include uplift and do not include wheeling charges.

3.2. Inputs

As detailed in Table 5, NERA sourced the following data for the backcast:

[20] NERA determines 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.

Type	Data Included	Source
Demand	Sum of metered generation for dispatchable resources in PLEXOS	SEMOpx
Demand	(+) *Pre-Brexit:* Metered Net Imports	SEMOpx
Demand	(+) *Post-Brexit:* Metered Net Imports	SEMOpx, MMU
Demand	Wind and solar generation (or DA forecast)	EirGrid
Fuel & CO_2 Prices	Historical Prices for Gas, Coal, Gasoil, Fuel Oil, and CO_2	CRU
GB Prices	Average of EPEX and Nordpool Exchange DA Prices	MMU
Generation	Metered generation	SEMOpx
Generator Technical/ commercial parameters	Prior Validated PLEXOS Model, as updated by NERA during the current 2024-2032 PLEXOS Model validation exercise	Generators
Interconnector Flows	(+) *Pre-Brexit:* Metered Net Imports	SEMOpx
Interconnector Flows	(+) *Post-Brexit:* Metered Net Imports	SEMOpx, MMU
Outages	Historical generator availability	MMU
SEM Prices	DA Prices	MMU
Wind & Solar	Wind and solar generation (or DA forecast)	EirGrid

Table 5: Data Included in the Backcast

3.3. Generator Parameters Refinement

NERA evaluated how closely the average generation levels from the PLEXOS backcast aligned with historical data. NERA assessed 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 where the data had changed materially, based on updated data NERA received from the generators, which also helped better align some generators with historical production levels.

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 non-trivial differences in backcast results when executing PLEXOS with and without a 6-hour lookahead: €130.31/MWh and €131.46/MWh, respectively, compared to €130.22/MWh for the actual historical prices[21]. NERA recommends continuing the use of a lookahead given its better alignment with historical prices.

NERA also tested a 12-hour lookahead, which produced very similar results (average backcast prices about 0.5% lower with the 12-hour lookahead versus the 6-hour look-ahead); thus on a results-basis, either lookahead length would be reasonable. However, increasing the look-ahead to 12 hours increases runtime. NERA recommends the use of the 6-hour lookahead, given the lower run time versus 12 hours and for continuity (NERA understands that every prior SEM PLEXOS Model has used a 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. When a generator shuts down, it generally must be offline for a period of time prior to a new startup, plus each new startup incurs start-up costs. Further, online generators typically have a minimum stable level of generation, which the generator must remain above when it is online. 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).

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21 The backcast results quoted come from "Option A", the scenario using available wind generation, uplift, and wheeling charges. Unless stated otherwise, all backcast results stated in this report reflect Option A. NERA focuses on just one option to simplify this report.

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.

The 2021 SEM PLEXOS Model uses MIP. Linear relaxation is not a reasonable alternative for the purposes of the SEM PLEXOS Model given its simplification of unit commitment. RR is a reasonable alternative and was used in the SEM PLEXOS Model in all models prior to the 2021 version. NERA recommends the use of MIP for the 2024 SEM PLEXOS Model for the following reasons which compare MIP to RR:

- MIP theoretically results in a lower-cost dispatch solution.
- MIP better aligns with the actual unit commitment algorithm used in the DAM in the SEM.
- MIP produces prices and interconnector flows that better align with historical prices and flows over the period of the backcast (discussed below).
- (For runs with uplift) MIP results in a lower uplift, which reduces the wheeling charge adjustment in the model. All things equal, NERA views this as positive, given that uplift and the wheeling charge are not part of the actual SEM market (the SEM PLEXOS Model includes them to improve model accuracy). The average uplift is about €2.33/MWh and €7.96/MWh in the MIP backcast run and RR backcast run, respectively.
- While MIP runtime is longer than RR runtime, MIP runtime can be reduced to an acceptable level with certain reasonable adjustments while maintaining accurate results, for example by reflecting one-state-start costs;
- Continuity with the 2021 SEM PLEXOS Model.

The 2021 PLEXOS Model Validation Report included a lengthy discussion of MIP and RR[22]. Interested readers may review that prior discussion. For this report, NERA presents the backcast results comparing MIP and RR runs. All MIP runs reflect one-state start costs rather than three-state start costs[23]. Using one-state start costs significantly reduces runtimes while maintaining accurate results. All RR runs reflect three start states (since RR runs in less time than MIP, it is reasonable to include the three start states for RR runs). The charts below demonstrate the somewhat better backcast alignment of MIP vs. RR. NERA notes the closer fit considering prices versus interconnector flows.

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[22] Section 4.2 of 2021-2029 Validation Report.

[23] The costs required to start-up a generation unit tend to increase the longer the unit is offline, as the unit transitions from so-called "hot" to "warm" to "cold" start states. Several SEM PLEXOS Models prior to 2021 reflected these three start states. Modelling three start states rather than one significantly increases run time, as the optimization problem becomes more complex. Modelling with one start state (reflecting warm-state start costs) is a common approximation to maintain reasonable accuracy while achieving an acceptable runtime.

As explained more in Section 4.3, NERA calibration to historical interconnector flows is inherently more challenging than calibration to historical prices.

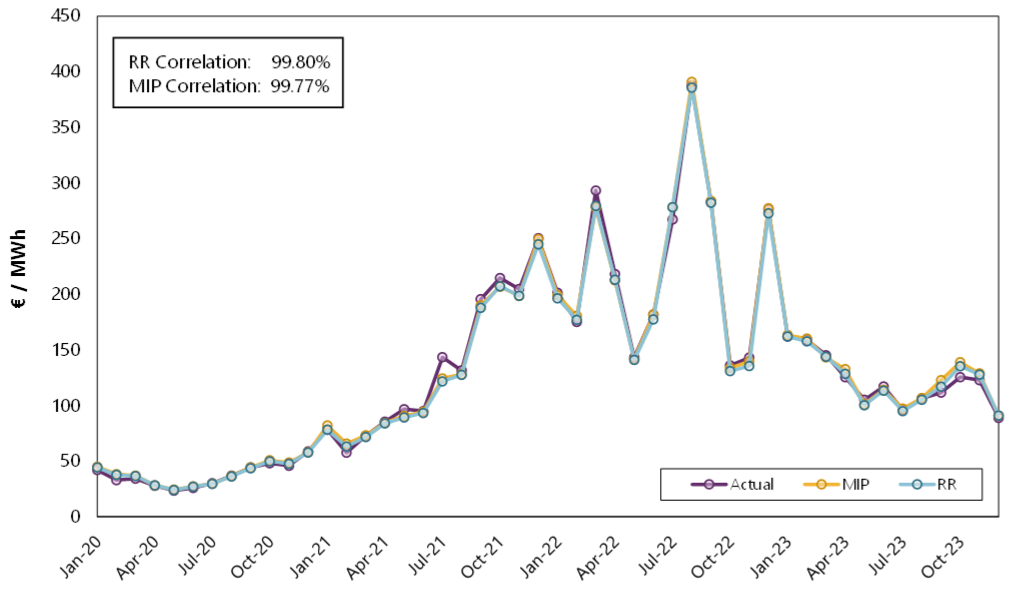

Figure 5: Actual vs. RR vs. MIP Average SEM Price by Month

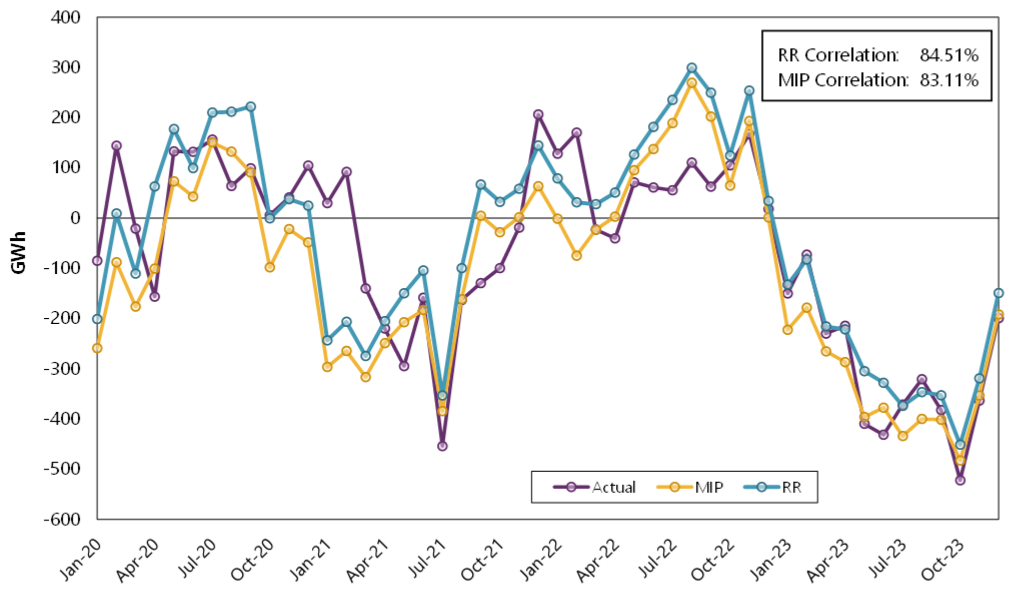

Figure 6: Actual vs. RR vs. MIP, Net Exports to GB, by month[24]

[24] Reflects net exports from the SEM to GB (i.e. total exports minus total imports). When the figure shows a negative number, imports exceed exports.

While NERA recommends MIP, NERA ultimately includes both three-state RR and warm-state MIP options in the SEM PLEXOS Model. However, NERA cautions that the three-state RR with Option B (actual wind, no wheeling charge and no uplift) and Option A2 (available wind, no wheeling charge and no uplift) tend to have noticeably lower prices in the backcast than what occurred historically (about 6.0% lower and 8.7% lower, respectively), whereas the other backcast options more closely align with historical prices (RR with Option A and all three MIP Options). Wheeling charges are calibrated separately for the MIP and RR versions of Option A. This is because Uplift tends to be higher in the RR version than in the MIP version, and wheeling charges are set to expected Uplift.

4.3. Backcast Calibration Results

The backcast model overall was successful at matching historical market prices. For simplicity, we show Option A in the results below.

Figure 7 below compares annual average backcast results against average historical results for the backcast period:

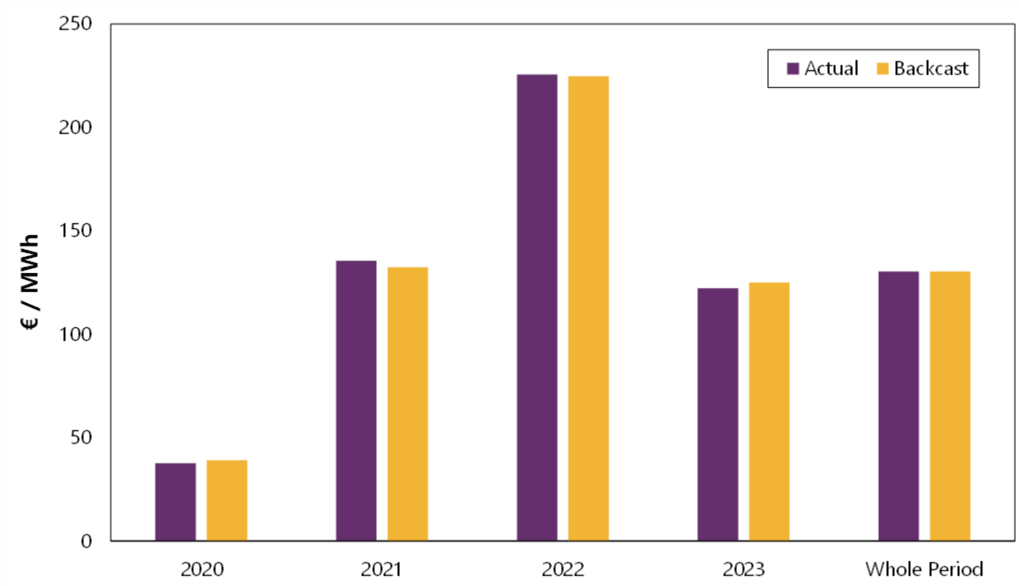

Figure 7: Average SEM Price by Year

The backcast model tracks price changes by month very well, as illustrated in Figure 8.

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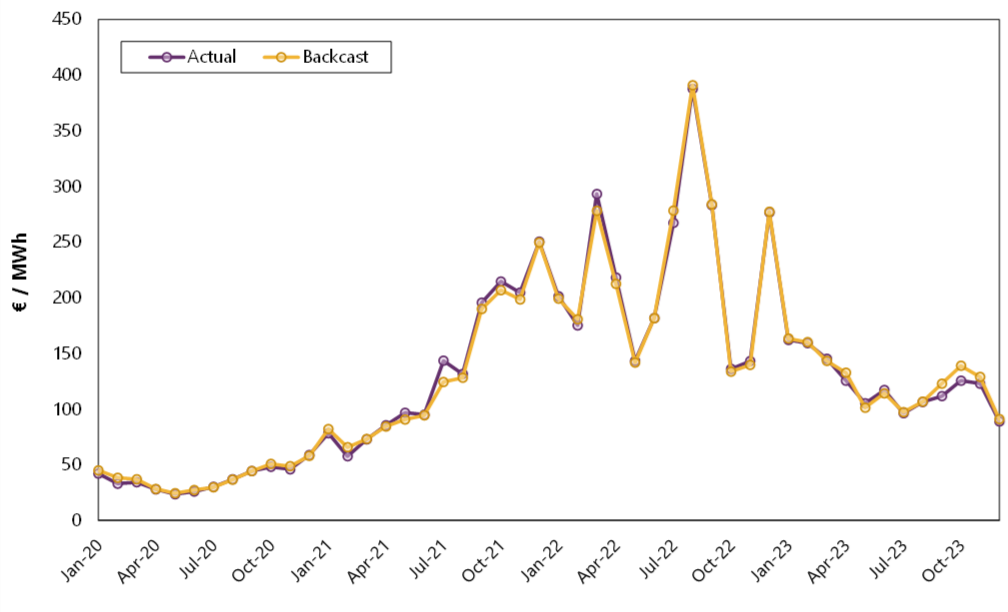

Figure 8: Average SEM Price by Month

As illustrated in Figure 9, the model reasonably matches hourly variations in prices, though backcast prices are slightly higher than SEM prices in the evening hours.

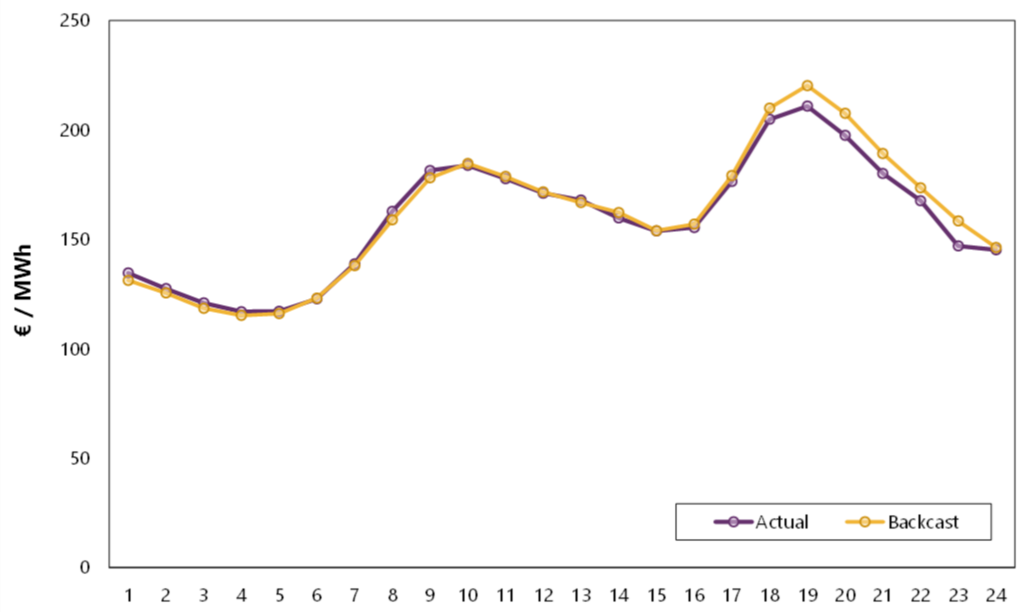

Figure 9: Average SEM Price by Hour

With regard to interconnector flows, and as illustrated in Figure 10, the model broadly matches the historical pattern. NERA notes that the backcast results align more closely to historical results with respect to prices than with respect to imports and exports over the interconnectors. NERA notes that it is simply more challenging for the SEM backcast model to match historical interconnector flows than to match historical prices. NERA views three principal reasons for this:

1. The SEM PLEXOS Model most closely attempts to mimic the SEM Day Ahead Market. Yet, GB and SEM Day Ahead Markets are not coupled, meaning that interconnector flows are not optimized through the DAM. Rather, the coupling of GB and SEM occurs only in certain intra-day markets[25]. This makes it more challenging for the SEM PLEXOS Model to accurately backcast interconnector flows.
2. On a related point, interconnector flow charts such as Figure 10 below compare backcast results to historical *metered* interconnector flows, which may differ from what might have been the DAM flows for various reasons. Namely, metered data reflects transmission constraints, non-synchronous limitations on renewables and any other operational and reliability realities of the real-time. Those real-time considerations are not in the SEM PLEXOS Model (that attempts to mimic the DAM).
3. In neighboring markets like the SEM and GB (where prices are, broadly speaking, similar and highly correlated), interconnector flows can be highly sensitive to small price differences. For example, if the price is €180/MWh in the SEM and €178/MWh in GB (converting from pounds to euro), one might expect the SEM to import from cheaper GB, all else equal. Imagine now that PLEXOS backcasts a SEM price of €176/MWh instead, a relatively modest difference of 2.2% versus €180/MWh. Yet, such a small difference in SEM prices could lead to PLEXOS showing the SEM as exporting to GB instead of importing, a complete reversal. This high sensitivity to small differences in price likely also explains the differences between backcast and actual interconnector flows.

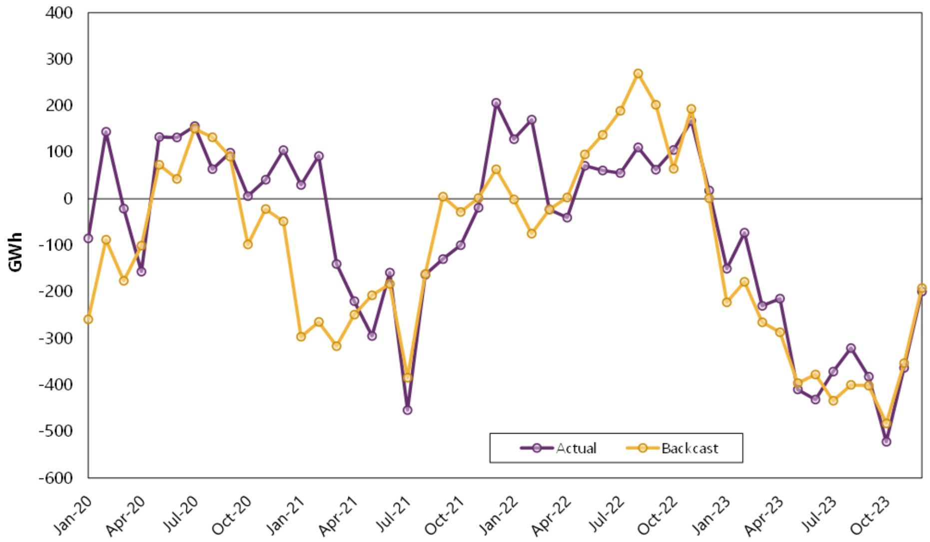

Figure 10: Interconnector Net Flows

As to generators, as illustrated in Figure 11, the model generally matched generation by fuel type. For model runs comparing generation levels by fuel type and for individual generators, NERA utilized

25 For example, see https://www.semopx.com/markets/intraday-market/.

an alternative DA market version of the backcast appropriate for testing how well PLEXOS backcast results matched historical DA market generation results[26].

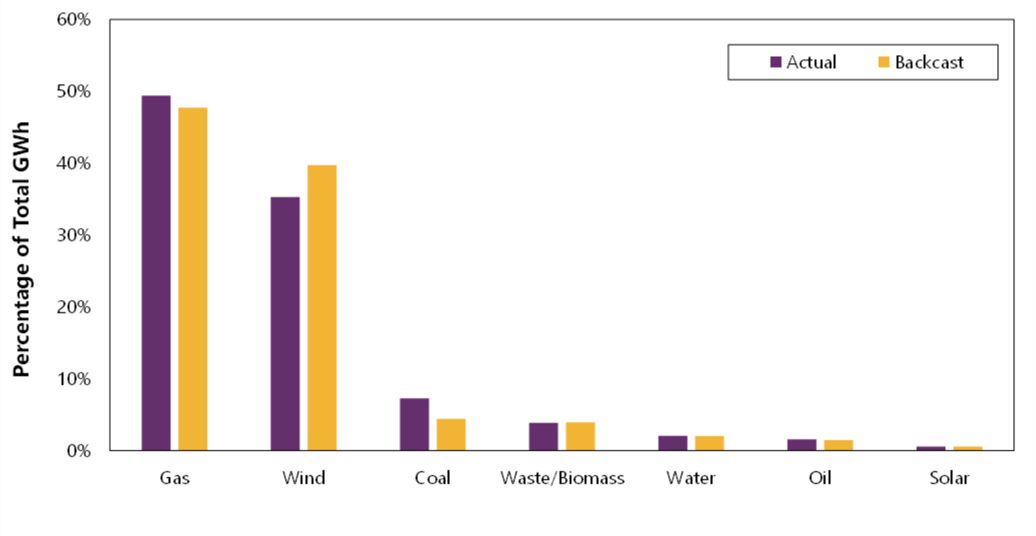

Figure 11: Average Hourly Generation Split by Fuel Type

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 12** 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.

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26 NERA developed an alternative backcast run using hourly load equal to the aggregation of DA Market instructions of the dispatchable generators plus historical DA-forecasted available wind plus historical net imports, and where wind generation was also equal to historical DA-forecasted available wind. This approach better mimics historical DA Market dispatch. The main backcast that considered loads equal to aggregation of metered generation better mimics the go-forward SEM PLEXOS Model, which has load equal to forecast metered load as represented by TER in the GCS.

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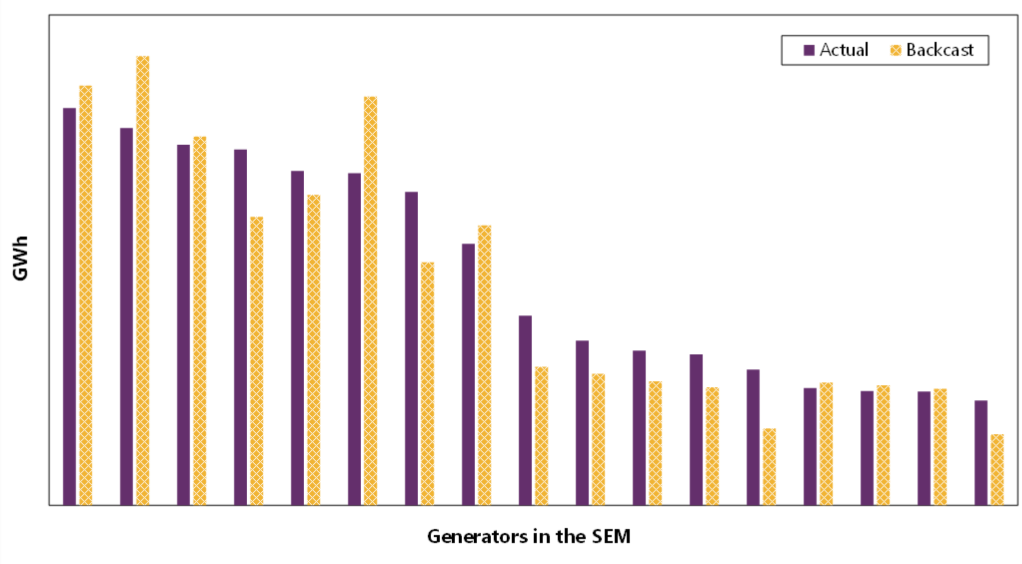

Figure 12: Average Hourly Generation by Generator

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 includes several new generation plants in the 2024-2032 SEM PLEXOS Model, as listed in Table 6 below. Note the "Assumed Online Dates" are merely a statement of the assumptions in the SEM PLEXOS Model. While these dates are based on NERA's correspondence with generators and the RAs, NERA makes no warranty as to what the actual online dates will be. Model users are free to put in different online dates as they see fit.

Unit	Jurisdiction	Fuel	Capacity (MW)	Assumed Online Date
Castlelost Flexgen	ROI	Gas	275	17-May-2025
Corduff Flexgen	ROI	Gas	65	7-Dec-2024
Data and Power Hub GT	ROI	Gas	59	1-Oct-2027
GIL Athlone Park	ROI	Gas	100	1-Nov-2025
GIL Profile Park	ROI	Gas	100	1-Nov-2025
Grange Backup Power GT	ROI	Gas*	111	1-Jul-2025
Kilroot GT6	NI	Gas	345	1-Aug-2024
Kilroot GT7	NI	Gas	345	1-Aug-2024
Knockfinglas A	ROI	Gas	200	1-Dec-2028
Knockfinglas B	ROI	Gas	200	1-Dec-2028
Platin	ROI	HVO	157	3-Aug-2027
Poolbeg Flexgen	ROI	Gas	65	14-Jun-2024
Poolbeg OCGT	ROI	Gas	299	01-Mar-2027
Powerhouse Generation (PH7)	NI	HVO	20	1-Oct-2024
Ringsend Flexgen	ROI	Gas	65	28-Jun-2024
Tarbert Unit 5	ROI	HVO	300	31-Aug-2027

*Grange GT uses a fuel blend consisting of 99% gas and 1% distillate.

Table 6: New Generation Plants

NERA developed this list by reviewing the list of new generators that have won capacity awards, reviewing cancelations of capacity awards, asking generation companies what new units they are developing (and following up for more information as needed), and discussing potential new generators with the RAs.

NERA recognizes that currently planned generation units may be cancelled and that additional units not on this list may come online prior to the end of the modelling horizon in 2032. Thus, the SEM PLEXOS Model should be a living model, with updates to the generation fleet as needed – either during a validation exercise or as feasible between validations. Indeed, it is likely that new generation capacity not on the above list will be developed and come online prior to the end of the 2032. Model users may, as they see fit, add additional capacity they might expect will come online in the later years of the model.

Generally, NERA obtained technical and commercial data for the new units from their owners. For new units where the owners did not provide estimated technical and or commercial parameters, NERA developed reasonable placeholder assumptions. For example, NERA derived a generic heat rate for new gas turbines from a recent Pöyry report to the RAs on the costs of new entry power plants[27].

The 2024-2032 SEM PLEXOS Model retires the following generation plants, based on the assumptions stated in the 2023 GCS (see Tables 5.3 and 5.5):

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-Jan-2024
Moneypoint (All Units)—Transition to Available in Emergencies*	ROI	750	Coal & Fuel Oil	1-Jul-2025

Table 7: Retired Generation Plants Based on 2023 GCS

* From discussions with industry and the RAs, NERA understands that on or around 1 July 2025 Moneypoint will transition to a new role in the SEM. Moneypoint will serve as backup a generator that does not participate in the regular SEM energy markets but is available in emergency conditions. The 2024 SEM PLEXOS Model retires Moneypoint as of that date, because the SEM PLEXOS Model simulates unconstrained dispatch under generally normal operations of the SEM – under such conditions Moneypoint is unlikely to generate. Nonetheless, users of the SEM PLEXOS Model can keep Moneypoint in the model if they wish to for their modelling purposes – users will want to

27 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. NERA applied this heat rate to the new gas turbines Data and Power Hub Services and Grange (NERA had unit-specific heat rates for the other new generation units.) Link: https://www.semcommittee.com/files/semcommittee/media-files/SEM-18-156a%20Poyry%20Report%20-%20Cost%20of%20New%20Entrant%20Peaking%20Plant%20and%20Combined%20Cycle%20Plant%20in%20I-SEM.pdf.

update MP1 and MP3 to be oil-burning in that scenario. Moneypoint's capacity of 750 MW in this table reflects its capacity as entered in the 2023 GCS.

The 2023 GCS states that Aghada unit 1 (AT1) will close before the end of 2023 (2023 GCS, Table A4-1), but from discussions with industry and the RAs, NERA understands it is still in operation and has no currently planned retirement date within the horizon of NERA's modelling. Thus, it remains in operation in the SEM PLEXOS Model. The Edenderry biomass unit extends through the full modelling horizon in the 2024 SEM PLEXOS Model. While the 2023 GCS notes that Edenderry's planning permission was extended to 2030, NERA understands that it may have its planning permission extended further. Users of the 2024 SEM PLEXOS Model may add in a retirement date for Edenderry if they chose to do so.

NERA also removed Data and Power Hub GT 2 from the SEM PLEXOS Model: that unit was included in the prior Model but its capacity contract was terminated. Data and Power Hub GT 1's capacity contract was terminated as well, but NERA understands that a new contract has since been awarded[28].

Figure 13 below shows total generation capacity by fuel in the 2024-2032 SEM PLEXOS Model and compared with the 2021-2029 SEM PLEXOS Model, comparing end of 2025 (a near term year common to both).

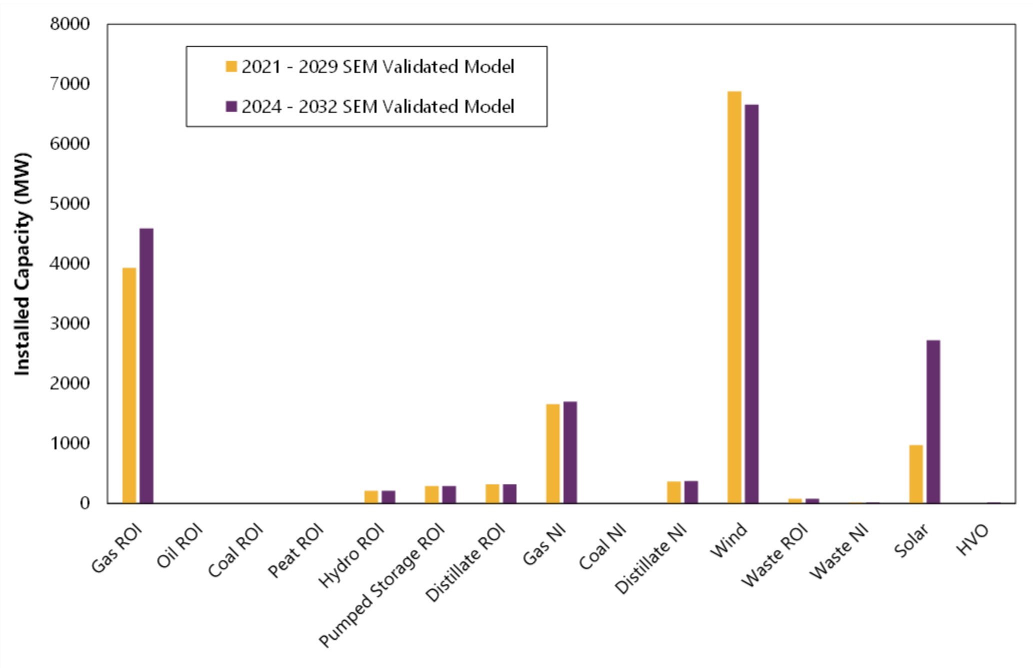

Figure 13: Generation Capacity in 2024-2032 SEM PLEXOS Model vs. 2021-2029 SEM PLEXOS Model (End of 2025)

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28 For the termination of prior capacity contracts, see https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_034087-Data-and-Power-Hub.pdf. For the new capacity award see https://www.sem-o.com/documents/general-publications/FCAR2728T-4-report-v1.0.pdf.

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 2024-2032 SEM PLEXOS Model, as shown in Table 8.

Battery	Jurisdiction	Capacity (MW)	Online Date
Beenanaspuck and Tobertoreen Battery	ROI	11	1-Apr-2020
Kelwin 4 Battery	ROI	27	1-Apr-2021
Gardnershill Battery	ROI	9	1-Apr-2021
Drumkee Battery	NI	50	1-Apr-2021
Mullavilly Battery	NI	50	1-Apr-2021
Lumcloon BESS 1	ROI	50	30-Jun-2021
Lumcloon BESS 2	ROI	50	30-Jun-2021
Shannonbridge BESS A1	ROI	50	29-Sep-2021
Shannonbridge BESS A2	ROI	50	29-Sep-2021
*Gorman**	*ROI*	*50*	*(turned off)*
Porterstown Battery Phase 1	ROI	30	6-Jul-2022
Aghada BESS	ROI	19	3-Aug-2022
*Kells BESS**	*NI*	*50*	*(turned off)*
Lisdrumdoagh Energy Storage	ROI	60	23-Mar-2023
Gorey Storage	ROI	9	31-Mar-2023
Avonbeg Storage	ROI	16	31-Mar-2023
Kylemore BESS	ROI	30	6-Oct-2023
Poolbeg BESS	ROI	75	28-Nov-2023
South Wall BESS	ROI	30	17-May-2024
Aghada BESS 2A	ROI	75	22-Aug-2024
Aghada BESS 2B	ROI	75	22-Aug-2024
Cloncreen BESS	ROI	25	1-Oct-2024
Cushaling Battery	ROI	23	1-Mar-2025
Shannonbridge BESS B	*ROI*	*63*	1-Oct-2025
Energy Stability Services Battery	ROI	25	1-Jan-2026
Energia Battery Storage	NI	50	1-Apr-2026
*Barnesmore**	*ROI*	*3*	*(turned off)*

Table 8: Assumed Existing and Planned Batteries

* NERA includes technical information for these batteries in the 2024 SEM PLEXOS Model, but they are turned off in the model, as explained below.

NERA developed this list based on best-available information at the time of writing this report from the generation companies, the RAs, and the results of capacity auctions. However, this list is subject to change. NERA recognizes that currently planned battery units may be cancelled and that additional units not on this list may come online prior to the end of the modelling horizon in 2032.

Thus, the SEM PLEXOS Model should be a living model, with updates to the battery fleet as needed – either during a validation exercise or as feasible between validations. Model users may as they see fit add additional battery capacity they might expect will come online in the later years of the model.

NERA exclude batteries if NERA understood, from discussions with their owners, that a) they would have little to no participation in energy markets going forward or b) their future status was uncertain. Several owners expressed uncertainty as to their level of energy market participation going forward. NERA's approach (discussed below) of transitioning all batteries from 10%, to 30% to 50% potential participation levels over time should capture this uncertainty – some batteries may participate at higher rates and some at lower rates, but those participation percentages are reasonable overall for SEM PLEXOS Model purposes.

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:

a) 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.

b) 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 (NERA notes the strike price may be higher depending on fuel and CO_2 prices, as calculated by SEMO on a weekly basis).

c) 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.

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:

1) 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.

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

3) 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 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 three methods for appropriately limiting participation in the energy markets:

a) Incorporating system services requirements into the SEM PLEXOS Model, thus allowing PLEXOS to determine how much batteries (and any other resources) participate in system services versus the energy markets. NERA did not adopt this approach as this would require a significant re-working of the SEM PLEXOS Model that was out of scope for NERA's engagement.

b) Adding a VOM charge that represents the opportunity cost of participating in the energy markets, i.e. the lost revenue from not providing system services. From an economic standpoint, this approach has advantages as it mimics the economic trade-off batteries implicitly or explicitly make. Yet, the challenge is estimating a reasonable VOM charge that mimics the opportunity costs of not providing system services, particularly given the reality that these opportunity costs may change: a) over time as market rules change and supply and demand changes, b) seasonally or during the hours of the day, and c) as fuel and CO_2 emissions prices change. It was out of NERA's scope to perform the comprehensive analysis needed even to determine whether this approach was workable in practice.

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

NERA adopted the third approach. NERA determined three different percentages that apply in three different time periods in the modelling horizon:

b) From present until April 2025: 10% energy market participation. From discussions with the RAs and stakeholders, NERA understands the following limit battery participation in SEM energy markets as of the writing of this report:
   a. batteries are limited in their ability to autonomously charge—specifically NERA understands that, without approval to do otherwise, batteries may only charge up to the minimum of their i) maximum import capacity ("MIC"), ii) 20 percent of their maximum export capacity ("MEC"), iii) 5 MW[29,30].

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29 MEC and MIC reflect limits imposed by the TSOs on the maximum and minimum amount of power that a resource can, respectively, export to or import from the power grid. While the MIC limits charging in all cases, the current policy towards battery charging imposes further limits. For example, a 30 MW battery might have a 30 MW MEC and a 30 MW MIC. In practice that battery can autonomously charge no more than 5 MW (the lower of MIC, 20% or MEC, and 5 MW). Similarly, the limit on a 20 MW battery with 20 MW of MEC and MIC would be 4 MW.

30 NERA does not explicitly model this minimum charging, but rather assigns a relatively low energy market participation level (10%) to account for the fact that such limits on autonomous charging exist.

b. the SEM does not presently have system services markets that are co-optimized with the energy market – such markets can allow batteries to automatically be dispatched into the market where the most profit is to be made, including potentially the energy markets.

c) April 2025 to December 2026: 30% energy market participation, representing the fact that restrictions on autonomously charging are expected to change around this time. 30% comes from the midpoint between 10% and 50% (see next).

- December 2026 and beyond: 50% energy market participation, representing the fact that DS3 regime will likely be replaced with a market-based system services regime, which we presume will be co-optimized with the energy markets (NERA's understanding is based on communication with stakeholders and the RAs). 50% represents a 50% split between energy and system services.

NERA received feedback from 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. NERA previewed the proposal for 10%, 30%, and 50% energy market participation factors with owners of batteries and asked whether different percentages would be more appropriate. NERA also engaged with the RAs on NERA's plan for battery modelling and the precise percentages proposed. While the precise percentages used are, strictly speaking, arbitrary, NERA's stakeholder engagement did not determine that different percentages would be better, and the RAs agreed that NERA's proposed approach was reasonable.

NERA notes that the 2021 SEM PLEXOS Model also started with 10% and then transitioned to 50% battery energy market participation, based on stakeholder feedback in the prior validation. NERA maintains those percentages, though NERA added a middle stage (30%). The 2024-2032 SEM PLEXOS Model also reflects an updated schedule for when 10% transitions to 30% and then transitions to 50%, based on the results of NERA's stakeholder engagement.

In the validation of the 2021 SEM PLEXOS Model, 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 become available, the RAs may refine this approach to modelling batteries in the SEM PLEXOS Model, when completing future backcast/validation exercises.

Separately, NERA incorporated the per-MWh grid fees charged in Ireland to resources such as batteries that charge from the grid. These fees are about €23.93/MWh for charging in peak hours (Hours Beginning 18-19) and €22.06/MWh for charging in off-peak hours[31]. All things equal, such fees will lead to lower participation of batteries in energy markets. NERA applied these fees uniformly to all batteries in ROI. While it is uncertain whether such fees will remain in place through

[31] Source: EirGrid Statement of Charges, Applicable from 1st October 2023. While NERA recognizes that the fees could differ based on the details of how batteries connect to the grid, for simplicity NERA applies the EirGrid fees uniformly to batteries in the ROI. NERA notes that fees have increased since October 2024, but this increase occurred after NERA's cut off for updates to this parameter.

the end of 2032 (the last year modelled in the 2024-2032 SEM PLEXOS Model), NERA maintains the fees through 2032. Based on discussions with the RAs, NERA is not aware of a firm plan to eliminate such fees. Model users may choose to remove the fees to the extent their view is that the fees may cease to apply.

NERA did not model battery degradation in the SEM PLEXOS Model. While degradation of battery capacity may occur, NERA understands a) that battery owners can augment their battery units to counteract degradation and b) NERA expects that the SEM will continue to add new battery capacity through 2032 (and beyond), including batteries not currently present in the SEM PLEXOS Model – thus NERA expects that excluding degradation may nonetheless result in a more accurate level of future capacity in PLEXOS than including degradation would.

Finally, we note that some stakeholders suggested that the SEM PLEXOS Model should directly model system services, co-optimizing those markets with the energy markets, taking effect from the date when the SEM may transition to such co-optimization. NERA recognises that modelling the co-optimization of system services and energy markets in models like PLEXOS is a standard approach, which at least has the potential to increase model accuracy. That said, there are many issues the RAs might consider prior to adopting such an approach: a) the cost and time required to build out such a model and maintain it; b) whether explicit incorporation of system services results in a model is helpful (or not) considering the modelling purposes for which the RAs use the SEM PLEXOS Model (such as for Directed Contract pricing)[32]; c) whether the incorporation of system services in practice improves model accuracy; and d) the timing of such an effort, given that as of the writing of this report the SEM does not co-optimize system services and energy markets.

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 and batteries 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.

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 and commercial and technical offer data. The RAs may wish to conduct such a comprehensive review in future validation exercises[33]. The data and information used here was the best available and assumed accurate at the time of writing this report. However, all information is subject to change.

NERA focused its 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

[32] See for example https://www.semcommittee.com/news/directed-contract-round-28-q1-2025-q4-2025.

[33] NERA generally relied upon outturn data and GCS-published values for reasonableness checks. For the Indaver Waste-to-Energy unit, however, while the 2023 GCS lists the capacity of the unit at 17 MW, NERA adjusted this to 19 MW for the purposes of the SEM PLEXOS Model. NERA understands 19 MW reflects typical average output including house load. NERA included the house load effect because demand in the SEM PLEXOS Model includes behind-the-meter demand.

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 some of 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 run when available, which NERA understands is their operational pattern[34].

The public version of the 2024-2032 SEM PLEXOS Model, and the accompanying Excel generator dataset (PUBLIC--GEN DATA 2024-32.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. While battery commercial inputs are confidential, the grid fees for charging discussed above are based on a public tariff, so those are reflected in the public model.

NERA delivered to the RAs a confidential 2024-2032 SEM PLEXOS Model which includes VOM costs, markups and cycling limits. For simplicity, we model only daily and yearly battery cycle limits. While some batteries have weekly and monthly cycle limits, we found that the weekly cycle limits were generally redundant given the daily limits and that while the monthly limits could bind in some cases, given the annual limits it seemed unlikely that they would bind.

5.4. Hydro and pumped storage data

NERA has maintained the hydro and pumped storage data from the 2021-2029 SEM PLEXOS Model in the 2024-2032 SEM PLEXOS Model, which NERA deemed reasonable 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 2024-2032 SEM PLEXOS Model to reflect the latest updated projections of outage schedules from 2024 to 2027, 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 and Greenlink interconnectors, as they are not yet included in the TSOs' outage schedules.

For the years 2028 to 2032, for existing resources, NERA utilized average-year outage schedules through the use of maintenance rates developed by averaging the 2025 to 2027 (inclusive) outage plan by category of resource[35].

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

[35] 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.

Category	2025	2026	2027	Average	Rate
Batteries	5	5	5	5	1.5%
CCGT	18	33	32	28	7.6%
CT	25	23	8	18	5.1%
Hydro	31	21	9	21	5.6%
Lines	9	4	6	7	1.8%
Pump	24	13	86	41	11.3%
Waste/Biomass	20	38	17	25	7.0%

Table 9: Average Planned Maintenance Outage Days by Type of Unit

For the new gas turbines, NERA assumed three weeks of outages per year (the same assumption from Table 5.12 of the 2023 GCS), which translates to a 5.8% maintenance rate ("MR"). NERA used that same MR for new gas-fired engines (gas engines are not listed in Table 5.12 of the 2023 GCS).

Once the new units and interconnectors are part of the TSOs' outage schedules, the RAs may wish to switch to precise outage modelling for these entities.

For all batteries, NERA maintained the aggregate placeholder availability rate assumption of 95% adopted in the 2021-2029 SEM PLEXOS Model. NERA assumed 3.5% FOR and 1.5% MR for batteries. The 2021-2029 SEM PLEXOS Model reflected 1% FOR and 4% MR. NERA reduced the maintenance rate based on its review of the battery planned maintenance outages schedules from the TSOs, which reflected average maintenance rates of 1.5%; NERA adjusted the forced outage rate correspondingly to maintain 95% availability. NERA and the RAs agreed to maintain use of a generic maintenance rate for batteries (rather than specific outage schedules) for simplicity of modelling and given the fact that batteries are still relatively low in terms of share of capacity and generation in the SEM. In future validations, when more data on battery availability is available, the RAs may either refine the assumed default outage percentages or switch to use of precise outage schedules for the validated SEM PLEXOS Model. In the meantime, model users are free to use precise outage schedules for batteries rather than maintenance rates if they see fit to do so. NERA is comfortable that the SEM PLEXOS Model will work under either approach, so long as the model user takes care not to double count maintenance outages.

Important note to avoid double counting of maintenance outages: The SEM PLEXOS Model is set up where maintenance outages are modelled *either* by approach a) specifying precise offline days *or* approach b) specifying a maintenance rate and PLEXOS running an optimization to determine precise offline days. As discussed above, the 2024-2032 SEM PLEXOS Model utilized maintenance rates (approach b) for several resources for the entire 2024-2032 modelling horizon. For all resources, the SEM PLEXOS Model uses maintenance rates for the post-2027 period (approach b). When and if the RAs or any modeller choose to switch to specified outages days (approach a) for particular resources or particular years, then the maintenance rates should be deleted or set to zero for those resources or years. Otherwise, both the specified days and the maintenance rates will apply, leading to double counting of maintenance outages. As a specific example, at some point the RAs (or any user) may wish to put in a precise outage schedule for 2028. At that point, the maintenance rates should be set to 0% for 2028 for all resources for which a precise 2028 outage schedule is added to SEM PLEXOS Model.

5.5.2. Forced outages

Forced Outage Rates ("FORs") were calculated using reported *ex post* FORs, annually, from 2019 through 2023 (and going back to 2016 for some generators). For each historical year and each category in Table 10, NERA calculated a weighted average FOR (weighted by generator capacity); NERA then averaged across the historical period years. Each unit in a generator category is attributed the same FOR in PLEXOS. For categories with only one generation plant, the averages reflect eight years (2016 to 2023) to reduce the chance of one-off events affecting the averages. Specifically, this applies to coal (only Moneypoint) and pumped storage (only Turlough Hill). The historical averages do not include generation units that retired as of 2024.

The 2024-2032 SEM PLEXOS Model include the forced outages rates in Table 10 below.

Generator Type	FORs Prior Validation	Updated FORs
Gas	5.5%	6.4%[36]
Oil	5.0%	n/a
Coal[37]	23.4%	19.1%
Peat/Biomass	3.7%	n/a
Hydro	4.1%	10.9%
Pumped Storage	6.3%	5.0%
Distillate	3.4%	5.9%
Waste/Biomass[38]	6.7%	11.4%

Table 10: Forced Outage Rates by Generator Type

The changes in FORs reflect the use of the most recent five years of data (or eight years for coal and pumped storage). While hydro forced outage rates nearly doubled, hydro generation will be nearly identical, as the SEM PLEXOS Model has set amounts of available generation by day for hydro. All the hydro plants have multiple units, so if one is offline, the others can increase generation to maintain the daily generation totals.

Adjustment to Moneypoint FOR: The coal outage rate of 19.1% is calculated based on a 250 MW capacity for each of the Moneypoint units. The 2024-2032 SEM PLEXOS Model assumes 250 MW capacity for each of the Moneypoint units, in line with the assumption of the 2023 GCS (Table A4-1). The 2023 GCS explains the use of 250 MW: *"MP2 is now running on Heavy Fuel Oil (HFO) with a capacity of 250 MW. The declared availability of MP1 and MP3 has declined recently and is now on*

36 Based on discussions with the RAs, NERA decided to remove two historical examples of high forced outage rates (one year removed for each of two units) that NERA understands were outliers.

37 Moneypoint 2 is included in the coal category . The "FORs Prior Validation" for Coal is based off of a 285 MW capacity for Moneypoint units. The "Updated FORs" for Coal is based off of a 250 MW capacity for Moneypoint, as discussed below.

38 For the present Validation, the Waste/Biomass category includes Edenderry. In the prior Validation, Edenderry was in the Peat/Biomass category.

average 250 MW"[39]. NERA's understanding is that Moneypoint's theoretical maximum capacity is 285 MW, but 250 MW reflects available capacity in practice. The SEM FOR data for Moneypoint is based on 285 MW capacity. Based on 285 MW, the average historical FOR for Moneypoint is 29.1%. To avoid double counting of forced outages, NERA adjusted the historical FOR downwards so that the FOR in PLEXOS is consistent with a 250 MW capacity for Moneypoint[40].

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, keeping the same FOR assumed in the 2021-2029 SEM PLEXOS Model.

For batteries, as already mentioned, a 3.5% FOR is assumed as a reasonable placeholder assumption.

39 2023 GCS, p. 81.

40 NERA notes the equivalence of (100% - 29.1%) * 285 and (100% - 19.1%) * 250 – both equal a FOR-adjusted capacity of 202 MW.

6. System Data

6.1. Demand

NERA uses an hourly demand forecast covering the years 2024 through 2032 in the 2024-2032 SEM PLEXOS Model. The demand forecast reflects the peak demand and the total annual energy requirements (TER) forecast from the 2023 GCS. Specifically, the "median" forecasts from the 2023 GCS are used, shown in Table 11.

Year	Peak Demand (GW)	Total Energy Requirement (TWh)
2024	7.59	45.1
2025	7.80	46.9
2026	8.02	48.8
2027	8.22	50.7
2028	8.35	52.1
2029	8.48	53.5
2030	8.64	54.9
2031	8.82	56.6
2032	9.03	58.4

Table 11: Demand Forecast for the All-Island Market

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 2024 through 2032 hourly demand forecast were produced, each based on a different base year demand profile. Historical hourly demand from 2018 to 2023 (skipping 2020, the initial year of the Covid-19 pandemic) was used to produce five different demand shaping patterns. Each of the five versions of the demand forecasts from 2024 through 2032 correlate with the forecast from Table 11. The only difference among the five forecasts is how the total annual energy from Table 11 is distributed within each year of the forecasts (where the different in-year distributions are based on the five historical hourly demand patterns from 2018 to 2023, skipping 2020). We note that five patterns go in order in PLEXOS: 2018 is pattern 1, 2019 is pattern 2, 2021 is pattern 3, etc.

6.2. Wind

The wind forecast is based on the 2023 GCS's forecast of wind capacity in Ireland and Northern Ireland, shown in Table 12 below[41].

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

At Year End	ROI Onshore Capacity (MW)	ROI Offshore Capacity (MW)	NI Total Wind Capacity (MW)
2024	5,060	25	1,443
2025	5,110	25	1,536
2026	5,755	25	1,607
2027	6,400	25	1,751
2028	6,700	725	1,989
2029	7,000	2,865	2,173
2030	7,000	5,000	2,958
2031	7,000	7,135	3,243
2032	7,000	9,270	3,528

Table 12: Wind Capacity Forecast

In Ireland, the wind forecast is split between onshore and offshore wind. Further, in PLEXOS, 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 in the 2023 GCS is split between small- and large-scale wind. The 2024-2032 SEM PLEXOS Model represented all of NI wind with a single generation object in PLEXOS (a change versus the prior model that included separate large- and small-scale NI wind generation objects). NERA utilized a single NI wind object because the historical generation dataset that NERA used did not distinguish between large- and small-scale wind.

Historical wind profiles are used to determine wind availability in PLEXOS on an hourly basis. For onshore wind in ROI and NI, wind profiles from 2018 to 2023 are used (again skipping 2020), to align with the same years as chosen for load profiles. As with prior validations, the SEM PLEXOS Model uses wind and load profiles from the same historical year (2018 wind is linked to 2018 load, etc.).

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

NERA developed two versions of the historical wind profiles: one based on historical available wind and one based on historical actual wind generation. The actual historical actual wind generation profiles reflect historical dispatch down of wind, whether due to transmission constraints or curtailments or other factors. NERA notes that the SEM has system non-synchronous penetration limits, which may lead to wind curtailment (wind is a form of non-synchronous generation).

For the planned new offshore wind in ROI, NERA uses a 45% available generation capacity factor, the same assumption stated in the 2021 GCS[42].

See Appendix B for details of how NERA developed historical hourly wind profiles.

42 2021 GCS, Table 12.

6.3. Solar

Solar generation forms a small percentage of generation in the SEM today (~2%). Yet, solar capacity is expected to increase significantly versus current levels up to 7.4 GW by 2032, according to the 2023 GCS. While annual capacity factors are small (~11%), at peak sun times solar will likely form a significant portion of generation in future years.

The solar forecast is based on the 2023 GCS's forecast of solar capacity in Ireland and Northern Ireland, shown in Table 13 below[43].

At Year End	ROI Solar (MW)	NI Solar (MW)
2024	1,838	280
2025	2,436	345
2026	3,089	401
2027	3,741	457
2028	4,327	509
2029	4,914	582
2030	5,500	617
2031	6,086	677
2032	6,672	731

Table 13: Solar Capacity Forecast

Historical solar profiles are used to determine solar availability in PLEXOS on an hourly basis. NERA developed two versions of the historical solar profiles: one based on available solar and one based on actual solar generation. Given the paucity of historical solar data, NERA used a combination of historical data, synthesized historical generation profiles, and extrapolation. See Appendix B for details of how NERA developed historical solar profiles. In future validations, there may be sufficient solar data to undertake a process similar to that completed for onshore wind to develop historical 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 2023 GCS lists a total of 754 MW of DSUs across Ireland and Northern Ireland (2023 GCS, Table 5.9, 2024 entry). 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 2021-2029 SEM PLEXOS Model had five 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 in the SEM, the average "generation" (generation is in quotes, because technically this represents reduced demand) from DSU resources is still relatively small, so it is reasonable to continue this

43 As with wind, the annual solar capacity growth forecast is extrapolated into a monthly growth forecast.

simplified aggregation into P-Q pairs. If average DSU "generation" expands significantly, NERA recommends that the RAs consider enhancing the modelling of DSUs in future validations.

In line with historical data, DSUs are rarely dispatched in the test runs of the 2024-2032 SEM PLEXOS Model, except for 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, such 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). Such DSU "generators" are excluded from the embedded generation determined by the TSOs, to avoid double counting.

The 2021-2029 SEM PLEXOS Model included the DSU values from Table 14. Note the quantities are incremental quantities, i.e. when DSU Block 3 is dispatched, the total quantity dispatched is the sum of blocks 1, 2, and 3.

DSU Blocks	Quantity (MW)[44]	Price (€/MWh)
1	6.1	0
2	4.5	20
3	4.6	30
4	2.3	100
5	7.1	250

Table 14: Demand P-Q Pairs, 2021-2029 I-SEM PLEXOS Model

In the 2024-2032 SEM PLEXOS Model also includes five demand P-Q, as shown in Table 15.

DSU Blocks	Quantity (MW)	Price (€/MWh)
1	0.9	0
2	4.5	50
3	6.0	75
4	2.5	100
5	4.7	230

Table 15: Demand P-Q Pairs, 2024-2032 SEM PLEXOS Model

The 2024-2032 SEM PLEXOS Model continued the approach adopted for the 2021-2029 SEM PLEXOS Model to determine DSU P-Q pairs. That approach uses historical data to assess what quantity of DSU capacity was dispatched (on average) at different price points. As Table 15 shows, the total amount of DSU capacity dispatched in PLEXOS even at the highest prices is well below the total DSU quantity in the SEM market of approximately 750 MW. Yet the numbers in PLEXOS reflect

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

historical dispatch patterns – what actually is dispatched, generally. NERA presumes that most DSU quantities would only be dispatched in very extreme situations, situations unlikely to appear in the SEM PLEXOS Model, which essentially models normal operations of the SEM. That said, if model users notice significant unserved energy or prices well above the strike price in CRM contracts, then the user may consider adding additional DSU quantities (potentially up to the total quantity of DSUs in the SEM) at a very high price P-Q pair. NERA notes that such situations (significant unserved energy or prices well above the strike price in CRM contracts) did not occur in NERA's test runs. The potential for unserved energy in PLEXOS in the SEM PLEXOS Model – and how to deal with it – is discussed in greater detail in Section 8.10 below.

NERA expects that the adopted backcast-based approach to determine DSU P-Q pairs will remain fit for purpose, at least so long as actual quantities of DSU dispatch remain relatively small. For completeness, NERA highlights below two alternative approaches that could be considered in future backcasts.

- 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, however it has the disadvantage of potentially causing high prices that may not reflect actual DSU dispatch in the SEM[45].

- 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.

Finally, NERA notes that the 2023 GCS shows the evolution of DSU quantities in the SEM through 2032 (2023 GCS Table 5.9), and NERA increases proportionally all DSU quantities in PLEXOS to reflect this growth path.

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 February 2025 (that date is per discussions with the RAs and TSOs), and the proposed Celtic Interconnector, between Ireland and France, is expected to come online in January 2027 (per the RAs and TSOs).

NERA made the following updates to the technical parameters of the existing interconnectors versus the parameters in the 2021-2029 SEM PLEXOS Model:

1) For the East-West ("EWIC") and Moyle interconnectors, the ramp rates start at 5 MW/min and increase to 10 MW/min in January 2030.

45 This can occur because simplified P-Q pairs will likely blend DSU "start costs" (a fixed payment the first hour of any level of dispatch) and DSU incremental costs.

2) A 1.8% maintenance rate is applied for EWIC and Moyle for the time period beyond the planned outage schedule (i.e. 2028 and beyond); the same MR is applied to Greenlink and Celtic over all years.

3) Loss rates were updated as suggested by the RAs and TSOs. The loss rate on Celtic was reduced from 7.5% to 4%, and the loss rate on Greenlink was reduced from 5% to 2.3%.

As per the previous SEM PLEXOS Models, Moyle's contract capacity is reflected in the 2024-2032 SEM PLEXOS Model: west to east 500 MW; east to west 450 MW from November to March and 410 MW from April to October. NERA notes the contract capacity on Moyle is lower than the maximum transfer capacity on Moyle, so potentially more exports could flow from SEM to GB. Yet, given the relatively good alignment of the PLEXOS Model with historical data in the backcast, NERA believes that maintaining the assumption of limiting exports to the contract capacity is reasonable[46].

For the East-West interconnector, the same assumptions from prior models are maintained in the 2024-2032 SEM PLEXOS Model, namely that max flow to GB from the SEM is 500 MW and 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 4.0% for Celtic and 2.32% for Greenlink. NERA set the ramp rates for both new interconnectors to 10 MW/min, per information provided by the RAs.

6.6 Transmission loss adjustment factors ("TLAFs")

As of the timeframe of NERA's update of the SEM PLEXOS Model, the 2023-24 TLAFs were the most up-to-date data[47]. For any new generation of battery units not in that data, NERA utilizes a system-average TLAF – users may update the model to use precise TLAFs when those are published for new resources[48].

6.7 Embedded generation

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

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

[46] NERA notes that on average, the backcast has higher net imports in PLEXOS than occurred historically. Thus, had NERA increased the capacity in the east to west direction, the issue would have been exacerbated.

[47] *See* https://www.eirgrid.ie/industry/customer-information/transmission-loss-adjustment-factors.

[48] Existing units' TLAFs are set with a data file. When new units are incorporated into the TLAF data file, the model user should link the Marginal Loss Factor property to the data file and remove the link to the generic TLAF.

- Wind and 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

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

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 by the TSOs) and multiplying that capacity factor by the total capacity for each category of partially / non-dispatchable generation. NERA implemented the 164 MW constant output in the SEM PLEXOS Model.

The relevant categories, as listed in the 2023 GCS, are:

- For ROI: Small Scale Hydro, Biomass and Biogas, Biomass CHP, Industrial, and Conventional CHP – see Table A4-2 of the 2023 GCS.

- For NI: Small Scale Biogas, Landfill Gas, Small Scale Biomass, Renewable CHP, Other CHP, Small Scale Hydro, and Waste to Energy – see Table A4-5 of the 2023 GCS.

7. Commodities

7.1 Fuels and CO_2 Prices in the All-Island Market

The indicative fuel and CO_2 prices from Table 16 below are included in the 2024-2032 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 market expectations around the time NERA performed its analysis. However, NERA cautions that these prices may quickly become obsolete. NERA uses the same prices each year from 2024 through 2032. When the RAs (or any user) use the model for forecast purposes, NERA recommends that they update the fuel price input data.

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 ($/t)	150	150	150	150
EU Carbon (€/t)	100	100	100	100
HVO ($/t)	813	813	813	813

Table 16: Indicative Commodity Prices used in 2024-2032 SEM PLEXOS Model

HVO is Hydrotreated Vegetable Oil, which is a biofuel similar to gasoil. A few existing and planned units plan to operate in full or in part on HVO. Based on conversations with generation companies, NERA determined a consensus ratio of 1.25, which estimates the premium of HVO to gasoil. So long as HVO and diesel prices tend to move in the same direction, and so long as HVO-fired generation resources tend to form a relatively low portion of generation in the SEM, such a ratio approach is reasonable.

For Edenderry, NERA includes in the model a generic biomass price. In the confidential version of the model, NERA reflects a precise price curve of biomass derived based on analysis of historical offer data and discussions with Edenderry's owner.

From discussions with generation owners and the RAs, NERA understands that generators that run on biomass or HVO will not face incremental CO_2 emissions costs for the purposes of their offers into the SEM – NERA reflects this in the SEM PLEXOS Model.

NERA used indicative foreign exchange rates of 1.07 $/€ 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.

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:

- the prices from the carbon trading scheme in the UK, known as UK ETS; plus
- The UK Government's carbon price support scheme, known as CPS. NERA notes that the CPS in the UK is £18/t[49]. The CPS has been at this price level for many years, and NERA keeps the CPS price at this level for 2024-2032 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.

While forward markets exist for UK CO_2 prices, NERA and the RAs agreed to use a formula to determine the UK CO_2 prices based on the PLEXOS inputs for EU CO_2 prices. 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[50]. Importantly, for that model to be accurate, the most-relevant 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.

Thus, NERA reviewed recent forward data for EU ETS and UK ETS CO_2 prices and determined that it is reasonable to model UK ETS CO_2 prices as equal to 0.71 times EU ETS CO_2 prices[51].

A complexity for GB modeling is the EU's forthcoming Carbon Border Adjustment Mechanism (CBAM)[52], which may affect imports from GB into the SEM. The CBAM could impose additional costs on electricity imports from GB to SEM, but how it will be implemented in practice is uncertain as of the timeframe NERA updated the SEM PLEXOS Model. NERA recommends as a default approach setting the GB CO_2 to match precisely the EU ETS price starting in 2026 (the first year of CBAM). Thus, rather than pricing CO_2 in GB as (UK ETS + CPS CO_2 floor), the GB CO_2 will be priced as EU ETS (without any additional CPS CO_2 floor). NERA's reasoning is:

- There is potential for EU and GB CO_2 pricing to converge anyway.
- Current forwards starting in 2026 (at least as of the period when NERA performed its validation work) show that EU ETS prices are broadly similar to UK ETS + CPS floor.
- To the extent that EU ETS forwards are slightly higher than UK ETS + CPS floor (which was the case as of when NERA performed its validation work), CBAM could result in an additional cost on exports from GB to the SEM. But this adder, at least at a high level, would be an

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49 See, for example, https://www.gov.uk/government/publications/uk-emissions-trading-scheme-and-carbon-price-support-apply-for-compensation/compensation-for-the-indirect-costs-of-the-uk-ets-and-the-cps-mechanism-guidance-for-applicants.

50 A recent information note on DC Prices may be found here: https://www.semcommittee.com/news/directed-contract-round-28-q1-2025-q4-2025.

51 This is based on the ratio of recent forward prices for EU and UK ETS CO_2 emissions, looking at products covering emissions in 2024, 2025, and 2026. NERA reviewed forward prices through 20 Sept 2024, looking backwards at the ratios of EU to UK CO_2 prices over different recent historical time frames.

52 See https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en.

attempt to equalize carbon taxes between GB and the EU. NERA's proposed approach would go directly to such an equalization.

- NERA's proposed approach is broadly in line with what NERA understands is the economic reasoning behind CBAM. According to the European Commission website, "The EU's Carbon Border Adjustment Mechanism (CBAM) is the EU's tool to put a fair price on the carbon emitted during the production of carbon intensive goods that are entering the EU, and to encourage cleaner industrial production in non-EU countries[53]." NERA's approach to set CO_2 prices in GB to EU prices for the purpose of interconnector trade presumably is consistent with the goal of a "fair price on the carbon emitted". It seems reasonable to assume that the EU CO_2 price would be a fair price from the EU's perspective.

NERA suggests equalization of SEM and GB CO_2 pricing starting in 2026 as the default option. Yet, for flexibility, NERA includes an alternative option to price GB CO_2 in PLEXOS as forecast UK ETS + CPS floor, even in 2026 and beyond[54]. This option essentially assumes that CBAM will in practice not affect the CO_2 costs that affect cross-border SEM-GB electricity trade. Given the similarity of current forward-looking CO_2 costs in EU and GB, there is little difference between this alternative option and the default option of explicit equalization of CO_2 cost for the purposes of trade in the SEM PLEXOS Model.

NERA also includes a placeholder PLEXOS parameter where the user can put in a custom "tax" on GB CO_2 prices in line with the user's view of CBAM – this placeholder appears in the fuel spreadsheet that accompanies the SEM PLEXOS Model.

NERA recommends the RAs review how CBAM is implemented and develop any needed corresponding adjustments to the SEM PLEXOS Model.

7.3 Fuel Adders

In general, the 2024-2032 SEM PLEXOS Model uses the same fuel transportation costs used in the 2021-2029 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 economic 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

53 See https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en.

54 This flexibility is present in the fuel spreadsheet "PUBLIC--SEM commodity setup file 2024-32.xlsx" (and there is a confidential version for the RAs), which is provided as a supporting file to the SEM PLEXOS Model. Users may re-run the fuel spreadsheet with the alternative approach and then copy the results into the SEM PLEXOS Model.

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

Appropriately determining which generators include short-term gas capacity charges in their offers is important for the accuracy of the SEM PLEXOS Model. Yet, generators typically keep their gas procurement arrangements confidential. Further complicating the situation is that some 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 and change how their procurement strategies affect their offers into the SEM. The 2024-2032 SEM PLEXOS Model includes options for no pass through of short-term gas transportation costs into offers into the market, 100% pass through of short-term gas transportation costs into offers into the market, and a 50-50 blend of the two options[55].

To determine how to represent gas transport costs:

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

- NERA reviewed historical (and confidential) data on actual procurement of daily versus long-term gas transport capacity;

- NERA considered economic theory, which would suggest that, all things equal, generators with lower variable costs and generators which tend to generate at higher capacity factors would tend to be less likely to procure short-term gas transport capacity (and less likely to pass through such costs into their offers into the market); and

- NERA tested in its backcast runs the effect of switching certain generators between the different options for passing through short-term gas transport capacity costs.

Taking into consideration the goals of 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:

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

- The **confidential** version of the 2024-2032 SEM PLEXOS Model includes NERA's assignment of generators to categories of gas transport capacity costs based on NERA's best judgement considering all the factors highlighted above.

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

55 NERA included the 50-50 blend for NI gas costs as well (the 50-50 option for NI was not present in the prior validated model).

NERA cautions that the generators' gas procurement strategies may change in the future versus what is represented in the 2024-2032 SEM PLEXOS Model. NERA recommends 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 Short-Term Gas Capacity tariffs as of NERA's analysis gas year (2023-to-2024) for ROI in the SEM PLEXOS Model[56]. NERA also incorporates an NI Short-Term Gas Transportation Capacity fuel object in PLEXOS, incorporating the most recent forecast of daily entry capacity costs[57]. (NERA understands that exit capacity in NI is only available as an annual product.)

NERA also notes that it uses markups to mimic fuel transport costs for certain generators where this was deemed most appropriate, given the confidentiality of their fuel transport costs. These markups are not present in the Public PLEXOS Model.

NERA updated the ROI Coal fuel transport costs in the confidential model, and NERA includes a placeholder value for such costs in the public version of the SEM PLEXOS Model. Otherwise, NERA did not change the fuel adders in the SEM PLEXOS Model. NERA understands that most, if not all, of the other fuel adders in the SEM PLEXOS Model reflect averages based on prior 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 some generators to update certain fuel adders, other generators suggested that current adders remained appropriate. 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 has produced a spreadsheet that calculates the fuel price inputs to the 2024-2032 SEM PLEXOS Model. NERA has provided this spreadsheet to the RAs (PUBLIC--SEM commodity setup file 2024-32.xlsx), and understand it will be published alongside the public version of the 2024-2032 SEM PLEXOS Model. NERA updated the fuel spreadsheet associated with the 2021-2029 SEM PLEXOS Model to produce PLEXOS inputs through Quarter 4 2033, reflecting the various updates to CO_2 costs, fuel commodity costs and fuel transport costs as discussed above.

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

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

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 maintains all these assumptions.

8.2. PLEXOS Version

NERA recommends updating to PLEXOS Version 10.000 R07. In the waterfall analysis presented in Figure 20, NERA found a total effect of about €0.19/MWh when switching versions.

8.3. Generator Offers

In the 2021-2029 SEM PLEXOS Model—and as far as NERA is 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, in runs with uplift, PLEXOS adds an uplift that (within certain limits) sets prices high enough to guarantee each generator recovery of start and no-load costs.

NERA understands the above approach has worked to the RAs' satisfaction to date, and this is a standard approach to power market modelling. The current backcast results show the continued effectiveness of this approach. NERA maintains this approach in the 2024-2032 SEM PLEXOS Model, though some options in the 2024-2032 SEM PLEXOS Model do not include uplift.

Nonetheless, NERA points out that there are other potential approaches to modelling generator offers in PLEXOS, including utilizing bidding algorithm options in PLEXOS and or various approaches where the SEM PLEXOS Model might explicitly mirror offers in the DA Market. Future validations could consider alternative approaches.

8.4. Uplift Algorithm

All previous SEM PLEXOS Models going back to the start of the SEM in 2007 have (to NERA's knowledge) utilized an uplift algorithm, which increases the SEM price in certain hours as needed to a level that ensures compensation for start and no-load costs (the precise process is controlled by an algorithm in PLEXOS). While there has been no uplift in the actual SEM DAM since I-SEM Go Live, the use of uplift to date has been determined in prior validations to be reasonable conceptually and to allow for a good fit to historical prices. For the present validation, NERA continues to view the use of uplift as a reasonable approach. That said, NERA also includes alternative approaches that reflect no uplift: Option A2 (available wind and solar generation, without uplift and without wheeling charges) and Option B (potential actual wind and solar generation, without uplift and without wheeling charges).

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 SEM before I-SEM), and a custom uplift approach. Since I-SEM Go Live, all SEM PLEXOS Models have used the Korean Uplift, and NERA recommends maintaining that choice. As NERA recommends a one-start-state approach (tied to a MIP recommendation), the choice of uplift is less important. NERA understands that the main difference in practice between the SEM and Korean uplift is in the treatment of different start states. NERA found trivial differences (about 0.1% difference in prices overall) between the two uplifts when running in the MIP one-start-state approach. Given such minor differences, NERA defaults to continuation of use of the Korean Uplift.

8.5. Scarcity Pricing

The SEM PLEXOS Model does not incorporate any explicit scarcity pricing. Given that most backcast runs tended to result in PLEXOS prices (slightly) above historical SEM prices, NERA is comfortable with not including scarcity pricing. That said, NERA recommends the RAs continue to evaluate possible options in PLEXOS to reflect scarcity pricing in future validations.

8.6. MIP vs. RR

NERA recommends continuity of the MIP unit commitment approach (also used in the previous SEM PLEXOS Model), as it better reflects unit commitment in the actual SEM and as it reduces the need for uplift and wheeling charges, as discussed above in Section 4.2.

NERA also includes an RR model option in the SEM PLEXOS Model, where the key assumptions for an 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 0.9.

8.7. Start States

NERA recommends using a single-state start cost approach tied to the MIP unit commitment approach for the 2024-2032 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.

8.8. PLEXOS Solver

PLEXOS offers various solvers. NERA conducted its backcast with the Gurobi solver, and this is also the default solver for the 2024-2032 SEM PLEXOS model. However, NERA does not expect that the choice of solver will have a material effect on the results of the SEM PLEXOS Model – users may use a different solver if they prefer.

8.9. Price Caps, Price Floors and Unserved Energy

NERA notes that the DAM has a price floor of -€500/MWh and a price cap of €4,000/MWh. The 2024-2032 SEM PLEXOS Model reflects the -€500/MWh price floor. Yet, the 2024-2032 SEM PLEXOS Model reflects a price cap in practice of €500/MWh (rather €4,000/MWh), where €500/MWh reflects the strike price in CRM Reliability Options in cases where gas and fuel oil prices are not so high to command an even larger strike price. NERA expects that under current energy market conditions and under energy market conditions anticipated in current forward prices, it would be rare for actual DAM SEM prices or SEM PLEXOS prices to exceed €500/MWh, and when prices do exceed that amount, it would be rare for prices to significantly exceed that amount. Under such circumstances, NERA recommends the €500/MWh price cap in PLEXOS rather than the actual €4,000 cap in the DAM. NERA recommends this for a few reasons:

1) Unserved energy in PLEXOS results in prices at the PLEXOS price cap[58]. However, NERA expects that unserved energy in the DAM in the actual SEM would be very rare. While unnerved energy is also rare in PLEXOS, NERA's *a prior* view is that any unserved in the SEM PLEXOS Model does not reflect actual anticipation of unserved energy in the actual SEM DAM. Thus, if unserved energy does occur in PLEXOS, NERA views a price of €500/MWh as reasonable but a price of €4,000/MWh as unreasonably high. Setting the price cap to €500/MWh ensures the price will be €500/MWh in cases on unserved energy.

2) Prices that exceed €500/MWh are exceedingly rare in the SEM DAM, at least under most natural gas price conditions. NERA also does not expect that PLEXOS will produce prices significantly above €500/MWh with any frequency at least assuming natural gas price conditions as of NERA's validation effort. However, to the extent that the PLEXOS Model produces prices above €500/MWh, NERA would have some skepticism whether similarly high prices would also occur in the DAM. Thus, in this case, NERA's *a priori* view is that capping prices at €500/MWh in PLEXOS is reasonable. Yet, under very high natural gas prices – similar to what occurred in 2022 and into the first part of 2023 – DAM prices above €500/MWh would not be unexpected. In such cases, a price cap above €500/MWh would be appropriate.

A more nuanced approach is to cap prices in PLEXOS at the strike price in the CRM Reliability Options. The strike price in the CRM Reliability Options exceeds €500/MWh under high natural gas and/or fuel oil prices (CRM strike prices also consider CO_2 prices). Thus, NERA recommends that model users pay attention to what the CRM Reliability Options strike price would be given the fuel

58 Unserved energy (USE) occurs when supply cannot meet demand in a power system. The SEM (like other global power markets) is designed to limit the possibility of USE to an acceptable very low minimum. NERA believes that any USE in PLEXOS is unlikely to be mimicked in the actual DA market.

price inputs into the SEM PLEXOS Model. If the expected CRM Reliability Option strike prices over the PLEXOS forecast horizon exceed €500/MWh, NERA presents two alternatives:

1) Raise the price cap in PLEXOS to be in line with the expected CRM Reliability Options strike price. This approach has the advantage of being easy to implement. However, this approach has the disadvantaged that the expected CRM Reliability Option strike price may vary over the modelling horizon (for example, the strike price may exceed €500/MWh during high-gas-price winter months but not during summer months). To counteract this, model users can make the price cap in PLEXOS vary appropriately over the forecast period as input fuel and CO_2 prices change.

2) Raise the price cap to €4,000/MWh in PLEXOS and use post-processing to cap prices at the strike price of the CRM Reliability Options. Post-processing would involve calculating the strike price of the CRM Reliability Options as it varies over the modelling horizon, based on input fuel and CO_2 prices. NERA notes that the default SEM PLEXOS Model runs five times based on the five input profiles for renewable generation and demand. **Thus, the model user should do the post-processing for each of the five individual sample runs, and then average across samples**[59]. NERA recommended this same approach to the RAs during the period of extreme high energy gas prices following the invasion of Ukraine[60].

NERA recognizes that in practice keeping the price cap at €500/MWh when the CRM Option strike price exceeds that amount only by a relatively small amount is likely to have minimal, if any, effect on the accuracy of results. This may give model users some flexibility[61]. Yet, NERA's official recommendation remains to update the price cap when the CRM Reliability Options strike prices. To the extent that model users expect that CRM Reliability Options strike prices would exceed €500/MWh over the PLEXOS Modelling Horizon based on the fuel and CO_2 prices in the PLEXOS Model, NERA recommends either updating the price cap in PLEXOS accordingly or (the most precise option) doing a full post-processing as described above.

NERA recommends that the CRM Reliability Options strike price be the price cap in PLEXOS because: a) DAM prices rarely if ever exceed that strike price; b) generators with CRM Reliability Options have incentives to be available in high price hours, which may keep prices below the CRM strike price; c) the CRM Reliability Options strike price automatically goes up when fuel and/or CO_2 prices go to high levels; d) NERA used the CRM Reliability Options strike price as the price cap in the backcast, so it is consistent to also use it in the forecast; and e) this is a known price relevant to the functioning of the SEM.

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59 For example, USE may appear in sample 3 only (a €4,000/MWh price in sample 3), but samples 1, 2, 4, and 5 may not have USE and thus may have prices under the CRM strike price. In this example, the user would adjust the price in sample 3 only to the CRM strike price, leaving the prices in the other sample unchanged.

60 See Section 3 of Directed Contract Round 18: Revised Subscription Window Dates and Amendments to the Process of Calculating Pricing Formula, Information Paper, SEM-22-017, 4th May 2022, available here: https://www.semcommittee.com/files/semcommittee/media-files/SEM-22-017_Information%20Note%20DC%20Round%2018%20Revised%20Dates%20and%20Amendment%20of%20Pricing%20Calculation%20Process.pdf

61 For example, if the CRM Reliability Option price cap rose to €550/MWh, the effect on average prices in the SEM PLEXOS Model from keeping the price cap at €500/MWh would likely be quite small, if any.

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8.10. Value of Lost Load

Internal VOLL in PLEXOS Optimization

PLEXOS places a cost on unserved energy for optimization purposes, which is called the Internal Value of Lost Load ("Internal VOLL"). Internal VOLL is set to the default value in PLEXOS of €100,000/MWh. While this is higher than actual estimates of VOLL in the SEM, NERA believes that it is appropriate to strongly discourage PLEXOS from resorting to loss of load, given the pricing implications of unserved energy discussed in the prior section. This is a change from prior SEM PLEXOS Models that utilized VOLL values in line with estimates of VOLL in the SEM.

8.11. Great Britain and France

8.11.1. Great Britain

Similar to previous SEM PLEXOS Models, the 2024-2032 SEM PLEXOS Model includes a representation of Great Britain (GB) in order to model the trade between the SEM and GB. There are several options to model GB, including:

- 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 as prices in GB would be static and not update as fuel and CO_2 prices change, leading to unrealistic flows.

- 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 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. Some generators suggested that the RAs use a broader European model to even better assess cross-border trade, but this would exacerbate the issues just discussed.

- 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 the third approach, there are several options. NERA's preferred option is to model GB as a single gas-fired generator with a heat rate that varies seasonally and within the day. 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. In reality, GB includes generators utilizing several different fuels, including nuclear and renewable resources. Nonetheless, GB electricity prices maintain a strong correlation with natural gas prices, as gas-fired generators often set the market price. This single-generator approach utilizes so-called market heat rates, rather than the actual heat rates of gas-fired generators. Market heat rates reflect the ratio of power prices to natural gas prices[62].

In past SEM PLEXOS Models (including the 2021-2029 SEM PLEXOS Model), the market heat rate for GB was based on the historical relationship between natural gas prices and power prices in GB. In reality, the relationship between gas prices and power prices can change over time, including due to changes in the supply and demand balance (tighter supply situations leading to a higher market heat rate) and in changes in the generation mix (such as increases in renewables penetration). While recent historical market heat rates generally are a reasonable proxy for future market heat rates, *NERA layers on a calibration of market heat rates to forward market prices in order to improve accuracy of the SEM PLEXOS Model*. Calibration to forward prices is reasonable especially for this validation because:

- In recent years, (NERA assessed prices back to 2019) extreme variation in electricity and natural gas prices was observed - this creates uncertainty as to whether market heat rates implied by this historical period are reasonable for use in a forecast model.
- European power markets are rapidly decarbonizing, which may lead to lower energy-market power prices all other things equal, thus lowering market heat rates. NERA observes that current forward prices suggest that market heat rates in GB will be somewhat lower in the future versus the market heat rates observed on average the last several years.

The precise approach is as follows:

1) NERA analysed historical GB power, gas and CO_2 prices, from 2019 to 2023, to calculate average market heat rates. Specifically, NERA calculated, separately for summer and winter, and separately for each hour of the day, average power prices and average gas plus CO_2 prices. NERA divided the average power prices by the average gas plus CO_2 prices[63]. NERA notes three relatively minor changes versus the historical GB price analysis in the prior SEM PLEXOS Model:

    a. The prior SEM PLEXOS Model used a VOM plus heat rate approach (with VOM from the constant in historical regressions). The current SEM PLEXOS Model only has heat rates. NERA's reasoning is that the VOM value will depend on the particulars of the historical period. NERA's concern was that when fuel and CO_2 prices change significantly, the presence of the VOM in GB pricing could lead to too little or too much change in price[64].

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62 NERA includes the cost of CO_2 emissions from natural gas in the cost of natural gas relevant for price formation. Thus, the market heat rate is the ratio of power prices to the sum of natural gas prices and the CO_2 costs associated with burning natural gas.

63 NERA reflected gas and gas-related CO_2 emissions prices in the historical analysis on a lower heating value basis (LHV), since the SEM PLEXOS Model reflects gas-generator heat rates and gas prices on a LHV basis. The energy in natural gas can be expressed in either LHV or High Heating Value ("HHV") terms. The energy expressed HHV terms is about 11% higher than that expressed in LHV terms. For example, 1 GJ in LHV is equivalent to 1.11 GJ in HHV terms. The difference is that HHV reflects energy contained in the water vapor produced when burning natural gas. A model can be set up in either HHV or LHV terms – consistency is what matters.

64 As an example, if a regression of recent years resulted in a very high VOM (based on very high GB prices in that period), that VOM may not be appropriate if the market returns to a situation of very low gas and power prices.

b. The current approach considers seasonal (winter vs. summer) heat rates, whereas the previous model had heat rates that varied on a quarterly basis. NERA acknowledges that in reality there may be quarterly patterns in market heat rates, but NERA's view was that, with the extreme prices and extreme variability in prices observed in the last several years, heat rate granularity at the quarterly level based on recent years may not repeat going forward.

c. The prior model set heat rates using a regression of historical hourly data. The current model assessed historical heat rates by taking the ratio of average historical power to average historical fuel plus CO_2 prices. Since NERA calibrates heat rates to forward prices, the choice of averaging historical prices to determine heat rates versus a regression of historical prices is of relatively low importance. Regardless of choice, it is the calibration to forwards that sets what average GB prices will be going forward in the SEM PLEXOS Model. Given that and given the simplicity of the averaging approach, NERA recommended averaging to determine market heat rates based on history.

2) NERA calculated market heat rates implied by forward prices for GB, and incorporated forward power, gas, and CO_2 prices (noting that CO_2 prices relevant within GB are EU UKS plus the CPS floor) with the formula:

$$HR_{Fwd} = \frac{P_{Fwd}}{(G_{Fwd} + (C_{Fwd} + C_{Fl}) * EmFac)}$$

where HR_{Fwd} is the forward market heat rate (GJ/MWh), P_{Fwd} is the average traded forward power price (per MWh), G_{Fwd} is the average traded forward price for gas (per GJ), C_{Fwd} is the average traded forward price for CO_2 (per tonne), C_{Fl} is the CPS floor (cost per ton), and *EmFac* is the CO_2 emissions factor from burning natural gas (tonnes of CO_2 per GJ of natural gas). NERA analysed the prior three months of trading data as of NERA's data cut off for forward data[65]. NERA determined market heat rates for seasonal forward power products from Winter 2024-25 through Summer 2028.

3) NERA noted relative similarity of the various summer and winter seasonal implied heat rates from forwards over the 2024 to 2028 period. For simplicity, NERA averaged the heat rates determined from summer forward products and the heat rates determined from winter forward products to arrive at consensus forward-calibrated seasonal heat rates for summer and winter of 5.86 LHV GJ/MWh and 6.23 LHV GJ/MWh, respectively.

   a. Note: In future validations, it could be the case that near term forward-implied market heat rates differ significantly from longer-term forward implied market heat rates. In such a case, the RAs and their consultant may decide to separately calibrate heat rates for each forward-looking season.

65 NERA's view is that three months of data is sufficient. Using a single day or just a few days of forward trading data may reflect a temporary trend including the possibility of unique situations in either the gas, power or CO_2 markets, resulting in market heat rates that are not reflective of longer-term expectations. Looking at too long a historical set of trading data may rely too much on older expectations of market conditions that are no longer relevant. In practice NERA utilized a few days fewer than three months, such that the historical period of forward trading data was contained within a calendar quarter, which significantly simplified the analysis.

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4) NERA multiplied the 24 different hourly summer heat rates based on historical analysis by a ratio such that the average of the 24 summer heat rates equals 5.86 LHV GJ/MWh. NERA similarly calibrated the 24 winter heat rates to 6.23 LHV GJ/MWh.

Despite the differences in approach, the net results of the GB model as recommended by NERA for the 2024-2032 SEM PLEXOS Model and the GB model used in the prior validation are relatively close. Figure 14 and Figure 15 below show the derived average market heat rates for each model. On average, the difference is that the updated model has lower heat rates by about 0.9 LHV GJ/MWh. This is because of differences between the historical heat rates used in the prior model and the calibration based on current forward prices in the current model. While NERA did not investigate the details of why the heat rates changed, it is possible that renewables growth in GB led to this trend. Another change since the 2021-2029 SEM PLEXOS Model is that the current model has different hourly patterns for summer and winter heat rates. The 2021-2029 SEM PLEXOS Model has the same pattern for summer and winter, but set average heat rates by quarter in line with historical levels. NERA views the switch to separate hourly patterns as an improvement, as it appears that, particularly in GB, the evening peak occurs later in the day in the summer than in the winter.

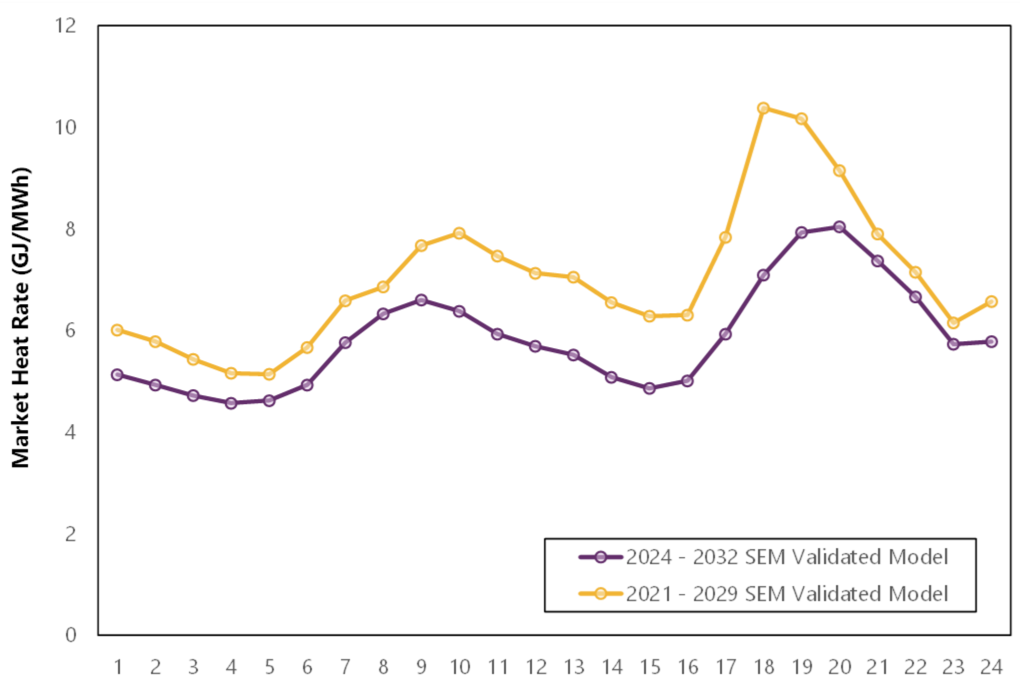

Figure 14: GB Heat Rates, 2021-2029 vs. 2024-2032 SEM PLEXOS Models, Summer[66]

66 2021-2029 SEM PLEXOS Model modelled GB as heat rate plus a VOM. NERA converted these to heat rates without a VOM using the same placeholder fuel and emissions prices from Table 16 above. NERA took the average of the quarterly heat rates in the 2021-2029 SEM PLEXOS Model, by season, for this comparison.

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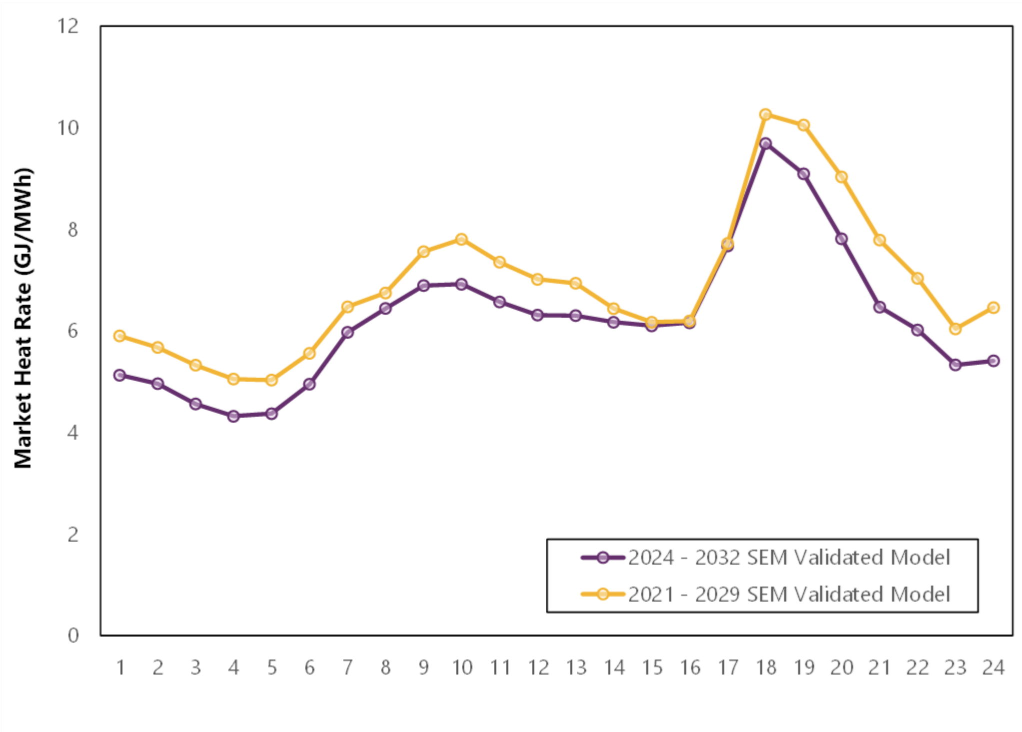

Figure 15: GB Heat Rates, 2021-2029 vs. 2024-2032 SEM PLEXOS Models, Winter

8.11.2 France

For France, NERA utilized a nearly identical approach as the one NERA utilized for GB. The difference is that the forward prices that NERA relied upon for France are yearly or quarterly, rather than seasonal. The yearly French forward prices go out further into the future than the quarterly forward prices, so NERA ultimately chose to calibrate to those yearly prices. Yearly forward products do not show seasonal variation. NERA used quarterly French power forwards to determine forward-looking seasonal variation in market heat rates in France. The end result is, just like for GB, a set of 24 different hourly market heat rates for summer and winter. The average forward-calibrated heat rates for France are 3.93 LHV GJ/MWh and 5.41 LHV GJ/MWh for summer and winter, respectively.

Figure 16 and Figure 17 below show the derived average market heat rates for each model (using the same approach as for GB). While the hourly pattern of heat rates is broadly similar between the previous and current SEM PLEXOS Models, the updated heat rates are significantly lower, particularly in the summer. The simple explanation is that the current heat rates in the SEM PLEXOS Model reflect market expectations of heat rates based on forward pricing out through 2027, which reflect relatively low market prices and hence relatively low heat market rates. NERA's *a priori* view is that rapid historical and projected increases in renewables generation in France have led to this change. NERA notes that the prior SEM PLEXOS Model based heat rates on historical price data from 2016 to 2021, where the current model bases heat rates on forward price data from 2025 to 2027. Over recent years, France has rapidly expanded its wind generation and especially its solar generation – and expanded each of those at faster rates than the UK. NERA also notes that neighboring countries to France – Germany, Italy, Spain, Switzerland, and Belgium – have each also increased their solar generation at more of a rapid pace than the UK in recent years, with especially rapid increases in

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Spain and Switzerland[67]. This change in renewables in recent years may help explain why French heat rates have fallen more precipitously than GB heat rates since the prior SEM PLEXOS Model, with the changes in solar being perhaps particularly relevant to the decrease in French heat rates, given that solar power generates significantly more in the summer than winter.

While NERA has not reviewed a forward-looking comparison of solar and wind generation for France and UK, NERA understands that both countries have ambitious plans to add renewables capacity, which presumably also help explain the decrease heat rates.

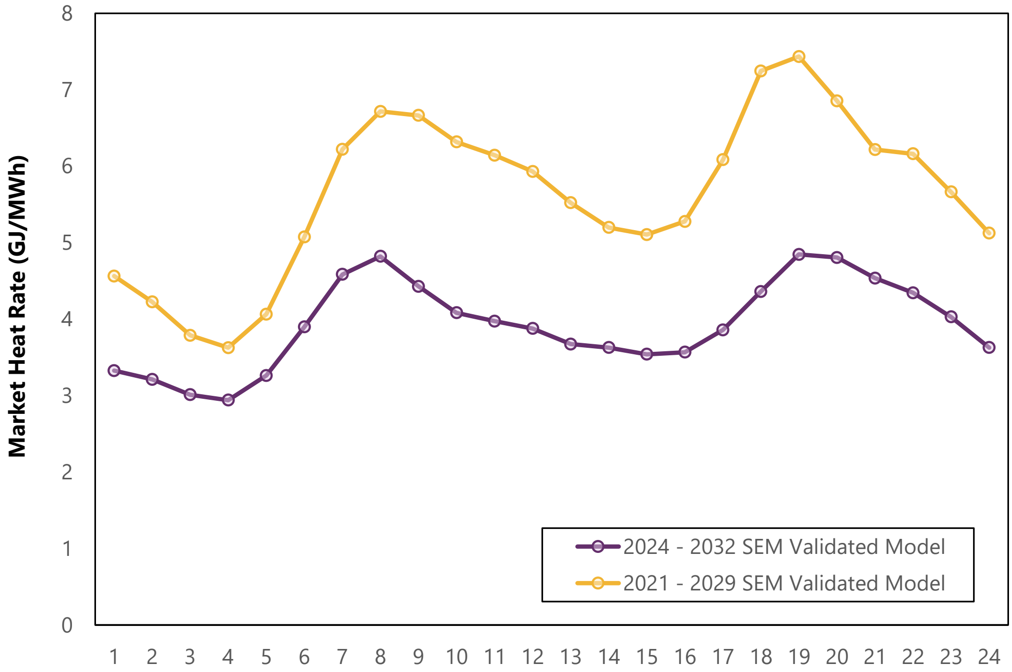

Figure 16: France Heat Rates, 2021-2029 vs. 2024-2032 SEM PLEXOS Models, Summer

[67] Analysis of the Energy Institute's 2024 Statistical Review of Energy, available here: https://www.energyinst.org/statistical-review. NERA compared 2023 solar and wind generation to the average of generation over the 2016 to 2021 historical period.

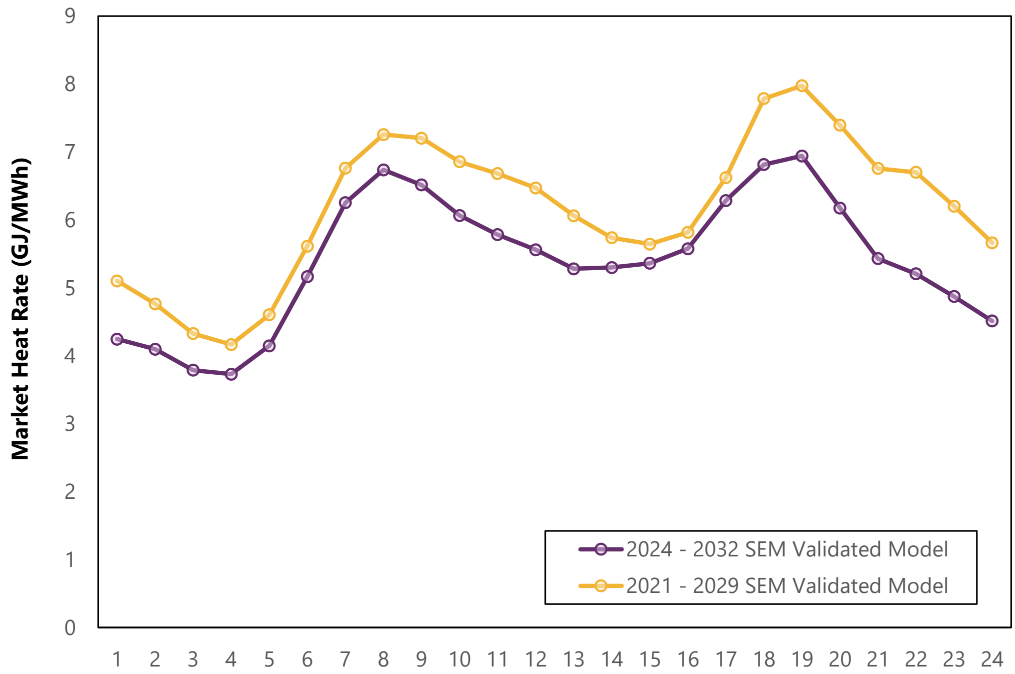

Figure 17: France Heat Rates, 2021-2029 vs. 2024-2032 SEM PLEXOS Models, Winter

Note on Gas Prices

NERA found a high correlation between NBP British gas prices and French 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.

NERA uses GB NBP gas prices to model France. While a continental European price index could have been used, NERA notes first that there is high correlation between the NBP gas price and potentially alternative continental European gas prices. Further, using a different gas price for France would complicate the RAs' DC modelling, as the DCs would need to consider two gas prices: UK NBP and a European gas price for France. Finally, NERA emphasises that it uses a parallel approach: NERA determines French market heat rates using the NBP gas price and the SEM PLEXOS Model applies those same market heat rates to NBP gas prices.

8.11.3 Long-Term Trend in Heat Rates

The 2021-2029 SEM PLEXOS Model held heat rates for France and GB constant for the entire modelling horizon. The 2024-2032 SEM PLEXOS Model holds France and GB heat rates constant for the period covered by the forward curves that NERA relied upon: through to 2028 in GB[68] and

[68] The GB forward curve goes through September 2028, but for simplicity NERA holds heat rates constant for all of 2028.

through to 2027 in France. Given the decarbonization goals for France and GB, NERA expects that renewables penetration will continue to increase in those countries through 2032 and beyond. This may lead to lower energy market prices by the end of the 2020s and into the 2030s. NERA notes that the 2024-2032 SEM PLEXOS Model (keeping fuel and CO_2 prices constant) shows significant declines in energy market prices starting in the late 2020s and accelerating in the early 2030s – see Figure 18 below. This occurs primarily because of the rapid increase in wind and solar generation capacity in the SEM (see Table 12 and Table 13 above).

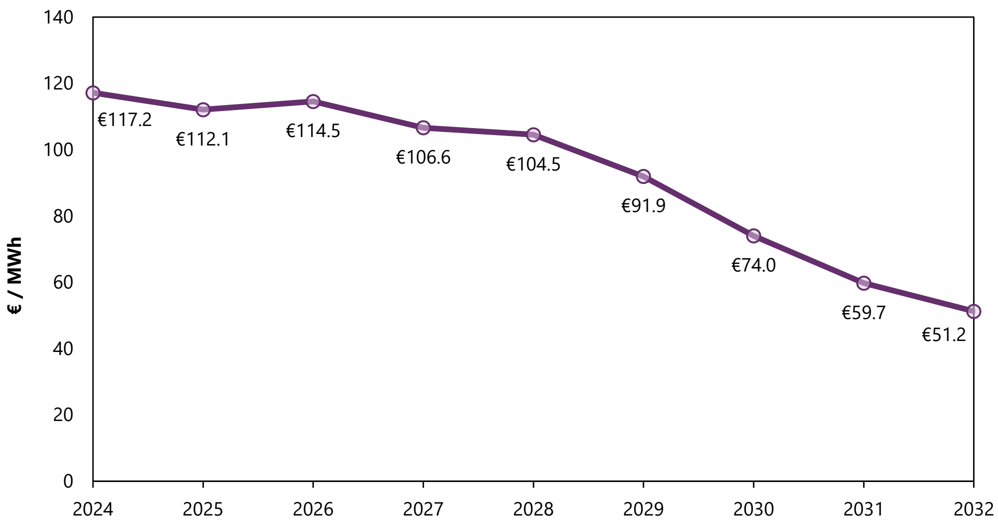

Figure 18: Annual Average Prices, 2024-2032 SEM PLEXOS Model (Prior to Adjusting GB and France for Potential Decline in Market Heat Rates)

NERA reiterates that the prices forecasted here are uncertain and dependent upon highly uncertain inputs of projected renewable capacity, system load, and fuel prices, among others. These figures represent the results of the 2024-2032 Validated SEM PLEXOS Model under certain assumed inputs; these figures do not constitute an official forecast or projection of SEM prices and should not be used as such.

While it was out of NERA's scope to perform long-term forecasting of GB and France market heat rates beyond the horizon of the current forward curve, the 2024-2032 SEM PLEXOS Model does include a reasonable placeholder assumption for how GB and France market heat rates may decline over time. Specifically, this placeholder assumption has market heat rates in France and GB decline in line with the decrease in energy prices from initial runs of the SEM PLEXOS Model (holding fuel and CO_2 prices constant). The resulting pattern of decreasing heat rates in France and GB is stated in Table 17 below, which shows ratios of heat rates relative to the default heat rates in the 2024-2032 SEM PLEXOS Model. As discussed, the decline starts in 2028 for France and 2029 for GB.

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Year	GB Decline Ratio	France Decline Ratio
2024	1.000	1.000
2025	1.000	1.000
2026	1.000	1.000
2027	1.000	1.000
2028	1.000	0.975
2029	0.873	0.852
2030	0.696	0.679
2031	0.558	0.544
2032	0.481	0.469

Table 17: Average Market Heat Rates Decline Ratios in GB and France 2024-2032

Implementing the above market heat rate ratios also may improve the ability of the SEM PLEXOS Model to forecast important and exports beyond the expiration of the current forward curve. All things equal, if France and GB prices are higher than they might be, this will tend to reduce net imports from those markets into the SEM.

While NERA puts forward the heat rate declines in **Table 17** as reasonable placeholders, NERA emphasizes that these are still placeholder values. NERA suggests that model users may wish to take their own view as how market heat rates in France in GB may change in the in the later years of the 2024-2032 SEM PLEXOS Model. NERA has not performed research into or analysis of how market heat rates may decline in GB and France after the end of the current forward curve. Rather, NERA provides a placeholder for potential decline as a courtesy to model users. Model users may arrive at their own forecast of power, natural gas, and CO_2 prices for France and GB for the late 2020s and into the 2030s to derive their own view of market heat rates in the end years of the modelling horizon.

8.11.4 Potential for More Detailed Modelling of GB and France

In NERA's engagement with stakeholders, some generation companies recommended NERA update the SEM PLEXOS Model to include fundamental models of Great Britian and France (i.e. models that include the specific generators and loads of those markets, with forecasts of new capacity additions, retirements, and load growth to 2032, including specific forecasts of growth of renewables in those markets). Such an approach has the advantage that, at least conceptually, it would naturally forecast the interrelated effects of renewables growth in SEM, Great Britian, and France on prices in those markets. However, NERA and the RAs agreed that such an approach was out of scope for NERA in its instant assignment, given the high level of complexity of building, calibrating and maintaining fundamental models of Great Britian and France, especially since each market is significantly larger than the SEM. Further, given the complexity of such a task, it is unclear whether the end result would be more reliable than the current approach.

Yet, NERA notes the potential for very high levels of renewables penetration to affect prices in GB and France as well as imports and exports along the interconnectors with the SEM, potentially particularly by about 2030 and beyond (assuming the level of renewables forecasted in the 2023 GCS). High levels of renewables may lead to lower average prices but also to high levels of price variability due to weather variability (sun and wind), which consequently may lead to many hours with zero or even negative prices along with many hours of higher prices during times when load is high and renewables are low. The RAs may consider enhancing GB and France modelling considering the effects of weather variability on renewables generation, prices, and interconnector flows. This could be achieved potentially with an enhanced statistical approach or a fundamental modelling approach to GB and France.

The RAs may wish to review the advantages and disadvantages of different approaches to GB and France modelling in the next Validation.

8.11.5 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, for the Option A run, which uses a wheeling charge (Option A2 also uses available wind generation and Uplift, but does not use a wheeling charge).

8.12. Choice of SEM PLEXOS Model Options

NERA found three PLEXOS options that perform well in the backcast, and each are reasonable choices for the 2024-2032 SEM PLEXOS Model:

> Option A: allowing wind generation at available wind generation levels (availability factor) and Uplift and wheeling charges turned on;
>
> Option A2: allowing wind generation at available wind generation levels (availability factor) but without Uplift and without wheeling charges; or
>
> Option B: limiting wind generation to actual generation levels (capacity factor) and uplift and wheeling charges turned off.

Each model performed well overall, and with different models having different advantages and disadvantages in different periods of the backcast.

	Price Diff. to Actual (€/MWh)			Net Exports Diff. to Actual (GWh/mo)		
Time Period	**Opt A**	**Opt A2**	**Opt B**	**Opt A**	**Opt A2**	**Opt B**
Jan 2020 – Jun 2021	1.22	0.63	2.34	-97	-65	-122
Jul 2021 – Sep 2022	-3.14	-4.14	0.09	24	52	32
Oct 2022 – Dec 2023	1.96	-0.60	3.13	-24	17	-50
Whole Backcast	*0.09*	*-1.25*	*1.89*	*-36*	*-3*	*-51*

Table 18: Price and Net Export Differences to Actual Across Backcast Periods

NERA cautions against overreliance on how well one model or another model performs in a backcast, particularly when the differences are relatively small. Yet, the somewhat better alignment of Options A and A2 in the backcast – along with their conceptual alignment with DA market treatment of wind – may favor use of either Option A over Option B. NERA suggests that the choice between Options A and A2 depends on the user's view as to whether to include uplift (Option A) or not (Option A2). Ultimately, NERA puts the choice between options in the model users. NERA also notes the following:

- Option B may have an advantage if energy market conditions tighten as they did in late 2021 and 2022.
- If energy market and electricity conditions change significantly versus current conditions (whether higher or lower prices), then uplift in Option A may also change (up or down). Consequently, wheeling charges may become outdated (too low or too high). In this situation, model users may wish to switch to Option A2 or to Option B, which have neither uplift nor wheeling charges. Alternatively, the user could update the wheeling charges in Option A.
- As installed renewable capacity increases in the SEM, the difference in the results of Options A and A2 (which use available renewable generation) and Option B (which uses estimated actual renewable generation) will likely increase. NERA does not know which method will prove more accurate with very high renewables penetration. The issue of accuracy with very high renewables penetration will become more important (and may be reassessed) in the next validation of the SEM PLEXOS Model.

Prices differ somewhat depending on the option selection, as shown below – holding fuel and CO_2 prices constant at the indicative levels in Table 16 above. Overall the trend in prices is the same across options, and it is challenging if not impossible to know ahead of time which forecast will be more accurate in retrospect. NERA reiterates that the prices forecasted here are uncertain and dependent upon highly uncertain inputs of projected renewable capacity, system load, and fuel prices, among others. These figures represent the results of the 2024-2032 Validated SEM PLEXOS Model under certain assumed inputs; these figures do not constitute an official forecast or projection of SEM prices and should not be used as such.

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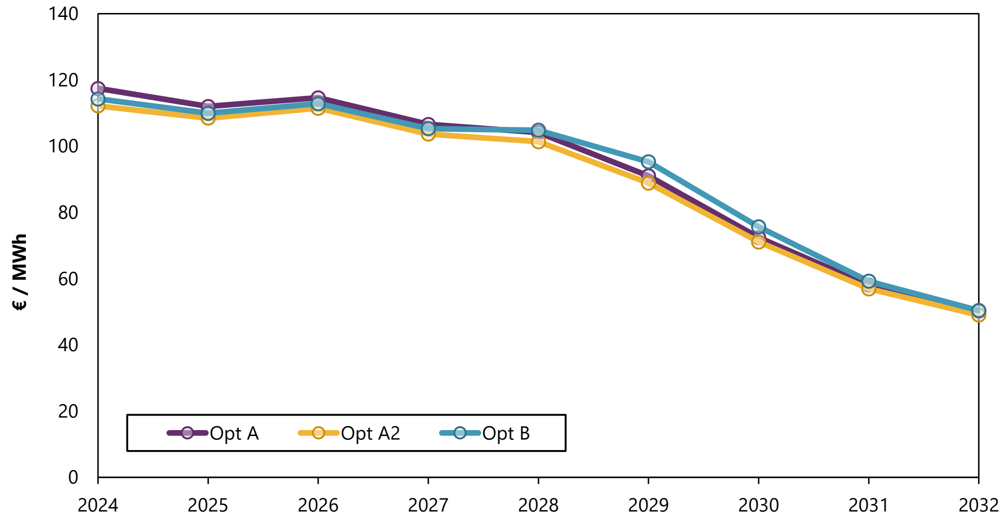


Figure 19: Average Annual SEM Price across Model Options, 2024-2032

NERA cautions against selecting a SEM PLEXOS Model option based on the resulting prices. Instead, NERA recommends the choice be based on the model user's view of the appropriateness of each option's approach considering renewables generation levels, uplift and wheeling charges, and in consideration of NERA's comments (in this section and in the executive summary) on choosing an option.

9. Summary of Results of the 2024-2032 SEM PLEXOS Model versus 2021-2029 SEM PLEXOS Model

9.1. Average SEM Prices

NERA compared prices from the 2024-2032 SEM PLEXOS Model to the previous 2021-2029 SEM PLEXOS Model, using 2025 as a sample year.[69] All results presented use model Option A (available wind, with uplift and wheeling charges). Average baseload prices are somewhat under €4/MWh lower in 2025 in the 2024-2032 SEM PLEXOS Model as compared to the 2021-2029 SEM PLEXOS Model, holding fuel and CO_2 prices constant. This difference (~3%) is relatively small, highlighting the consistency of modelling at a high level, despite various differences in the details. Figure 20 below shows the largest factors that explain the reduction in price between the two models.

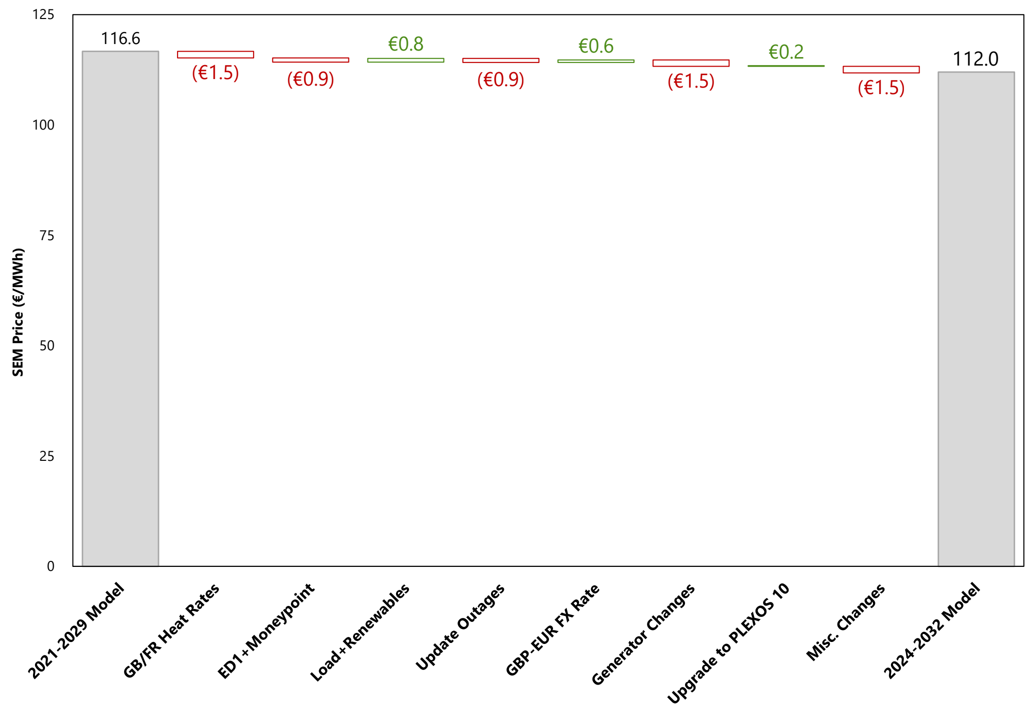


Figure 20: Drivers of Price Changes between 2021-2029 and 2024-2032 PLEXOS Models

Specifically, the drivers of the decrease in prices are:

1) Lower heat rates in GB and France (now based on calibration to current forward prices) (lowers prices by approximately €1.5/MWh). This leads to lower prices in GB and France which leads to increased imports in the SEM, thus reducing SEM prices, all else equal.
2) The "un"-retiring of Edenderry (lowers prices by approximately €0.9/MWh). In the 2021-2029 SEM PLEXOS Model, Edenderry was assumed to retire as of 2024, but in the 2024-2032 Model Edenderry is online and assumed to not retire for the entire modelling horizon. Adding back in a relatively large unit and important unit such as Edenderry will lower prices, all things

[69] A few minor changes were made to the model based upon generator responses received after the results here were calculated. NERA anticipates these changes would have little on the results below.

equal. NERA also includes the updated retirement date for Moneypoint in this category. Moneypoint was assumed to be retired on 1 October 2024 in the 2021-2029 Model, versus 1 July 2024 in the 2024-2032 Model (note it is not technically retired, rather it is transitioning to an emergency-only unit, which is treated as retiring in the PLEXOS Model). Having Moneypoint online for three fewer months slightly mitigates the price-lowering effect of un-retiring Edenderry.

3) Updated load and renewables generation inputs (increases prices by approximately €0.8/MWh). The load forecast is higher in the 2024-2032 SEM PLEXOS Model than in the 2021-2029 Model. Installed renewables capacity is also higher in the 2024-2032 Model (driven by additional solar), which offsets the increase in prices from increasing load, somewhat.
4) Updated Outage Schedule and FORs (decreases prices by approximately €0.9/MWh). FORs increased for natural gas units (by far the most important thermal fuel in the SEM) in the 2024-2032 SEM PLEXOS Model versus the 2021-2029 Model, which all things equal increases prices. Yet this effect is counteracted by the differences in planned outages in the 2024-2032 Model versus the prior model. In the 2021-2029 SEM PLEXOS Model during the September to October 2025 period, several combined cycles had long planned outages that are not present (or are much shorter) in the 2024-2032 Model. Even with higher forced outages, prices are higher in the 2024-SEM PLEXOS Model due to the effects of planned outages by approximately €5/MWh on average in the September to October 2025 period. The impact of such a price difference influences the average price difference for the entire year. This example shows the importance of unit availability, particularly for CCGTs in the SEM.
5) Updated FX Rates (increases prices by approximately €0.6/MWh). This affect is due largely to a slight decrease in the assumed Euro to GBP exchange rate: 0.855 GBP/€ in the 2021-2029 SEM PLEXOS Model to 0.85 GBP/€ in the 2024-2032 Model. While this is only a ~0.6% decrease, this decrease in the exchange rate leads directly to an increase in euro-denominated natural gas prices by about the same amount (all things equal). This is because the gas prices in the SEM PLEXOS Model equal the NBP gas price (in GBP) divided by the Euro-to-GBP exchange rate. This results in an increase in SEM prices by approximately the same percentage (since natural-gas-fired generators nearly always set prices in the SEM DAM), with the end result being the approximately €0.6/MWh increase in SEM prices. At the same time, the Euro-to-USD exchange rate increased – and increased by a larger percentage: 8.4%[70]. This leads to more expensive oil and coal prices in the SEM PLEXOS Model (since those fuels are denominated in USD and are then converted to euro prices using an exchange rate). This effect also contributes to the increase in prices.
6) Changes in the heat rates for CCGTs (decreases prices by approximately €1.5/MWh). Several generation companies updated the heat rate curves for several of their generators for the 2024-2032 SEM PLEXOS Model. NERA understands that these updates from generation companies relate to better understanding and presentation of the performance capabilities of their generation units (for example, from more recent performance tests). While some updates led to higher CCGT heat rates, on average the trend was to lower heat rates, led by a material decrease in the average heat rate for Dublin Bay CCGT (other CCGT changes were

70 The EUR-USD exchange rate in the 2021-2029 SEM PLEXOS Model was 1.07 USD/EUR, which increased to 1.16 USD/EUR in the 2024-2032 SEM PLEXOS Model.

less significant). Given the high importance of CCGTs to the SEM market, it is not surprising that lowering of heat rates leads to lower prices, all things equal.

7) All other changes (approximately €1.4/MWh). Several other inputs changed between the 2021-2029 and the 2024-2032 SEM PLEXOS Models. However, such effects tended to cancel each other out. For example, various other generation technical and commercial parameters changed in ways that would increase or decrease prices. Various fuel transport capacity costs for generators went up or down. Certain system parameters changed. The net effect is relatively small – less than a 1.3% change in average prices.

Figure 21 below shows the monthly price pattern for total price and shadow price (total price equals shadow price plus uplift). Overall, the price pattern is similar.

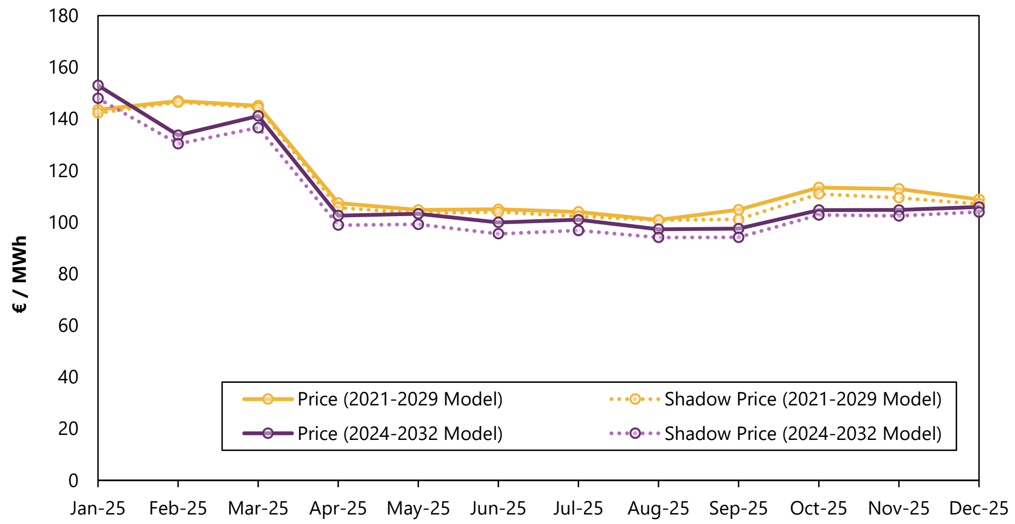


Figure 21: Total and Shadow Prices in 2024-2032 and 2021-2029 I-SEM PLEXOS Models (Year 2025)

Figure 22 below shows the uplift components of the price, comparing the two SEM PLEXOS Models. While uplift is higher in the 2024-2032 version versus the 2021-2029, this effect is more than counteracted by the decrease in shadow prices in the updated version, leading to (slightly) lower prices overall. The monthly pattern in uplift is somewhat different between the two models, but this is not surprising as uplift can be more volatile than shadow prices. In fact, uplift to some extent depends on the shadow price (lower shadow prices may require higher uplift). NERA recommends focusing on the overall price (shadow price plus uplift). In interpreting Figure 22, NERA also stresses that the scale is small, so what might appear to be major differences by the visible differences between the lines are actually small differences in the context of SEM prices at or above €100/MWh.

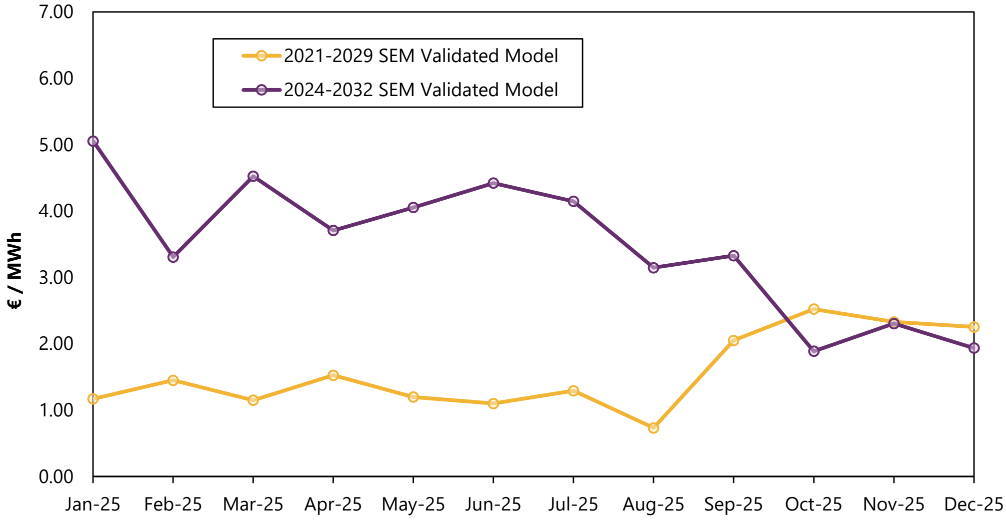


Figure 22: Uplift in 2024-2032 and 2021-2029 I-SEM PLEXOS Models (Year 2025)

Figure 23 shows that the current and prior PLEXOS Models have similar hourly patterns. NERA notes that the largest drop in prices is on or near 12 pm, which may be explained by the significantly higher solar generation levels in the updated SEM PLEXOS Model.

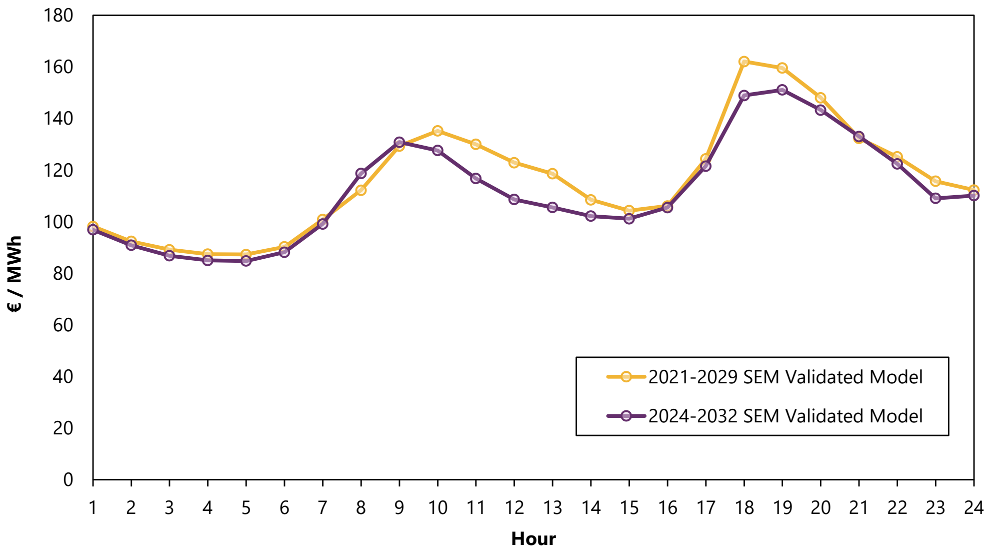


Figure 23: Hourly Prices in 2024-2032 and 2021-2029 I-SEM PLEXOS Models (Year 2025)

Figure 24 shows the annual average prices from 2024 to 2032 (with the same fuel prices each year for comparison purposes). The prices reflect placeholder fuel prices from Table 16 above and (for GB and France) the market heat rate decline pattern from Table 17. As shown in Figure 24, prices tend to decline over time. The decline is relatively modest through 2028 (under 3% annual rate of decline). The drops in 2025 and in 2027 are explained, to a large extent, by the Greenlink and Celtic interconnectors, respectively, coming online. The rate of decline accelerates substantially in the final four years of the model, with average prices in 2032 about 60% lower than average prices in 2024. The rapid decline over the last four years of the modelling horizon is due to the rapid increase in new wind and solar capacity in the SEM those years, with new generation from those sources far outpacing load growth. NERA reminds the reader that the renewables expansion in the 2024-2032 SEM PLEXOS Model (and as reflected in the prices below) is the renewables forecast from the 2023 GCS. By the end of 2032, the PLEXOS Model reflects about 27 GW of wind and solar in the SEM (per the 2023 GCS, see tables A4-3 and A4-6), which compares with a forecasted peak load of about 9 GW (2023 GCS, Table A1-1). On an annual basis, the total available generation from that level of wind and solar would likely exceed the total energy requirement in the SEM for 2032. However, NERA reiterates that the prices forecasted here are uncertain and dependent upon highly uncertain inputs of projected renewable capacity, system load, and fuel prices, among others. These figures represent the results of the 2024-2032 Validated SEM PLEXOS Model under certain assumed inputs; these figures do not constitute an official forecast or projection of SEM prices and should not be used as such. NERA notes that Table 16 above presents the indicative fuel prices assumed for test runs of the SEM PLEXOS Model (including the run that produced Figure 24 below) – actual fuel prices will presumably differ from those prices, and PLEXOS Model users are encouraged to update fuel prices to contemporaneous forecasts when running PLEXOS.

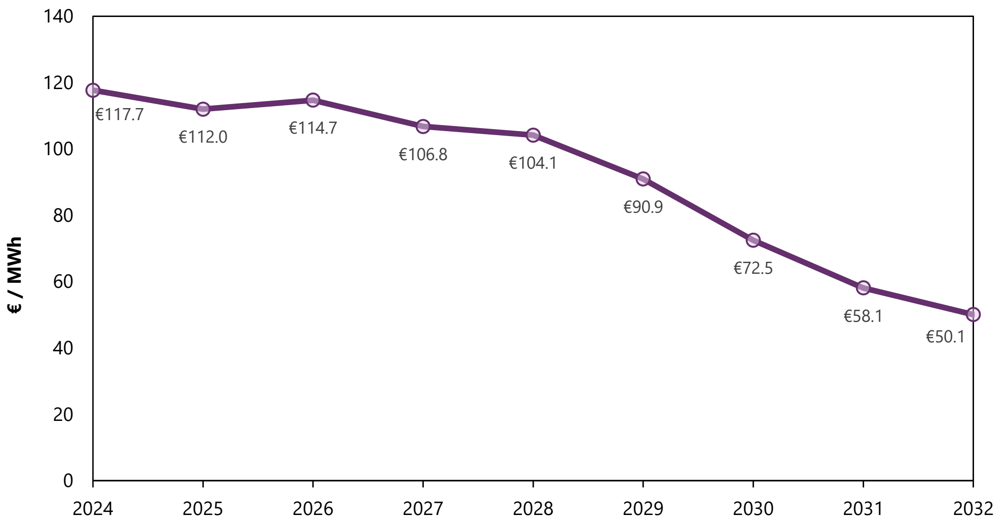


Figure 24: Annual Average Prices, 2024-2032 SEM PLEXOS Model

9.1.1. Commentary on Decline in SEM Prices Particularly in 2030s

The large amount of new renewables installed in the SEM per the 2023 GCS (an especially large amount between 2029 and 2032) naturally results in declining prices from the SEM PLEXOS Model, even when holding fuel and CO_2 prices constant, as seen in Figure 24 above. In many hours in such years, available renewable energy exceeds load, resulting in zero prices in the SEM output from the SEM PLEXOS Model. While such a trend makes sense, **NERA recognizes that there is uncertainty as to how precisely prices in the SEM will react once renewables penetration reaches the levels forecast by the early 2030s.**

NERA raises several options for the RAs to consider going forward. Each of these was out of NERA's scope for the instant assignment, however.

1) Explicitly model the system services market in the SEM, which NERA understands will be co-optimized on a day-ahead basis with the energy market starting in 2026. This would presumably affect dispatch decisions especially in a high renewables-penetration environment;
2) Make adjustments to how PLEXOS models generation offers align with best expectations of how the actual SEM DA Market will handle generation offers and price formation with the very high levels of renewables penetration forecasted by the early 2030s;
3) Consider potential changes to the supply mix in the SEM by the 2030s. If prices go very low, some units may retire, which could result in higher prices. Further, the very high levels of intermittent generation by the early 2030s may correspond with increasing amounts of storage capacity including (if feasible) longer-term storage, which could affect prices as well;
4) Potentially make updates to Great Britain and France modelling to incorporate (discussed above in Section 8.11.4).

9.2. Generation and Interconnector Flows

Figure 25 shows average interconnector flows. Net imports are higher in the 2024-2032 SEM PLEXOS Model, with the decrease in GB market heat rates likely the principal driver of this.

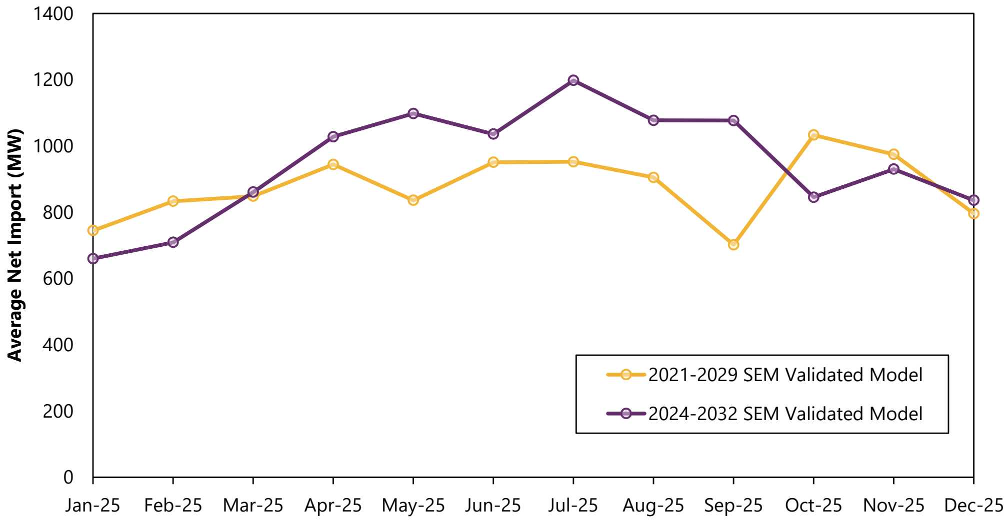
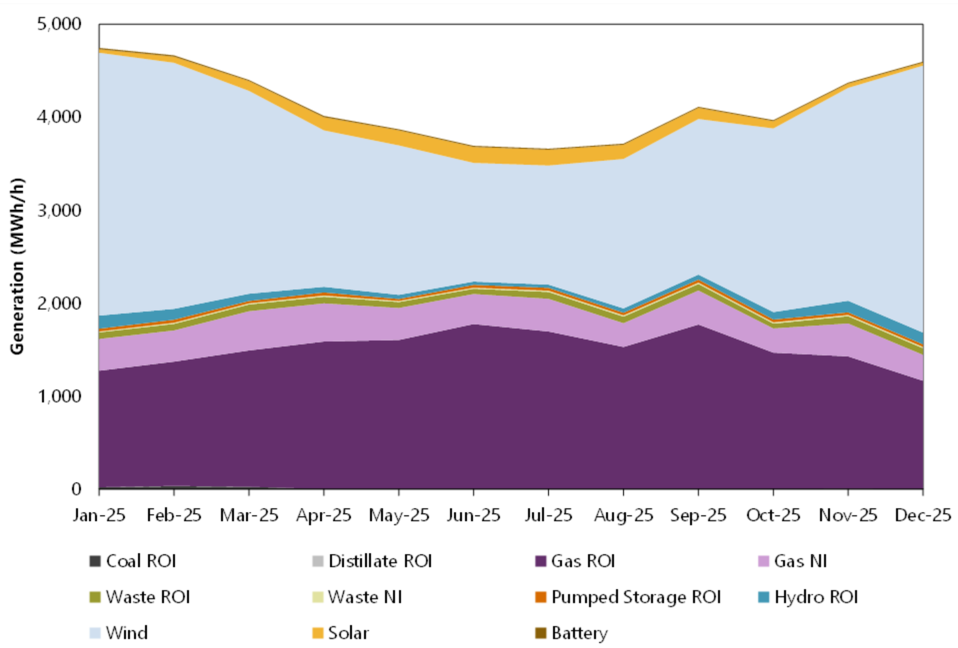


Figure 25: Net Imports, in 2024-2032 and 2021-2029 SEM PLEXOS Models (Year 2025)

Figure 26 shows average hourly generation in the SEM by plant type by month for the 2021-2029 SEM PLEXOS Model (Part A) and the 2024-2032 SEM PLEXOS Model (Part B). The patterns are broadly similar.

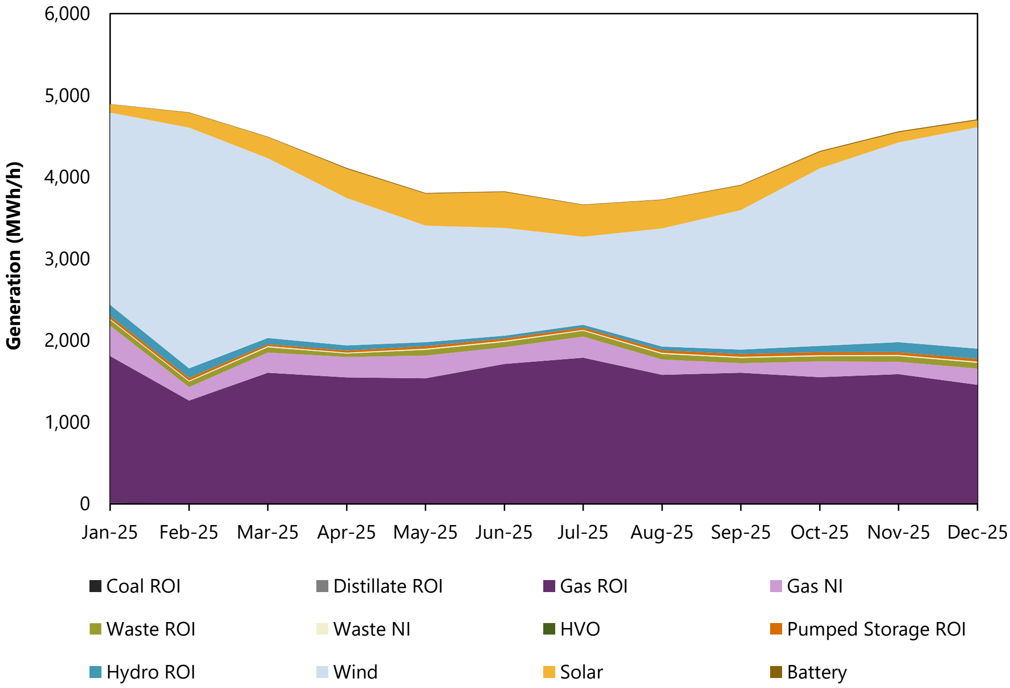
Figure 26: Average SEM Generation (MWh/h) by Plant Type

Part A: 2021-2029 SEM PLEXOS Model (Year 2025)



Note. The following plant types do not appear on the chart because of zero generation in the model: Peat ROI, Coal NI, Oil ROI, and Distillate NI

Part B: 2024-2032 SEM PLEXOS Model (Year 2025)



Note. The following plant type does not appear on the chart because of zero generation in the model: Oil ROI, Distillate NI
The following plant type does not appear on the chart because of unit retirements: Coal NI

Figure 27 shows the forecast of generation in the SEM by plant type in the 2024-2032 SEM PLEXOS Model, showing a long-term reduction in gas and increase in wind and solar. The increase of generation of wind and solar in the later years is clear.

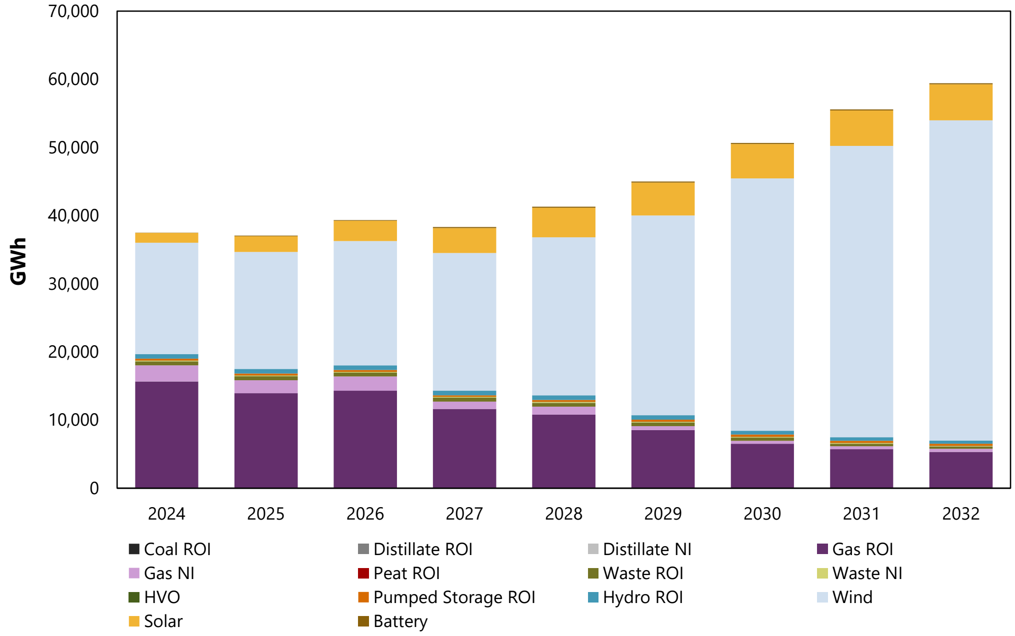


Figure 27: Total SEM Generation by Plant Type by Year, 2024-2032 SEM PLEXOS Model

10. Changes to SEM PLEXOS Model

NERA implemented the following key changes in the 2024-2032 SEM PLEXOS Model (versus the previous 2021-2029 SEM PLEXOS Model).

Item	Prior SEM PLEXOS Model	2024-2032 SEM PLEXOS Model
Wind and Solar Generation Levels	Wind and solar generation only based on available wind generation	Option of wind and solar generation based on either available wind generation or (historical levels of) actual wind generation
Uplift and Wheeling Charge	Uplift turned on and wheeling charges set equal to uplift	The same, but with alternative options of uplift and wheeling charges turned off (Option A2 and Option B)
GB and France Modelling	Regression-based approach on historical data to determine market heat rates; includes market VOM	Hourly patterns of market heat rates based on historical data, with calibration to forward curve, plus placeholder for potential decline following the end of the forward curve; no market VOM
Short-Term Gas Capacity	Fuel options of ST Gas Capacity in ROI and NI, plus a 50% ST Gas Capacity in ROI	Same, but with an option of 50% ST Gas Capacity in NI
Price Cap and prices when USE occurs	€500/MWh (default strike price for CRM contract); in cases of USE: €500/MWh	Same, with explicit direction to adjust the price cap upwards when and if the strike price for the CRM contract exceeds €500/MWh

Table 19: Key Changes in 2024-2032 SEM PLEXOS Model vs. Prior SEM PLEXOS Model

Item	Prior SEM PLEXOS Model	2024-2032 SEM PLEXOS Model
PLEXOS Version	8.3	10.0
Batteries	10% to 50% participation in SEM energy markets	10% to 30% to 50% participation in SEM energy markets
NI Wind	Modelled as separate small-scale and large-scale generation objects	Modelled as one generation object

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Item	Prior SEM PLEXOS Model	2024-2032 SEM PLEXOS Model
Internal VOLL	€10,988.90/MWh	€100,000/MWh
Planned outages after end of last forecast planned outage schedule from TSOs	Specific days set *by unit* based averaging unit's specific outage pattern in final years of outage forecast	Set as a maintanance rate *by type of unit* based on average maintanance rate in final years of outage forecast

Table 20: Additional Minor Changes in 2024-2032 SEM PLEXOS Model vs. Prior SEM PLEXOS Model

11. Recommendation for Future Validations

NERA provides the following recommendations for future validations.

Area	Recommendation	Preconditions	Priority	Notes
New Additions and Retirement	Monitor changes in retirement plans and planned new additions	None	High	
ST Gas Capacity Charges[71]	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
Price formation with very high renewables	Review modelling options best suited for very high renewables penetration	None	Medium then High	Possible areas to consider listed in Section 9.1.1 above.
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

[71] 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.

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Area	Recommendation	Preconditions	Priority	Notes
System Services Co-optimization with DAM	Consider whether it is worthwhile and feasible to incorporate system services into the PLEXOS Model	Sufficient information about go-forward system services market	Medium	Adding system services co-optimization would increase the complexity of the PLEXOS Model—a good understanding of the pros and cons is suggested
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; NERA already includes two methods that remove uplift
Solar Profile	Base solar profiles on historical hourly solar capacity and availability factors	Sufficient solar generation history be available	Low then medium	It may several years before sufficient historical data are available
Offshore Wind Profile	Use historical data	Not possible until large offshore wind projects come online	Low then medium	With new offshore not due until 2028, 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 and a period of relative stability of rules affecting batteries	Medium	Recommend assessing each Validation – it may be several years before rules affecting batteries stabilize where historical analysis can better inform the forecast
DSUs	Review DSU P-Q Pairs	None	Low/ Medium	Recommend assessing each Validation – a lower priority so long as only small quantities are regularly dispatched

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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

Table 21: Recommendation for Future SEM PLEXOS Validations

Appendix A. NERA Quality Assurance

This appendix provides the details of the checks NERA performed to ensure the accuracy and quality of the 2024-2032 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 2021-2029 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 2021-2029 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 2024-2032 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 2024 to 2032, 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 (2024 to 2032) 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.

- The demand shape from the five 2024 to 2032 forecasts indeed lined up with the historical years upon which they were based.

NERA also performed various checks on the outputs of the 2024-2032 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.

Appendix B. Development Historical Wind and Solar Profiles

NERA developed the wind and solar profiles used in the 2024-2032 SEM PLEXOS Model as follows.

Onshore Wind

1) NERA started with the historical dispatch down reports[72], which show historical half hourly wind generation and available generation, separate for ROI and NI. NERA aggregated the half hourly to form hourly data.
2) NERA calculated historical installed wind capacity in ROI and NI based on historical installed capacity and project online dates in the TSOs' System & Renewable Summary Report Spreadsheet[73].
3) Separately for ROI and NI, NERA divided the hourly available generation (step 1) by the wind installed capacities over time (step 2) to determine hourly historical available generation factors. NERA similarly created historical hourly generation factors (i.e., generation after dispatch down).
4) NERA understands that the dispatch down reports rely on SCADA data, though metered data are more accurate. NERA observed historical metered data in the TSOs' System & Renewable Summary Report Spreadsheets – which contained metered data on an annual basis. NERA adjusted the available generation or actual generation factors from step 3, based on the proportional difference between annual metered generation and aggregate annual generation from the dispatch down reports.

Offshore Wind

Given the absence of historical generation data for large-scale offshore wind projects in Ireland, NERA instead relied on Ireland offshore wind profiles from the ENTSO-E Pan-European Climate Database ("PECD"), a database of synthesized historical climate data across 36 European countries[74].

1) The historical profiles from step 1 only go through 2019. NERA lined up 2018 and 2019 historical offshore wind profiles with the load profiles from 2018 and 2019. NERA aligned the historical profiles from step 1 for 2014 to 2017 (excluding 2016, which was aligned with 2020 to match leap years) with load profiles from 2021 to 2023.
2) NERA determined the ratio between available offshore generation and available onshore generation in Ireland in the PECD database. NERA then applied that ratio to the NERA-calculated onshore wind availability from above to calculate an offshore wind availability.
3) NERA adjusted the available generation from step 3 to match an average annual available generation factor of 45%.
4) NERA then determined the ratio between the adjusted available generation and the onshore available generation and applied that ratio to the onshore wind capacity factor to produce an offshore wind capacity factor.

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72 Available at https://www.eirgrid.ie/grid/system-and-renewable-data-reports.

73 Available at https://www.eirgrid.ie/grid/system-and-renewable-data-reports.

74 Available at https://www.entsoe.eu/outlooks/eraa/2023/eraa-downloads/.

Solar

1) NERA started with PECD solar profiles for ROI and NI. NERA notes these have annual available generation factors of 11%, which based on conversations with the TSOs NERA understands are reasonable for solar in the SEM. These form the availability factors (with similar lining up of years as from step 2 of offshore wind).
2) For the actual generation factors, NERA relied on the ratios (on an hourly basis) between NI solar generation and NI solar available generation from the Dispatch Down reports. There was insufficient data for ROI to reasonably estimate dispatch down specific to ROI. There was more history of dispatch down solar data in NI, so NERA used the dispatch down ratios from NI for both ROI and NI.

QUALIFICATIONS, ASSUMPTIONS, AND LIMITATIONS

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 and associated model. The primary audience for this report includes the stakeholders in the electricity market of Ireland and Northern Ireland.

NERA shall not have any liability to any third party in respect of this report and associated model or any actions taken or decisions made as a consequence of the results, advice or recommendations set forth herein.

This report does not represent investment advice or provide an opinion regarding the fairness of any transaction to any and all parties. This report does not represent legal advice, which can only be provided by legal counsel and for which you should seek advice of counsel. The opinions expressed herein are valid only for the purpose stated herein and as of the date hereof. Information furnished by others, upon which all or portions of this report and associated model are based, is believed to be reliable but has not been verified. No warranty is given as to the accuracy of such information. Public information and industry and statistical data are from sources NERA deems to be reliable; however, NERA makes no representation as to the accuracy or completeness of such information and has accepted the information without further verification. The findings contained in this report and associated model may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. NERA accepts no responsibility for actual results or future events. No responsibility is taken for changes in market conditions or laws or regulations and no obligation is assumed to revise this report to reflect changes, events or conditions, which occur subsequent to the date hereof.

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

All decisions in connection with the use of the Model or any results produced by the Model are the sole responsibility of the client or any other third party. There are no third party beneficiaries with respect to the Model (the confidential or public versions), and NERA does not accept any liability to any third party. In particular, NERA shall not have any liability to any third party in respect of the Model or any results produced by the Model or any actions taken or decisions made as a consequence of the results produced by the Model.

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