Determination of the market-based CO_2 emission factor for Belgium

20 October 2021

Fabien Roques, Nicolas Hary

Disclaimer

This report has been prepared by FTI France SAS (“FTI”), trading as Compass Lexecon (“Compass Lexecon”) for the Department of Economy, Science and Innovation (EWI) of the Flemish government (the “Client”) under the terms of the Client’s contract with FTI.

This report has been prepared solely for the benefit of the Client in connection with estimating the market-based CO_2 emission factor for Belgium. It makes part of the procedure described in the "Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post-2021 (2020/C 317/04)" in which such an emission factor can be calculated but must be approved by the national regulatory authority and must be submitted for notification by the Commission. No other party than the Client and the authorities responsible for approval are entitled to rely on this report for any purpose whatsoever.

This report is not to be referred to or quoted, in whole or in part, in any registration statement, prospectus, public filing, loan agreement, or other agreement or any other document, or used in any legal, arbitral or regulatory proceedings other than the approval procedure cited above, without the prior written approval of FTI. FTI accepts no liability or duty of care to any person other than the Client (under the relevant terms of the Contract) for the content of the report and disclaims all responsibility for the consequences of any person other than the Client acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

This report contains information obtained or derived from a variety of sources. FTI has not sought and accepts no responsibility for establishing the reliability of those sources or verifying the information provided.

This report is based on information available to FTI at the time of writing of the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

No representation or warranty of any kind (whether express or implied) is given by FTI to any person (except to the Client under the relevant terms of our contract) as to the accuracy or completeness of this report.

Nothing in this material constitutes investment, legal, accounting or tax advice, or a representation that any investment or strategy is suitable or appropriate to the recipient’s individual circumstances, or otherwise constitutes a personal recommendation.

Executive Summary

1.1 As part of its policies to reduce greenhouse gas emissions and to fight against climate change, the European Commission set up an EU Emissions Trading Scheme (EU ETS) in 2005, that created a CO_2 price signal for EU companies.

1.2 This CO_2 price has been reflected into higher power prices paid by EU companies. Indeed, electricity producers must pay for each CO_2 emission they emit to produce electricity. This additional cost is then factored in their bids submitted on the power market, and ultimately reflected in the power prices paid by consumers. The extent of this pass-through (measured in tCO_2/MWh) is referred to as the CO_2 emission factor and depends on the technology which sets the power price, i.e. which is marginal, and which can vary from hour to hour.

1.3 The higher power prices paid by EU industry due to the introduction of the EU ETS may impede their competitiveness compared to companies in countries that have less stringent climate regulations. To avoid the transfer of industrial production to the latter countries, the Guidelines on certain State Aid measures in the context of the greenhouse gas emission allowance trading scheme post-2012 (the "2012 Guidelines") allow Member States to compensate the most electro-intensive sectors for increases in electricity costs as a result of the EU ETS. The compensation depends, among other factors, on the calculation of an annual CO_2 emission factor.

1.4 The 2012 Guidelines also define a methodology to compute an annual CO_2 emission factor (referred to as "the historic methodology" in this report) based on macro indicators. However, this methodology has several drawbacks that tend to underestimate the CO_2 emission factor computed for Belgium, compared to neighbouring countries, by ignoring the cross-border exchanges and the fact that Belgian prices can be set by technologies with high CO_2 emission in neighbouring countries (coal, lignite…). On the contrary, this methodology tends to overestimate the emission factor for countries relying on baseload polluting technologies, such as lignite. This is notably the case for Germany.

1.5 In 2020, the Guidelines were revised and now give the opportunity to Member States to establish the emission factor based on an alternative methodology, looking at the CO_2 content of the marginal technology determining the price on the electricity market: this is referred as the market-based CO_2 emission factor.

1.6 In this context, Compass Lexecon was mandated by the Department of Economy, Science and Innovation (also known as EWI) of the Flemish region in Belgium to compute the CO_2 emission factor for Belgium with the market-based methodology.

1.7 As asked by EWI, this methodology has to rely on the computation of hourly power prices in two scenarios: (i) with the observed CO_2 prices (the actual scenario) and (ii) without CO_2 prices

(the counterfactual scenario). The final market-based CO_2 emission factor should then be determined as:

$$CO_2\ emission\ factor = \frac{Belgian\ annual\ power\ price\ with\ \mathrm{CO2}\ prices - Belgian\ annual\ power\ price\ without\ CO2\ prices}{Annual\ CO2\ prices}$$

1.8 Moreover, as specified by EWI, this study focuses on the calculation of the CO_2 emission factor for the year 2019 only.

1.9 To perform this analysis, Compass Lexecon uses its in-house European Power Market Dispatch Model that simulates the day-ahead power markets across Europe and the associated hourly merit order, aligned with the requirements of the 2020 Guidelines. The model also captures the impact of cross-border and import/export on the price formation as it is run and optimised over the entire European countries at the same time, considering import/export constraints. Compass Lexecon power dispatch model is implemented on the commercial modelling platform Plexos®, used worldwide by utilities, regulators, TSOs and consulting firms, relying on data and assumptions based on publicly available sources (in particular from ENTSO-E) or based on Compass Lexecon proprietary databases.

1.10 In order to ensure that our power dispatch model is accurate and can be relied upon to determine power prices in a hypothetical scenario without CO_2, we first use our model to simulate prices over a historic period (2019) and then compare them with the actual prices observed over the same historical period: this is called the backtesting exercise. For 2019, results show that for Belgium but also for neighbouring countries, annual differences between actual and modelled prices are well within the 5% margin often considered to validate a power market dispatch model based on international experience. On average, the difference between actual and modelled prices is around 0.80€/MWh for Belgium, i.e. a 2% error margin: the backtesting exercise for the year 2019 confirms the accuracy of our power market dispatch model to replicate day-ahead prices that can then be used to simulate power prices in a scenario without CO_2 prices.

1.11 In this counterfactual scenario without CO_2, the Belgian price would be equal to 26.56€/MWh on annual average, i.e. a 13.6€/MWh decrease compared to the scenario with CO_2. Applying the formula to compute the market-based CO_2 emission factor results in a **coefficient of 0.55 tCO_2/MWh for Belgium for 2019**.

1.12 Given that our backtesting exercise results in 2% error margin for Belgian prices, we can apply this margin to the annual prices computed in the scenario without CO_2 to estimate a range of uncertainty for the final CO_2 emission factor between 0.53 and 0.57 tCO2/MWh.

1.13 This result can be compared with the emission factor that would result from the historic methodology, 0.37 tCO_2/MWh based on 2018 data. This significant difference with the market-based emission factor highlights the fact that **the historic methodology tends to underestimate the CO_2 emission factor for Belgium** since it ignores foreign thermal units that can set the Belgian power prices. On the contrary, the methodology based on a power market dispatch model replicating the merit order on a European level considers cross-border

exchanges and better reflects how foreign units can impact the Belgian power prices actually paid by Belgian industrials.

1.14 The market-based CO_2 emission factor can also be compared with the study performed by the French TSO, RTE, who computes the market-based CO_2 emission factor for France, based on 2019 data and based on the same methodology. Both studies result in slightly different CO_2 emission factors for France (0.55 tCO_2/MWh for Compass Lexecon and 0.59 tCO_2/MWh for RTE). However, this difference is well within the level of uncertainty of a power dispatch model and can be explained by (i) different modelling tools and (ii) different input data.

1.15 Moreover, according to our modelling results, the market-based methodology should result in similar market-based CO_2 emission factor for France and Belgium (0.55tCO_2/MWh). It can also be assumed that this equivalence should apply in the other direction, i.e. that if the RTE modelling were used to compute the CO_2 emission factor for Belgium, we would get the same value as for France (0.59tCO_2/MWh). Thus, a similar market-based CO_2 emission factor should be considered for both countries, independently of the power market dispatch model chosen for its computation or the underlying data. Different market-based emission factors for France and Belgium would only be explained by the modelling choice (either of the modelling tool or of the input data) but would not be explained and justified by the underlying economic drivers of the power price formation. Different CO_2 emission factors would not guarantee a level playing field between French and Belgian industries whereas, according to our results, the impact of CO_2 on power prices paid by French and Belgian industrials should be similar in both countries.

Contents

Section 1 The CO_2 emission factor and the new methodology introduced by the 2020 Guidelines

1.1 In this section, we introduce the context of this study: the concept of the CO_2 emission factor, as well as the methodologies to calculate this factor according to the 2012 and 2020 EC Guidelines. We also present the objective of this report.

The impact of the EU ETS on power prices paid by European industrials

1.2 As part of its policies to reduce greenhouse gas emissions and to fight against climate change, the European Commission set up an EU Emissions Trading Scheme (EU ETS) in 2005.

1.3 The EU ETS is a "cap and trade" system on greenhouse gas emissions, the most prevalent being the CO_2: a cap is set on the total amount of greenhouse gas that can be emitted by factories, power plants and other installations. The cap is reduced annually over time so that total emissions fall. Within the cap, companies receive or buy emission allowances which they can trade with one another. The EU ETS thus creates a CO_2 price signal for businesses.[1]

1.4 This EU ETS and the associated CO_2 price affect EU companies in two ways. On the one hand, these companies have to buy CO_2 certificates corresponding to their own industrial emissions, creating a new cost compared with a situation without EU ETS (so-called "direct ETS costs"). On the other hand, they also pay more for the electricity they consume (so-called "indirect ETS costs"). Indeed, electricity producers are also covered by the EU ETS: they must pay for each CO_2 emission they emit to produce electricity. This cost is then reflected into their generation costs and ultimately in the electricity price which is paid by EU companies, as explained in detail in the following paragraphs.[2]

---

1 §1.1., *Impact assessment accompanying the document Communication from the Commission on Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post 2021*, https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report_ets_2021_en.pdf

2 *Ibid*

Impact of the EU ETS on power producers' offers

1.5 For a power generator burning a fossil fuel which emits CO_2 (gas, lignite, coal…), the EU ETS creates an additional cost to produce electricity that is reflected in the bids submitted on the power market, in particular in the day-ahead market which is the reference market in Europe. More precisely, in a competitive market, economic theory indicates that thermal plants should offer their generation at their short-run marginal cost ("SRMC"). SRMC can be approached as:

$$SRMC\left(\frac{€}{MWh}\right) = Variable\ O\&M(€/MWh) + \frac{Fuel\ Cost\ (€/MWh)}{Plant\ Efficiency\ (\%)} + \frac{CO2\ price\ (€/tCO2) \cdot Fuel\ emission\ factor\ (tCO2/MWh)}{Plant\ Efficiency\ (\%)}$$

1.6 As a result, the higher the CO_2 prices, the higher the SRMC and the offers submitted by all thermal plants. The extent of this increase depends on the fuel emission factor, which measures the quantity of CO_2 emitted when burning a given quantity of fuel, and on the efficiency of the plant.

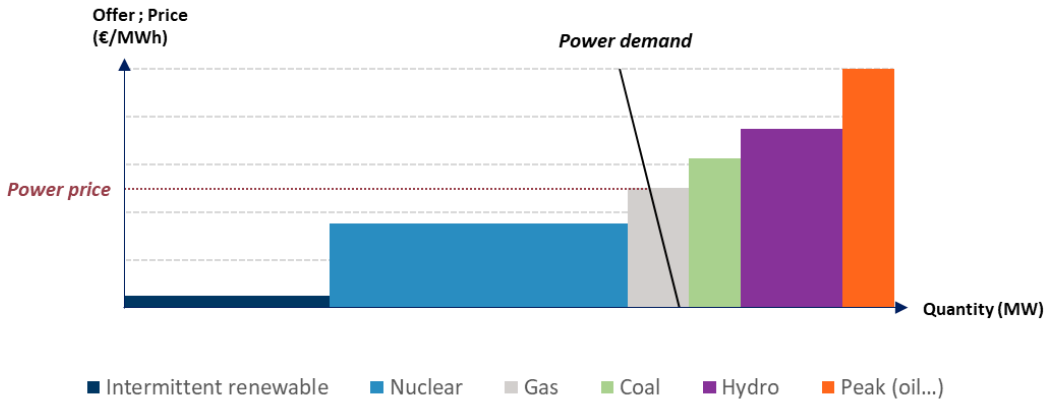
1.7 As will be further explained in §2.11, CO_2 prices can also have an impact on the bids submitted by storage-limited technologies (such as hydro), even if these technologies are CO_2-free and do not need to purchase CO_2 allowances. Indeed, operators of these technologies should not only consider their SRMC to produce electricity but also the foregone profits of not being able to produce later due to the limited storage. These foregone profits can depend on the CO_2 prices: then, offers from storage-limited technologies can also incorporate a CO_2 price, the magnitude of which will depend on the calculation of foregone profits and on the operator's strategy.

1.8 On the contrary, some technologies, such as intermittent renewables (wind or PV) do not emit CO_2 and do not have storage constraints: their offer is then independent from the CO_2 prices.

Impact of the EU ETS on power prices

1.9 Once bids submitted by each technology have been determined, considering the CO_2 prices (or not, depending on the technology), power prices can be calculated based on the merit-order principle. All bids are ranked by increasing prices and aggregated to one supply curve: the final power price is set at the intersection of the demand and the supply curves as illustrated in Figure 1. The power price is then defined by the offer submitted by one specific plant called the marginal unit (a gas unit in the example below on Figure 1). This merit-order principle is applied for each hour to determine the day-ahead price.

Figure 1: Illustration of the merit-order concept and definition of power prices



Source: Compass Lexecon

1.10 As a result, CO_2 prices are reflected in the bids submitted by generators (the magnitude of which depends on the technology), and ultimately reflected in the power prices paid by consumers. The extent of this pass-through depends on the technology which sets the price, i.e. which is marginal, and which can vary from hour to hour.

1.11 The relationship between CO_2 prices and power prices (in tCO_2/MWh) is referred to as the CO_2 emission factor.[3]

Risk of carbon leakage and compensation for indirect costs according to the 2012 Guidelines

1.12 Direct and indirect ETS costs tend to decrease EU companies' competitiveness compared with companies in countries that have less stringent climate regulations. So businesses may choose to transfer production to those countries: this is referred as the carbon leakage risk.[4]

1.13 To safeguard the competitiveness of EU industries covered by the EU ETS, production from sectors deemed to be exposed to a significant risk of carbon leakage has been compensated for direct ETS costs with free ETS allowances. On top of that, the Guidelines on certain State Aid measures in the context of the greenhouse gas emission allowance trading scheme post-2012 (the "2012 Guidelines") allow Member States to compensate some energy-intensive industries for the higher electricity costs resulting from the EU ETS, i.e. the indirect ETS costs.[5]

---

3 *Ibid*, §1.2. "*The CO_2 factor (measured in tCO_2/MWh) measures the extent to which the price of the electricity consumed by the beneficiary is influenced by ETS costs*"

4 *Ibid*, Box 1 page 6

5 Communication from the Commission — Guidelines on certain State aid measures in the context of the greenhouse gas emission allowance trading scheme post-2012, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020XC0925%2801%29

1.14 The 2012 Guidelines define a formula to compute the compensation level payable per installation for indirect ETS costs, which, among other factors, depends on the national and annual CO_2 emission factor.[6]

1.15 The 2012 Guidelines also define a methodology to compute an annual CO_2 emission factor (referred to as "the historic methodology" in this report) based on macro indicators. This is equal to the annual CO_2 equivalent emissions of the energy industry (in tCO_2) divided by the annual gross electricity generation based on fossil fuels (in TWh). This coefficient shall be computed per country, but the 2012 Guidelines authorize that a unique CO_2 emission factor could be considered for several countries if price convergence between these countries is high enough.[7]

1.16 However, this historic methodology has several drawbacks:

- It focuses on thermal generation only and ignores generation from nuclear, hydro or renewables. This was justified by the fact that, at that time, the marginal units on the day-ahead market were most of the time thermal units. However, as mentioned by the EC in the 2020 Guidelines, "*the increasing share of renewable generation may have had the effect of changing the typology of price-setting generation plants*"[8]: the fact that thermal technology is marginal most of the time can then be challenged.

- It tends to ignore neighbouring countries and the fact that power prices can be set by foreign units. According to the historic methodology, the CO_2 emission factor for Belgium for the period 2021-2030 must be computed based on the Belgian CO_2 emission and thermal generation only and must ignore generation from neighbouring countries.[9] However, as highlighted by CREG, the Belgian power market is very often coupled with at least one neighbouring country (for instance during almost 70% of the time in 2019)[10]:

---

6 See §28 of the 2012 Guidelines for further explanations on the definition of the aid

7 This was the case for all Central-West Europe ("CWE") countries, including Austria, Belgium, France, Germany, the Netherlands and Luxembourg, for which a unique CO_2 emission factor of 0.76 tCO_2/MWh was defined between 2012 and 2020.

8 §6.3.1.2, *Impact assessment accompanying the document Communication from the Commission on Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post 2021*, https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report_ets_2021_en.pdf

9 This was not exactly the case for the period 2012-2020 when 2012 Guidelines authorized computing a unique CO_2 emission factor for the CWE zone, which enabled to capture partially the impact of neighbouring countries on Belgian prices. However, with the 2020 Guidelines, Belgium is now considered as a unique geographic zone and the CO_2 emission factor computed according to the historic methodology will rely on Belgian data only.

10 CREG, Annual report 2019, p46 https://www.creg.be/sites/default/files/assets/Publications/AnnualReports/2020/CREG-AR2019-EN.pdf

during those hours, Belgian power prices can be set by a foreign plant (for instance a coal or lignite plant, whose technology is not present in Belgium). Relying on Belgian data only does not capture this in the calculation of the CO_2 emission factor. This limit is also mentioned by the EC in the 2020 Guidelines: "*the indirect ETS costs supported by electricity consumers in a given Member State not only depend on the production mix of this Member State but can also depend on the production mix of neighbouring Member States and the degree of cross-border capacity*".[11]

- Finally, the historic methodology considers the generation of each thermal technology but does not consider how often this technology is marginal and sets the power prices. Based on the merit-order principle, the power price is defined by only one marginal unit. Units with cheaper bids (named infra-marginal units) produce but do not define power prices. When assessing the CO_2 emission factor for this hour, the bids submitted by infra-marginal units do not matter and only the offer of the marginal unit is important. The historic methodology does not distinguish infra-marginal and marginal technologies, which can wrongly estimate the CO_2 emission factor.[12] This last drawback of the historic methodology is also mentioned by the EC in the 2020 Guidelines: "*As electricity prices are generated via the merit order, this* [CO_2 emission] *factor measures the impact of certain technologies on price formation (not the overall generation mix in a given country)".*[13]

Impact of the historic methodology on the Belgian CO_2 emission factor and on the competitiveness of the Belgian industry compared with neighbouring countries

1.17 Those three main drawbacks can have a significant impact on the Belgian CO_2 emission factor, given the importance of the market coupling with neighbouring countries relying on technologies with high CO_2 emissions (lignite and coal).

1.18 In particular, the historic methodology would result in a CO_2 emission factor of 0.37 for Belgium based on 2018 data, 0.51 for France, 0.50 for the Netherlands and 0.75 for

---

11 §5.3.2., *Impact assessment accompanying the document Communication from the Commission on Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post 2021*, https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report_ets_2021_en.pdf

12 In particular, given that lignite technology is often inframarginal, the historic methodology tends to overestimate the role of lignite and then the CO_2 emission factor.

13 §1.2., *Impact assessment accompanying the document Communication from the Commission on Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post 2021*, https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report_ets_2021_en.pdf

Germany/Luxembourg/Austria (more than twice the Belgian coefficient).[14] This significant discrepancy is explained by the generation mix of each country: whereas Belgium only relies on gas as thermal generation, France, the Netherlands and more importantly Germany also rely on coal and/or lignite, whose emission factor is much higher. [15]

1.19 However, when looking at power prices, Belgium was coupled with a least one of these countries during almost 50% of hours in 2018, meaning that the Belgian prices can in theory be explained by a foreign unit, including coal or lignite, during almost half of the year.[16] Ignoring the cross-border exchanges and the fact that Belgian prices can be set by technologies with high CO_2 emission in neighbouring countries tends to underestimate the Belgian CO_2 factor and does not create a level playing field with industrials in other EU countries.

1.20 On the contrary, the historic methodology tends to overestimate the CO_2 emission factor for countries relying on polluting technologies as baseload generation, such as lignite. This is notably the case of Germany. Indeed, due to its cheap generation costs, lignite often produces as baseload and then is very often infra-marginal, i.e. is rarely setting the price paid by industrials. However, as mentioned in §1.15, while the CO_2 emission factor should only consider marginal technologies, the historic methodology also considers infra-marginal technologies and then includes lignite generation in the emission factor calculation.

1.21 Based on 2015-2017 data, while the marginality of lignite in Germany was assessed between 3% and 15% of the time[17], the share of lignite in the German fossil fuel power production was about 43% over the same period[18]. In other words, while the weight of lignite in the power price determination should be between 3% and 15%, the historic methodology gives a weight of 43%. Given the important emission factor of the lignite technology compared to other

---

14 Cf. Table 3 of the impact assessment accompanying the 2020 Guidelines (https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report_ets_2021_en.pdf)

15 Average emission factor for lignite is around 1.05 tCO2/MWh whereas it amounts to 0.41 tCO2/MWh for CCGT units and 0.83 tCO2/MWh for coal units. See Ladage, S., Blumenberg, M., Franke, D. et al. *On the climate benefit of a coal-to-gas shift in Germany's electric power sector.* Sci Rep 11, 11453 (2021). https://doi.org/10.1038/s41598-021-90839-7

16 CREG, Study on the functioning and price evolution of the Belgian wholesale electricity market – monitoring report 2018 page 36, https://www.creg.be/sites/default/files/assets/Publications/Studies/F1958EN.pdf

17 Robert Germeshausen, Nikolas Wölfing, *How marginal is lignite? Two simple approaches to determine price-setting technologies in power markets*, Energy Policy, Volume 142, 2020, 111482, ISSN 0301-4215, https://doi.org/10.1016/j.enpol.2020.111482.

18 Compass Lexecon computation based on data provided by Arbeitsgemeinschaft Energiebilanzen e.V. (https://ag-energiebilanzen.de/index.php?article_id=29&fileName=ausdruck_strerz_abgabe_feb2021_a10_.pdf)

technologies[19], this results in an **overestimation of the German CO_2 emission factor** with the historic methodology.

The alternative methodology introduced with the 2020

1.22 In order to solve those issues and to increase competitivity of industrials in countries where the CO_2 emission factor can be underestimated with the historic methodology, the 2020 Guidelines give the opportunity to Member States to establish the emission factor based on an alternative methodology, looking at the CO2 content of the marginal technology determining the effective price on the electricity market: this is referred as the **market-based CO_2 emission factor.**

1.23 According to the 2020 Guidelines, this market-based CO_2 emission factor shall be computed "*based on a model of the electrical system simulating price formation and observed data on the margin setting technology over the entire year t-1 (including the hours when imports were margin setting)".* [20]

Objective of this study

1.24 Compass Lexecon was mandated by the Department of Economy, Science and Innovation (also known as EWI) of the Flemish region in Belgium to compute the CO_2 emission factor for Belgium with the newest market-based methodology, as authorized by the 2020 Guidelines.

1.25 As asked by EWI, the alternative methodology has to rely on the computation of hourly power prices in two scenarios: (i) with the observed CO_2 prices (the actual scenario) and (ii) without CO_2 prices (the counterfactual scenario). The final market-based CO_2 emission factor should then be determined as:

$$CO2\ emission\ factor = \frac{Belgian\ annual\ power\ price\ with\ \mathrm{CO2}\ prices - Belgian\ annual\ power\ price\ without\ CO2\ prices}{Annual\ CO2\ prices}$$

1.26 Moreover, as specified by EWI, this study focuses on the calculation of the CO_2 emission factor for the year 2019 only.[21]

---

19 See footnote 15

20 Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post-2021, definition (11), https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020XC0925(01)&from=EN

21 Indeed, the 2020 Guidelines seem to consider this specific year to compute the CO2 emission factor based on the historical approach ("*The Commission will update the Annex of the Guidelines in order to reflect 2019 data for CO2 factors, once these data will be made available*" https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report

1.27 The application of this methodology is structured in four different steps, which will be further described in the following sections:

a. Presentation and justification of the power market dispatch model – Section 2

b. Backtesting of the power market dispatch model in order to validate its accuracy: comparison of 2019 actual and modelled prices – Section 3

c. Simulation of the power market model without CO2 prices and calculation of the associated power prices - Section 4

d. Calculation of the final CO_2 emission factor – Section 5

_ets_2021_en.pdf page 59). Moreover, relying on 2020 data appears less relevant given the specificities of this year due to the COVID-19 outbreak and its impact on the power market (very low prices).

Section 2

Presentation of the power market dispatch model used in this study

2.1 In this second section, we present the power market dispatch model which is used to simulate hourly power prices. We also justify the use of this model to apply the alternative methodology.

Presentation of Compass Lexecon's power market dispatch model

2.2 To perform this analysis, we use our in-house European Power Market Dispatch Model that simulates the day-ahead power markets across Europe and the associated hourly merit order. The model is implemented on the commercial modelling platform Plexos®, using data and assumptions based on publicly available sources or based on Compass Lexecon proprietary databases as described in §3.5.

Presentation of the Plexos platform

2.3 Plexos is an optimisation platform developed by Energy Exemplar.[22] It allows finding solutions using advanced optimisation procedures taking into account a large number of variables and complex constraints of transmission network and power plants. It also provides a flexible and user-friendly interface allowing testing multiple scenarios, performing stochastic sampling and optimisation, and presenting the results in a graphical form.

2.4 This optimisation platform is used worldwide by utilities, regulators, transmission system operators ("TSOs") and consulting firms. For instance, in Europe, it is used by the association of European TSOs for electricity ENTSO-E and for gas ENTSO-G, as well as by the Irish TSO Eirgrid and the Estonian TSO Elering. The Australian Energy Market Operator ("AEMO") also uses Plexos for its analysis. Moreover, Compass Lexecon has used its power market dispatch model over the last years for a range of assignments and clients across Europe to provide a robust and reliable source of market intelligence. Recognizing that the best source of market insights stems from stakeholders, Compass Lexecon's power market dispatch model has been developed collaboratively using our experts' insights and stakeholders' contributions, in particular from national TSOs and ENTSO-E.

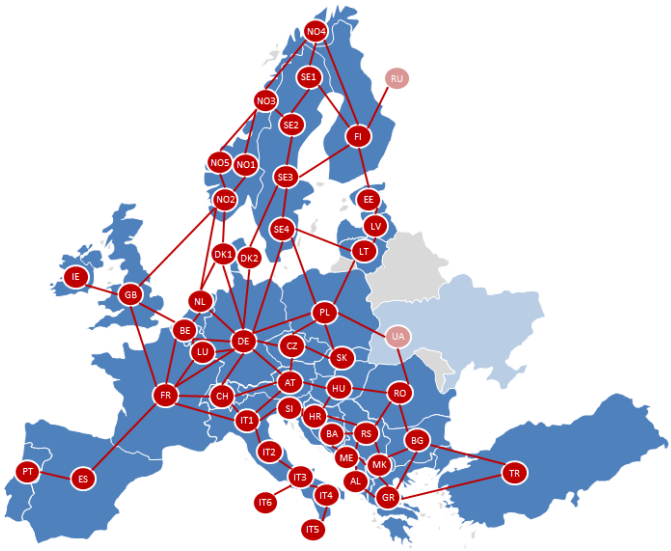
---

22 https://energyexemplar.com/solutions/plexos/

Optimisation principles

2.5 Compass Lexecon's power market dispatch model covers the EU-27 countries as well as the United Kingdom, Switzerland, Norway, the Balkans and Turkey. Countries beyond this geographic scope are modelled at an aggregate level. The model uses the zonal transmission network representation that matches with the market bidding zones currently implemented in Europe. The geographic scope of the model is shown below.

Figure 2: Geographic scope of Compass Lexecon's model



Source: Compass Lexecon

2.6 Our model seeks to determine the least cost unit commitment and dispatch solution to meet power demand, while respecting some constraints summarised below:

1. Energy balance constraints
2. Operation reserve constraints
3. Generator technical constraints: ramp, min up/down, min capacity
4. Generator energy limits: hourly / daily / weekly / …
5. Transmission limits
6. Emission limits (if any): daily / weekly / …

2.7 In order to minimise costs and determine the unit commitment and economic dispatch of each unit, the dispatch model simulates a merit order[23] for each price zone at an hourly level, while

[23] As described in the Figure 1 but taking into account complex technical considerations (for instance start up costs, minimum stable level…)

allowing for the possibility of transferring power generation between interconnected price zones up to the available Net Transfer Capacity ("NTC").[24] The model calculates the price in each price zone as the marginal value of energy delivered in that zone (also known as the shadow price of the energy balance constraint).

Supply curve modelling

2.8 This model uses a detailed bottom-up methodology to represent the supply side: each technology (thermal, hydro, nuclear, renewable…) is modelled with its own technical and cost characteristics and is used as the basis of the dispatch model.

Focus of thermal units

2.9 Regarding thermal units, Compass Lexecon has developed a European power plants database that is regularly updated to include the latest announcements from plants operators, utilities and regulators. In our modelling, each thermal unit is individually modelled and is assumed to offer its generation at its SRMC as explained in §1.5.[25] The dispatch on these units also takes into account their technical constraints (minimum stable level, ramping constraints…).

Focus on renewable technology

2.10 Intermittent renewable technologies, such as solar, wind or run-or-river, are assumed to bid at 0 €/MWh on the market and then to produce up to their available capacity.

Focus on energy-constrained technology

2.11 For energy-constrained technology (such as hydro units), a specific modelling is applied to reflect its specificities. Indeed, due to a limited storage, the operator has to carefully manage the quantity of available fuel (for instance water) to optimise its revenues. For instance, it may decide to reduce the generation during hours with low prices, even if prices are higher than the variable costs, in order to save fuel and to use it during hours with higher prices instead.

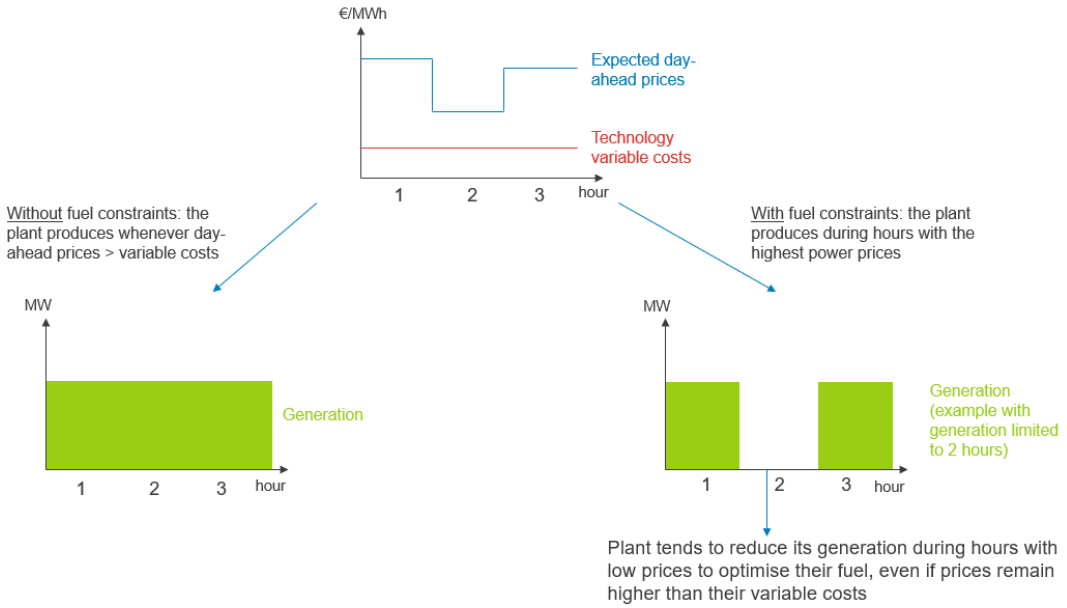
2.12 This point is illustrated below in the Figure 3. Without fuel constraints, the plant would produce over the three hours since the day-ahead price is higher than the variable cost of the technology. With fuel constraint, in a situation where the plant has only two hours of stock, it would only produce at hours one and three, when power prices are the highest. During the second hour, the plant prefers to save fuel.

---

24 Aligned with the current methodology used by ENTSO-E in the MAF 2020 study. Due to data unavailability for simulation purposes, the flow-based approach which is currently used in the CWE power markets is not modelled.

25 A mark-up can also be added on top of the SRMC to reflect additional costs, such as start-up costs.

Figure 3: Illustration of the concept of opportunity cost for energy-constrained technology



Source: Compass Lexecon

2.13 The generation decisions of an energy-constrained plant are taken depending on their variable costs but more importantly on profits it foregoes by not being able to produce in another hour due to limited fuel. This latest consideration is referred as the opportunity cost in the economic literature and implies a different modelling compared with thermal units which are assumed to bid their SRMC.

2.14 The opportunity cost principle is true for hydro plants with limited storage capacity but also for French nuclear plants.[26] Indeed, the limited storage of French nuclear plants is explained by the limited amount of uranium that a reactor can use between two refuelling outages. These outages are planned well in advance and are quite inflexible. As a result, between two refuelling outages, the operator of the plant has to carefully manage the quantity of available uranium to optimise its revenues. French nuclear plant output is dispatched and offered on the

26 Given that Belgian and French power prices are very often the same (60% of hours in 2019), the French nuclear bidding strategy can have significant impact of power prices experienced in Belgium.

market based on an opportunity cost bidding strategy and not based on its variable costs only.[27],[28]

2.15 Our power market dispatch model replicates this bidding strategy based on opportunity costs for hydro units and French nuclear plants:

a. For hydro plants, Plexos directly calculates the opportunity cost in its optimization algorithm (the so-called "water value")[29]

b. Regarding French nuclear pants, we determine the associated bidding strategy based on an analysis of historical nuclear generation and the relationship with power prices, as described below

Box 1. Modelling of the opportunity costs bidding strategy of French nuclear plants based on historical data

Both figures below depict the evolution of the hourly French nuclear generation depending on the hourly day-ahead prices for two illustrative weeks in 2020. Three different areas can be distinguished on these figures:

a. Area 1: For power prices higher than the gas SRMC, nuclear generation appears constant and at the maximum available;

b. Area 2: For prices lower than the gas SRMC, the lower the electricity price, the lower the nuclear generation. This trend reflects the fuel constraints and the associated opportunity costs bidding strategy: nuclear operators prefer to save fuel for hours with higher prices;

c. Area 3: Even in case of very low prices, nuclear plants must produce above their minimum stable load due to technical constraints.

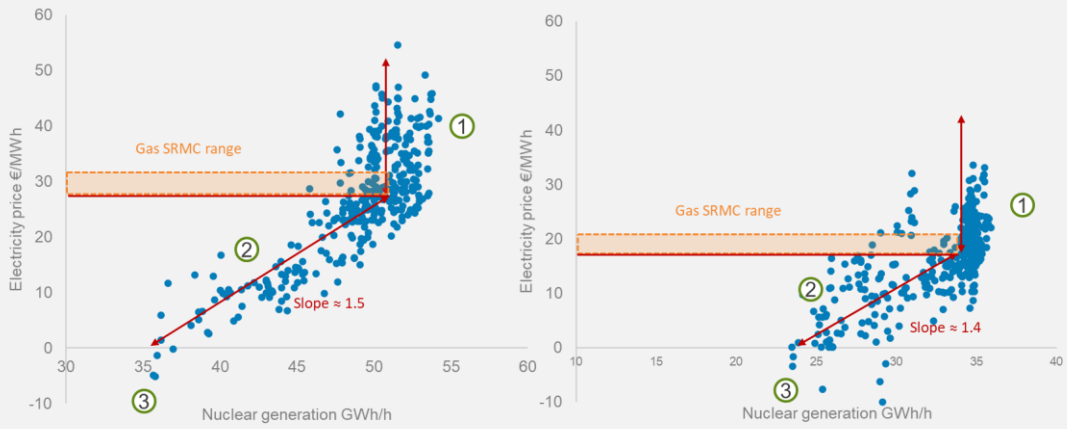
---

27 As is recognised by the French regulator: "[les producteurs nucléaires] *peuvent améliorer la gestion de leurs moyens de production en tenant compte non seulement de leur coût variable de production mais également du coût d'opportunité qu'ils ont du fait de l'arbitrage entre une production à un certain moment et une production ultérieure*" (cf. https://www.cre.fr/Documents/Deliberations/Approbation/approbation-du-rapport-de-rte-sur-le-facteur-d-emission-associe-au-marche-de-l-electricite-francais)

28 This bidding strategy based on the opportunity costs is not relevant for foreign nuclear plants as nuclear in foreign countries is often less flexible than at French plants, can less easily modulate its generation depending on prices and is barely marginal given its limited share in the power mix.

29 More exactly, Plexos determines the optimal planning solution in the medium term assuming perfect foresight and then uses the obtained results in a detailed short-term unit commitment and economic dispatch problem. Further details on the way hydro is optimised and modelled in Plexos can be found here: https://energyexemplar.com/wp-content/uploads/02-15-Price-Forecasting-Forum-Berlin_-TF_Final.pdf

Figure 4: Hourly French nuclear generation and day-ahead prices for two illustrative weeks (February 3-16 2020 on the left and 25 May-7 June 2020 on the right)



Source: RTE, Energy Market Price, Compass Lexecon

Our modelling of the bidding strategy of French nuclear plants follows this historical analysis and the relationship between generation and power prices, considering the three different areas highlighted above.

Compass Lexecon's power market dispatch model meets the EC guidelines requirements

2.16 According to the 2020 Guidelines, the alternative methodology shall rely "*on a model of the electrical system simulating price formation and observed data on the margin setting technology over the entire year t-1 (including the hours when imports were margin setting)*".[30]

2.17 Compass Lexecon's power market dispatch model is aligned with these requirements. Indeed, as described in the previous section, Compass Lexecon's model computes hourly power prices, replicating the merit-order principle and the day-ahead price formation as required by the 2020 Guidelines ("*simulating price formation*"). This model enables to determine the marginal price setting technology on an hourly basis ("*the margin setting technology over the entire year t-1*"). It also captures the impact of cross-border and import/export on the price formation as the model is run and optimised over the entire European countries at the same time, considering import/export constraints ("*including the hours when imports were margin setting*").

30 Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post-2021, definition (11), https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020XC0925(01)&from=EN

2.18 Moreover, the accuracy of our model and its ability to replicate power price formation is regularly assessed based on historical data. Assessment of this accuracy for the year 2019 is presented in the next section.

2.19 Finally, relying on Compass Lexecon's power market dispatch model enables us to overcome the main drawbacks of the historic methodology as described in §1.16:

- The power market dispatch model considers all technologies when defining the merit-order curve and determining power prices (thermal but also nuclear, hydro and renewable).
- It determines prices in all EU countries at the same time, taking into account interconnections. In the model, Belgian power prices can be set by foreign units (depending on the merit-order principle and on the available cross-border capacity), which will be reflected in the final market-based CO_2 emission factor.
- The power market dispatch model determines power prices based on the marginal technology only, ignoring the infra marginal ones. So, contrary to the historic methodology, infra-marginal technologies do not impact the market-based CO_2 emission factor.

2.20 Relying on a power market dispatch model would necessarily imply some errors since a model always means some simplifications, for instance due to computation time constraints or data unavailability. In this study, possible errors in the computation of hourly prices and then in the final market-based CO_2 emission factor are minimized thanks to several measures:

a. The accuracy and quality of our power market dispatch model are frequently assessed and improved if needed thanks to a backtesting exercise. Results of the backtesting for year 2019 are presented in the Section 3 and show that our power market dispatch model is able to well replicate historical prices with less than 1€/MWh difference.

b. In the formula of the CO_2 emission factor (§1.25), we rely on modelled prices for the scenario with CO_2 prices, as simulated in our backtesting exercise, instead of using the actual prices. Then, we compare modelled prices with CO_2 and modelled prices without CO_2: the difference between the prices is only due to the CO_2 price. On the contrary, if we had used instead the actual observed prices in the scenario with CO_2, the difference with the modelled prices in the scenario without CO_2 would be due to (i) the CO_2 price but also to (ii) the power market dispatch model and the associated possible errors. Using modelled prices in both scenarios minimizes possible errors of the power market dispatch model in the calculation of the CO2 emission factor.

Section 3

Results of Compass Lexecon's backtesting exercise for the year 2019

3.1 This section introduces the backtesting exercise that we develop to ensure that our power dispatch model is accurate and can be relied upon to determine power prices in a hypothetical scenario for which we cannot rely on actual data. First, we describe the backtesting methodology, including the input data on which we rely. Then, we present the results for the year 2019 and the comparison between actual and modelled prices.

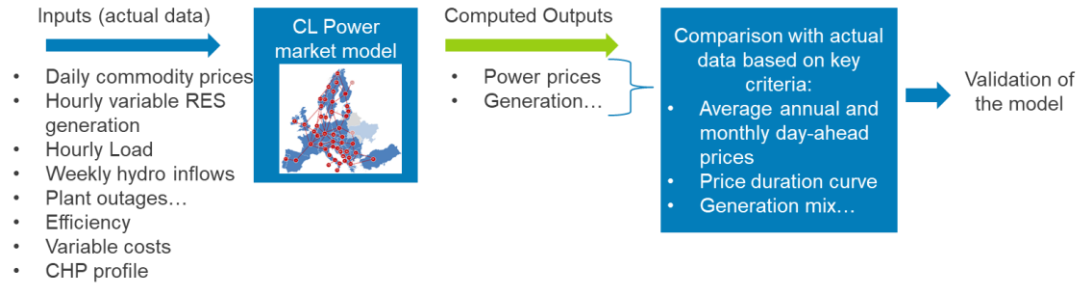
Presentation of the backtesting methodology

3.2 Backtesting is a process by which we use our power market model to simulate prices over a historic period and then compare with the actual prices observed over the same historical period. The lower the difference the greater comfort we can draw that our model replicates correctly day-ahead prices and will produce reliable results in a scenario without CO_2 prices.

3.3 As request by EWI, we focus on the year 2019 in this report.[31]

3.4 Figure 5 describes the general backtesting methodology.

Figure 5: Overview of the backtesting methodology and validation of the power market dispatch model



Source: Compass Lexecon

31 However, our model is calibrated every year with respect to historical prices simultaneously on all interconnected European power markets.

3.5 As inputs, for all European countries, we rely on a set of key inputs from the sources listed in the table below. Most of data come from the ENTSO-E Transparency Platform,[32] an online data platform for European electricity system data. This platform is technically operated by ENTSO-E but data is provided by other participants, such as TSOs or generators according to the Regulation 543/2013.

Table 1: Inputs and associated sources used for the backtesting exercise

Input	Source
Hourly power demand	ENTSO-E Transparency Platform, adjusted with national statistics provided by TSOs, regulators or statistical agencies [33]
Installed capacity	ENTSO-E Transparency Platform and Compass Lexecon database
Availability (nuclear and large thermal units)	ENTSO-E Transparency Platform
Hourly generation of RES (wind, solar, run-of-river…)	ENTSO-E Transparency Platform, adjusted with national statistics provided by TSOs, regulators or statistical agencies
Weekly hydro inflow and reservoir constraints	Computed based on reservoir level data from ENTSO-E Transparency Platform
Daily fuel prices (CO_2, gas, coal…)	Bloomberg and EnergyMarketPrice
Technical and economic characteristics of thermal plants (efficiency, VOM, ramp up…)	Compass Lexecon database, based on third-party sources (Platts, ENTSO-E), market intelligence and regularly updated based on latest announcements from plants operators, utilities and regulators
Opportunity costs of hydro plants	Optimised and computed directly by the power market dispatch model
Opportunity costs of French nuclear plants	Based on historical analysis and the observed relationship between nuclear generation and thermal SRMC[34]
Cross-order capacity and availability	ENTSO-E Transparency Platform

Source: Compass Lexecon

32 https://transparency.entsoe.eu/

33 For some values and countries, data provided by ENTSO-E is not aligned with annual statistics provided by TSOs, regulators or statistical agencies (for instance, for some countries data provided by ENTSO-E does not seem to consider generation from the distribution network or self-consumption). In these situations, data provided by ENTSO-E has been adjusted to be in line with national annual statistics.

34 Another solution would be to rely on the offers submitted by nuclear/hydro plants in the French balancing mechanism, assuming that these offers are a good estimation of their opportunity costs. RTE uses this solution in their backtesting exercise of the year 2019 (cf. https://www.cre.fr/Documents/Deliberations/Approbation/approbation-du-rapport-de-rte-sur-le-facteur-d-emission-associe-au-marche-de-l-electricite-francais). However, such data is not publicly available.

3.6 As outputs, the power market dispatch model computes hourly power prices in each country, generation for each unit as well as cross-border exchanges between countries. These modelled results are then compared with actual data, in particular for power prices which are the main component in the market-based CO_2 emission factor equation.

3.7 Deviations are to be expected between actual and modelled prices, since the model cannot capture all market complexity and that not all of the data used by market participants is publicly available. Based on international experience,[35] the differences between annual market results and modelled results would be expected to sit within a 5% margin in order to validate the model accuracy.

Results of the backtesting exercise for the year 2019

3.8 The power market dispatch model is mainly assessed based on the comparison of modelled and actual day-ahead prices on an annual average, since this value is used at the end to compute the CO_2 emission factor. However, power prices with a shorter timeframe are also compared.

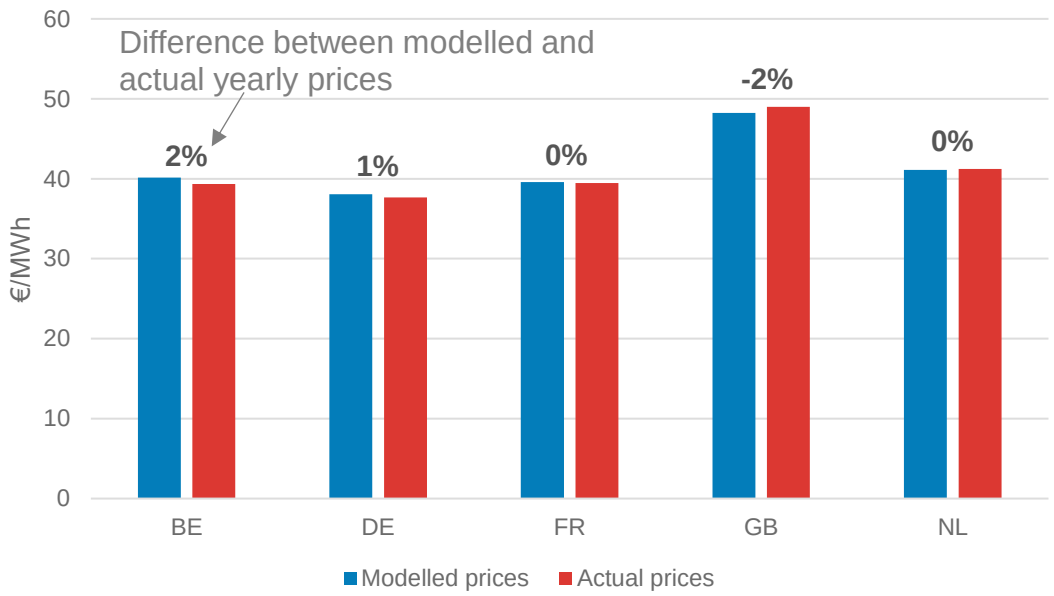
Comparison of annual prices

3.9 The figure below presents the yearly average power prices, modelled and actual, for Belgium as well as neighbouring countries. It shows that our modelled prices, for Belgium but also for neighbouring countries, are well within the 5% margin often considered to validate a power market dispatch model.

---

35 See for instance the backtesting exercise performed for the Irish TSO (https://www.semcommittee.com/sites/semc/files/media-files/SEM-20-004%20SEM%20PLEXOS%20Validation%20%282019-2025%29%20and%20Backcast%20Report.pdf))

Figure 6: Yearly modelled and actual prices in 2019



Source: Compass Lexecon for modelled prices, ENTSO-E for actual prices

3.10 On average, the difference between actual and modelled prices is around 0.80€/MWh for Belgium, i.e. a 2% error margin.

3.11 Several reasons can explain this small difference, such as:

a. The actual bidding strategy may differ from the SRMC principle or be based on slightly different costs or technical assumptions;

b. Optimisation for technologies with limited storage (hydro, nuclear for France) depends on the operator's strategy and price projections and then can differ from our modelling;

c. For some input parameters (for instance for renewable generation), our model relies on realised data whereas day-ahead power prices are determined one day in advance (i.e. one day before the delivery) and then rely on day-ahead forecasts instead. The difference between day-ahead forecasts and realized values is limited but could explain remaining price differences.

3.12 Comparisons of monthly and daily prices are presented in the Annex A. When considering a more granular view such as daily prices, larger differences may appear on some specific hours due to the high volatility of electricity prices. However, our modelled prices largely succeed in capturing the monthly/hourly fluctuations of historical prices.

Comparison of hourly prices

3.13 The figure below represents the Belgian price duration curve for 2019 both for actual and modelled prices. Except for extreme prices (very high and very low prices), our power model correctly replicates the hourly duration curve observed in Belgium.

Figure 7: Price duration curve for Belgium in 2019

Source: Compass Lexecon for modelled prices, ENTSO-E for actual prices

3.14 Moreover, the higher discrepancies observed for extreme prices should have a very limited impact on the CO_2 emission factor:

a. For peak prices, our power market dispatch model does not perfectly capture those prices as they highly depend on peak units that are almost never dispatched and whose parameters are more uncertain (efficiency, bidding strategy ……). However, the impact on the CO_2 emission factor should be very low since it concerns about 25 hours only (over a total of 8,760 hours).

b. Very low prices strongly depend on the strategic behaviour of some market players (e.g. start-up costs, bidding strategy of RES), that our model cannot fully capture. However, this should not impact the CO_2 emission factor calculation as, during those hours, prices should not be correlated with the CO_2 prices. The prices should be the same without CO_2 prices.

3.15 As a result, the backtesting exercise for the year 2019 confirms the accuracy of our power market dispatch model to replicate day-ahead prices. This model can then be used to simulate power prices in a scenario without CO_2 prices.

Section 4

Power prices in a scenario without CO_2 prices

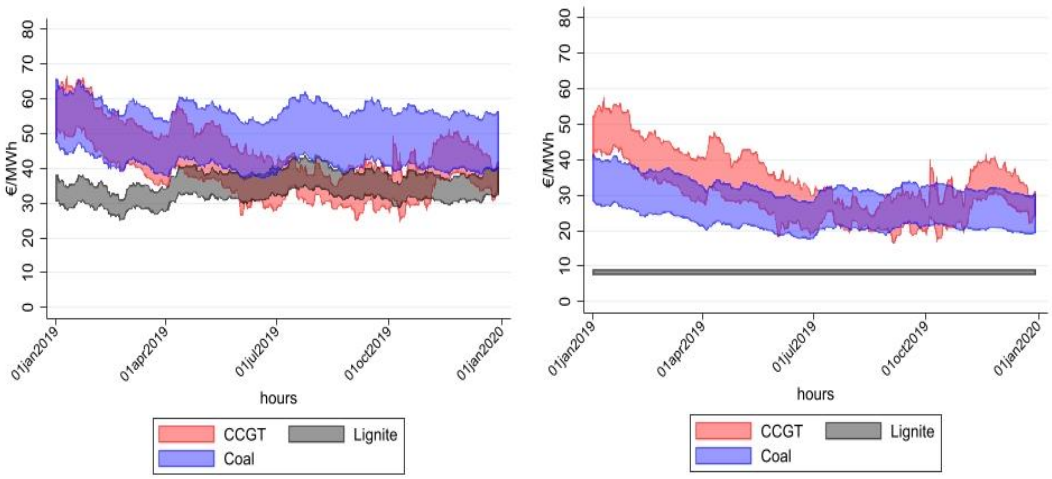
4.1 In this section, we describe first the impact of the CO_2 prices on the bids of the different technologies. Then, we present the resulting power prices that will be used to determine the market-based CO_2 emission factor.

Impact of the absence of CO_2 price on the offers of each technology

Offers of thermal technologies

4.2 As explained in §1.5, the CO_2 price has a direct impact of the SRMC of thermal units. This impact depends on (i) the type of fuel (one MWh of coal emits more CO_2 than one MWh of gas) and (ii) the efficiency of the plant (the higher the efficiency, the lower the impact of the CO_2 prices). Figure 8 shows the SMRC of the main thermal technologies with and without CO_2 prices in the CWE zone. For each technology, a range is depicted reflecting the different efficiencies observed in the CWE zone.

Figure 8: SRMC of main thermal technologies in the CWE zone in the scenario with CO_2 prices (left) and without CO_2 prices (right)



Source: Compass Lexecon

4.3 As described in this figure, SRMCs decrease without CO_2 prices. This decrease is higher for lignite plants than for CCGT units, given the higher CO_2 emission rate for lignite.

4.4 This figure also highlights how the CO_2 price can impact the competitiveness of the different technologies and then the merit-order. For instance, for the month of January, coal units have the same SMRC as CCGT units in the scenario with CO_2 prices. However, without CO_2 prices, coal units become more competitive and will be dispatched before CCGTs. This impact of CO_2 on the merit-order and on the power prices is directly taken into account in our power market dispatch model.

Offers of technologies with storage constraints

4.5 As described in §2.11, technologies with storage constraints (hydro units or French nuclear plants) are offered based on an opportunity cost, which reflects the profit they forego by not being able to produce in another hour due to limited fuel. This foregone profit depends directly on power prices, which in turn depend on the price of CO_2. Thus, the opportunity cost of storage facilities should evolve with CO_2 prices.

4.6 In a scenario without CO_2 prices, power prices tend to be lower. So, the profit that a unit with storage constraints will forego by using its fuel immediately should be lower compared with the same situation with CO_2 prices.

4.7 For hydro units, the opportunity cost in the scenario without CO_2 is directly determined by our power market dispatch model, reflecting the optimization of the limited storage and taking into account the foregone profits. The impact of a lower CO_2 price on the offers of hydro units is then automatically captured.

4.8 Regarding French nuclear units, the opportunity costs in the scenario without CO_2 are computed in two steps.

a. First, as presented in § 2.11, their opportunity costs are linked with the SRMC of thermal units. Then, we can determine the opportunity costs in the scenario without CO_2 depending on the SRMC of thermal units without CO_2 prices.

b. Second, we assume that the annual generation from French nuclear units should be the same in the scenarios with and without CO_2 prices. Indeed, total nuclear generation should depend mainly on the plant availability and on the quantity of available uranium: both factors should be the same in the scenario without CO_2. This assumption is aligned with RTE's assumptions.[36] Then, in an iterative way, we slightly decrease the opportunity costs of the French nuclear units so that the annual generation is the same in both scenarios.

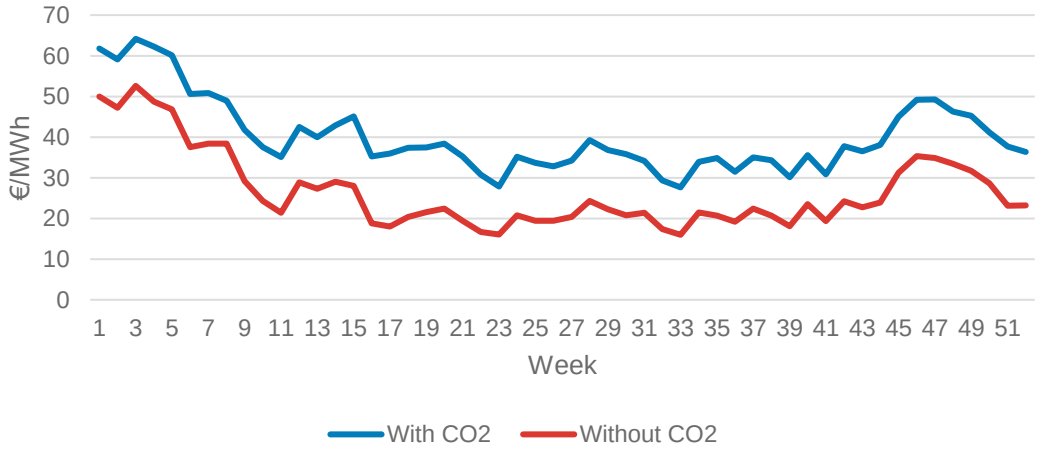
---

36 Cf. p8, https://www.cre.fr/Documents/Deliberations/Approbation/approbation-du-rapport-de-rte-sur-le-facteur-d-emission-associe-au-marche-de-l-electricite-francais

Results of the scenario without CO_2

4.9 Figure 9 presents the power prices in Belgium in the scenario without CO_2 prices. On annual average, the Belgian price is equal to 26.56€/MWh, i.e. a 13.6€/MWh decrease compared with the scenario with CO_2 prices.

Figure 9: Weekly power prices in Belgium with and without CO_2 prices



Source: Compass Lexecon

Section 5

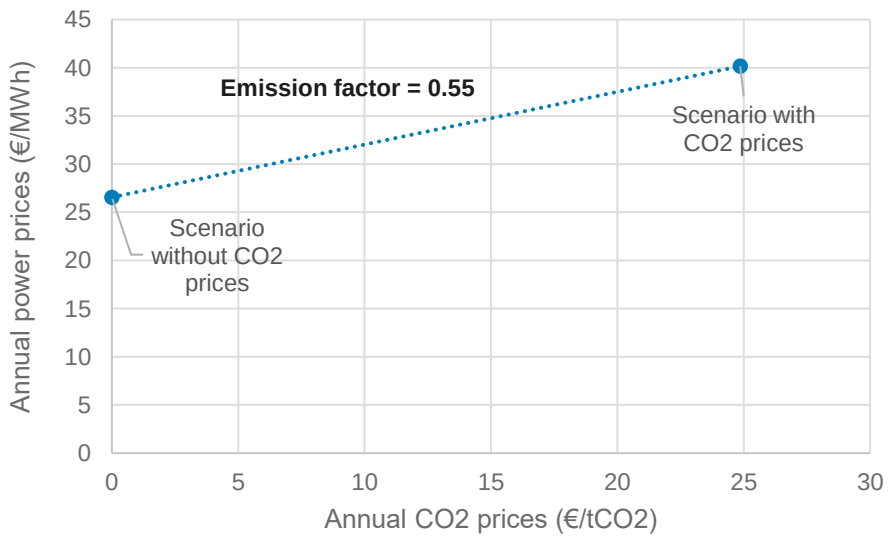
Calculation of the market-based CO_2 emission factor for Belgium

5.1 In this final section, we compute the market-based CO_2 emission factor for Belgium for 2019 based on the methodology and the modelling results described in the previous sections. We also compare the computed CO_2 emission factor with other relevant studies.

Market-based CO_2 emission factor for 2019

5.2 Based on an average Belgian power prices of 40.16€/MWh in the scenario with CO_2 prices,[37] on an average price of 26.56€/MWh in the scenario without CO_2 prices and an average CO_2 price of 24.86€/tCO_2, applying the formula to compute the market-based CO_2 emission factor results in **a coefficient of 0.55 tCO_2/MWh for Belgium**.

Figure 10: Market-based CO_2 emission factor for Belgium



Source: Compass Lexecon

[37] As computed with our backtesting exercise.

5.3 Given that our backtesting exercise results in 2% error margin for Belgian prices as described in Figure 6, we can apply this margin to the annual prices computed in the scenario without CO_2 to estimate a range of uncertainty for the final CO_2 emission factor between **0.53 and 0.57 tCO_2/MWh**.[38] With a 5% error margin (often considered to validate a power market dispatch model based on international experience), the final CO_2 factor ranges between 0.49 and 0.60 tCO_2/MWh.

Comparison with other relevant studies

5.4 First of all, the market-based CO_2 emission factor can be compared with the emission factor that would result from the historic methodology. Even if the coefficient for Belgium for the year 2019 as computed with the historic methodology has not been published yet, we can expect that this value would be closed to the emission factor computed for previous years given the small changes in the Belgian thermal generation mix (which mainly relies on CCGT). Based on 2018 data, the emission factor for Belgium is equal to 0.37 tCO_2/MWh with the historic methodology.[39]

5.5 This significant difference with the market-based emission factor highlights the fact that the historic methodology tends to underestimate the CO_2 emission factor for Belgium since it ignores foreign thermal units that can set the Belgian power prices. On the contrary, the methodology based on a power market dispatch model replicating the merit order on a European level considers cross-border exchanges and better reflects how foreign units can impact Belgian power prices.

5.6 Our power dispatch model can also be used to determine the market-based CO_2 emission factor for Germany for 2019: it would result in a coefficient of 0.64 tCO_2/MWh whereas the historic methodology would give a coefficient of 0.75 tCO_2/MWh[40]. This significant discrepancy also highlights the fact that the historic methodology tends to overestimate the impact of infra-marginal polluting technologies, such as lignite, whereas these technologies rarely set the price paid by industrials. On the contrary, the market-based methodology only considers the marginal technology which defines the power price and does not consider infra-marginal ones.

5.7 The market-based CO_2 emission factor can also be compared with other studies available in the literature (academic or from the industry).

---

38 A 2% error margin in the scenario without CO_2 gives an annual price between 26€/MWh and 27.1€/MWh.

39 Cf. Table 3 of the impact assessment accompanying the 2020 Guidelines (https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report_ets_2021_en.pdf)

40 Cf. Table 3 of the impact assessment accompanying the 2020 Guidelines (https://ec.europa.eu/competition/state_aid/what_is_new/2020_ets_revision/impact_assessment_report_ets_2021_en.pdf). This value is based on 2018 data but the coefficient should be very close for 2019 given the very similar generation mix.

5.8 However, such a comparison is often limited due to different methodologies[41] and/or a different geographic scope or time horizon.[42] To the best of our knowledge, the only publicly available study that can be used as a comparison is the study performed by the French TSO, RTE, in order to compute the market based CO_2 emission factor for France, based on 2019 data and based on the same methodology (the computation of the power market prices for 2019 in a scenario without CO_2 prices using a power market dispatch model). [43]

5.9 First, it is worth mentioning that RTE and Compass Lexecon's power models differ on several points, in particular: (i) RTE relies on a different modelling tool, Antares, and (ii) RTE relies on some non-publicly available data as inputs.[44]

5.10 Regarding results for France,[45] our power market dispatch model results in a CO_2 emission factor of 0.55 tCO_2/MWh for France[46] whereas RTE has computed a value of 0.59 tCO_2/MWh.

5.11 This difference can be explained by the several differences in the modelling approach and underlying data as described above. In particular, even with the same input data, two power modelling tools can result in slightly different outcomes given different optimisation algorithms. This fact is highlighted by ENTSO-E in its MAF study: "*Even though the same input data is used for all modelling tools, differences in […] results can occur due to different geographical or temporal distributions of unserved energy in the case of multiple optimisation solutions, as well as the different approaches to optimising hydro plants*".[47] In this study, ENTSO-E relies on several modelling tools, including Plexos and Antares, to obtain consolidated and reliable results, while understanding their sensitivity to the assumptions and modelling choices made. Even with the same input data, modelling tools used by ENTSO-E can result in slightly different outcomes (see Annex B for further details).

5.12 Moreover, the difference of 0.04 tCO_2/MWh between RTE and Compass Lexecon's results corresponds to a difference of about 1€/MWh in average annual power prices. According to our experience in power market dispatch model, a difference of 1€/MWh in annual power

---

41 Most academic literature calculates a CO_2 emission factor based on empirical econometric studies.

42 For instance Poyry used the same methodology to compute the CO_2 emission factor but for the Nordic countries (http://docplayer.net/155275719-Carbon-transfer-factor-in-the-nordic-power-market-final-presentation-geir-bronmo-and-clemence-carnerero.html)

43 The RTE report is not publicly available. However, the deliberation of the French Energy Regulatory Commission (CRE) is available: https://www.cre.fr/Documents/Deliberations/Approbation/approbation-du-rapport-de-rte-sur-le-facteur-d-emission-associe-au-marche-de-l-electricite-francais

44 In particular for the opportunity costs of nuclear and hydro units, as explained in the footnote 34

45 Since the RTE study only provides results for France, we cannot compare results for Belgium. However, since our market modelling is run over all European countries, we can determine French power prices in a scenario without CO2 and then compute a market-based CO_2 emission factor for France.

46 Based on an annual price of 39.6€/MWh with CO2 and 26.04€/MWh without CO_2.

47 https://www.entsoe.eu/outlooks/midterm/

prices is well within the level of uncertainty of a power dispatch model. For comparison, a 5% margin on annual prices is often considered in the backtesting exercise to validate the accuracy of a power market model (cf. § 3.7). This error margin would translate into a margin of 1.3€/MWh in the scenario without CO_2 prices, aligned with the annual prices difference observed between RTE and Compass Lexecon results.

5.13 To conclude, the difference between RTE and Compass Lexecon results for France is limited compared with the level of uncertainty of a power dispatch model and can be explained by (i) different modelling tools and (ii) different input data.

5.14 Moreover, according to our modelling results, the alternative methodology should result in similar market-based CO_2 emission factor for France and Belgium (0.55tCO_2/MWh). It can also be assumed that this equivalence should apply in the other direction, i.e. that if the RTE modelling were used to compute the CO_2 emission factor for Belgium, we would get the same value as for France (0.59tCO_2/MWh). Thus, a similar market-based CO_2 emission factor should be considered for both countries, independently of the power market dispatch model chosen for its computation or the underlying data. Different market-based emission factors for France and Belgium (for instance based on the value computed by RTE for France and the value computed in this report for Belgium) would only be explained by the modelling choice (either of the modelling tool or of the input data) but would not be explained and justified by the underlying economic drivers of the power price formation. Different CO_2 emission factors would not guarantee a level playing field between French and Belgian industries whereas, according to our results, the impact of CO_2 on power prices paid by French and Belgian industrials should be similar in both countries.

Annex A

Comparison of modelled and actual monthly and daily prices for 2019

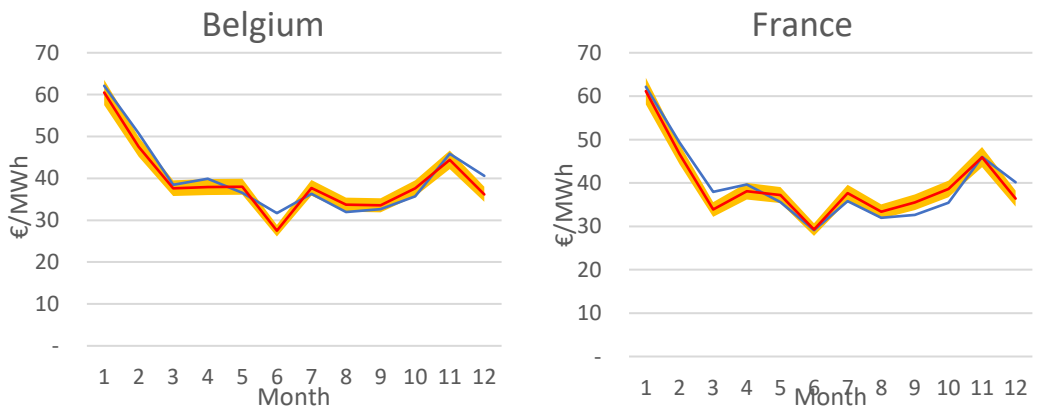
A.1 The figure below presents the monthly actual and modelled power prices as well as a 5% margin: monthly prices simulated in Belgium and neighbouring countries remain very close to the actual observed prices, and mostly within the 5% margin. Note, however, that this margin is generally used to compare annual averages rather than monthly averages. When moving to a more granular view, larger differences will appear due to the high volatility of electricity prices.

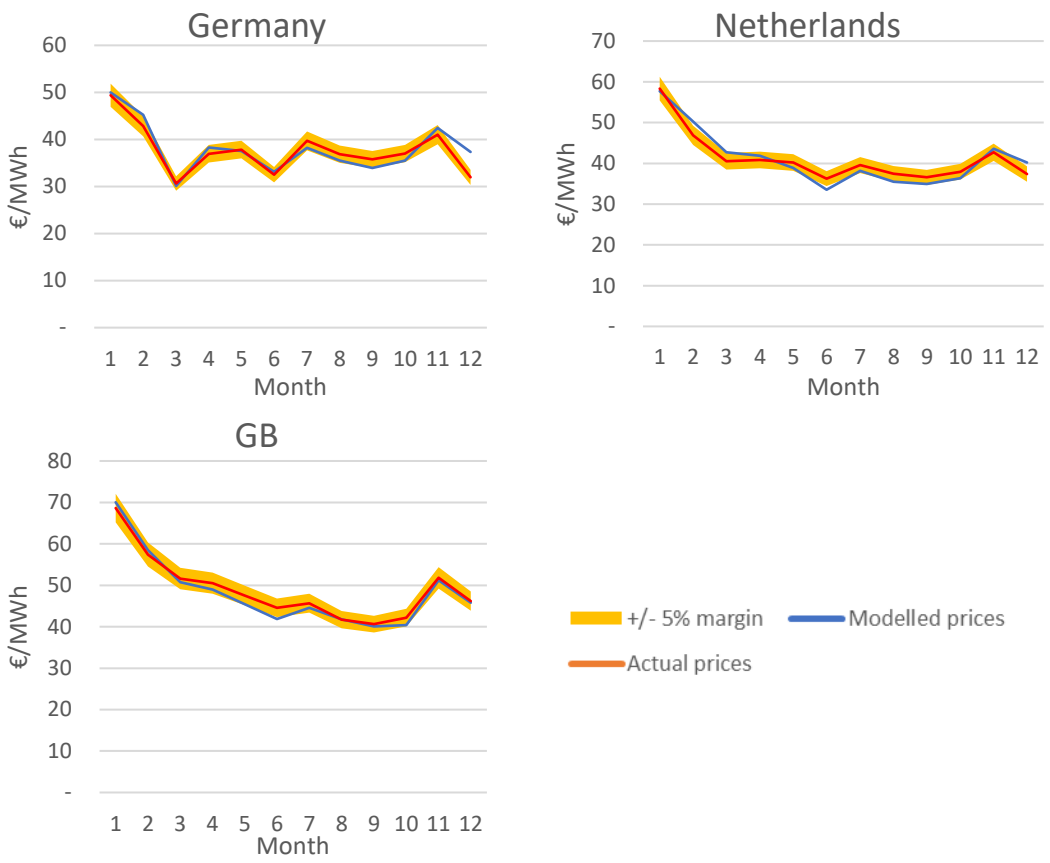
A.2 The few months where the difference is larger than 5% can be explained by very specific situations when actual prices were very low on a few days (negative prices):

a. June 2019 in Belgium: Low actual prices are explained by one day with highly negative prices that our model cannot replicate. Average without those hours is around 32€/MWh, i.e. aligned with the modelled monthly prices

b. December 2019 in Germany: Low actual prices are explained by the very low prices during the Christmas week.

Figure 11: Monthly modelled and actual prices for 2019

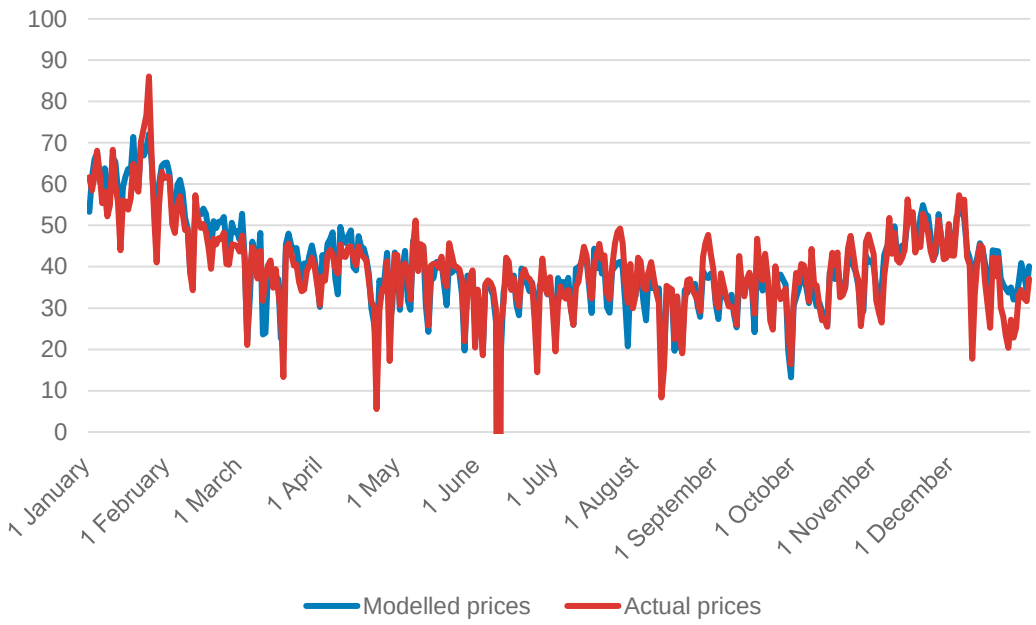




Source: Compass Lexecon for modelled prices, ENTSO-E for actual prices

A.3 When considering a more granular view such as daily prices (see Figure 12), larger differences may appear in some specific hours due to the high volatility of electricity prices. However, our modelled prices largely succeed in capturing the hourly fluctuations of historical prices. Extreme prices (very low and high prices) are more difficult to replicate but this has a limited impact on the CO2 emission factor since it concerns a very limited numbers of hours.

Figure 12: Daily modelled and actual prices for 2019



Source: Compass Lexecon for modelled prices, ENTSO-E for actual prices

Annex B

Illustration of the impact of the modelling tool based on ENTSO-E studies

B.1 The impact of the modelling tool on outcomes can be illustrated with the ENTSOE modelling studies (MAF and TYNDP):

a. In these studies, ENTSOE relies on several modelling tools, including Plexos and Antares, to obtain consolidated and reliable results

b. Each tool relies on the same input data. However, they can provide slightly different outcomes, given different optimisation algorithms and different strength of each tool (e.g. hydro modelling, CHP modelling…)

B.2 More precisely, the TYNDP study aims at assessing the cost-benefit analysis of proposed new interconnectors or lines in Europe. Benefits of such assets are determined based on several indicators, for instance the impact on fuel savings, on avoided CO2 emission, on social welfare. Such indicators are computed relying on a power market dispatch model. ENTSO-E relies on several modelling tools, including Plexos and Antares, to obtain consolidated and reliable results, while understanding their sensitivity to the assumptions and modelling choices made.

B.3 The figures below highlight the results for two specific projects (the Nautilus project, a new cross-border line between the UK and Belgium, and the upgrading of existing lines in the Netherlands). The minimum and maximum figures are indicating the spread between the results provided by separate market modelling software tools used and should be treated as uncertainty range for each indicator.

Figure 13: Increase in welfare for the Nautilus project depending on several modelling tools

		NT2025	NT2030
Increase in socio-economic welfare			
B1 Annual Socio-Economic Welfare (SEW) increase (M€ / year)	max	12	39
	average	**11**	**37**
	min	9	36
- B1_CO2 Annual Socio-Economic Welfare increase resulting from CO2 emissions reduction	max	3	15
	average	**3**	**13**
	min	2	12
- B1_RES Annual Socio-Economic Welfare increase resulting from RES integration	max	1	7
	average	**1**	**5**
	min	0	4

Notes: The minimum and maximum figures are indicating the spread between the results provided by separate market modelling software tools
Source: ENTSOE Website (https://tyndp2020-project-platform.azurewebsites.net/projectsheets/transmission/121)

Figure 14: Increase in welfare for the Reinforcements Ring NL phase I project depending on several modelling tools

		NT2025	NT2030
Increase in socio-economic welfare			
B1 Annual Socio-Economic Welfare (SEW) increase (M€ / year)	max	2	14
	average	**1**	**9**
	min	1	7
- B1_CO2 Annual Socio-Economic Welfare increase resulting from CO2 emissions reduction	max	0	7
	average	**0**	**5**
	min	-3	3
- B1_RES Annual Socio-Economic Welfare increase resulting from RES integration	max	1	7
	average	**0**	**6**
	min	0	5

Notes: The minimum and maximum figures are indicating the spread between the results provided by separate market modelling software tools
Source: ENTSOE Website (https://tyndp2020-project-platform.azurewebsites.net/projectsheets/transmission/103)

B.4 As it can be noticed, results computed with different modelling tools can vary, up to 50% for instance for the upgrading lines project in the Netherlands.