Empirical Analysis of the Iberian Electricity Price Cap (Version II/II)

Lessons Learned from the Price Reduction Mechanism in Spain and Portugal and Implications for an EU-wide Application

WORKING PAPER

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Executive Summary

Since summer 2021, European energy markets have been experiencing an unprecedented price rally, which has intensified further since February 2022 due to the Russian war of aggression on Ukraine and the resulting concerns about security of supply, especially with regard to natural gas. The recent development of wholesale prices in the electricity market can essentially be attributed to the strong rise in prices for natural gas (and also price increases for substitute fuels such as coal).

During recent months various ideas regarding the limitation of price increases have been developed and proposed. One of the mechanisms that have recently been discussed for adoption on an European level is the so-called Iberian Price Cap, or Iberian Model, which was first implemented in Spain and Portugal in June 2022. The Iberian Price Cap follows the idea of decoupling electricity and gas prices consistently. The aim of the Iberian Price Cap is to lower the bids of fossil power plants in the national electricity supply curves of the electricity auctions. To ensure that the order of deployment of power plants of the so-called "merit order" (MO) does not change, all fossil power plants (in particular natural gas, coal and oil-fired power plants) are obliged to include a fixed price discount in their bid that is the same for all these power plants. The subsidy costs are covered by electricity consumers, not the public budget.

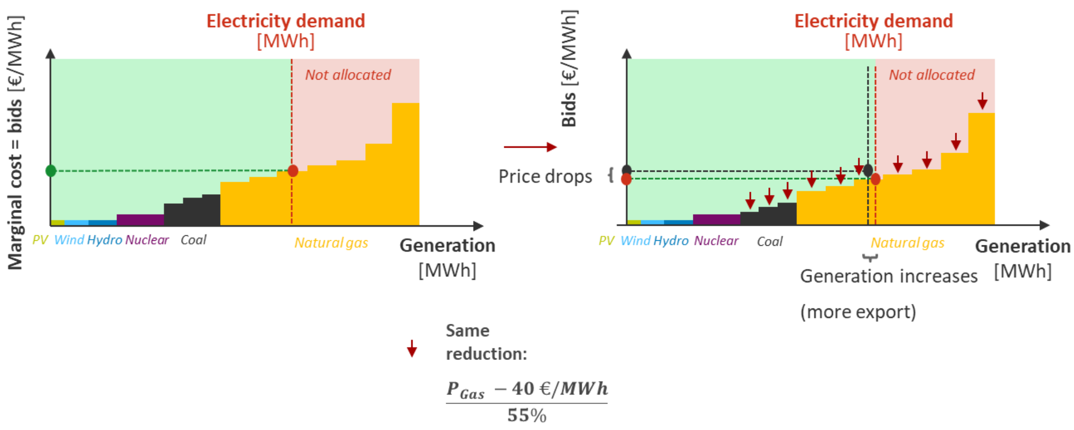

Figure 1: Visualisation of the effect of the Iberian price cap on the merit order curve (own depiction)

The Austrian Federal Chamber of Labour (AK) has commissioned the Austrian Energy Agency to analyse and monitor the first months of market results under the Iberian Price Cap, with a dedicated focus on electricity price and gas consumption effects. This Executive Summary summarises the resulting working paper. The first part of the paper was published on 30 November, presenting the results of said investigation, covering the timeframe since the mechanism's inception until 30 September 2022. The second part will be published around 21 December and additionally contains an extension focusing on EU electricity interconnections to non-EU neighbours.

Part A: Findings on the effects of the cap in Spain and Portugal

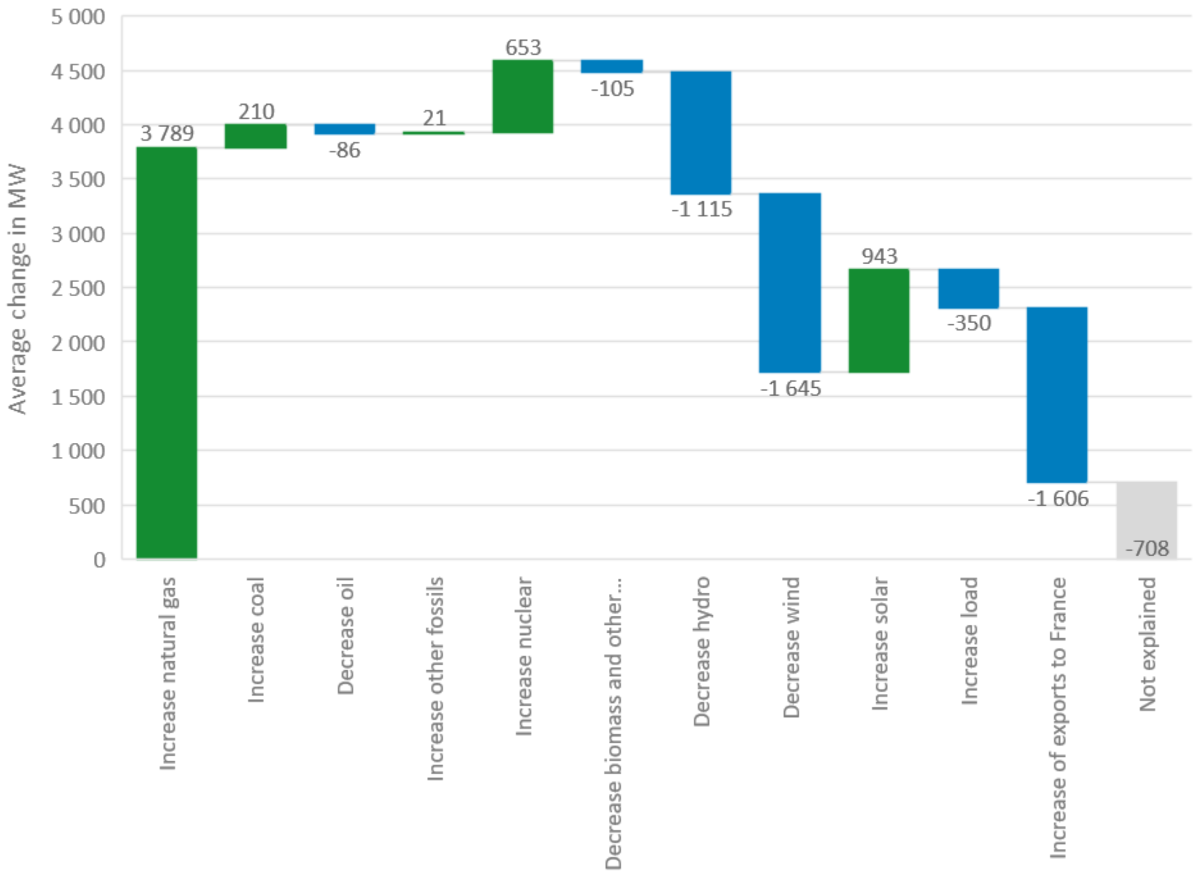

Figure 2: Average energy volume changes on the Iberian Peninsula since 15 June 2022 (until 30 September 2022, own calculations based on data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022)), colour code: green: generation increase, blue: generation decrease or demand increase, grey: not accounted for

The results obtained in this paper regarding the historical results of the Iberian Price Cap show some clear tendencies:

- Under the premise of high natural gas prices, the Iberian Model reduces electricity spot price levels significantly.
- On the Iberian Peninsula, the price cap has been accompanied by a significant increase of electricity production from natural gas. However, a more detailed analysis of this effect is necessary.
- About one third of this increase needs to be counted towards generation unavailabilities during the 2022 summer period.
- About half of this increase can be attributed to a surge in electricity exports to France and Morocco. However, it is not definitive that all these additional exports can be solely linked to

the Iberian Price Cap, as electricity prices might have been higher in Central Europe even without the Cap.

- About one tenth of this increase can be attributed to a higher electricity demand, which at least partly could be linked to high temperatures during the investigated time period.
- Electricity price drops only partly materialise for electricity customers, as the subsidy costs need to be paid by means of a levy by market participants. The relative impact of said levy was increased by a low renewable generation output and a higher electricity export during the investigated time period.

Despite ocurring under local market circumstances, the historical observations in Spain and Portugal may still give an indication of what might happen in other market areas if the Iberian Cap were applied across Europe. Still, observed effects do not have to occur in the same manner everywhere. Thus, the Iberian example should be observed with caution and without overinterpreting every effect of the Iberian Cap. This requires a more profound analysis across Europe.

Part B: Transmission capacities at the EU border – a volume assessment of possible effects of an EU-wide application

The identified effect of the historical analysis of the Iberian Price Cap with regard to the increase in electricity generation from natural gas, linked to higher exports from subsidised electricity, raises the question how this effect would play out in the rest of Europe, if the EU as a whole decided to adopt this measure as well.

The available transmission exchange between EU and non-EU countries is therefore investigated by looking at additional export potential if the Iberian Price Cap was applied across Europe. To do so, installed transmission potential[1] is deducted from historical import data of the year 2021 and compared to actual electricity generation data from 2021 in neighbouring non-EU countries from hard coal and natural gas plants that would potentially be substituted due to a cross-border merit-order change. Electricity generation from cogeneration is hereby conservatively included into substitution potential, despite being quite unlikely to be fully replaced by other heat sources. The assumption of a full exploitation of the transmission potential at all times also is conservative, as price fluctuations and occasional import direction reversions are likely, e.g. depending on hourly available renewable generation.

All borders between EU and non-EU counties are evaluated under the assumption of two different scenarios:

1. Introduction of an Iberian Price Cap as in Spain and Portugal, with a target energy price of about 40 €/MWh; and a joint subsidisation of all fossil fuels (i.e. hard coal, oil and natural gas) within the subsidy.

2. Introduction of an Iberian Price Cap-like intervention that focuses solely on subsidisation of natural gas power plants and sets a much higher, automatically adjusted target energy price depending on current coal and CO_2 price levels. This ensures that EU-internal merit orders are not distorted. Under the current market situation as of early December 2022, this would be the case with a target energy price of about 125 €/MWh.

The comparison of transmission potentials and existing national electricity system cost structures imply that the UK and Türkiye are the neighbouring countries to the EU most likely to benefit from the import of subsidised electricity, as domestic fossil electricity production can be substituted. Similar conditions apply to Morocco, which is however already affected by the existing Iberian Price Cap.

Despite having substantial transmission capacities towards the EU, Switzerland, Norway and the Southeast Central European neighbour countries (Albania, Bosnia & Herzegowina, Montenegro, North Macedonia and Serbia) do not have a large potential for additional import from subsidised electricity from natural gas due to the availability of own lower-cost generation capacity.

[1] Due to data availability, available transmission capacity was proxied by using hourly maximum values of physical flows in 2021 as reported on the ENTSO-E Transparency Plattform.

However, a temporary small additional demand effect by Switzerland at the time of cap introduction appears likely, as there is an incentive to sell electricity stored in pumped hydro water storages before Cap introduction and refill storages with subsidised electricity afterwards.

Table 1: Iberian Price Cap as in Spain and Portugal
Overview of transmission potentials and additional exports in case of a 40 €/MWh EU target price for fossil fuels

Import border	Estimated transmission potential [MW]	Additional annual export potential [TWh]	Generation switch potential from non-EU fossil fuel to EU natural gas [TWh]	Additional annual export [TWh]
EU-> UK	5.688	22.9	133.3	22.9
EU -> Norway	7 467	57.6	0.6	0.6
EU -> Switzerland	13 569	96.0	0.6	0.6
EU -> Ukraine	1 963	14.8	38.6	14.8
EU -> Moldova	-	-	44.5	0.0
EU -> Türkiye	1 017	7.8	179.8	7.8
EU -> Morocco	1 400	11.6	30.7	11.6
EU -> South-East Central Europe	6 931	51.0	1.7	1.7
Total (without Ukraine)				**45.2**

Table 2: Iberian Price Cap-like intervention
Overview of transmission potentials additional exports in case of an adjusted target price for natural gas set based on hard coal electricity generation costs

Import border	Estimated transmission potential [MW]	Additional annual export potential [TWh]	Generation switch potential from non-EU natural gas to EU natural gas [TWh]	Additional annual export [TWh]
EU -> UK	5.688	22.9	121.6	22.9
EU -> Norway	7 467	57.6	0.5	0.5
EU -> Switzerland	13 569	96.0	0.6	0.6
EU -> Ukraine	1 963	14.8	14.2	14.2
EU -> Moldova	-	-	5.8	0.0
EU -> Türkiye	1 017	7.8	122.1	7.8
EU -> Morocco	1 400	11.6	4.0	4.0
EU -> South-East Central Europe	6 931	51.0	1.7	1.7
Total (without Ukraine)				**37.1**

Export effects in (North-)Eastern Europe due to the Iberian Cap are assumed to be limited (due to sanctions and other existing export limits to Russia and Belarus) or subordinated (for Ukraine and Moldova), as EU electricity exports to these countries have already been rising due to the destruction of energy infrastructure in Ukraine. Therefore, additional electricity exports to Ukraine and Moldova are hardly attributable to market mechanisms and hence, the effects of the Iberian Price Cap.

We estimate an increase of annual electricity exports of about 45 TWh, respectively 37 TWh due to the introduction of an Iberian (-style) Price Cap across Europe, under the assumption that merit-order effects due to fuel switch between natural gas and hard coal power plants within the EU are omitted by an intelligent intervention design. This could be achieved either by subsidisation of all fossil fuels (as with the implemented Iberian Price Cap), or by establishing an adaptive target price, considering coal and CO_2 price levels. These numbers, that amount to in between 1.5% and 1.8% of annual electricity generation within the EU in the year 2021, lie well below the theoretical additional export potential of 261.7 TWh that would materialise if all export capacities were fully used at all times. In the case of production of this additional electricity by natural gas and an assumed mean gas plant efficiency of 50%, this would result in an additional gas consumption of 90 TWh, and 74 TWh respectively.

The results of this volume assessment only represent a rough approximation of possible effects at the border of the European Union and not a holistic evaluation of a measure such as the Iberian Price Cap. Especially, demand side effects that might occur due to lower electricity prices within the EU are not taken into account. However, these are difficult to assess, as many EU member states have by now taken measures to subsidise or limit end user electricity prices by varying degrees.

Further research into this question should additionally focus on an accurate depiction of welfare effects of the Iberian Price Cap or similar measures. A decline of electricity prices would, among other effects, translate in lower production costs for goods and therefore likely contribute to a lowering of inflation rates within and outside the electricity sector. However, the price-lowering effect in the electricity sector under such a mechanism would not materialise in the same manner in different countries with diverse electricity generation mixes, leading to distribution effects across Europe that should be adressed before the introduction of a singular mechanism. Still, a jointly negotiated measure by EU countries would potentially enhance fair competition compared to the status quo of uncoordinated national subsidisation. In return, the impact on gas prices resulting from subsidy leakage and electricity exports also affects other economic sectors. Therefore, these effects should additionally be taken into consideration when deciding on an impactful measure such as the Iberian Price Cap. Electricity demand effects by an increased export to non-EU countries and resulting gas consumption increases could be significantly reduced by targeted political measures on the EU borders (such as agreements or taxes), especially concerning the UK and Türkiye. All in all, the results of our analysis show that an EU-wide application of an intelligent Iberian(-style) Price Cap omitting merit order effects within the EU and limiting merit order effects at the borders of the union would not lead to the massive increase of gas consumption that is often feared. Nonetheless, any measure potentially increasing gas consumption should be considered with care in the current supply-constrained market situation.

1 Introduction

Since summer 2021, European energy markets have been experiencing an unprecedented price rally, which has intensified further since February 2022 due to the Russian war of aggression on Ukraine and the resulting concerns about security of supply, especially with regard to natural gas. The recent development of wholesale prices in the electricity market can essentially be attributed to the strong rise in prices for natural gas (and also price increases for substitute fuels such as coal). The correlation between the development of electricity and gas prices can be graphically illustrated using the cost development of a fictitious gas-fired power plant on the basis of current gas and CO2 future price quotations in comparison with simultaneous actual future electricity prices.

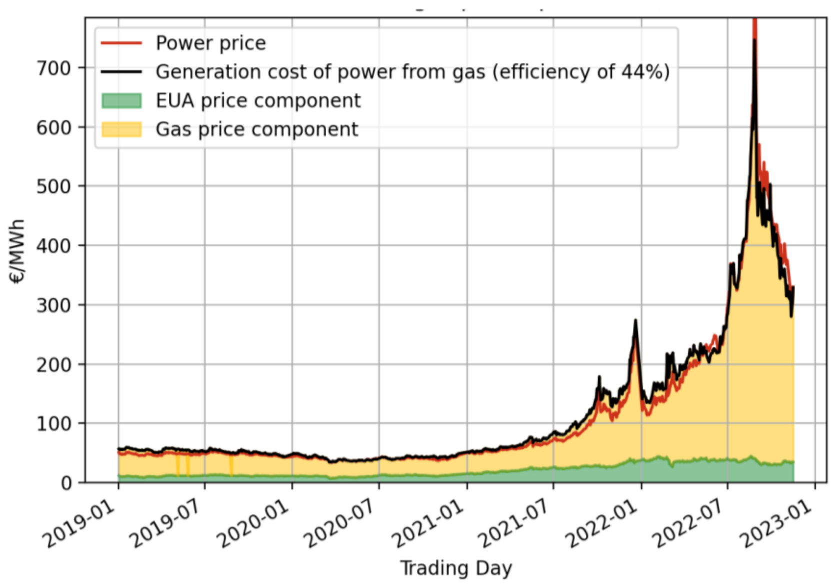

Figure 3: Description of power future prices by means of gas and CO2 future prices (own depiction, data: EEX)

During recent months various ideas regarding the limitation of price increases have been developed and proposed. In September 2022, the Austrian Energy Agency has released a (German) Policy Paper in which nine of the most prominent ideas to lower electricity wholesale prices have been described and evaluated regarding their overall advantages and disadvantages (Austrian Energy Agency 2022). One of the mechanisms that have recently been discussed for adoption on an European level is the so-called Iberian Price Cap, or Iberian Model, which was first implemented in Spain and Portugal in June 2022.

The Austrian Federal Chamber of Labour (AK) has commissioned the Austrian Energy Agency to analyse and monitor the first months of market results under the Iberian Price Cap, with a dedicated focus on electricity price and gas consumption effects. A first version of this working paper was published on 30 November, presenting the results of said investigation, covering the timeframe since the mechanism's inception until 30 September 2022 (Part A in Section 2). This second version additionally contains an extension focusing on EU electricity interconnections to non-EU neighbours (Part B in Section 3).

How does the Iberian Price Cap Work?

The Iberian Price Cap follows the idea of decoupling electricity and gas prices consistently and was put into law within Real Decreto-ley 10/2022 for Spain (Spanish Government 2022) and Decreto-Lei 33/2022 (Portuguese Government 2022) for Portugal.

The aim is to lower the bids of fossil power plants in the national electricity supply curves of the electricity auctions. To ensure that the order of deployment of power plants of the so-called "merit order" (MO) does not change, all fossil power plants (in particular natural gas, coal and oil-fired power plants) are obliged to include a fixed price discount in their bid that is the same for all these power plants. The obligation of all fossil generation technologies has the consequence that the order of the domestic producing power plants in the MO does not change. The price discount to be applied is determined by a predefined formula based on the current gas price P_{Gas} provided online by the local gas market operator Mibgas:

$$P_{New\ bid} = P_{Old\ bid} - \frac{P_{Gas} - 40\ €/MWh}{55\%}$$

Both the gas price and the resulting bid reduction price are fixed by the market operator ahead of the day-ahead auction. Consequently, the bid has to be adjusted by the difference between the current gas price and a target fuel price (in the beginning 40 €/MWh, with a monthly price increase of 5 €/MWh starting after six months), divided by an assumed average efficiency of electricity generation from the fossil power plants of 55 %. The higher the gas price in the market, the higher the price discount on the electricity bids. The aim is thus to stabilise the electricity price level, even if the gas price continues to rise – electricity and gas prices are decoupled. Possible unwanted side effects of the obtained electricity price reduction are an increase in electricity generation from fossil (i.e. gas) power plants due to higher electricity demand or increasing electricity exports due to the domestic subsidisation of electricity.

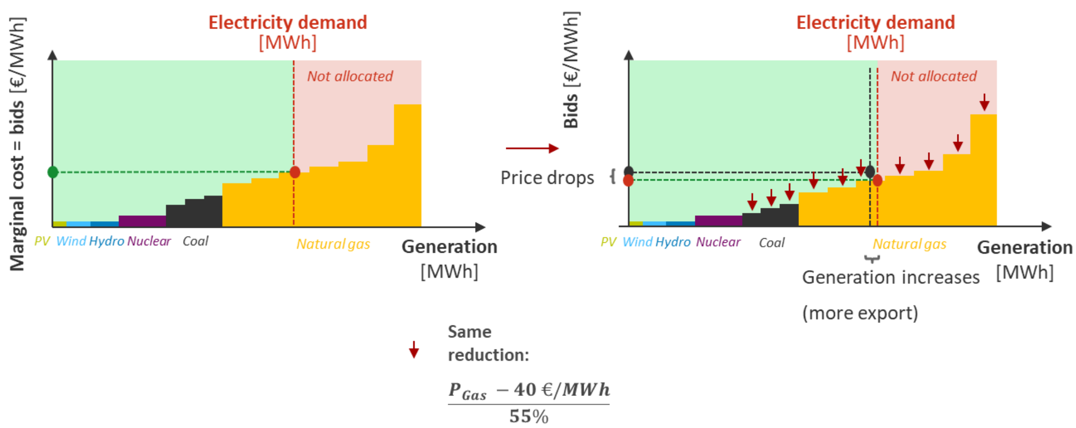

Figure 4: Visualisation of the effect of the Iberian price cap on the merit order curve (own depiction)

2 Part A: Findings on the effects of the cap in Spain and Portugal

In the next sections, the historical results of the Iberian Price Cap model are investigated, starting with the cap's inception on 15 June 2022 and ending on 30 September 2022. Hereby, supposed effects (i.e. electricity price decrease) as well as side effects of the cap (i.e. gas consumption increase from electricity production) and statistical evidence are compared. For contrast, data prior to the cap's introduction since the beginning of the year 2022 are used. The data sources used for the following analyses[2] are:

- for day-ahead electricity prices: data published by the market operator OMIE (OMIE 2022)
- for electricity generation, load and physical cross-border exchanges between France and Spain: data published by the Entso-E Transparency Platform (European Network of Transmission System Operators for Electricity (Entso-E) 2022)

2.1 Regression analysis 1: Price effects of the Iberian Cap

For the investigation of the price effect of the Iberian Cap, the given electricity price data are analysed by means of an ordinary least squares (OLS) linear regression model on hourly data of the following form:

$$y_i = \beta_0 + \beta_1 x_{i1} + \cdots + \beta_8 x_{i8}$$

With:

y_i: day-ahead electricity price of hour i

β_0: constant

β_{1-8}: regression coefficients

x_{i1}: binary value indicating the operation of the Iberian Cap Model (is 1, if date of hour i is later than 14.06.2022)

[2] For the following regression analyses, the available data timeseries for 2022 (as of 10 October 2022), were downloaded and postprocessed to fit an hourly time resolution. In case of a given quarter-hourly time resolution of the raw data, hourly data values were computed as the mean value of available data entries, usually given in MW (for load, generation and physical cross-border exchange), or €/MWh (for day-ahead prices). Double data entries were removed from the dataset. In the case of missing data for one or more relevant data categories, timesteps were excluded from the respective regression analysis.

x_{i2}: binary value indicating peak hours (is 1, if i is a peak hour[3])

x_{i3-8}: binary value indicating day of week, i.e. 3: Monday, …, 8: Saturday (is 1, if day of week of hour i is Monday, …, Saturday)

The regression was performed separately on Spanish and Portuguese price data, achieving an adjusted R-squared of 0.320 for Spain and 0.308 for Portugal, indicating that this simplified linear regression model, while not perfect, depicts price dependencies reasonably well considering that only binary variables are used. The regression shows good results with regard to the significance of the resulting coefficients. These are summarised in Table 3.

Table 3: Computed coefficients for price effects [€/MWh] 01.01.–30.09.2022 (significance level: *< 10%, **< 5%, ***< 1%, own calculations based on data from (OMIE 2022))

Coefficent	Spain [€/MWh]	Portugal [€/MWh]
Constant	188.38***	191.93***
Iberian Cap	**-68.27*** **	**-66.79*** **
Peak hour	-8.52***	-4.73***
Monday	32.10***	26.28***
Tuesday	37.91***	31.85***
Wednesday	32.83***	27.34***
Thursday	36.38***	30.69***
Friday	31.95***	26.25***
Saturday	14.84***	10.86***

The regression results indicate that the price-lowering effect of the Iberian Cap is significant for both countries and amounts to about **66–68 €/MWh** compared to the period before its introduction.

Besides a comparison with historical price levels prior to cap introduction, the spot price effects can also be measured against the counterfactual of not introducing the price cap. The Portuguese Direção-Geral de Energia e Geologia publishes the result of the cap mechanism on its website (Direção-Geral de Energia e Geologia 2022) with daily updates. Between the mechanism's inception and 30 September, the average spot price difference with and without the mechanism was estimated at 173.34 €/MWh or 54% of the computed counterfactual spot price. If the adjustment costs (the levy

[3] Peak hours are the hours of the day between 8:00 and 20:00 between Monday and Friday (60 hours of the week in total). The remaing 108 hours of the week are often denoted as off-peak hours.

paid by electricity consumers to compensate the subsidy of fossil plants) are also taken into account, the average price difference amounts to 54.16 €/MWh, or 17% between 15 June and 30 September. The difference between these price differences results from the share of generation that is coming from subsidised fossil power plants – the more fossil plants are producing, the higher the levy and the lower the resulting price difference. Thus, in times of reduced renewable generation or high demand, more fossil power plants are needed and the price reduction effect of the cap for customers decreases.

2.2 Regression analysis 2: Gas consumption effects of the Iberian Cap

The additional gas consumption effect is analysed with two different regressions. First, a regression approach equivalent to the price regression described in 2.1 is applied to electricity generation from natural gas in Spain and Portugal, as a supposed surplus gas consumption in times of scarcity is one of the key arguments against the implementation of the Iberian Cap Mechanism.

The data on given electricity generation from natural gas are analysed by means of a similar ordinary least squares (OLS) linear regression model on hourly data of the following form:

$$y_i = \beta_0 + b_1 x_{i1} + \cdots + \beta_8 x_{i8}$$

With:

y_i: electricity generation from natural gas of hour i

β_0: constant

β_{1-8}: regression coefficients

x_{i1}: binary value indicating the operation of the Iberian Cap Model (is 1, if date of hour i is later than 14.06.2022)

x_{i2}: binary value indicating peak hours (is 1, if i is a peak hour[4])

x_{i3-8}: binary value indicating day of week, i.e. 3: Monday, …, 8: Saturday (is 1, if day of week of hour i is Monday, …, Saturday)

The regression was performed separately on Spanish and Portuguese generation data and on the sum of both countries, achieving an adjusted R-squared of 0.246 for Spain, 0.342 for Portugal and 0.299 for the combined model, indicating that this simplified linear regression model, while not perfect, depicts gas consumption patterns reasonably well considering that only binary variables are used. Again, the regression shows good results with regard to the significance of the resulting coefficients. These are summarised in Table 4.

[4] cf. footnote 3

Table 4: Computed coefficients for gas consumption effects [MW] 01.01.–30.09.2022 (significance level: *< 10%, **< 5%, ***< 1%, own calculations based on data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022))

Coefficient	Spain (ES) [MW]	Portugal (PT) [MW]	ES + PT [MW]
Constant	5,735.56***	1,104.83***	6,816.49***
Iberian Cap	**3,293.08*** **	**298.84*** **	**3,586.78*** **
Peak hour	-376.82***	107.94***	449.34***
Monday	2,660.45***	737.55***	2,881.35***
Tuesday	3,501.15***	923.26***	4,242.47***
Wednesday	4,008.89***	1,015.80***	4,245.11***
Thursday	3,119.17***	928.81***	3,642.66***
Friday	2,281.95***	812.77***	2,895.01***
Saturday	552.59***	316.49***	945.09***

The regression results indicate that the effect of the Iberian Cap on gas consumption for electricity generation is highly significant for both countries and amounts to about **3,600 MW** of additional electricity produced from natural gas between 15 June and 30 September compared to the period before introduction of the price cap (1 January until 14 June) – with a 5% confidence interval of [3,402.19 , 3,771.37] MW. These results illustrate that gas consumption in the electricity sector has grown significantly. However, this regression alone is not sufficient to determine the reasons for this development.

Therefore, Section 2.4 intends to identify and explain possible reasons of this increase. The following section, however, first focuses on the stability of the obtained results over time.

2.3 Development of regression results over time

In the previous sections, the regression analyses were conducted for all days since the start of the Iberian Cap until and including 30 September 2022. Figure 5 describes the development of the estimated coefficients for electricity price reduction (cf. Section 2.1) and gas consumption increase (cf. Section 2.2) over time. Note that the value of a coefficient of a certain day in this figure represents the coefficient of the respective regression performed on the entire dataset available until and including this day. For example, the coefficient values for 1 August were extracted from the regression including data from 1 January until 1 August. This means that earlier values contain a smaller number of observations *with* the implemented Iberian Cap than later values, which explains the smoothing of the curve for later dates.

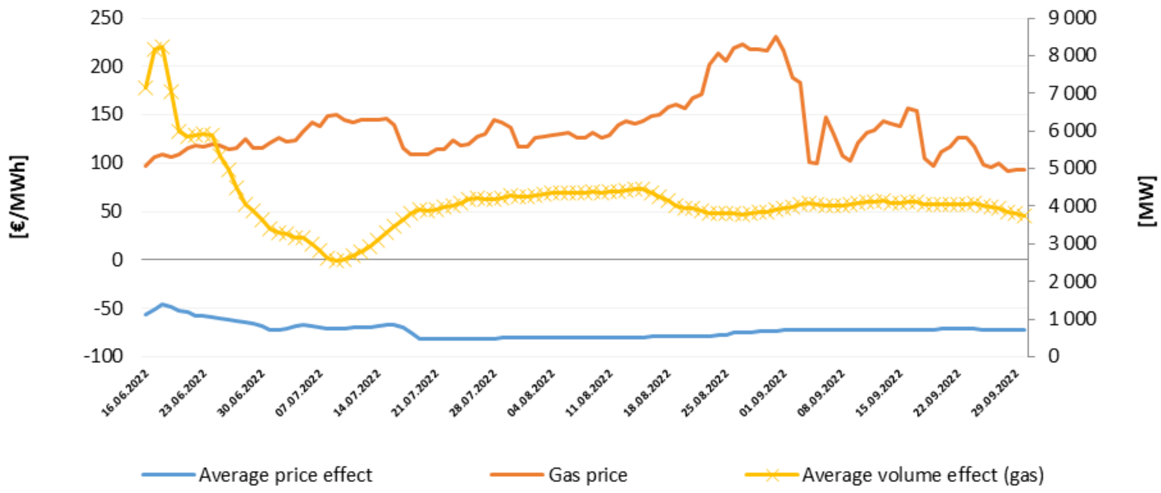

Figure 5: Regression parameter development of electricity price reduction (blue, primary axis) and gas consumption increase (yellow, secondary axis) over time; own calculations, based on data from (OMIE 2022) and (European Network of Transmission System Operators for Electricity (Entso-E) 2022); gas price development in [€/MWh] from (Mibgas 2022) given for reference.

While gas consumption patterns have differed especially at the beginning of the Iberian Cap, with a huge increase in gas consumption in the second half of June followed by a consumption dip in July, the long-term trend in both price and volume effects seems to be rather stable until 30 September. This underlines that the results in sections 2.1 and 2.2 are representative of the available dataset and are not due to an insufficient number of observations.

2.4 Regression analysis 3: Which influences drive gas consumption in the electricity sector?

The Iberian Price Cap with its decoupling effect of gas and electricity prices has one obvious and intended effect – a decrease in the spot market electricity price, as shown in 2.1. However, the reason behind the observed increase in electricity production from gas shown in 2.2 could in theory be attributed to various reasons – some resulting from the Iberian Cap, others not. As the Iberian Price Cap is designed in a manner that all fossil power plants are subsidised for lowering their electricity market bids by the same value in €/MWh, a fuel switch from coal or oil plants to natural gas due to the mechanism may be excluded as a possible explanation.

Fundamental influences that may affect gas consumption patterns for electricity generation, but that are not dependent on the Iberian Cap, include:

- Reduction of electricity production in renewable power plants (e.g. due to decreased availability because of droughts and other weather effects), such as hydro, solar and wind power, and
- Reduction of electricity production in nuclear power plants (e.g. due to decreased availability of cooling water because of droughts).

For both technology groups, marginal costs of production can still be assumed to be lower than for the subsidised fossil power plants – a substitution of these technologies by natural gas *due to the Iberian Cap* can be ruled out. A substitution of generation by fossil technologies due to a change in the merit order can be ruled out as well, as every fossil plant gets paid the same subsidy.

Fundamental influences that may affect gas consumption patterns and could be considered to be (at least partly) stemming from the Iberian Cap include:

- Load increases due to demand effects (e.g. switching from natural gas to subsidised electricity as energy source for heating processes). However, load increases may also result due to other reasons than the Iberian Cap, such as external demand effects like heat waves that result in a higher electricity demand for cooling devices and air-conditioning.
- Increases in cross-border electricity exports, as subsidised electricity is more likely to be exported to more expensive neighbouring market zones. In the case of the Iberian Peninsula, this could affect exports to France and Morocco in particular. The increased export opportunities due to the subsidy lead to a surge in domestic electricity generation and thus to an increase of electricity generation from the price-setting technology, i.e. electricity generation from natural gas power plants.

In order to identify all major influences on electricity generation from natural gas, another linear regression analysis is perfomed on the combined generation data from Spain and Portugal:

The data on given electricity generation from natural gas are analysed by means of an ordinary least squares (OLS) linear regression model on hourly data of the following form:

$$y_i = \beta_1 x_{i1} + \cdots + \beta_6 x_{i6}$$

With:

y_i: electricity generation from natural gas of hour i

β_{1-6}: regression coefficients

x_{i1}: electricity generation from run-of–river and pondage hydro power of hour i

x_{i2}: electricity generation from solar power of hour i

x_{i3}: electricity generation from wind power of hour i

x_{i4}: electricity generation from nuclear power of hour i

x_{i5}: electricity demand (load) of hour i

x_{i6}: electricity cross-border export from Spain to France of hour i

The regression is performed for the whole year as well as for the split time periods before and since the inception of the Iberian Cap up to 30 September. Table 5 below states the coefficients of the individual explanatory variables and their devlopment over time.

Table 5: Computed coefficients for gas consumption explanatory variables [MW] (significance level: *< 10%, **< 5%, ***< 1%, own calculations based on data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022))

Coefficient	Year 2022 [MW]	1 January – 14 June [MW]	15 June – 30 September [MW]
Hydro	-1.7375***	-0.9444***	**-2.7635*****
Solar	-0.5294***	-0.4413***	**-0.6903*****
Wind	-0.7042***	-0.6384***	**-0.7645*****
Nuclear	0.4760***	0.7376***	**-0.7549*****
Load	0.5154***	0.4000***	**0.8095*****
Export to France	0.7234***	0.5881***	**1.1447*****

All computed coefficients are significant. While the correlation between renewable generation and electricity generation from natural gas is negative (the more renewable generation, the less electricity is generated from gas), the effects of load and export to France clearly have a positive sign (the higher the demand and exports, the higher the electricity generation from natural gas). The effect of nuclear production is more ambiguous – the sign of the coefficient changes from positive to negative during the investigated timeframe, meaning that nuclear production historically used to be connected to a higher electricity generation from natural gas and is now seemingly contributing to lower the natural gas electricity output.

Another interesting finding is that the absolute value of almost all coefficients has increased since the Iberian Cap has been introduced – meaning that existing relations have been amplified since 15 June. It is especially interesting that the coefficient describing the influence of exports has climbed to a value greater than 1 – which indicates that an increase in exports by 1 MW is on average accompanied by an increase in Iberian electricity production from gas by more than 1 MW since 15 June.

All regression variants show a particularly high R-squared value (between 0.955 and 0.993), which indicates that most likely all relevant explaining factors for electricity production from natural gas have been included in the regression.

These regressions (like all regressions), however, can only deliver information about correlation, not causation. Thus, they do not definitvely prove that existing gas consumption increases in the electricity sector are caused by the Iberian Cap – but there is a clear indication that a structural break has been induced in the data on 15 June and that consumption has gone up. In order to quantify the observed relationships, a volume analysis is presented in the following section.

2.5 Quantification of volume effects since the start of the Iberian Price Cap

For the following analysis, the mean changes of the aforementioned generation, load and exchange patterns after the introduction of the Iberian Cap are computed as mean hourly changes compared to the first months of the year. The resulting waterfall diagramm, which is depicted in Figure 6, contrasts how much of the average generation increase of natural gas and other fossil fuels can be attributed to other factors, including the significant factors identified in Section 2.4.

The data from Entso-E (European Network of Transmission System Operators for Electricity (Entso-E) 2022) show that the increase of electricity generation from fossil fuels of on average 3.9 GW (of which 3.7 GW have been produced with natural gas) has been accompanied by a generation increase of a few other generation technologies like nuclear power plants and solar, but also by a sharp decline in generation from other technologies, especially hydro (due to this summer's drought) and wind power plants (which may be explained by a hot summer with stable high-pressure areas). If all non-fossil generation technologies are netted, **about 1.3 GW**, roughly one third of the increase of electricity generation from fossil fuels, can thus be attributed to a **lower generation from other energy sources**.

About **350 MW** can be attributed to a **higher average load** – an effect, which might or might not be connected to the Iberian Cap. It should be mentioned in that context that a historic heat wave coincided with load peaks in the second half of June and first half of July, whereby a higher-than-usual electricity demand and thus electricity production from natural gas could be observed (Reuters 2022), presumably resulting from cooling and air conditioning applications. Nonetheless, an influence of lower electricity prices due to the Iberian Model cannot be ruled out.

About 1.6 GW are linked to a **higher average (physical) electricity export from the Iberian Peninsula to France** – before 15 June, Spain on average imported electricity from France and now exports electricity, often at full available capacity. In general, lowering electricity prices increases the attractivity of electricity imports for neighbouring countries, at least if their price level exceeds the subsidised electricity price. Therefore, it seems intuitive to attribute this enormous additional average export effect to the Iberian Price Cap. However, it appears likely that at least some of this volume shift would have happened without the price cap as well – the French electricity price has risen in recent months due to a high share of non-available nuclear power plants, which account for about half of the total installed capacity in France (Reuters 2022).

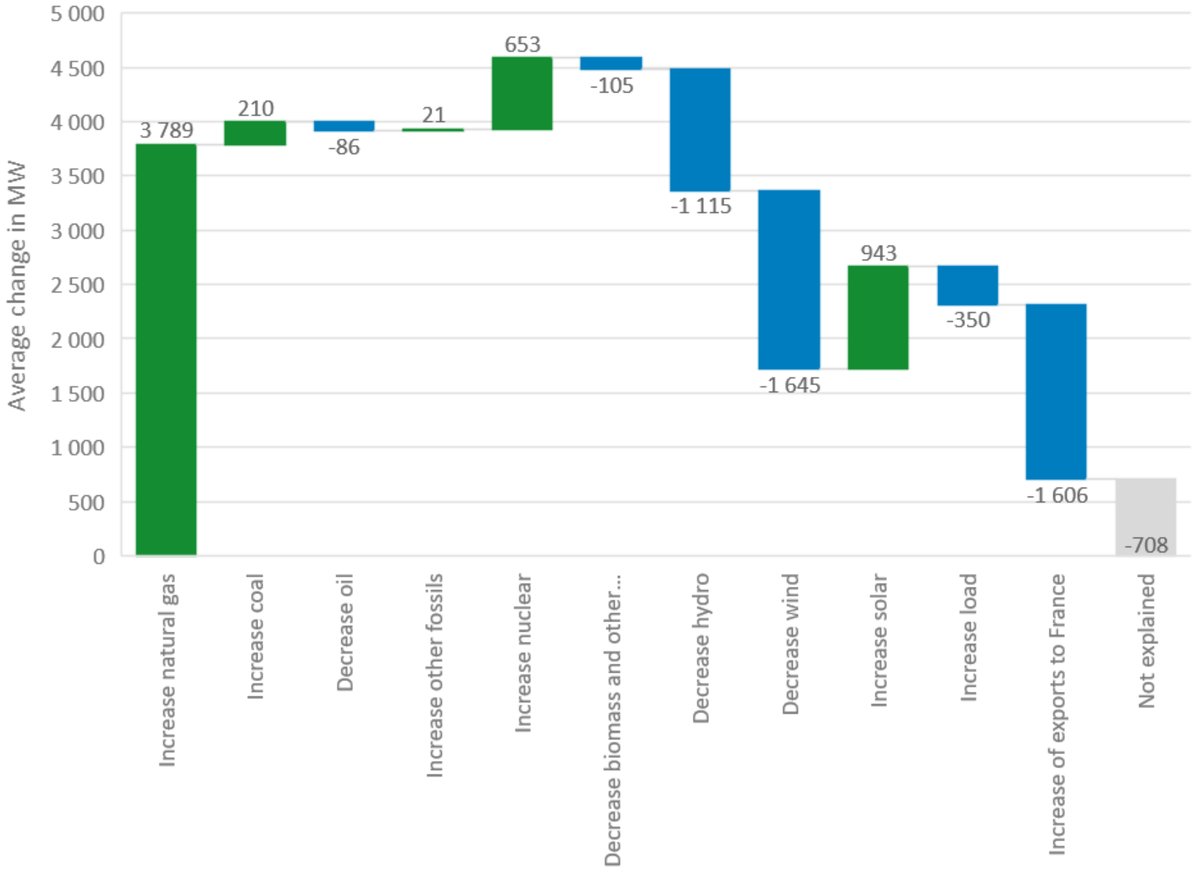

Figure 6: Average energy volume changes on the Iberian Peninsula since 15 June 2022 (until 30 September 2022, own calculations based on data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022)), colour code: green: generation increase, blue: generation decrease or demand increase, grey: not accounted for

Finally, about **700 MW** of additional production **cannot be attributed** unequivocally to any of the aforementioned effects. One puzzle piece obviously missing is the export from the Iberian Peninsula (from Spain) to Morocco, which is not included in Entso-E data. However, partly preliminary data from the Spanish grid operator REE (Red Electrica 2022) indicate that "only" **about 250 MW** of the additional average production increase can be directly attributed to an increase in electricity **exports from Spain to Morocco** during the investigated timeframe. The remainder of this position cannot be fully explained with the given dataset.

Taken together, **additional electricity exports to France and Morocco** seem to **amount to about 1.850 MW**, which corresponds to roughly half of the increase observed in electricity production from fossil fuels such as natural gas.

2.6 Limitations

The analysis provided in this paper has limitations that should be recognised for all conclusions drawn from its results. The quality and completeness of the used data provided by the mentioned sources cannot be guaranteed by the authors.

Other institutions have suggested alternative comparison periods for individual factors under investigation, such as using data from 15 June and following months of the previous years 2017–2021 instead of using 2022 data. For example, a recent study by the Spanish government (Spanish Government 2022) has indicated a drop in electricity demand (instead of the demand increase found in this paper) if demand is compared to previous years, leading to different results regarding the volume effects attributed to the Iberian Cap.

Moreover, gas consumption for electricity production has regularly increased during the summer months during recent years on the Iberian Peninsula which is – given the findings of the previous sections – not at all surprising. Changed renewable generation patterns and temporal load increases due to heat and drought are not unique events limited to the year 2022, but tend to happen every summer with differing degrees of intensity, likely amplified by effects of global warming in recent years. Figure 7 shows the average gas consumption development of Spain and Portugal of the year 2022 and compares it to the average of previous years.

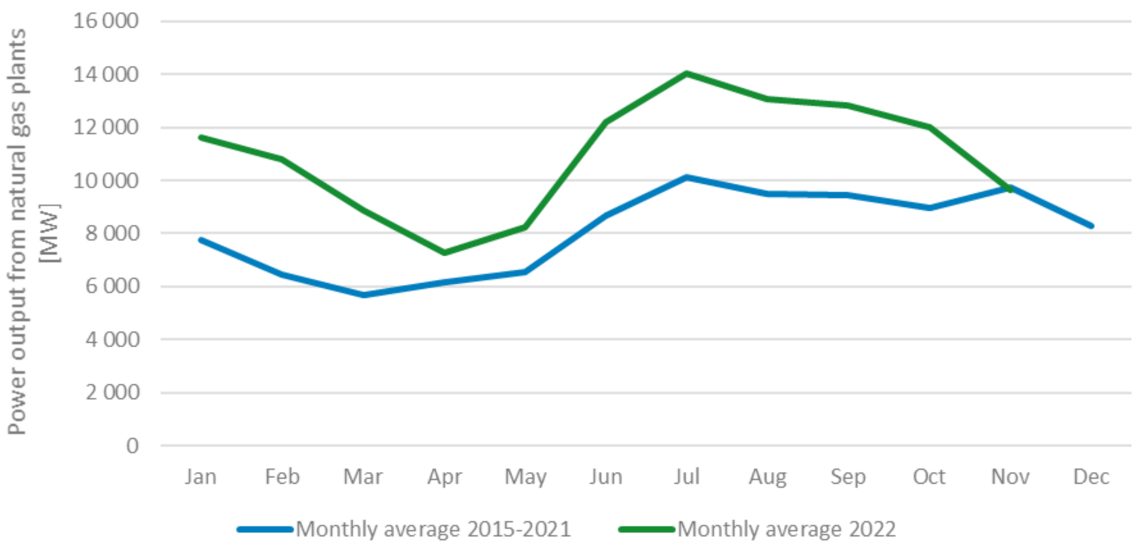

Figure 7: Monthly average power production from natural gas in 2022, compared to 2015-2017, Data (as of 6 December 2022) from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own depiction.

As a further aspect, generation distribution effects between Spain and Portugal have been neglected due to fairly similar observed price patterns and generation fleets of these two countries.

It should especially be noted for Section 2.5 that the high electricity export from the Iberian Peninsula to France is most likely not solely a product of the Iberian Cap. Clearly, not only the subsidised Spanish but also the prevailing high French electricity price levels due to scarce production capacity in Central

Europe have played an important role in this question over the summer. Put simply, even without the Iberian Cap, electricity prices in France might have often been higher than in Spain – and thus exports and an increased production from Iberian fossil power plants might have resulted in any case. However, an hourly price differential analysis of the Iberian Peninsula and Central Europe was beyond the scope of this analysis.

2.7 Theoretical considerations regarding the effectiveness of the Iberian Price Cap

A decoupling of natural gas and electricity prices is much less likely to succeed if the underlying assumption of a high dependency of electricity and natural gas prices (through the merit order) loses significance. This can happen in various ways. An obvious, unproblematic example is that electricity generation from fossil fuels such as natural gas can at times be displaced by cheaper generation technologies (i.e. renewable energies) – for these hours, the subsidy is not paid out and there should also be no price effect.

However, the opposite effect is also possible – and much more troubling. A subsidised natural gas plant group can still become inframarginal if another, more expensive technology group, sets the price. In the current market environment, this may happen mainly in two cases:

- Incomplete coverage: If not all fossil fuels in the electricity mix get paid the subsidy (for example, only natural gas power plants are covered), fossil power plants may switch their position in the merit order. In case a non-subsidised plant sets the price, the price reduction effect becomes smaller than the subsidy that is paid out. As a result, the net benefit of the measure could become negative, as levies covering the subsidy could be higher than the reduction in wholesale electricity market prices. It should be noted that this is not the case for the Iberian Price Cap, as all fossil plants are equally covered by the regime.

  A similar effect is at play if imported electricity that is not covered by the domestic subsidy sets the price.

- Electricity scarcity: If there is not enough generation capacity (and/or fuel) available to cover demand, electricity prices rise sharply due to so-called scarcity pricing. In this case, either the demand side of the electricity market, i.e. the willingness of electricity customers to pay, determines the price or the administratively set maximum price level of the electricity market (at the moment 4,000 €/MWh in the day-ahead auction) defines the price.

The intended price-lowering effect of the Iberian Cap on electricity prices may vanish in these cases, while side-effects such as high gas consumption for electricity production may still prevail. Electricity and gas prices would indeed be decoupled – but not in the direction that is intended.

As a result, a careful consideration of likely outcomes should always be made, before a market intervention is decided. Rules preventing unwanted side-effects should be considered before, rather than after, any such market intervention is implemented. These include exit rules that allow a suspension of the cap model in case of prolonged electricity emergencies.

3 Part B: Transmission capacities at the EU border – a volume assessment of possible effects of an EU-wide application

As summarised in the previous sections, the Iberian Price Cap has shown a high effectivity in achieving its main goal, lowering wholesale electricity prices. However, the increase of electricity generation from natural gas that is apparently linked to higher exports from subsidised electricity raises the question, how this effect would play out in the rest of Europe, if the EU as a whole decided to adopt this measure – or a similar measure, focusing only on natural gas power plants – as well. We assume that any such implemented measure would be designed in a manner that would not lead to merit order effects within the EU electricity system itself, either by subsidising all fossil fuels; or by limiting subsidisation to natural gas plants to obtain a price level that is still higher than electricity generation costs from coal. Without this premise, the result of such a measure would be an enormous natural gas consumption increase, likely impairing security of supply and leading to skyrocketing natural gas prices.

In the context of market system analysis, questions like these usually are tackled by setting up comprehensive and complex power system models. However, building, calibrating and solving a European model of the European power sector in times of crisis (or also just a subset of these activities), including the estimation of accurate gas and electricity demand elasticities (that are often not explicitly accounted for in exisiting models) requires substantial time resources. Moreover, by definition, models are not calibrated for times of crises and thus will have difficulty depicting the current unique situation. Other approaches that simply extrapolate the quantitative effects of the measure on the Iberian Peninsula for the rest of Europe also don't seem appropriate, as local circumstances and seasonalities have influenced gas production and electricity export patterns, as has been shown in the previous sections as well.

A timely estimation of effects of the Iberian Price Cap – a short-term intervention mechanism that could be implemented within months – should therefore aim for a simplified, but targeted approach, especially as a range of possible outcomes can give more insight into this question than predicting a seemingly exact result based on very rough input estimations.

Thus, the following sections intend to give an overview on the scale of transmission capacities and electricity generation fuel switch potentials towards natural gas on the borders of the European Union. The goal is to provide a range estimation of realistic annual electricity export adjustments due to a rollout of the Iberian Cap Model across Europe. For this, firstly, the interconnection capacities themselves are presented and grouped and information about local electricity systems of EU's neighbours is gathered. In a second step, the obtained data are compared to obtain maximum effect ranges of an application of the Iberian Price Cap or a similar measure.

Section 3.1 presents the methodology how transmission capacities between individual countries were computed and which data was used. In Section 3.2, a general overview on installed transmission capacities over EU borders and short descriptions of electricity systems of neighbouring non-EU countries is presented. In Section 3.3, the gathered information is composed to derive a conservative volume assessment of exploitable electricity import potentials for neighbouring countries in case of the introduction of an Iberian Price Cap. In Section 3.4, the results of Section 3.3 are analysed regarding their implications on gas demand. Section 3.5 critically assesses the chosen methodology and results and identifies their limitations.

3.1 Data and Methodology

The following assessment of additional electricity export potentials in case of the introduction of an Iberian Price Cap consists of three steps: First, available transmission capacities between EU and non-EU countries are derived based on 2021 data. Second, historical utilisation of capacities and additional export potentials are computed by summing up physical export volumes and remaining capacities at the respective borders. Third, historical fossil generation data from the same year (or 2020, if no data for 2021 is available) are used to identify electricity generation substitution potentials of non-EU neighbours due to cross-border merit order changes.

For the estimation of transmission potential data, different datasets that may be used to derive transmission capacities between individual countries exist. However, data completeness and up-to-dateness is often not a given for some borders in the European periphery. Therefore, data of transmission lines (as provided by the TYNDP of Entso-E), data on commercial exchange flows or forecasted transfer capacities (as provided by Entso-E Transparency) or data on available transfer capacities (as provided by JAO) were discarded as references.

Instead, the historical hourly physical import $imp(c,n,h)$ in [MW] from EU country n to non-EU county c of the year 2021 (data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022)) was used to compute the historical maximum hourly electricity import as a proxy for the installed capacity between two countries. The maximum import potential pot_max_{import} in [MW] of each non-EU country c was subsequently computed as the sum of individual maximum historical imports from all individual neighbouring EU countries eu[5].

$$pot_{import}(c,n) = \max_{h \in 2021} imp(c,n,h)$$

$$pot\_max_{import}(c) = \sum_{n \in eu} pot_{import}(c,n)$$

[5] The only exception to this rule was the border between Spain and Morocco, as it is not contained within the data provided by (European Network of Transmission System Operators for Electricity (Entso-E) 2022). For this border, an installed capacity of 1,400 MW (Tsagas 2019) and the yearly physical exchange of the year 2021 (Red Electrica 2022) were manually researched and added to the dataset.

The principle is also visualised in Figure 8, a mode of presentation, which is also used in Section 0 of this paper. On the left side, the historical utilization of transmission capacities is visualised, using three different metrics. The **grey bar** describes the **sum of maximum net imports from individual neighbour countries** as in the formula given above. The right side of the diagram describes the composition of the grey bar, by displaying all individual maximum imports from neighbour countries. The **dark blue** share of the grey bar describes the actual, measured **hourly maximum net import** for this country in 2021. By definition, this value is smaller or equal to the individual neighbour country's maximum observed imports.

The **light blue** bar indicates the **mean net** position of the country in question in 2021, whereby a positive value indicates an import from the EU, while a negative value indicates an export towards the EU. By definition, this value is smaller or equal than the historical hourly maximum import.

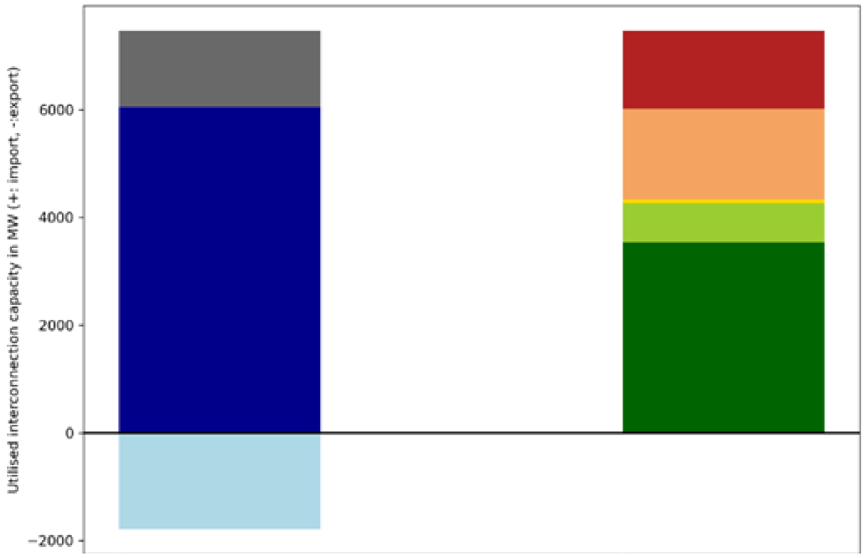

Figure 8:Visualisation of maximum import capacity computation.

This computed maximum transmission potential thus represents a conservative estimate, especially for countries with more than one neighbour, as maximum imports to various countries do not coincide often. However, it is still possible that individual maximum border capacities are underestimated in case the transmission capacity was never fully used in the chosen reference year, or further grid expansion has taken place since 2021.

In a second step, the historical full-load-hour utilisation of the individual borders $flh_{utilisation}$ in [h] was computed by summing up imports by border of the year 2021 from the same Entso-E dataset (European Network of Transmission System Operators for Electricity (Entso-E) 2022). Those were converted into full-load line utilisation hours for individual countries by dividing the obtained energy amounts by the computed maximum import potential.

$$flh_{utilisation}(c) = \frac{\sum_{n€EU,h\in 2021} imp(c,n,h)}{pot\_max_{import}(c)}$$

The additional annual import potential to the non-EU country c, add_{import} in [MWh] is computed as the unused full-load hours for importing electricity times the maximum import potential.

$$add_{import}(c) = \left(8760 - flh_{utilisation}(c)\right) \cdot pot\_max_{import}(c)$$

In a third step, the annual import potential is contrasted with electricity generation data from hard coal and natural gas plants in the respective non-EU countries, collected from (enerdata 2022). For a comprehensive overview of results, see Section 3.3.

Section 3.2 first presents general useful information about the existing electricity borders between EU and non-EU countries, and the electricity systems of these neighbouring countries. Please note that raw data quality cannot be guaranteed by the authors of this paper.

3.2 EU borders and transmission capacities – a short overview

Of the 27 EU countries, most countries only have a low number of non-EU neighbours with non-zero transmission capacities at the border. However, there are not many countries that have none (cf. Figure 9).

Obvious examples of countries without such interconnections that are therefore irrelevant for an analysis of interconnection capacities are some of the European islands: Iceland and Cyprus do not have electricity grid connections to other countries at all, and Malta is connected to fellow EU-member Italy only. Ireland, on the other hand, is closely connected to the UK, which has left the EU in 2020.

Another special case are small countries on the continent that are often part of the electricity regulation zone of a bigger neighbouring country, i.e. EU-member Luxembourg (covered by a common regulation zone with Germany), or non-EU members Andorra and Gibraltar (Spain), Liechtenstein (Switzerland), Monaco (France), San Marino & the Vatican (Italy). Often, special agreements are in place between these countries assuring the swift inclusion in the bigger market areas. For most of these countries, no individual country data on all generation, transmission and load are readily available or they are usually included in the neighbouring country’s dataset. Therefore, the electricity exchange between these small non-EU countries and their EU-neighbours is discounted in the remainder of this section. This results in a slight underestimation of EU transmission border potentials and thus influences of an Iberian Price Cap-like intervention in the following sections.

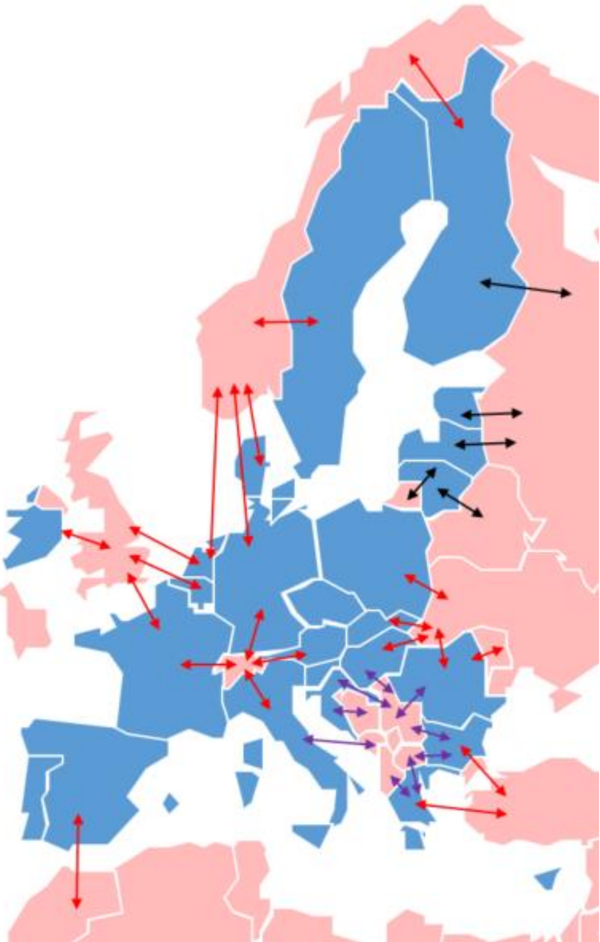

Figure 9: Overview of EU electricity borders (own depiction), based on data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022). (red arrows: analyzed transfer capacities; purple arrows: aggregated subgroup of analyzed transfer capacities to Balkan non-EU countries; black arrows: not included due to sanctions and other existing import limits)

Apart from Malta and Luxembourg, three other EU-countries only border other EU-countries with regard to physical electricity exchange: the Czech Republic, Portugal and Slovenia. In contrast, besides Spain which - as was already discussed in part A of this paper – shares a transmission line with Morocco, also Belgium, Denmark and the Netherlands are examples of countries which do not share a geographical border with non-EU countries, but are connected with at least one non-EU country via underwater transmission lines, i.e. the UK and/or Norway.

In the following, these borders are adressed by grouping them – roughly differencing between the three most interconnected Central European neighbours UK, Norway and Switzerland and other neighbours.

3.2.1 Most interconnected neighbours of the EU

Of the various electricity market zones neighbouring the EU, three stand out due to their strong physical interconnection with EU countries, bordering at least four EU countries, respectively market zones and having transmission potentials of more than 5,000 MW each:

- Norway: direct links to Denmark, Finland, Germany, the Netherlands and Sweden (plus non-EU UK),
- The UK: direct links to Belgium, France, Ireland and the Netherlands (plus non-EU Norway), and
- Switzerland: direct links to Austria, France, Germany and Italy.

Figure 10-Figure 13 show key transmission potentials for these three countries *for the year 2021*.

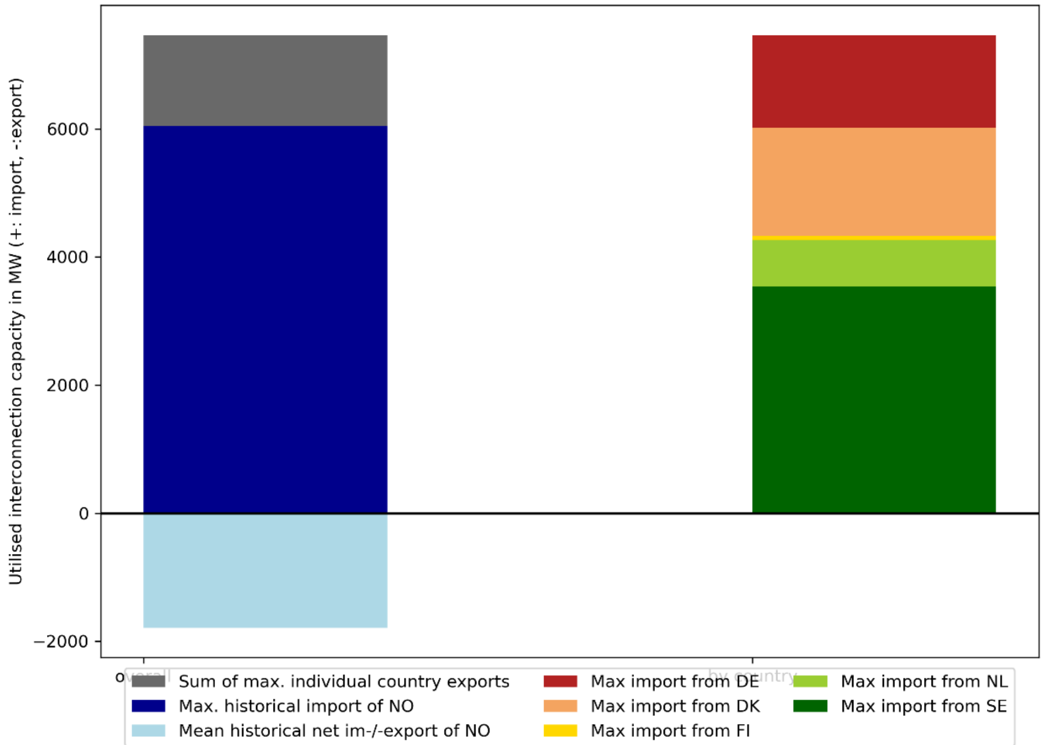

Figure 10: Historical maximum and mean physical exchanges of Norway for the year 2021, transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.[6]

Norway (cf. Figure 10) has been a clear net exporter to the EU in 2021, mainly due cheap generation resources from offshore wind and hydro (storage) power. Nevertheless, a maximum hourly import of about 6,000 MW has been metered, and individual max imports by neighbouring country sum up to about 7,500 MW.

As a result, there is, at least in theory, a substantial potential for additional exports from the EU to Norway, with Sweden and Denmark being the most important electricity exporters. However, the mentioned cheap generation structure of Norway, with a renewable electricity generation share of more than 95% in 2021 (European Network of Transmission System Operators for Electricity (Entso-E) 2022), questions a significant change of import/export dynamics due to a subsidisation of fossil electricity generation in neighbouring countries.

[6] For the meaning of country codes, we have included an overview table in section 5 of this paper as a reference.

This picture looks quite different for the other strongly interconnected neighbours. Looking at the EU borders with the United Kingdom (cf. Figure 11)[7], it becomes clear that the UK has already been a net importer in 2021, with on average more than half of the available transmission capacity being used for imports, mostly from France. This picture has changed drastically in 2022, amid the French nuclear generation capacity crunch. At the moment, the UK has become a net exporter of electricity to the European continent. The UK has a quite diversified electricity generation fleet of its own, whereby renewable plants, i.e. wind and solar power, and fossil power plants like natural gas play vital roles. Compared to a maximum electricity demand of more than 50 GW in 2019[8], the identified maximum import capacity of about 5,700 MW is not particularly high – but still very relevant due to substitution potentials of fossil electricity generation.

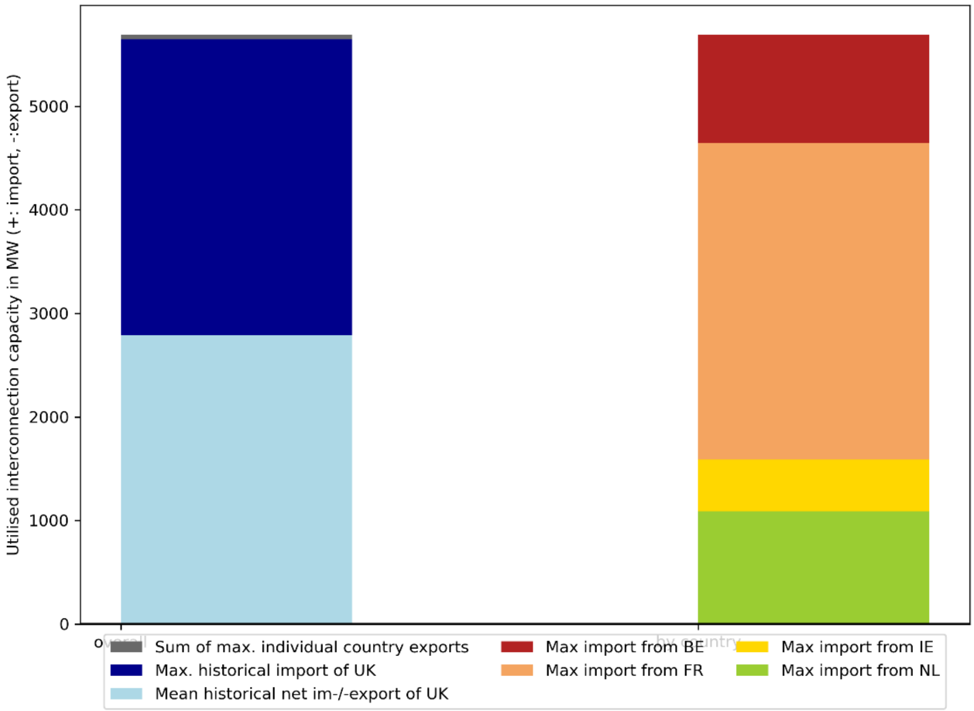

Figure 11: Historical maximum and mean physical exchanges of the UK for the year 2021, transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.

[7] Despite referring to the EU neighbour United Kingdom as political entity, the transmission data, figures and tables displayed here actually refer to the island if Great Britain, as there is a common electricity market on the island of Ireland, including Northern Ireland. This is further elaborated below..

[8] The UK has stopped supplying generation and load data to Entso-E Transparency in June 2021. 2019 has been chosen as a reference, as it was the last full year before demand effects of the corona virus became visible.

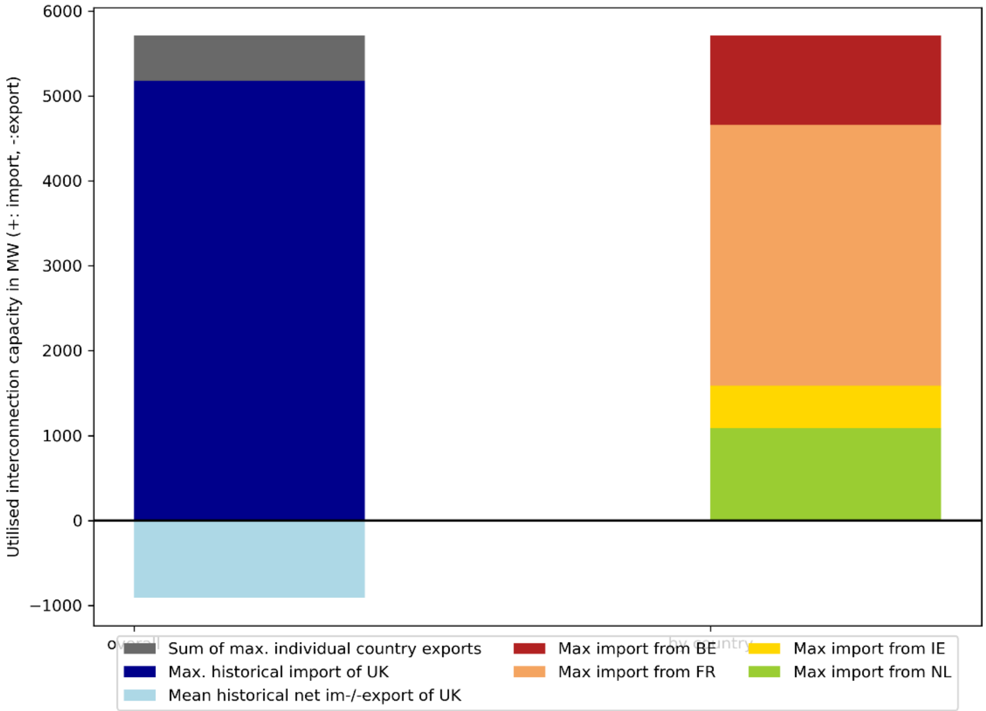

Figure 12: Historical maximum and mean physical exchanges of the UK for the year 2022 (data until 4 December), transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.

A special case is the border on the Irish island. Since 2018, Ireland and Northern Ireland form a common electricity market (the "Single Electricity Market", SEM) that still works in the same manner as pre-Brexit (as if it were still fully part of the EU), based on the Protocol on Ireland/Northern Ireland (often denoted as "backstop") (Mason, Hayes & Curran 2021). Therefore, electricity trade on the Irish island itself is not restricted by Brexit provisions and the displayed transmission potentials actually refer to exports from the Irish island (from the SEM, i.e. including Northern Ireland) to the island of Great Britain. We thus assume in the following that the application of an Iberian Price Cap model would cover power plants in Northern Ireland as well.

For Switzerland, the picture shows a quite different dynamic (cf. Figure 13). Switzerland often is an electricity transit country (meaning that the net country position on average is rather balanced, but individual neighbour country positions are often large with contrary signs) and – on average – Switzerland imports electricity from Austria, France and Germany and exports to Italy. The massive overhang of the grey bar compared to the dark and light blue bar implies a high volatility in intensity of imports from and exports to individual countries. It also shines a light on the physical rules of electricity flows, as individual maximum exports from countries never happen at the same moment in time – likely prevented by grid topology.

As a further effect, Swiss pumped hydro storages also often use electricity price differences during the day to storage and release water. Therefore, Swiss net imports and exports also depend a lot on the time of day, as a boxplot of individual country positions dependent of the hour of day during the last years since 2015 shows (cf. Figure 14). Switzerland only has a low number of fossil power plants (mostly used for cogeneration, so joint production of electricity and heat) and mostly covers its demand by renewable and nuclear power, and its large (pumped) hydro storages. While this implies that no big structural effect on import balances from the EU to Switzerland is to be expected from an Iberian Price Cap, installed pumped hydro electricity storages could cause an additional temporary demand effect at the time of introduction. Put simply, there is an incentive to sell electricity stored in pumped hydro water storages before Cap introduction and refill storages with subsidised electricity afterwards.

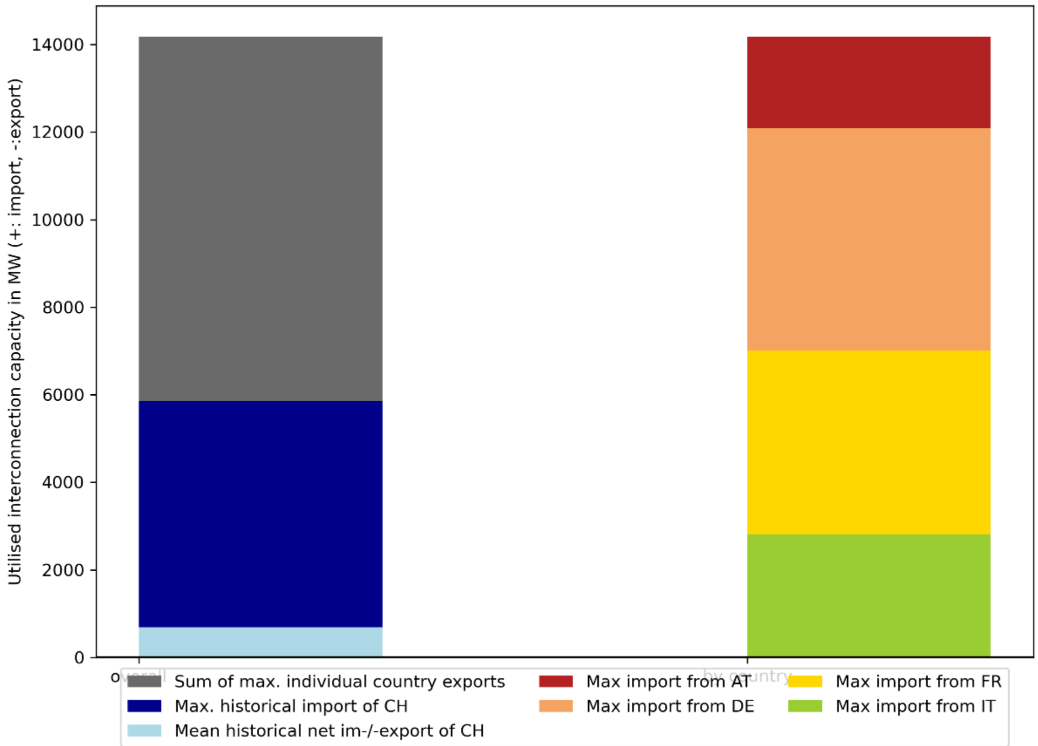

Figure 13: Historical maximum and mean physical exchanges of Switzerland for the year 2021, transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.

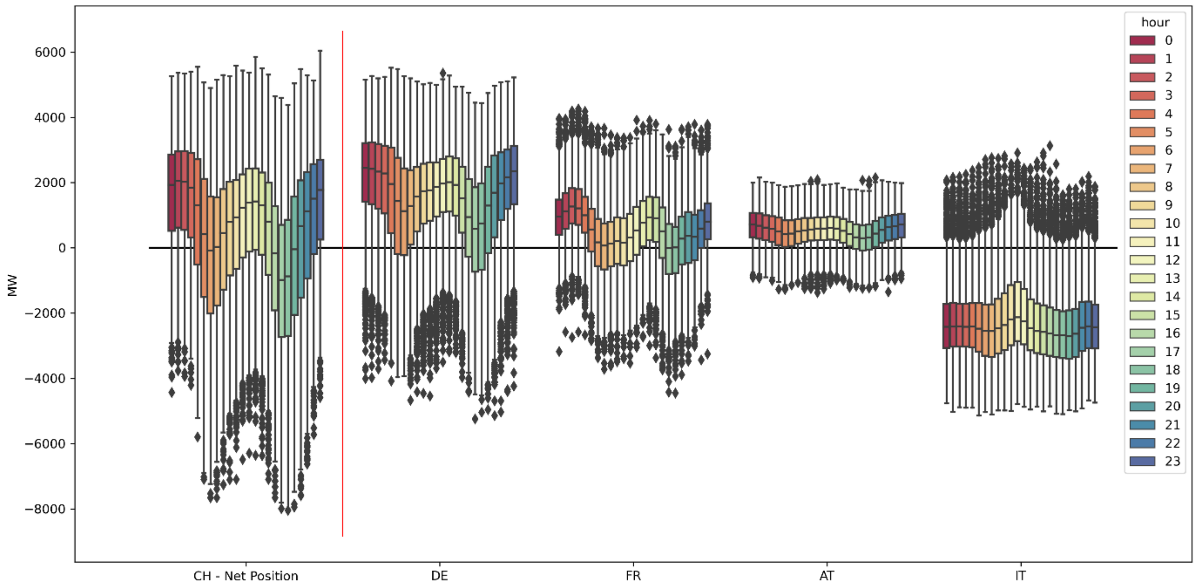

Figure 14: Boxplot of ranges of hourly import and export positions [MW] of Switzerland since 2015 (left of red line: total net position, right of red line: net position of Switzerland to mentioned countries), Data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own depiction.

3.2.2 Further neighbours of the EU

Besides the highly interconnected countries listed in the previous section, numerous further EU-borders with a lower degree of interconnection exist. They are in the following clustered by their geographical position, to ease orientation:

- Borders to Central South East European countries:
  - Albania: direct link to Greece
  - Bosnia & Herzegovina: direct link to Croatia
  - Montenegro: direct link to Italy
  - North Macedonia: direct links to Bulgaria and Greece
  - Serbia: direct links to Bulgaria, Croatia, Hungary and Romania
- Borders in North-Eastern Europe:
  - Belarus: direct link to Lithuania
  - Moldova: direct link to Romania
  - Russia: direct links to Estonia, Finland and Latvia
  - Russia, Oblast Kaliningrad: direct link to Lithuania
  - Ukraine: direct links to Hungary, Poland, Romania and Slovakia
- Border to Türkiye: direct links to Bulgaria and Greece
- Border to Morocco (as mentioned in previous sections): direct link to Spain

Among individual country borders, the one with the highest individual transmission capacity is the border between Bosnia & Herzegovina and Croatia that had an individual maximum hourly physical exchange of more than 1,000 MW in 2021. Adding all individual borders to EU countries together, however, also North Macedonia, Serbia, Türkiye and Ukraine reach that threshold. The physical exchange with **Morocco** is not included in the Entso-E dataset, however official sources also suggest an installed transmission capacity of more than 1,000 MW (Red Electrica 2019).

As a general rule of thumb, **Central South-East European** electricity systems mostly rely on lignite coal as fossil energy carrier, complemented by hydropower. Only rarely, natural gas or hard coal are used for electricity generation, often within cogeneration application settings. In sum, the most interconnected country is Serbia, with potentially about 2,800 MW of combined import capacity (cf. Figure 15).

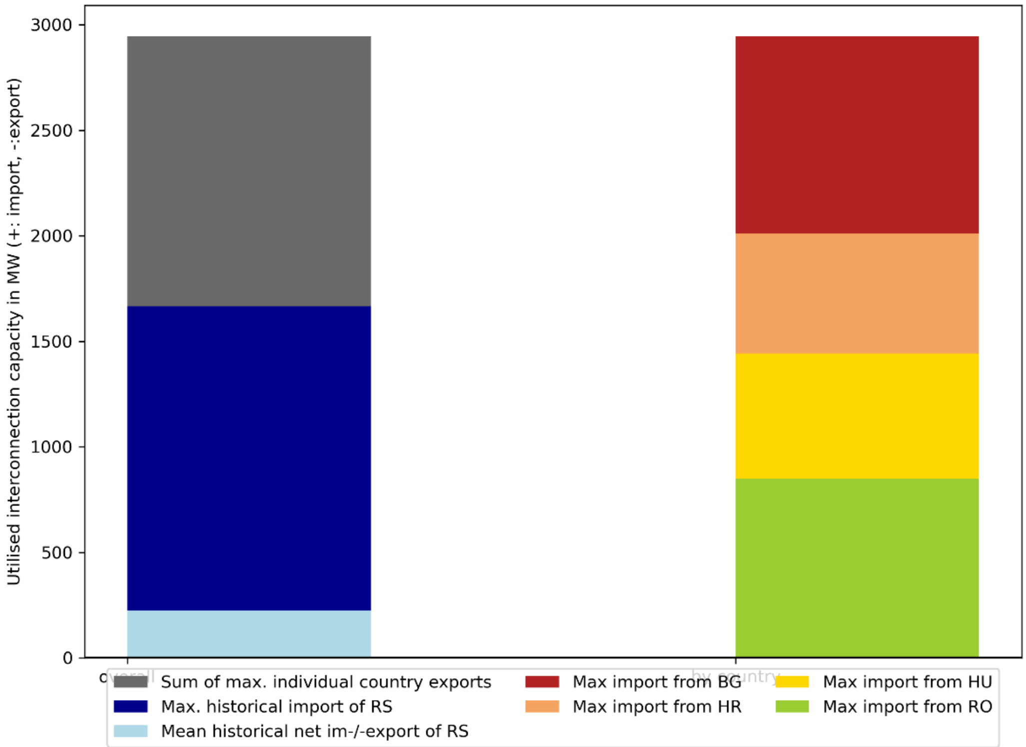

Figure 15: Historical maximum and mean physical exchanges of Serbia for the year 2021, transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.

Regarding the current geopolitical situation, the electricity connections to **Belarus, Russia, Ukraine, and Moldova** have to be analysed with special care. In 2021, Russia on average exported electricity to its EU neighbours (cf. Figure 16). After Russia's attack on the Ukraine, commercial electricity exchange has been suspended between Russia and EU countries, following EU sanctions. In the case of Finland and Russia, there has been no electricity exchange since May (AFP 2022). The Baltic states have also suspended trade with Russia, but since their electricity systems are synchronised with the Russian electricity system, there is still physical electricity exchange not associated with trading activities.

Another special case is Lithuania, as it shares common interconnectors with both Russian Oblast Kaliningrad and Belarus. In 2022, net exports from Kaliningrad to Lithuania and Belarus to Lithuania have also decreased significantly compared to 2021, as trading with Russia has been suspended and physical exchange had thus been limited. In the case of Belarus, electricity imports had already been limited by Lithuania in 2021 as a reaction to the controversial construction of the Belarusian Nuclear power plant Ostrovets (World Nuclear News 2021). Poland does not have interconnectors to both Oblast Kaliningrad and Belarus.

In sum, the borders to Russia and Belarus can largely be discarded when analysing the effects of an EU-wide Iberian Price Cap – there will be no export leakage, if no, respectively hardly any trading is taking place.

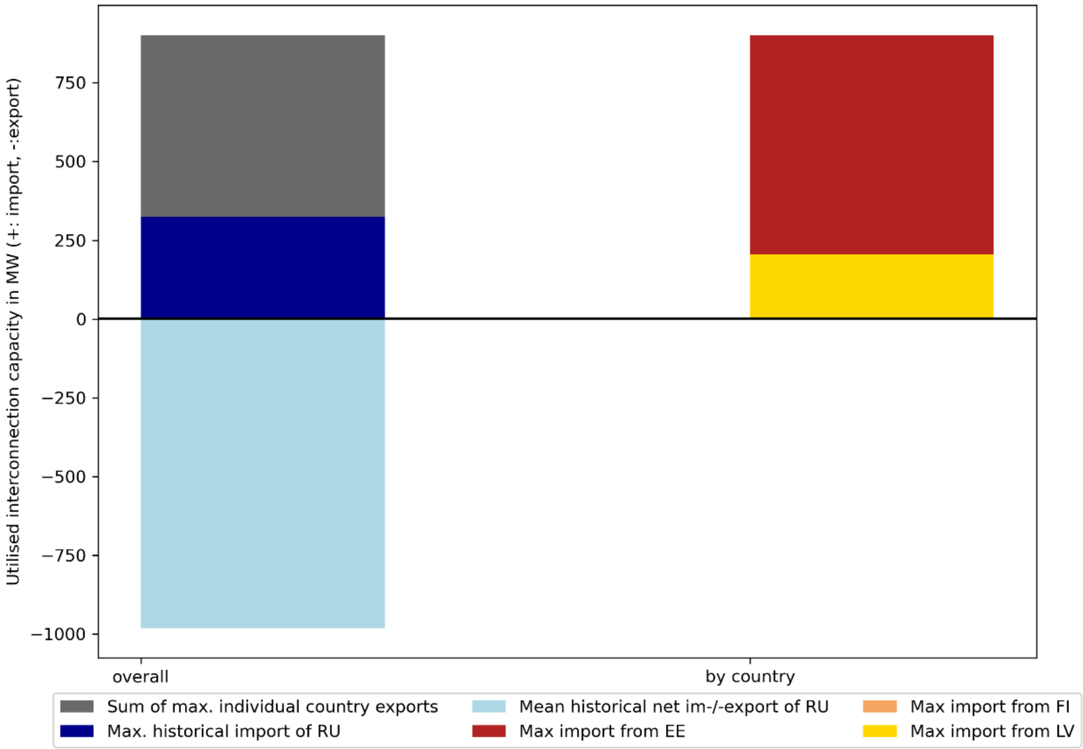

Figure 16: Historical maximum and mean physical exchanges of Russia (except Oblast Kaliningrad) for the year 2021, transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.

Ukraine has been a net electricity exporting country in recent years (cf. Figure 17). In 2021, only Slovakia on average exported electricity to Ukraine. This is mostly due to a large share of relatively cheap Nuclear power plants in the Ukranian (pre-war) electricity mix. Since the beginning of the war, electricity and heat production facilities have increasingly become target of Russian attacks, leading to an increasing number of plant non-availabilities and blackouts and therefore also to reversions of the electricity flow direction at the border. Moldova, which is strongly interconnected with the Ukrainian electricity system, has supplied significant parts of electricity production to cope with deficits in recent months. Before the attack on Ukraine, Moldova has imported about 30% of its electricity demand from Ukraine, which had to stop large-scale exports since. As a result, Moldova is now forced to import electricity from Romania, presumably at higher costs (Banila 2022).

Thus, it has to be assumed that increasing electricity exports to both Ukraine and Moldova will take place in the coming months in any case and that those exports will not be primarily associated with the introduction of an Iberian Price Cap. Therefore, their additionality to electricity exports and natural gas consumption will be computed according to the methodology described in Section 3.1, but discarded for the conclusions from this paper, as this additionality is virtually impossible to predict under the given circumstances.

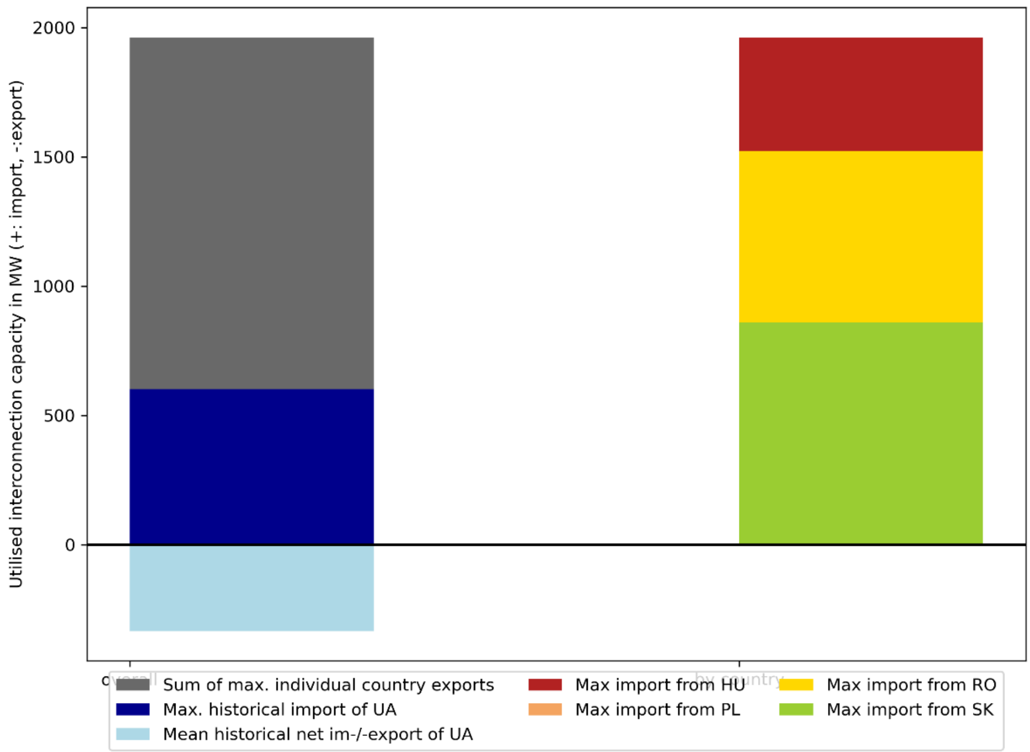

Figure 17: Historical maximum and mean physical exchanges Ukraine for the year 2021, transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.

Türkiye, with a combined transmission capacity of more than 1,000 MW towards the EU, on average exports electricity, whereby Greece was a net importer, and Bulgaria a net exporter in 2021. The Turkish electricity sector is quite diversified, with a total installed generation capacity of more than 100 GW across the entire country. Hydroelectricity, natural gas and coal are the most important primary energy sources of the electricity sector (US International Trade Administration 2022).

Türkiye does not yet have a CO_2 market for the energy sector (Tastan 2022), meaning that domestic electricity prices do not factor in CO_2 costs. The same is true for Morocco. Therefore, these countries usually have fewer incentives to import electricity generated in times with fossil fuels as price setting technology compared to own production from these sources.

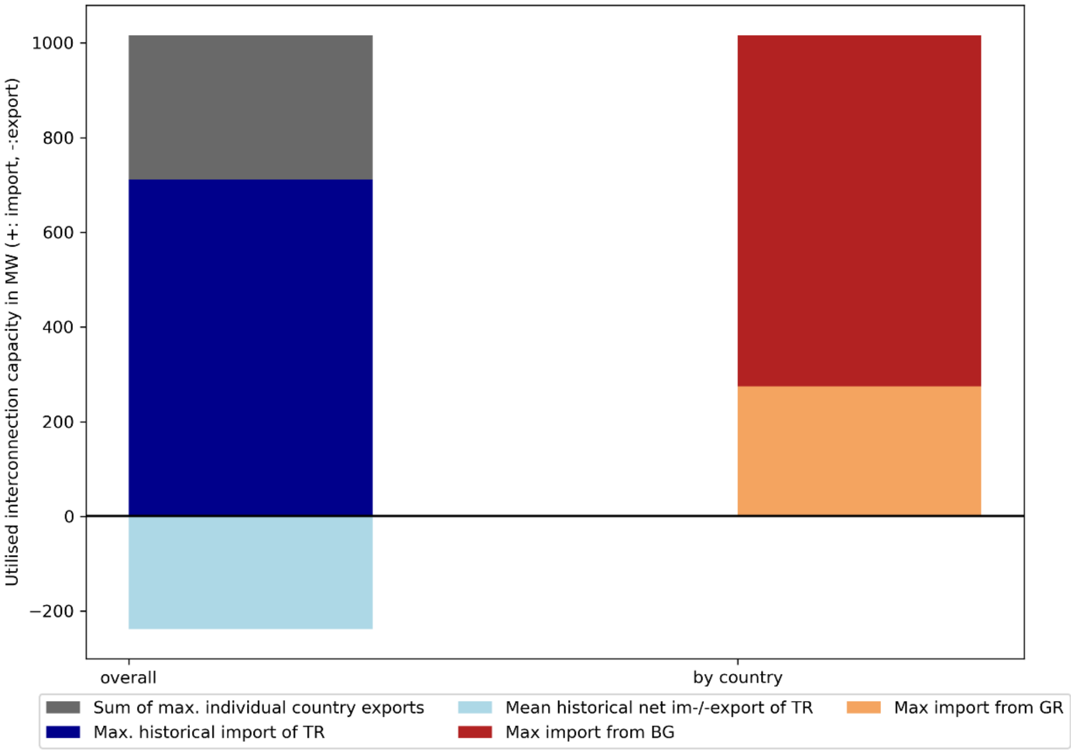

Figure 18: Historical maximum and mean physical exchanges Türkiye for the year 2021, transmission data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022), own calculations and depiction.

3.3 Volume Assessment: possible effects of an EU-wide application

In the following, all mentioned EU border transmission capacities are evaluated following the methodology described in Section 3.1 , and differentiating between two different scenarios:

1. Introduction of an **Iberian Price Cap as in Spain and Portugal**, with a target energy price of about 40 €/MWh; and a joint subsidisation of all relevant fossil fuels (i.e. coal, oil and natural gas) within the subsidy.

2. Introduction of an **Iberian Price Cap-like intervention** that focuses solely on subsidisation of natural gas power plants and sets a much higher, ideally automatically adjusted target energy price (ensuring that the current *clean spark spread* remains higher than the current *clean dark spread*[9]), therefore only capping costs of electricity production from natural gas to a certain degree. This ensures that electricity generation costs from natural gas remain higher than cost from electricity generation from coal. Thus, EU-internal Merit Orders are not distorted.

   Based on price levels at the time of this paper's production (early December 2022[10]), we would estimate this (automatically adjusted) target energy price at about 125 €/MWh, if a certain

[9] The so-called *clean dark spread* describes the difference between the current electricity price and the generation costs of a hard coal-fuelled power plant including the cost of CO_2 certificates. If this spread is positive, electricity production from hard coal is economically viable. Analogously, the *clean spark spread* describes the difference between the current electricity price and the generation costs of a natural gas-fuelled power plant.

[10] Those have been at about 260 USD per tonne of coal and 90 € per tonne of CO_2 (as of 7 December 2022)

buffer to safely avoid fuel switch from hard coal to natural gas within the EU is included. However, this price level could quickly become higher, if relevant coal and/or CO_2 prices rise.

With the Iberian Price Cap as in Spain and Portugal, the electricity price of EU countries is lowered more, and incentives for electricity exports to non-EU countries may arise for electricity demands that would have otherwise been satisfied by natural gas or hard coal[11] power plants.

However, electricity costs of generation from lignite coal can still be assumed to be lower than subsidised electricity levels. For cogeneration plants, a much lower rate of displacement is plausible, as they are often primarily used for heating purposes with electricity as a side product. The complete displacement of these plants within the Merit Order due to the Iberian Cap is therefore not plausible, as they don't bid at marginal costs, but at lower prices to ensure allocation. However, this electricity generation is in the following still included into the replaceable generation potential, to obtain a conservative estimate.

With the Iberian Price Cap-like intervention, the electricity price reduction is much lower, and incentives for electricity exports to non-EU countries mainly apply to gas power plants. However, this assumption needs to be handled with care, as not all neighbouring countries (such as Türkiye and Morocco) have to include CO_2 costs in their domestic market bids – meaning that in case of a low gas price and a resulting lower subsidy, domestic production could still be cheaper than import of electricity from the EU.

Iberian Price Cap as in Spain and Portugal

Table 6 shows the derivation of additional export amounts from EU countries to non-EU countries that could result from the introduction of an Iberian Price Cap compared to the real export levels of the year 2021. Table 7 shows the same derivation for the Iberian-Price Cap-like intervention[12]. The computed additional potentials therefore always refer to the year 2021 as base year.

Exports to Russia and Belarus are discarded in their entirety because of exisiting sanctions, respectively import constraints set by EU countries. Exports to Ukraine are included in the table to allow for completeness and comparison, but identified potentials are not included into the total sum, as these exports are not considered attributable to the effects of an Iberian Price Cap.

For a list of limitations of this very simplified approach, please also read Section 3.5.

[11] The actual cost difference and the displacement in the Merit Order depends on actual coal and CO_2 price levels. It is very well possible that electricity production from hard coal may still be less expensive. The approach taken here conservatively assumes a higher rate of displacement.
[12] The used data and methodology were presented in Section 3.1.

Table 6: Iberian Price Cap as in Spain and Portugal
Overview of transmission potentials and additional exports in case of a 40 €/MWh EU target price for fossil fuels

Import border	Estimated transmission potential [MW]	Additional annual export potential [TWh]	Generation switch potential from non-EU fossil fuel to EU natural gas [TWh]	Additional annual export [TWh]
EU-> UK	5.688	22.9	133.3	22.9
EU -> Norway	7 467	57.6	0.6	0.6
EU -> Switzerland	13 569	96.0	0.6	0.6
EU -> Ukraine	1 963	14.8	38.6	14.8
EU -> Moldova	-	-	44.5	0.0
EU -> Türkiye	1 017	7.8	179.8	7.8
EU -> Morocco	1 400	11.6	30.7	11.6
EU -> South-East Central Europe	6 931	51.0	1.7	1.7
Total				60.0
Total (without Ukraine)				**45.2**

As can be seen in Table 6, we conservatively compute a reasonable increase of annual exports of about **45 TWh**. This overall increase, comparable to the annual electricity consumption of Portugal (43.3 TWh in 2021, based on data from (European Network of Transmission System Operators for Electricity (Entso-E) 2022)) consists of the following individual increases:

Full exploitation of interconnections towards the UK. Ireland has enough natural gas power plant capacities to fill the available transfer capacity of 500 MW with production towards Great Britain. The continental gas plant capacity can also be assumed to be sufficient to export over the other UK interconnectors. Transfer capacities would become the binding restriction, as more fossil production in the UK could be replaced if more lines existed.

No significant switch potential towards Norway and Switzerland, and South East Central European countries. The vast majority of Norway's and Switzerland's electricity production may still be assumed to have cheaper costs than their EU neighbours. The countries in Southeast Central Europe widely use lignite coal for electricity generation, which also suggests that no significant fuel switch is likely.

Additional effects towards Moldova and Ukraine can hardly be estimated, due to uncertain political and thus electricity system circumstances. We suggest that additional electricity exports compared to 2021 should not be attributed to a possible Price Cap, but would likely happen anyway.

Türkiye and Morocco will likely import at full available transport capacity. Türkiye is able to substitute production from domestic gas power plants, with transmission capacities being the binding constraint. Morocco produces a lot of electricity from hard coal power plants that might be substituted, depending on the actual applicable coal price. Note that as the Iberian Cap is already in place between Spain and

Morroco, these electricity exports should already be happening with existing regulations. This example illustrates well, why this is a conservative computation: between July and October 2022, about 0.935 TWh were net exported from Spain to Morocco (Red Electrica 2022), which would lead to an extrapolated annual net export of about 2.8 TWh, compared to 11.6 TWh that have been computed as maximum additional export potential.

Iberian Price Cap-like intervention

In case of a much higher target energy price in an Iberian Price Cap-like intervention, overall dynamics do not change a lot, as Table 7 shows.

Of the dynamics listed above, only the exchange to Morocco is strongly affected. UK and Türkiye's electricity production from natural gas are still higher than available transfer capacities, meaning the latter still determine the additional export of electricity. However, the dynamic between Morocco and Spain changes, as Morocco's production from natural gas power plants is lower than the available transmission potential. Changes at other borders, such as the Norwegian, Swiss and the Central South East European, are rather small. A net export reduction of about 7 TWh leads to an annual increase of electricity exports of about **37 TWh** for the entire EU. This implies that an adjustment of said price reduction rule in the existing Iberian Price Cap would lead to fewer exports from Spain to Morocco compared to today.

Table 7: Iberian Price Cap-like intervention
Overview of transmission potentials additional exports in case of an adjusted target price for natural gas set based on hard coal electricity generation costs

Import border	Estimated transmission potential [MW]	Additional annual export potential [TWh]	Generation switch potential from non-EU natural gas to EU natural gas [TWh]	Additional annual export [TWh]
EU -> UK	5.688	22.9	121.6	22.9
EU -> Norway	7 467	57.6	0.5	0.5
EU -> Switzerland	13 569	96.0	0.6	0.6
EU -> Ukraine	1 963	14.8	14.2	14.2
EU -> Moldova	-	-	5.8	0.0
EU -> Türkiye	1 017	7.8	122.1	7.8
EU -> Morocco	1 400	11.6	4.0	4.0
EU -> South-East Central Europe	6 931	51.0	1.7	1.7
Total				51.3
Total (without Ukraine)				**37.1**

The computed numbers, that amount to in between 1.5% and 1.8% of annual electricity generation within the EU in the year 2021 (about 5,224 TWh, according to (European Network of Transmission

System Operators for Electricity (Entso-E) 2022)), lie well below the theoretical additional export potential of 261.7 TWh that would materialise if all export capacities were fully used at all times – a worst case scenario that has been mentioned frequently in the discussion about the Iberian Price Cap.

Under such a scenario, the existence of available electricity generation within the EU and price differentials high enough to trigger full exports to non-EU countries are constantly assumed, even if their electricity demand would normally be lower. Especially in the case of Switzerland, where maximum import potentials surpass the maximum hourly electricity demand, this is not a realistic assumption.

For an extensive summary of the limitations of this analysis, please also note Section 3.5. The computed ranges of electricity import increases (compared to 2021) give an indication, but not a precise forecast of additional electricity generation potentials from expensive fossil power plants (i.e. natural gas power plants) within the EU.

3.4 Implications for gas demand

With the computed additional electricity export potentials, it is possible to compute a conservative estimate for additional gas consumption as well. If we assume a mean conversion efficiency in electricity production from natural gas of 50%, which is quite low for combined-cycle gas and quite high for open-cycle gas plants[13], we can roughly double the numbers obtained for additional electricity exports, conservatively assuming that only electricity from natural gas is additionally imported.

The total electricity generated from natural gas within the EU amounted to 432 TWh in 2021 (European Network of Transmission System Operators for Electricity (Entso-E) 2022). The corresponding natural gas consumption for electricity production under the assumption listed above thus has been about 864 TWh in the same year. The overall consumption of natural gas in the EU amounted to about 4,398 TWh (eurostat 2022).

In the case of the Iberian Price Cap as in Spain and Portugal, this would indicate an increase in gas consumption within the European Union of about 90 TWh (+10 % of natural gas used for electricity production, +2% for total natural gas consumption) of natural gas. In the case with the Iberian Price Cap-like intervention limited to subsidising of natural gas, this would indicate an increase in gas consumption within the European Union of about 74 TWh (+8.5 % of natural gas used for electricity production, +1,7% for total natural gas consumption). This lies well below a theoretical – and highly unlikely – worst case additional gas consumption increase of about 522 TWh, in case a full exploitation of electricity import potentials is assumed at all times[14].

[13] It is also lower (and therefore more pessimistic) than the average efficiency assumed within the Iberian Price Cap model (55%).
[14] From a market point of view, this would only be the case of a much heavier subsidization of all electricity (e.g. to prices of zero).

3.5 Limitations

The methodology of the analysis presented above and its results are subject to a lot of uncertainties and simplifying assumptions that should be acknowledged before drawing conclusions from its results.

The approach of using historical maximum exports in itself is designed as a conservative approach, which means that export effects are likely smaller than estimated. However, at various borders only low effects were assumed due to fundamental generation cost considerations, such as a low generation cost of Swiss and Norwegian power plants. Although this fundamental reasoning is plausible, additional export effects could still be larger, e.g. due to opportunity cost considerations in storage management, or due to the neglected fact that Norway consists of more than just one price zone, with a diverse generation capacity and demand distribution.

The assessments, based on fundamental merit order logics, simplify electricity system dynamics and electricity market rules a lot, likely leading to overestimations of replacement effects for countries where fundamental incentives for electricity substitution are assumed, and possibly leading to underestimations of effects where no such effect is assumed.

Another important aspect is that, as no hourly resolution of generation data outside the EU was available, generation was assumed to be uniformly distributed over the year, meaning that the replaced historic production of non-EU fossil power plants was assumed to surpass the available hourly transmission potentials at all times. In reality, load and renewable generation patterns may lead to hours without the need for fossil fuel generation, lowering annual substitution potentials.

Additionally, no demand lowering effect due to high energy prices was considered, as data from 2021 was used directly for both transmission and generation amounts. Thus, consumption differences do not take existing energy saving measures (or electricity demand elasticities in general) into account.

This assessment does not depict welfare effects and possible energy price effects of an Iberian Price Cap or an Iberian price Cap-like intervention. For a thorough analysis of such effects, a much more complex approach would need to be chosen. Generally spoken, a measure such as the Iberian Price Cap may have a dampening effect on inflation and thus a positive effect on the enonomy as a whole, but can still have a negative impact on individual sectors, if gas prices rise sharply due to additional consumption.

The maximum historically observed electricity imports for each neighbouring country have been used as a proxy for total transmission potentials, which does not need to be accurate. The maximum additional export has been computed as a difference between these values and the historical mean imports. However, electric grids are neither copperplates nor water pipe systems. A constant maximum export from one country to another does not need to be technically feasible, for example due to physical constraints in the electricity grid. In Flow-Based Market Coupling (FBMC), these are accounted for when finding market results and often lead to maximum available exchange capacities that are below the computed theoretical import potentials. Besides that, also grid congestions within countries influence available transmission potentials between countries. A maximum exploitation of transmission capacities at all times, as assumed here, is not realistic.

Finally, natural gas and coal prices have been assumed at uniform levels across the EU and neighbouring countries – an assumption that has already been shown to be wrong during recent months, as European gas prices have started to differ a lot, depending on transport or conversion restrictions of national gas grid infrastructures. The effects of this key assumption could go both ways –lower gas prices in non-EU countries could lead to less substitution of electricity generation by imported subsidised EU energy, higher gas prices in non-EU countries would have the opposite effect.

4 Conclusions

Part A: Findings on the effects of the cap in Spain and Portugal

The results obtained in part A of this paper regarding the historical results of the Iberian Price Cap show some clear tendencies:

- Under the premise of high natural gas prices, the Iberian Model reduces electricity spot price levels significantly.
- On the Iberian Peninsula, the price cap has been accompanied by a significant increase of electricity production from natural gas. However, a more detailed analysis of this effect is necessary.
- About one third of this increase needs to be counted towards generation unavailabilities during the 2022 summer period.
- About half of this increase can be attributed to a surge in electricity exports to France and Morocco. However, it is not definitive that all these additional exports can be solely linked to the Iberian Price Cap, as electricity prices might have been higher in Central Europe even without the Cap.
- About one tenth of this increase can be attributed to a higher electricity demand, which at least partly could be linked to high temperatures during the investigated time period.
- Electricity price drops only partly materialise for electricity customers, as the subsidy costs need to be paid by means of a levy by market participants. The relative impact of said levy was increased by a low renewable generation output and a higher electricity export during the investigated time period.

Despite ocurring under local market circumstances, the historical observations in Spain and Portugal may still give an indication of what might happen in other market areas if the Iberian Cap were applied across Europe. Still, observed effects do not have to occur in the same manner everywhere. Not all countries border non-EU-countries; for these, the mentioned export and generation effects are likely to be much lower – but not zero, as the Portuguese example shows.

The generation structure in the Iberian Peninsula differs from the generation structure in other European countries, meaning that the share of subsidised electricity would differ greatly from country to country. Maybe even more importantly, other countries in Europe have higher interconnection rates (see Figure 19) and export effects could be much more pronounced. Therefore, an EU-wide application of an Iberian Price Cap is the preferred option to national implementations of similar measures, as this is necessary to achieve consistent results within the Union.

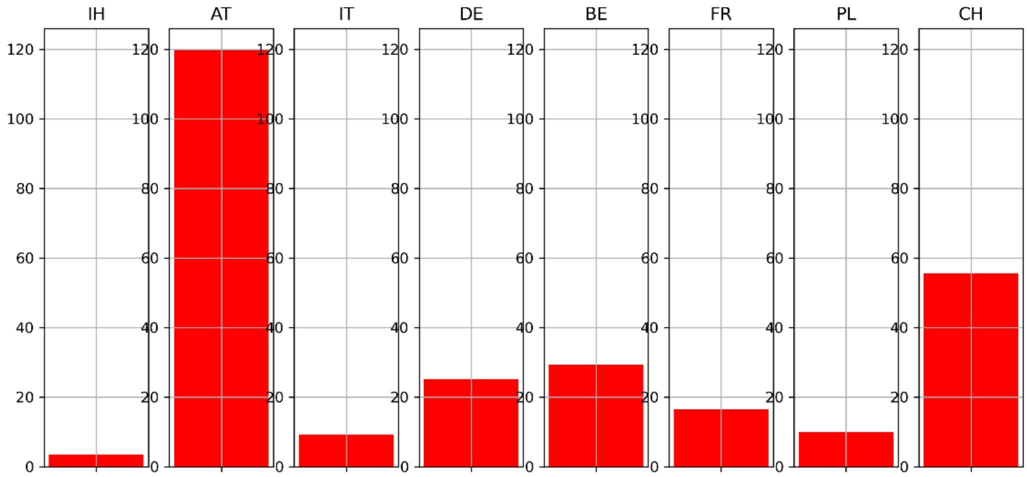

Figure 19: Interconnection rates of the Iberian Peninsula (IH) in [%] compared to other countries (from (Austrian Energy Agency 2022)), country codes: AT: Austria, IT: Italy, DE: Germany, BE: Belgium, FR: France, PL: Poland; CH: Switzerland

Thus, the Iberian example should be observed with caution and without overinterpreting every effect of the Iberian Cap. This requires a more profound analysis across Europe.

As a first step of such an analysis, a volume assessment regarding additional electricity export potentials was performed in part B of this paper.

Part B: Transmission capacities at the EU border – a volume assessment of possible effects of an EU-wide application

The available transmission exchange between EU and non-EU countries was investigated by looking at additional export potential if the Iberian Price Cap was applied across Europe. To do so, installed transmission potential[15] was deducted from historical import data of the year 2021 and compared to actual electricity generation data from 2021 in neighbouring non-EU countries from hard coal and natural gas plants that would potentially be substituted due to a cross-border merit-order change. Electricity generation from cogeneration was hereby conservatively included into substitution potential, despite being quite unlikely to be fully replaced by other heat sources. The assumption of a full exploitation of the transmission potential at all times also was conservative, as price fluctuations and occasional import direction reversions are likely, e.g. depending on hourly available renewable generation.

All borders between EU and non-EU counties were evaluated under the assumption of two different scenarios:

3. Introduction of an Iberian Price Cap as in Spain and Portugal, with a target energy price of about 40 €/MWh; and a joint subsidisation of all fossil fuels (i.e. hard coal, oil and natural gas) within the subsidy.

[15] Due to data availability, available transmission capacity was proxied by using hourly maximum values of physical flows in 2021 as reported on the ENTSO-E Transparency Plattform.

4. Introduction of an Iberian Price Cap-like intervention that focuses solely on subsidisation of natural gas power plants and sets a much higher, automatically adjusted target energy price depending on current coal and CO_2 price levels. This ensures that EU-internal merit orders are not distorted. Under the current market situation as of early December 2022, this would be the case with a target energy price of about 125 €/MWh.

The comparison of transmission potentials and existing national electricity system cost structures imply that the UK and Türkiye are the neighbouring countries to the EU most likely to benefit from the import of subsidised electricity, as domestic fossil electricity production can be substituted. Similar conditions apply to Morocco, which is however already affected by the existing Iberian Price Cap.

Despite having substantial transmission capacities towards the EU, Switzerland, Norway and the Southeast Central European neighbour countries (Albania, Bosnia & Herzegowina, Montenegro, North Macedonia and Serbia) do not have a large potential for additional import from subsidised electricity from natural gas due to the availability of own lower-cost generation capacity.

We estimate an increase of annual electricity exports of about 45 TWh, respectively 37 TWh due to the introduction of an Iberian (-style) Price Cap across Europe, under the assumption that merit-order effects due to fuel switch between natural gas and hard coal power plants within the EU are omitted by an intelligent intervention design. This could be achieved either by subsidisation of all fossil fuels (as with the implemented Iberian Price Cap), or by establishing an adaptive target price, considering coal and CO_2 price levels. These conservatively estimated numbers, that amount to in between 1.5% and 1.8% of annual electricity generation within the EU in the year 2021, lie well below the theoretical additional export potential of 261.7 TWh that would materialise if all export capacities were fully used at all times. In the case of production of this additional electricity by natural gas and an assumed mean gas plant efficiency of 50%, this would result in an additional gas consumption of 90 TWh, and 74 TWh respectively.

The results of this volume assessment only represent a rough approximation of possible effects at the border of the European Union and not a holistic evaluation of a measure such as the Iberian Price Cap. Especially, demand side effects that might occur due to lower electricity prices within the EU are not taken into account. However, these are difficult to assess, as many EU member states have by now taken measures to subsidise or limit end user electricity prices by varying degrees.

Further research into this question should additionally focus on an accurate depiction of welfare effects of the Iberian Price Cap or similar measures. A decline of electricity prices would, among other effects, translate in lower production costs for goods and therefore likely contribute to a lowering of inflation rates within and outside the electricity sector. However, the price-lowering effect in the electricity sector under such a mechanism would not materialise in the same manner in different countries with diverse electricity generation mixes, leading to distribution effects across Europe that should be adressed before the introduction of a singular mechanism. Still, a jointly negotiated measure by EU countries would potentially enhance fair competition compared to the status quo of uncoordinated national subsidisation.

In return, the impact on gas prices resulting from subsidy leakage and electricity exports also affects other economic sectors. Therefore, these effects should additionally be taken into consideration when deciding on an impactful measure such as the Iberian Price Cap. Electricity demand effects by an increased export to non-EU countries and resulting gas consumption increases could be significantly reduced by targeted political measures on the EU borders (such as agreements or taxes), especially concerning the UK and Türkiye. All in all, the results of our analysis show that an EU-wide application of an intelligent Iberian(-style) Price Cap omitting merit order effects within the EU and limiting merit order effects at the borders of the union would not lead to the massive increase of gas consumption that is often feared. Nonetheless, any measure potentially increasing gas consumption should be considered with care in the current supply-constrained market situation.

5 List of country codes

Code	Country	Code	Country
AL	Albania	LT	Lithuania
AT	Austria	LV	Latvia
BA	Bosnia & Herzegovina	MD	Moldova
BE	Belgium	ME	Montenegro
BG	Bulgaria	MK	North Macedonia
BY	Belarus	PL	Poland
CH	Switzerland	PT	Portugal
CZ	Czech Republic	RO	Romania
DK	Denmark	RS	Serbia
DE	Germany	RU	Russia
EE	Estonia	RU_KGD	Russia (Oblast Kaliningrad)
ES	Spain	SE	Sweden
FI	Finland	SK	Slovakia
GR	Greece	SI	Slovenia
HU	Hungary	TR	Türkiye
HR	Croatia	UA	Ukraine
IE	Ireland	UK	United Kingdom
IT	Italy	XK	Kosovo

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ABOUT THE AUSTRIAN FEDERAL CHAMBER OF LABOUR (AK)

The Austrian Federal Chamber of Labour (AK) represents by law the interests of about 3.8 million employees and consumers in Austria. It acts on behalf of its members in fields of social-, educational-, economical-, and consumer issues both on the national and on the EU-level in Brussels. Furthermore, the Austrian Federal Chamber of Labour is a part of the Austrian social partnership. The Austrian Federal Chamber of Labour is registered at the EU Transparency Register under the number 23869471911-54.

www.arbeiterkammer.at www.akeuropa.eu

ABOUT THE AUSTRIAN ENERGY AGENCY (AEA)

The Austrian Energy Agency offers answers for a climate-neutral future. The aim is to organise our lives and economic activities in such a way as to no longer affect our climate. New technologies, efficiency and the use of natural resources, such as sun, water, wind and forests, lie at the heart of the solutions. This ensures that we and our children can live in an intact environment and that ecological diversity is preserved without being dependent on coal, oil, natural gas or nuclear power. This is the missionzero of the Austrian Energy Agency.

More than 80 employees from a wide range of disciplines advise decision-makers in politics, business, administration and international organisations on a scientific basis and provide support in reconstructing the energy system and implementing measures to tackle the climate crisis.

On behalf of the federal government, the Austrian Energy Agency manages and coordinates the climate protection initiative klima**aktiv**. The federal government, all federal states, leading companies in the energy and transport sectors, interest groups and scientific organisations are members of this Agency.

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