European electricity markets – policy deficiencies, design deficiencies, and opportunities for policymakers

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A. Fundamental deficiencies of the political approach to the electricity sector

1. Paraphrasing a well-known dictum, one can say that 'design follows policies'. Therefore, before discussing questions of market design, one has to clarify the policies which the desired market design is supposed to implement. Hence, this paper starts by briefly reviewing the status of current policies for the electricity sector. Specifically, it will discuss political objectives, the choice of the basic regulatory paradigm, and the issue of subsidiarity between the EU and the member states.

A1. Objectives

2. Political objectives should be visible, balanced, credible, and consistent. Currently, there are no visible, let alone balanced, credible or consistent political objectives for the electricity sector beyond 2020 – neither on the European level nor within the member states.

3. In the recent past, policymakers have focused their priorities on the ecological angle of the policy trilemma (environmental concerns, economic concerns, security of supply concerns). They have formulated quantitative targets for CO_2 mitigation pathways, for RES-E-shares and for energy efficiency whilst leaving the two other angles of the trilemma largely undiscussed. Such an approach would be justifiable only if there were no trade-offs (which is not the case) or if the ecological objectives were given absolute priority (which can hardly be rationalised given the intricate structure of the global GHG challenge). Hence, policymakers should be expected to actively manage the existing trade-offs present in the trilemma rather than accepting their attempts to ignore them. Insufficient balance between the policy objectives is a major deficiency of the

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current political approach to the electricity sector, also undermining its long-term credibility.

4. An important factor in managing the trade-offs present in the trilemma is the choice of the speed of transitionIn particular, policymakers have to decide how fast the transition should take place. Obviously, the choice to move fast creates even more disruption when demand is suppressed and the economy is weak (compared to a situation with a growing electricity market and a buoyant economic climate). In general, the choice of speed should be reflective of the adaptability of the entire system, including, notably, the grid.[2]

5. In this context, European and national policymakers should also clarify their objectives on the environmental angle itself. With flat demand and sufficient generation capacity, there must be an additional motive for forcing the electricity sector into rapid transition mode. Originally, this motive was a commitment to GHG mitigation in Europe as a positive element of global climate change negotiations. So far, this strategy clearly has not been successful. A revision of the EU's overall strategy for the global climate negotiations seems to be timely, including a thorough debate on the relative merit of unilateral commitments regarding the mitigation of emissions compared to other potential measures and activities inside the EU[3].

6. But even when maintaining a unilateral EU commitment to mitigation, policymakers need also to clarify whether and why they want to pursue additional objectives such as, e.g., the deployment of certain types of mitigation technologies. Thus, an important issue for policymakers is to clarify their position on technology choice. Standard arguments offered to legitimate such technology-specific support (such as considerations with respect to industry policy or social vs. private risk) are typically not convincing because they fail to clearly identify the market failure addressed by the intended state intervention.[4]

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[2] For example, the rapid increase in intermittent RES-E capacity in Germany and Denmark has not been complemented by an equally rapid expansion of the transmission grid, leading to significant adaptation problems in the grids of Germany and its neighbouring countries. Thus, significant challenges were created for TSO in maintaining voltage control and coping with loop flows. Cf. below.

[3] Such measures and activities could, e.g., include introducing and harmonising CO_2 taxes in the EU, limiting the extraction of fossil fuels in the EU (rather than their consumption), fostering basic research in a broad range of relevant technology domains (rather than spending a lot of money on the diffusion of existing technologies), introducing border-tax adjustments, or offering systematic transfer payments as a part of a potential "deal" with other world regions. None of these or further potential measures can be seen as the "silver bullet" for a successful contribution of the EU to the global climate negotiations. However, any effective negotiation strategy of the EU needs to consider and balance a portfolio of such activities.

[4] For example, the argument put forward to support learning curves and to create blossoming industries (e.g., notably for RES-E) needs to be judged with caution. Market failure in the innovation chain exists only inasmuch as private gains from innovation cannot sufficiently be appropriated by the innovator. While this is typically true for basic research, thus requiring an active role for the state in supporting higher research institutions, this is generally not the case

A2. Regulatory approach

7. The electricity sector in the European Union has been organised according to a liberalisation paradigm since 1998. Specifically, value-added steps that allow for effective competition have been liberalised (generation, trade, retail). However, some restrictions still remain, in particular on the retail level and in the Eastern European member states. The grid, representing a natural monopoly, has been unbundled from the competitive sectors and was made subject to regulation. Non-discriminatory access to the grid is the cornerstone of the liberalisation paradigm and has been largely implemented.[5]

8. Main objectives of the liberalisation policy were (i) the establishment of a *level playing field* for the industry within Europe (as a major driver for further European integration) as well as (ii) efficiency gains (from more intensified competition - both within- and cross-border - and from reducing monopolistic inefficiencies).

9. European wholesale markets, and the prices generated on these markets, are *the* pivotal element of the liberalised electricity market. These prices reflect the scarcity between supply and demand at any moment in time with high temporal resolution[6] and thus deliver important and reliable indicators for investors, operators, and consumers.

10. A high quality of such a coordination mechanism is of utmost importance for the efficient and effective management of a complex structure such as the electricity system. Without such signals, actions by market participants need to be centrally coordinated, e.g., by way of state-owned or state-regulated monopolies, as was the case in many EU member states prior to 1998.

11. Therefore, there is a fundamental choice of approach to be made: coordination by competitive prices versus coordination by a central authority, e.g., by a monopolist. With the decision to liberalise the electricity sector, the EU has opted for the former of these two options. However, since 1998, policymakers have also found it attractive to distort competitive price formation

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further down in the innovation value chain. In particular, it is most likely not true in the stage of diffusion of a technology. Moreover, the hypothesis that European, let alone national, state subsidies can help certain industries to (sustainably) outcompete competition in the global energy arena should be seen as courageous, to put it mildly. The technologies, e.g., required to make the shale gas revolution happen in the U.S., have not received state subsidies. They have, however, made the global business case for RES-E much harder as a consequence.

[5] However, implicit privileges for certain market participants still persist, e.g., for RES-E generators or certain industrial consumers in the German grid.

[6] For balancing the market in the very short term, wholesale electricity markets are complemented by regulated balancing markets.

in certain parts of the market, e.g., by regulating retail prices or defining fixed feed-in tariffs for certain generation technologies.[7]

12. In this context, it has to be stressed that technology choice is *endogenous* in a liberalised market. It is well known that the private incentives generated in open markets lead to superior results both in terms of innovation and investment decisions.[8] However, many policymakers (as well as their voters) have strong opinions about the relative merit of certain technologies, in particular regarding generation. Thus, they want to treat technology choice as *exogenous* and, as a consequence, interfere in the price formation mechanism, e.g., by granting fixed remuneration. The choice of objectives, therefore, must be consistent with the choice of regulatory approach.[9]

13. Forcing certain technologies into the market on purely political grounds, however, is statically and dynamically inefficient: It leads to significant political rent-seeking, which further distorts policymaking and market expectations. In the beginning of such action, the distortion remains limited, making it rather easy for the policymaker to argue about its irrelevance. However, typically, any distortion to the price formation process generates more and more critical follow-on effects over the longer term, inviting policymakers to scale up the scope of their market intervention. Hayek, von Mises, and others have argued that such a spiral of state intervention into the workings of the price process will ultimately pave the way to central planning.[10]

14. A major case study backing this contention is the development of the RES-E support mechanism in Germany, [11] and the accompanying ripple effects in the competitive part of the electricity sector.[12] Similarly, the debate surrounding the introduction of national capacity mechanisms in almost all of the EU member states is contributing to this process of renationalisation and recentralisation (the latter mostly on the member state level only).

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[7] E.g., German renewable promotion system (EEG), see below, or the planned support for new nuclear power plants in the UK.

[8] Imposing a CO2 certificate scheme, such as the EU-ETS, or a CO2 tax does not alter this argument, as long as these are technology neutral.

[9] Cf. 6

[10] This observation is also referred to as the "oil stain theory", cf., e.g., von Mises (1929), "A critique of Interventionism", or von Hayek (1944), "The Road to Serfdom".

[11] Main drawbacks of the German RES-E support system include the lack of competition between technologies and locations, the lack of responsiveness of RES-E-investment to the power price, and the fact that TSOs have to bid RES-E-volumes into the market at a price of EUR -3.000/MWh rather than at their minimal economic value (which is EUR 0/MWh). Moreover, the system does not contain any stringent 'sunset clauses' which would serve to effectively limit the volume of potential RES-E-investments. A limit on PV expansion has been introduced; however, at 51.2 GW, this limit can hardly be regarded as stringent.

[12] E.g., a lively discussion about state support for conventional back-up capacity, as well as the introduction of phase-shifters by Germany's neighbours, cf. below.

15. Thus, after the shift from regulated monopolies (i.e., central planning by the state or by regulated monopolists) to liberalised competition, the paradigm of European electricity market design has now rapidly progressed to an approach of *prima facie* competition in conjunction with more and more state-induced price interventions. However, in contrast to the 1998 liberalisation process, this development has not been initiated deliberately, or top-down, by the EU and its member states but rather is the result of a variety of heterogeneous, idiosyncratic, and largely uncoordinated measures of member state governments.

16. A major aspect making state-induced price distortions attractive to policymakers is of course their typical construction as a levy, exemplified by the German EEG: As the levy is not charged by the state, but has to be collected by retail companies as a cost component in the total power price, the blame for rising electricity prices has for a long time been attributed, at least emotionally, to the retailers rather than to policymakers. Hence, neither the distributional effects nor the trade-offs related to the cost have played a major role in the German political debate so far, although this seems to be changing at present.[13]

A3. Subsidiarity

17. Policies for the electricity market are not reasonably coordinated within the multi-level governance structure of Europe. Within the European internal market, many policy measures close to the heart of national policymakers (e.g., retail prices, technology support) create repercussions all across the market. The EU lacks the explicit competencies[14] needed to effectively and efficiently coordinate member states' actions in order to reduce the negative fall-out from these interactions.

18. On the other hand, market structures and perceived national priorities for the electricity sector are still very heterogeneous across the member states of the EU. Substantial harmonisation of electricity sector policies, therefore, seems very difficult to implement within the current governance structure of the EU.[15]

19. In addition, state ownership in utilities that are actively participating in competitive electricity markets is pervasive across Europe, either by the national

[13] In terms of political accountability, this way of quasi-subsidies can be strongly contested, as has been shown, e.g., by a ruling of the German Constitutional Court in 1994 regarding the financing of hard coal subsidies by the power consumers. At the time, the court ruled that the hard coal subsidies were to be paid for from the state budget rather than from the power consumer. If the same logic were to be applied to the EEG levy, the annual RES-E subsidies would consume roughly 5% of the federal government's budget

[14] Except for potential restrictions on illicit state aid.

[15] The political problem at hand bears strong resemblance to the challenges within the Eurozone, where a single currency is not backed-up by sufficient harmonisation of economic policies and economic regulation.

government (e.g. EDF, Enel, CEZ), by regional governments (e.g. EnBW), or by municipalities (e.g. RWE, Steag, or more than 800 municipal utilities in Germany alone). Given the important role of the state as a regulator and "market designer" of these competitive parts of the value chain, conflicts of interest are well imaginable and may hinder the development of an effective level playing field in Europe.

20. In a certain sense, therefore, Article 194 of the Lisbon treaty contains an inherent paradox when it calls for a stronger integration of the internal market while guaranteeing full national sovereignty over the energy mix. While reflecting heterogeneity between the member states, it fails to organise subsidiarity in a way which is consistent with an integrated electricity market. Furthermore, although promoting the internal market (which is a paradigm based on competitive prices), the leeway it leaves to national member states entails frequent member state intervention into this very price mechanism.

B. Current market design and major deficiencies

B1. Market integration

21. In general, wholesale markets and the corresponding power exchanges are by now well-developed throughout Europe.

22. However, major improvement potential on the member state level still exists, in particular in some Eastern European countries where liquidity in the wholesale markets has not yet reached satisfactory levels. Further initiatives to open the markets and to generate more wholesale activities in those member countries would be useful. Markets in Central Western Europe, in the UK, and in Scandinavia, by contrast, can be seen as fully operational.

23. The integration of wholesale markets within Europe has made significant progress during recent years. For some borders, price differentials have almost completely vanished, while they still persist for others.[16]

24. Remaining price differentials can result from either one of three reasons: institutional discrimination of cross-border trade, inefficient allocation of cross-border transmission rights, or insufficient physical transmission capacity (i.e., a physical bottleneck). Wherever market coupling between national power exchanges has been implemented, remaining price differentials can therefore – with a very high probability – be solely attributed to physical transmission bottlenecks.

25. Market coupling has already been implemented in the region Germany-France-BeNeLux-UK-Denmark-Norway-Sweden-Finland and for the DC-Link

[16] Cf. e.g. ACER and CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas (2012)

between Sweden and Poland. As next steps, it is planned to integrate Switzerland, the Baltic States and Iberia into this large coupled market region.[17]

26. Overall, integration of European wholesale electricity markets can be regarded as advanced, especially in Scandinavia and Central Western Europe.[18] However, due to the unbalanced development of the generation mix across Europe (specifically due to increasing shares of intermittent RES-E in Germany and Denmark vs. continuing focus on conventional generation elsewhere), the level of market integration will most likely *decrease* as long as physical grid connections are not expanded.[19]

27. Regarding efficient and timely grid expansion, the activities of ENTSO-E in developing a European 10-year network development plan have already delivered significant progress. However, major areas for concern are remaining. For example, the appropriate burden sharing for national grid projects with cross-border relevance is still all but solved. Moreover, it cannot be excluded that national TSOs (with mostly national ownership) apply different priorities in grid expansion than, say, a Pan-European TSO would.

B2. The functioning of wholesale power markets

28. Power prices in Continental Europe currently range around 40 EUR/MWh on average, both on the day-ahead and the forward markets. Wholesale prices have drastically come down compared to the price level of 2008, both in average and peak hours.

29. In general, the low prices for electricity in Continental Europe should be seen as a reflection of the current balance between demand (decreased, in particular due to the economic crisis) and supply (increased both in conventional generation capacity and in subsidised RES-E in-feed).

30. Further reasons for the substantial decrease in Continental European electricity prices since 2008 include strongly decreased CO_2 prices (see below) as well as strongly decreased prices for hard coal (partially due to the strong decrease of gas prices in the U.S. caused by the so-called 'shale gas revolution').

[17] The contribution of market coupling to market integration can, e.g., be assessed by observing the effects of integrating Germany with some of its neighbouring countries. Cf., e.g., Monopolkommission, Sondergutachten 65, Energie 2013: Wettbewerb in Zeiten der Energiewende.

[18] Cf. EU-COM „A functioning internal market"(COM(2012) 663 final) and ACER/CEER „Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas" (29 Nov. 2012).

[19] In some instances, transmission capacities are even reduced by the installation of phase-shifting equipment which can disconnect two neighbouring markets in situations of high RES-E in-feed.

31. In addition, the strong increase in the feed-in of RES-E, in particular of electricity generated from PV (Photovoltaics), has substantially altered the structure of the price-duration curve.[20] In particular, on sunny summer days, the previous mid-day peak has basically vanished in Continental Europe. This development puts additional pressure on the existing conventional generation mix, in particular on such power stations whose business cases mostly relied on the existence of a strong mid-day peak in the past. An optimal generation mix with high shares of intermittent RES-E would include many more peaking units (such as OCGTs) than the current generation mix, which is largely a legacy from a rather different past.

32. The current price levels of electricity, fuels, and CO2 certificates, as well as the current structure of the price-duration curve, imply that some existing generation units are cash-negative (i.e., not recovering their operating cost), particularly gas-fired power stations. Moreover, many generation units are profit-negative (i.e., not recovering the depreciation on the initial investment), particularly the units invested in the recent past. Given the rather high degree of financial leverage, i.e., debt, in the sector, the current situation therefore has the potential to unfold into a major structural crisis.

33. The weak profitability of existing generation units should be seen as a direct consequence of the economic crisis on the one hand, and of the political support given to RES-E (in particular in Germany) on the other hand. Put differently, expectations formed by investors a couple of years ago regarding the development of demand and of RES-E-deployment have not materialised, implying stranded assets as of now. Notably, this situation occurred despite Germany shutting down almost 9 GW of nuclear capacity within weeks after the Fukushima disaster.

34. Given current overcapacity and little sign that the main underlying drivers (weak demand, state-supported RES-E build-up) will subside in the near future, conventional generators have started closing or moth-balling some of their capacity, and further such action has already been announced.

35. From a private perspective, the recent development in the electricity market has destroyed utilities' shareholder value, putting some of the utilities in a critical situation with respect to their balance sheet. In general, such down-turns are typical for capital-intensive industries such as electricity (or steel, pulp & paper, or many other such industries), and they are typically characterised by a consolidation of the industry structure.

[20] It does not, however, seem to have a major impact on the average price level compared to the other factors mentioned.

36. From a societal perspective, the major risk associated with the current down-turn in the conventional generation sector is of course the potential drop in the capacity margin, leading to more frequent and more pronounced price spikes and maybe even to rationing of demand in the case that demand is not sufficiently price-elastic and hence has to be curtailed.

37. As of now, wholesale prices show no sign of such trend. Prices have barely moved, and there is not yet a marked increase in the frequency and/or size of price spikes. Also, forward prices do not show a significant increase in price expectations for the coming years.

38. From this angle, and from most projections of the supply-demand balance, one can conclude that there does not seem to be an immediate risk of insufficient generation capacity *on the wholesale level* (i.e., on the level of the bidding zones). However, it is of course impossible to deliver a proof that such a hypothesis concerning the future is false.[21]

39. However, even if as of now there are no signs for immediate concern about generation adequacy on the wholesale level, wholesale generation capacity margins should still be closely monitored. The supply curve is rather flat at the point where it currently intersects with demand. Thus, it could be imagined that too many similar units are taken out of the market at roughly the same point in time, thereby creating an over-reaction of the supply side and thus a sudden lack of adequate capacity. Even if this would not necessarily lead to a blackout scenario, it would in any case entail a sudden increase in the price level which can hardly be properly anticipated by market participants.

40. Moreover, wholesale prices only reflect the (geographical) average of the demand-supply balance in a given bidding zone. By construction, wholesale prices are not able to render an insufficient generation adequacy transparent on a regional level *beneath* the scope of the bidding zone. As long as there are substantial bottlenecks within a certain bidding zone, insufficient regional capacity may remain undetected as long as only wholesale prices are observed.[22]

[21] In essence, the standard argument pro additional capacity mechanisms goes as follows: "We cannot rule out with 100% certainty that at some point in the future there will not be adequate generation capacity to cover that part of the demand which is not price-elastic below a certain, insupportably high threshold. Such a situation would be very expensive due to the value of lost load. Therefore, we need to prevent such a situation. This can only be guaranteed by introducing a capacity mechanism." If a 100% certainty of ruling out such a situation is required, there surely is no other choice than introducing additional measures. Whether or not this prior is economically reasonable should, however, be part of the legitimation of such a far-reaching intervention.

[22] Germany is a prime example for a critical mismatch between the geographical scope of the bidding zone (the whole of Germany) and the grid topology. In fact, the phase-out of nuclear capacity in 2011 has led to a significant imbalance between Northern and Southern Germany. Internal bottlenecks are now occurring much more frequently in Germany. As there still is only a

41. Germany has introduced a discretionary mechanism to guarantee generation adequacy. In 2013, the German government released a directive[23] which allows bilateral contracts between the TSO and generators deemed to be "system-relevant" and which includes payments from the TSO to the generator in order to keep the generation unit running. The regulatory authority, Bundesnetzagentur, has to be involved throughout the process. Obviously, such a case-specific approach is suitable for avoiding critical situations in the grid, in particular if the number of generation units of concern remains small. But it does not provide a systematic solution to the problem. However, before being dismissed as inadequate, costs and challenges of alternative and more systematic approaches need to be carefully evaluated.

42. The Continental European wholesale market currently also exhibits the unusual feature of negative prices for electricity in certain hours. Paying money to consumers to use a valuable good such as electricity is of course a clear sign of market inefficiencies. Firstly, due to the structure of the support schemes, intermittent RES-E is not fully curtailed in such hours, although this would be economically reasonable. Secondly, the demand side can obviously not fully make use of the negative price signal - partially because of a lack of flexibility, but partially also because it typically has to pay other cost components as well (grid fees, taxes, levies, etc.), such that the potential gain from using electricity at negative prices cannot be completely utilised.[24] Thirdly, the conventional supply side displays an insufficient degree of flexibility, preferring to pay someone to use the electricity generated rather than shutting down the plant, for example, because of schedule optimisation due to heat requirements in a CHP plant.

B3. Retail level

43. In spite of the decrease in prices on the wholesale level, electricity prices in Europe still are substantially higher on average than in other world regions, in particular the U.S.. Low prices for gas and for electricity currently support a

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single bidding zone in Germany, however, these bottlenecks require a much more frequent use of redispatch interventions by the TSOs, activating (out-of-the-money) power plants in the South and curtailing (in-the-money) power plants in the North. In order to be able to do this, sufficient generation capacity needs to be available in the South; however, this is capacity which is not profitable relative to the (average) German wholesale price. Unless the single bidding zone is split, further regulatory action is required to keep those power plants in the system. It has to be noted that the German determination to maintain a uniform bidding zone across the country even *increases* the pressure on South German generation because of the excess demand it creates from our Southern neighbours. Any solution that maintains a uniform bidding zone in Germany can counter this problem only by making use of systematic cross-border redispatch, i.e., by effectively enlarging the German price zone.

[23] Reservekraftwerksverordnung

[24] In fact, it can even be overcompensated if flexibility is treated as a "bad". Cf. Footnote 26 on the example of grid fees based on maximum capacities used in Germany.

renaissance of U.S. industrial production, with investments by European companies in the U.S. being a part of this trend.

44. Reasons include the higher fuel prices paid for hard coal (transport) and gas (no U.S. shale) in Europe and the inclusion of a price for carbon in Europe. Further important cost factors for many electricity customers in Europe are the many additional state-imposed taxes and levies.

45. For the case of Germany, on top of the EEG-levy,[25] the state has induced further cost components into the retail price, notably the electricity tax (at EUR 20/MWh, implying an equivalent CO_2 tax of roughly EUR 35/MWh at the CO_2 emissions factor of the German electricity mix in 2012), the concession levy for the grid, a CHP levy for subsidising CHP plants, and an offshore liability levy to finance the cost of delays in the grid connection between offshore wind farms and the onshore grid. Together, these cost components amounted to roughly EUR 100/MWh for households and to roughly 70 EUR/MWh for industrial consumers in 2012. Moreover, the state is collecting value added tax of 19% on all of these cost components. Thus, the end price paid by the consumer up to now is roughly twice as large as the economic cost entailed by generation, grid, and retail.

46. The substantial wedge between end customer prices and economic cost of procurement has several detrimental effects: It incentives inefficient self-production for self-consumption, both in the industry and on the household level, it leads to various undesirable distributional effects, and it stifles retail competition.[26] Moreover, given the current construction of grid fees and the various levies, the trend to self-produce threatens to turn into a self-promoting vicious cycle.

47. On the retail level, moreover, there still exists improvement potential for further European market integration, e.g., in terms of regulated prices or import/export tariffs, in particular in Eastern Europe.

48. The wide range of competencies still residing with national policymakers lead to a wide range of market design choices across the EU. For instance, from the point of view of a Spanish customer, the electricity market (in the sense of prices and price structures) looks very different compared to the perspective of, say, a German customer. Pan-European retail or procurement strategies are thus being hampered. Therefore, this patchwork structure by itself is a major

[25] Cf. 14

[26] In addition, grid fees are calculated on the basis of energy and maximum capacity actually used. These design elements reduce the elasticity of consumers with respect to the wholesale price without any economic benefit since grid cost are basically fixed in the short term. Because of this distortion, e.g., industrial consumers in Germany find it hard to beneficially react to very low or even negative power prices in situations with high wind and solar in-feed.

deficiency of the market design, effectively dividing the European internal market into 28 pieces and thereby stifling productivity and innovation.

B4. GHG-mitigation

49. Prices for CO_2-certificates under the EU-ETS currently range between 4 and 5 EUR/t of CO2. The current price level is far below previous expectations at the time the cap was defined[27], and below estimates for the external cost of damage created by CO_2 emissions.[28] In essence, the certificate price should reflect the market participants' expectations for the tightness of the cumulative cap for the 2013-2020 period. Although there have been some irregularities in the trading of CO_2 certificates in the past, there is no substantial evidence supporting the hypothesis that the certificate market is not functioning properly.

50. On the contrary, several observations support the hypothesis that the EU-ETS price correctly reflects the expectation that the market will not be particularly tight up to 2020. These observations include, e.g., a weak demand for CO_2-certificates in the wake of the economic crisis in Europe since 2009[29], a strong increase in the inflow of CO_2-offsets from CDM[30] projects realized at low mitigation cost, past and expected future member state support for certain mitigation technologies (in particular, RES-E) suppressing demand for CO_2-certificates, and no political commitment on the 2020-30 period.[31].

51. For the EU-ETS, therefore, major deficiencies comprise the lack of firm political commitment to the mechanism beyond 2020, the scope and role of CDM as well as the discussion around set-aside/backloading, which threatens to further undermine the political credibility of the mechanism without significantly impacting the CO_2 price. On the latter point, there is insufficient explicit governance in the EU-ETS for dealing with situations with unexpectedly low (or high) demand for certificates.

52. On top of the EU-ETS, the EU has defined two other elements of the so-called "climate package", namely an increasing share of RES-E and an increased energy efficiency. Such additional efforts do not lower the EU's emissions in the EU-ETS-sector but only serve to lower the price of the certificates, at the same time inflicting additional cost on the economy because of the privileges that are

[27] Cf. e.g. https://www.db.com/medien/en/content/press_releases_2007_3588.htm?dbiquery=null%3A%26%238220%3BCarbon+Emissions%3A+Banking+on+Higher+Prices

[28] Cf. Tol (2009).

[29] Excess certificates from the 2008-2012 period could be banked into the 2013-2020 period.

[30] Clean Development Mechanism.

[31] Hence, there exist no prospects for banking certificates into the next period, and hence the market likely assigns a positive probability to a situation where the CO2 price will be zero at the end of 2020.

given to those specific mitigation technologies (rather than letting the EU-ETS market do the job of selecting the mitigation pathway on its own). In essence, e.g., the coal-to-gas option is crowded out by the generous support given to more expensive mitigation options such as RES-E[32]. In any case, by superimposing RES-E subsidies on top of the EU-ETS, the EU is significantly increasing its CO_2-mitigation cost. A revision of this policy is strongly advised, starting with the definition of the corresponding objectives.[33]

53. Moreover, the EU has left the implementation of the RES-E- and the Energy-efficiency directive to the member states. While for energy-efficiency this may be defended on the grounds of subsidiarity arguments, national RES-E support schemes clearly impose burdens on neighbouring countries and have paved the way for inefficient schemes aimed more at pleasing national constituencies rather than attaining the European RES-E objective in a cost effective manner.[34] Having a level playing field between RES-technologies and locations across Europe would generate enormous benefits in reducing the cost for attaining any given RES-E target. Furthermore, an integrated and thus larger market for these technologies would serve as an additional catalyst for innovative activity in this sector.

C. Opportunities for optimising European electricity market policies and design

C1. Clarifying the set of objectives and the regulatory approach

54. First of all, policymakers should clarify and coordinate their objectives before introducing *new* interventions into the market. This can credibly only be achieved as long as policymakers explicitly take into account all inherent trade-offs and refrain from trying to micro-manage market outcomes.

55. Priority should be given to reducing regulatory risk by making long-term political commitments to objectives and regulatory design choices.

56. In particular, exogenous (political) price distortions on a national level are not compatible with long-term credibility of policymaking – at least as long as the EU and its push for integrating European markets continue to exist. If national

[32] In fact, the share of gas in the European electricity mix is going down rather than up (the 'gas-paradox'), and is expected to continue to decrease in typical business-as-usual scenarios.
[33] Cf. Section A.
[34] For the important case of Germany in 2012, note that the average feed-in tariff paid to the installations supported under the EEG was EUR 189/MWh, while the average market value of the RES-E volumes sold on the power exchange amounted to EUR 67/MWh only. To cover the resulting cost differential, the German power consumer had to support the RES-E operators with a levy amounting to roughly EUR 13 bn in 2012. The levy taken from power consumers has constantly risen from EUR 2/MWh (2000, year of introduction of EEG) to EUR 36/MWh (2012) and EUR 53/MWh (2013). In 2014, it will increase further to EUR 65/MWh.

privileges for the implementation of certain technologies remain a part of the EU energy policy governance, they should be harmonised on a European level.

57. Moreover, even if policymakers were able to effectively coordinate on a European level, policymakers, or regulators, would most likely never be able to solve the central planning exercise required. The liberalised market is much better able to pick and integrate the multitude of existing and new technologies which will be part of the future European electricity market.[35] This is particularly true in times of rapid change, and when many different actors are involved in the decision-making process.[36]

58. Thus, policymakers should make the internal European market the 'fixed star' of their future regulatory approach, in particular refraining from distorting market prices as much as possible, especially on the 28 member state level. Hence, if national privileges for the implementation of certain technologies remain a part of the EU energy policy governance, they should at least be required to be non-distorting to the price mechanism.

C2. Specifying the subsidiarity principle in European electricity policy

59. Currently, price distorting behaviour by individual member states can only be addressed by the EU on the basis of general competencies mostly in the context of illicit state aid. However, the debates surrounding, e.g., the German RES-E promotion scheme or the British plan for supporting nuclear illustrate the structural weakness on the EU level, at least in the context of the electricity sector. Thus, the typical counter-reactions of member states do not leverage European competencies but rather mobilise national resources,[37] thereby typically impacting the well-functioning of the internal market further.

60. In accepting the challenges to a full-fledged political union in the field of electricity policy, it should, however, be at least required that member states agree to gradually reverse the detrimental spiral of the renationalising and recentralising of the European electricity sector by specifying the subsidiarity intended by the Lisbon treaty in a way that is consistent with the move towards a more and more integrated European electricity market.

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[35] In particular, this will also include many small-scale technologies, which can be deployed as distributed technologies (on the supply side as well as on the demand side) and be virtually connected. The development of these technologies as well as of the IT required for connecting them has dramatically decreased the cost advantage of an electricity system based purely on large-scale, asset-heavy central power stations and, thus, the value of shielding such assets from competition.

[36] E.g., the coordination task becomes significantly more complex the more a few large, central generation units are replaced by many smaller scale distributed units, or the more prosumers are actively managing their own power supply/demand-balance.

[37] Examples include, e.g., the installation of phase-shifting technologies or the introduction of national market interventions such as, e.g., capacity mechanisms.

61. Technology support is at the heart of the subsidiarity conflict between the EU (internal market) and the member states (sovereignty over the energy mix). Hence, it would be most important to clarify the subsidiarity principle in the field of explicit technology support. For example, member states could agree that any support they give to specific technologies is generally accessible to investors in other EU member states as well, and that the support is given in a (largely) non-distorting manner, e.g., through tax breaks, quota systems, or premia. On the other hand, the EU would guarantee the member states the sole right to the permitting process, with the exception of some minimum standards agreed on the EU level. Such an agreement could be framed as an amendment that specifies the rather general terminology used in Art. 194 of the Lisbon treaty.

62. Prime issue number one in this context is nuclear energy. The risks of the civil use of nuclear energy in Europe cannot be confined to national borders, nor can – in integrated markets - the benefits to consumer rents from keeping existing nuclear stations in operation. However, the producer rent from nuclear power stations mostly remains with the member states, either directly (through nuclear fuel taxes or state ownership of nuclear power stations) or indirectly (through the taxes paid by the operator in the country of residence). Hence, there is an opportunity to optimise on the intra-European risk sharing around the use of nuclear energy in Europe. Without an explicit discussion of these issues, a major nuclear accident somewhere in Europe would most likely create enormous political tension within the EU.

63. Prime issue number two in this context is the support given to RES-E. As shown by many studies, Europe has significant opportunities in providing a level playing field for the investment into RES-E technologies. For RES-E, the crucial choice is between a mitigation policy purely implemented through the EU-ETS (generating higher prices and, among other effects, higher profits for the existing nuclear fleet across Europe, but leaving more room for competition between different mitigation technologies) and a policy using complimentary support schemes (*ceteris paribus,* reducing the EU-ETS price and, accordingly, nuclear profits).

64. If Europe decides to go ahead with an explicit RES-E target beyond 2020, it should aim to attain such a target through a joint and harmonised support scheme.[38] In order to be cost-efficient, and thus maximise European synergies, such a joint European RES-E support scheme should be technology neutral, location neutral, and it should remunerate RES operators on the basis of 'wholesale price plus X'. Here, 'X' can be determined in various ways, e.g., by a joint European quota reflecting the respective common RES-E objective. Such a quota system, which is analogous to the EU-ETS, can be implemented rather

[38] Interestingly, the EU has decided on RES-E objectives for the EU and the individual member states for 2020, while leaving the implementation of these objectives strictly to the member states.

easily, especially since a system of certificates of origin has already been implemented in the EU. Moreover, a quota system would provide a simple way to accommodate different preferences about the RES-E target among member states: Member states could differ in the quota they impose on the customers residing in their territory, with the weighted average of member states' quotas leading to the joint European quota.

65. Even prior to having a joint RES-E support scheme, member states could benefit from location-based synergies by pooling their RES-E targets and RES-E support mechanisms on a bilateral basis, as suggested by the EU RES-E directive.

C3. Improving upon market integration

66. There are many opportunities to further strengthen the functioning of the European internal market. Most important, markets can be opened up further in Eastern Europe, interconnections can be improved physically and commercially[39], and bidding zones can be redesigned to reflect the topology of the grid in a more optimal way.

67. Further improvements – apart from the continued removal of commercial and physical bottlenecks – can be expected from the implementation of the Network Codes in the context of the finalisation of the EU-internal energy market by the end of 2014. Important aspects are, e.g., the introduction of optimal bidding zones (i.e., bidding zones which optimally balance the trade-off between liquidity (the larger the better)) and internal bottlenecks (the less the better). Moreover, the reduction of the time span between gate closure (currently day-ahead) and physical fulfilment would help to integrate larger shares of intermittent RES-E more efficiently.

68. Europe would benefit from more cross-border harmonisation in grid regulation and from a deeper cross-border integration of TSOs. Maximising the available cross-border transmission capacity should be a clear priority for all European TSOs, independent of potential political or commercial interests to isolate the national market.

69. Furthermore, common rules for cross-border cost allocation for infrastructure projects of common interest should be established.

70. Moreover, there is substantial improvement potential regarding the harmonisation of balancing mechanisms and their cross-border accessibility. The

[39] Further improvements to market coupling can, e.g., be achieved through the introduction of flow-based market coupling, which takes into account the loop flows existing in a highly meshed transmission grid. For all other borders, improvements can be attained by rendering allocation mechanisms more efficient, in particular by migrating to an implicit allocation mechanism, i.e., to market coupling.

new network codes are expected to bring significant progress, especially in this dimension.

71. There is a debate on how to integrate power wholesale trading into the context of new regulation for the financial sector (EMIR). There are worries that such regulation could stifle liquidity on electricity wholesale markets in an undue manner, which may even endanger the very functionality of these markets. This issue should be closely observed.

C4. Securing generation adequacy

72. With respect to the introduction of capacity markets, there still is substantial empirical analysis required as to whether the 'missing money' problem really exists, or will exist, in the European internal market and, if so, what are the major causes. [40] Solutions to a potential 'missing money' problem should then be pin-pointed to solve the underlying causes and may include capacity mechanisms but could also consist of other measures such as, e.g., changes in the trading rules at the power exchanges, case-by-case decision making of the regulatory authorities[41], or additional activities of the cartel authorities.[42]

73. In any case, the appropriate level to define adequacy standards would be the bidding zone level, ideally after rearranging bidding zones in an optimal way. The role of the EU at the European level, therefore, consists of formulating standards for the structure of such mechanisms and ensuring that they are not misused as a surrogate for illicit state aid.

74. Regarding such standards for capacity mechanisms, they should be technology neutral, transparent, and non-distortive to the electricity wholesale market.[43] Moreover, capacity mechanisms need to be accessible in a non-discriminatory fashion (especially cross-border).

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[40] Major needs for empirical research comprise both the demand side (e.g., elasticity, DSM, level of maximum load to be guaranteed) and the supply side (e.g., shape of mid-term merit order, market structure in tight market conditions, role of cross-border interconnection, role of distributed generation).

[41] Cf. 41 on the selective intervention mechanism by the BNetzA in Germany.

[42] In the context of capacity mechanisms, the wholesale market is often referred to as an „energy-only market". Strictly speaking, this nomenclature is misleading. On the wholesale market, traders trade blocks of energy by time, with the time dimension becoming shorter and shorter until physical fulfilment. In this sense, wholesale markets jointly trade energy and capacity and deviations from a block within the smallest time interval traded are then settled through so-called balancing mechanisms. A pure energy-only situation only exists on the retail level for customers without real-time meters and who pay an energy (and a capacity) price independently of the time of consumption. For Germany, this part of the market can safely be assumed to be much smaller than half of the total.

[43] Cf., e.g., the comprehensive capacity mechanism for Germany suggested and discussed in Elberg at al. (2012), "Investigation into a sustainable electricity market design (Summary)", available at www.ewi.uni-koeln.de.

75. Furthermore, there should be guidelines how to define and to compute "generation adequacy". For instance, it is fully insufficient to define just a certain peak load in the past as the minimum requirement for secured capacity in the system. In particular, adequacy standards by bidding zones should reflect the diversification effects from Pan-European trade, which should lower adequacy standards relative to a world with inelastic or inexistent imports and exports.

C5. Improvements on the retail level

76. Throughout Europe, a revision of the state-induced components of electricity prices is warranted. In particular, traditionally, it has been assumed that household electricity consumption is a fixed factor and thus can be significantly taxed. The new opportunity of own-production on the small scale brought about by liberalisation and technological advances means that this assumption is no longer valid.

77. Harmonisation of the state-induced price components across the EU would bring additional benefits, especially to those electricity producers and consumers operating in several member states. In general, power prices should closely reflect the true economic cost of generation (including the internalised price of CO2 emissions), grid, and retail and should not be distorted by additional cost components. Furthermore, given the very high share of fixed cost in the grid, payments for grid use should ideally be based on maximum capacity potentially required rather than on energy or capacity used in a given period of time. Such a change in the grid fee calculation would help to make consumers more price-elastic to short-term changes in the electricity price.

78. On a more general note, there is substantial opportunity in rethinking the distributional aspects of the electricity market design. In particular, there should be a careful discussion on how to make use of the state income from the EU-ETS (potentially realising a so-called 'double-dividend').

C6. Improving upon the EU-ETS

79. If the objective to mitigate CO2 emissions in the electricity sector remains an essential part of the political agenda, the EU-ETS should be strengthened and receive firm political commitment. In particular, caps for the period 2020-2030 should be defined as soon as possible and the future role of CDM should be clarified at the same time.

80. Moreover, if based on the recent experience with the EU-ETS during the economic crisis policymakers feel that the cap should be made more flexible in such situations, they should explicitly define such a flexibility mechanism rather than arbitrarily intervening into the market. Possible mechanisms to achieve this

are, e.g., price floors/caps or the setting-up of an institution responsible for such decisions.

D. Summary and perspectives

81. In general, there is substantial economic opportunity from a more European approach not only to electricity market design but also to energy policy in general. Two related *political* issues emerge as central aspects to this task: the role and the definition of appropriate policy objectives on the EU- and member state level, as well as the division of competencies between the EU and the member states.

82. Therefore, the issue of improving the functioning of European electricity markets should not be regarded as primarily an *economic* issue of optimal market design. Rather, *political* issues are central to the challenge of removing the many deficiencies in the functioning of the European electricity sector and have to be solved prior to the question of appropriate market design.

83. The main elements controlled on the European level (competitive wholesale markets, EU-ETS) are the cornerstones of the European regulatory approach and are, with minor issues remaining, well-designed by themselves. However, due to market distortions mostly induced by the individual member states' policy measures (wholesale) and due to a lack of visibility beyond 2020 (EU-ETS), their well-functioning is more and more put into question. Key challenges on the EU level, therefore, are the clarification and definition of objectives for the period 2020-2030, the strengthening of the existing pillars of the internal electricity market and the EU-ETS, as well as further progress in terms of effectively and efficiently coordinating national regulation.

84. The alternative to a path of continued, deliberate integration (based on a sound application of the subsidiarity principle) would be a 'muddling-through' with more and more national interventions to counter the cross-border effects of the interventions of other member states. With a very high probability, such a process would inflict growing cost for providing electricity to the European economy. While 'muddling-through' may likely continue to go on for several more years, it is clear that this approach is highly unstable, and policymakers will most certainly find it impossible to stick to it *ad infinitum*.

85. Thus, a redrawing of European electricity market design can only be effective as a joint effort between the EU and the member states. Therefore, it would be helpful to explicitly rethink subsidiarity between the EU and member states for the electricity sector. Article 194 of the Lisbon does not provide a satisfactory answer to this challenge, if only, because it is not sufficiently precise. It is well beyond the scope of this study to make explicit suggestions for a new and more precisely defined balance of subsidiarity between EU and member states.

However, from the analysis presented, it becomes clear that leaving the (exogenous?) definition of the energy mix to the member state without sufficient EU guidelines and EU enforcement potential is not consistent with the well-functioning of an integrated internal market.

86. In this context, harmonisation of energy policies and corresponding market design will become the more important the more electricity markets are integrated between the respective member states. Hence, even if an integration of energy policies along the lines suggested can – for political reasons – not be achieved across the entire EU-28 in a first step, it would be extremely helpful to achieve progress into this direction within those regional pockets within the EU-internal market that are already well-integrated. Therefore, one of the most important starting points would be an integration of energy policies *and* market designs between the countries of the so-called 'Pentalateral Forum', i.e., France, Belgium, the Netherlands, Luxemburg, and Germany.

87. In summary, actors in electricity markets face enormous challenges, most (although not all) created by incoherent and inefficient policies and design choices. Thus, there is substantial need for action by European and national policymakers to improve upon the framework given to the electricity sector.