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Fragmented Policies and Regulations Lead to Significant Concerns

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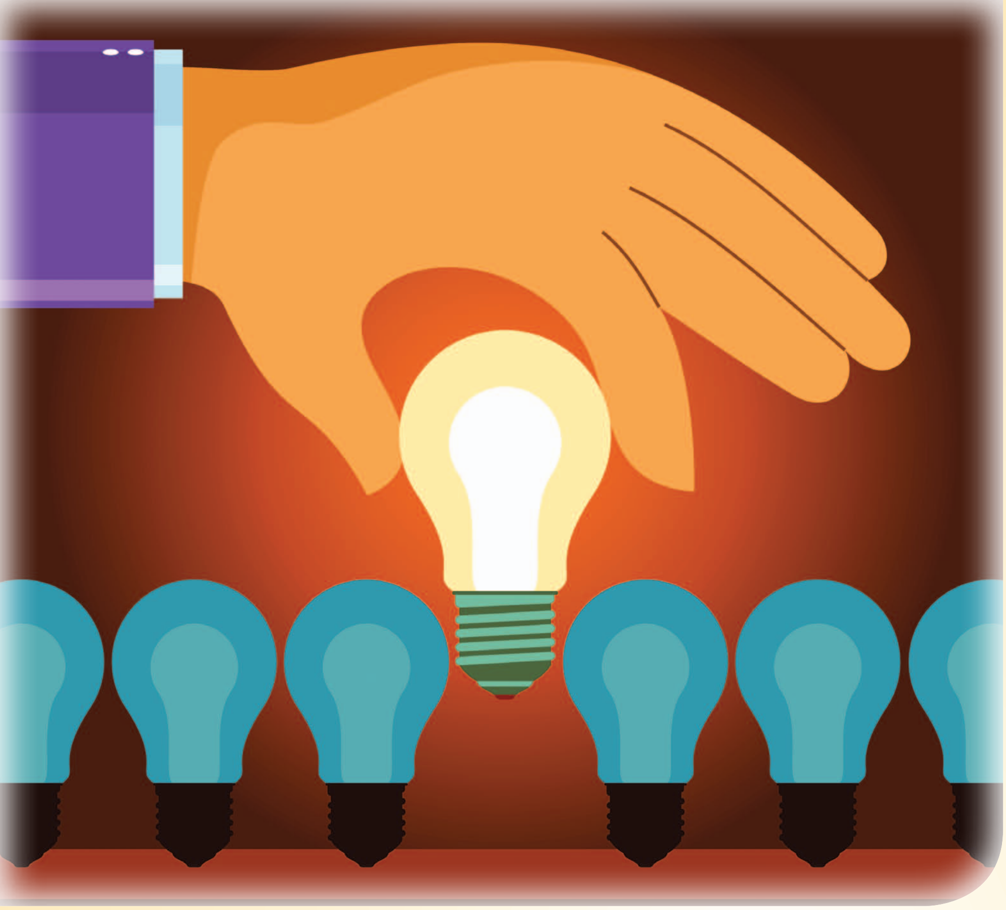

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Fragmented Policies and Regulations Lead to Significant Concerns

Flexibility Challenges for Energy Markets

By William D'haeseleer, Laurens de Vries, Chongqing Kang, and Erik Delarue

FOLLOWING THE FORMULATION OF CERTAIN strategic policy goals, such as reducing greenhouse gases (GHGs) and including more renewable sources (RES) as part of the energy mix in several parts of the world, the practical translation and actual implementation of these goals have led to the introduction of substantial volumes of intermittent renewable electric sources. Because affordable bulk storage for electricity is still lacking, demand and supply need to be (instantaneously) balanced. The resulting challenge that intermittent renewable power sources pose to the controllability of the electric power system requires greater flexibility from other parts of the system, as well as flexibility through interaction with other energy sectors such as the heating sector, the natural gas sector, and the transportation sector.

As a consequence, the overall energy system becomes increasingly coupled, which requires appropriate communication within and among sectors and flexible adjustment and collaboration capabilities, while certain technical, economic, and consumer comfort constraints are still satisfied. Because this coupling, which has a multitude of feedback options, makes the system less predictable (due to unexpected choices

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and decisions by market participants but also due to intrinsic nonlinear behavior), flexibility will undoubtably be key.

In this article, we address the influence of policy and regulation on the efficient behavior of energy markets and illustrate the extent to which implementation of some well-intended, but possibly conflicting, policy choices may result in inadequate or unexpected performance within the overall energy system. We further highlight the importance of flexibility and stress that more flexibility will be required in nonideal markets to avoid unanticipated side effects.

It is not our goal here to comment on or evaluate the legitimacy of certain strategic policy objectives in themselves; we accept these as the prerogative of policy makers. Rather, we focus on how these strategic objectives are translated into concrete implementation targets. The strong push for investments in certain intermittent renewables impacts the performance of other instruments (e.g., those aimed at CO_2 emission reduction) or electricity wholesale markets. By moving too rapidly (and, in so doing, ignoring system interactions), a variety of simple, well-intended (local) targets may counteract or even oppose each other with the result that, while some individual targets may be reached, the larger strategic objective will be compromised (or even missed) or only reached at an unnecessarily high cost.

We illustrate these issues using some typical examples drawn mainly from Europe, although interesting system interaction scenarios in the United States and China are also mentioned. We next identify several possible attractive avenues for fostering flexibility through robust policies and markets with the goal of mitigating the current situation and allowing for—and even promoting—better system integration in the future. Finally, we suggest some challenges, open questions, and research issues for policy and regulation.

The State of Play: The Need for Flexibility and Analysis

European Policy Measures and Their Consequences

An example of European energy policies with substantial side effects are the so-called 20-20-20 targets. The European Energy and Climate Change Package of 2008 was based on three main pillars, or targets, to be reached by 2020:

- ✔ 20% of overall consumed end energy to be from RES, with a subtarget for the transportation sector of 10%, mainly from biofuels
- ✔ 20% reduction of GHGs compared to 1990
- ✔ 20% more efficient energy consumption compared to a (then undefined) benchmark evolution.

Of these targets, the first two are mandatory; the last was implemented through a variety of individual binding "directives," including, among others, one for combined heat and power (CHP) and one for energy use in dwellings; but the overall target for the European Union (EU) was not compulsory. Before addressing the interaction effects among them, some comments on each of these targets are in order.

Renewable Energy Policy

The 20% RES requirement for the overall EU is distributed across member states (or, more simply, "countries"). After much effort on the part of the EU's administration services to devise a partitioning based on the "potential" to "produce" energy from RES, it turned out to be impossible to reach a consensus; thus, a purely administrative partitioning was determined, not at all related to "potential." Starting from the existing volume of RES in 2005 and taking into account a slight "bonus" for early starters, the overall gap of 11 percentage points for the entire EU was filled by allocating half of that to each member state (i.e., each country had to increase its RES contribution by 5.5% of its end energy). The second 5.5 percentage points were redistributed across countries based on gross domestic product (GDP) per capita, so that the richer countries carried the heaviest burden. As a result, some countries with substantial potential have a relatively small target, while (relatively rich) countries with almost no potential face a very challenging target. Note that the EU Commission documents refer to a "fair" and "effective" distribution; that it be "efficient" is not mentioned.

The three EU decision-making bodies (the Commission, the Council, and the Parliament) could reach no agreement on a mandatory European-wide renewables certificate trading system, by which green certificates would be exchangeable per country. Instead, every country was allowed to set up its own individual support scheme, resulting in local certificate systems in some countries (or even in parts of countries), feed-in tariffs, investment support, and tax breaks.

A number of cooperation mechanisms (statistical transfers, joint projects, and joint support schemes) made it possible to both offer flexibility and meet part of a member state's target through the deployment of renewables in another member state. However, all countries opted for their own targets. Statistical transfers may be used to "balance the books" at the end in 2020, such that a country not meeting its target by domestic production can buy a transfer from another country with a surplus. However, in the absence of a real market at the moment and uncertainty as to whether countries will meet their own targets, the use of these transfers is not actually stimulated and, therefore, remains uncertain.

The overall renewables target refers to a fractional requirement of 20% of overall end-energy consumption; the subtarget within the transportation sector is a minimum of 10%. Given the limited options for deploying renewables in the heating and cooling and transportation sectors, the electricity sector will need to compensate and so faces a much higher target. Moreover, low-carbon options often involve electrification, e.g., in the cases of electric vehicles and heat pumps. Together, the policy targets as laid out in the National Renewables Energy Actions Plans lead to an overall requirement for the electricity system of 33–34%, or about one-third of total European generation (in terms of electric end energy) by 2020. The implications will be different for different countries, depending on their individual required targets and actual potential. But a simple calculation for "average" countries in Europe for the period 2008–2020 leads to the following orders of magnitude observations, which may seem obvious but do not appear to be fully recognized by many policy makers.

- ✔ With respect to hydro power (except, perhaps, for some Eastern European countries), only small increases are possible, largely due to environmental constraints.
- ✔ As to biomass, the potential is difficult to predict because it competes with other types of land use and there are competing applications for biomass, such as transportation. In addition, its very environmental sustainability is questioned. Consequently, there is considerable resistance to its use for electricity generation.
- ✔ Wind, both onshore and offshore, is characterized by an "average" effective number of operating hours (ENOH) of about 2,200 h/a and about 4,000 h/a, respectively.
- ✔ Solar photovoltaics (PVs) has an "average" ENOH of about 1,200 h/a.
- ✔ All this leads to capacity factors (CFs) for intermittent sources (wind plus PVs) as follows:
  - onshore and offshore wind/CFs: ~ 25–45%
  - solar PVs/CFs: ~ 13–14%.
- ✔ To produce, say, 20 percentage points of the 34% electric end energy with technologies that operate only 13–14% and/or 25–40% of the time requires a large volume of installed power-generation capacity.
- ✔ If a good deal of wind and sun is available and demand is low (e.g., during weekends), situations in which too much electricity is produced will start to arise.
- ✔ However, sometimes (as in the case of a cold spell, such as the European winter of February 2012) with temperature inversion, little wind, and dark skies (hence, no PVs), at 17:00–18:00 h when peak demand arises in northwestern Europe, very little RES electricity will be produced, requiring classic thermal backup (as long as electric storage is not available in bulk quantities at affordable cost).

An example of what a residual load profile could look like for different levels of wind and solar PVs is presented in Figure 1.

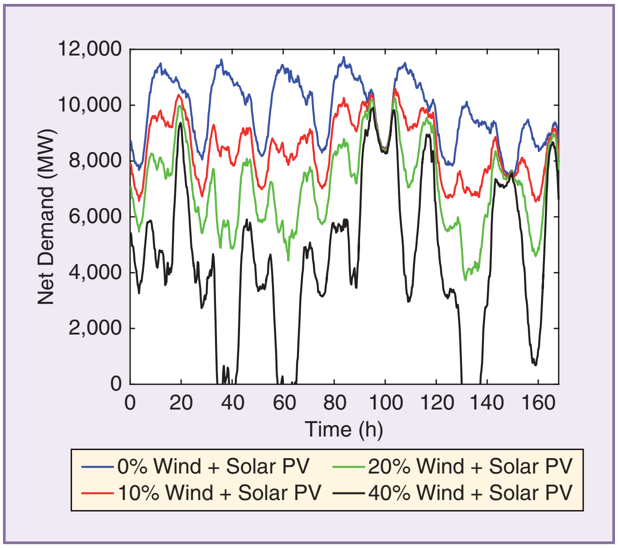

figure 1. Net electrical power load during one week for various fractions of annual renewable electrical energy generation. [Figure based on extrapolated data from Belgian Transmission System Operator Elia (2016), http://www.elia.be/.]

CO_2 Policy

The 20% GHG reduction target with respect to 1990 is recalibrated as a 14% reduction compared to 2005 (because of more complete and reliable numbers) and is then subdivided in two distinct categories (see Figure 2). The primary CO_2 policy instrument is the EU emission trading scheme (ETS), which represents roughly half of CO_2 emissions. It affects energy-intensive industries and the electric power and heat sector with an emissions cap that decreases by 1.74 percentage points annually up to 2020. The remaining non-ETS sectors (amounting to the other 50% of CO_2 emissions) mainly comprise transportation, the residential and service sector, small-and-medium-size industries, and agriculture. They work under a country allocation scheme that should lead to a 10% reduction compared to 2005. As for renewable energy, the European target for the non-ETS sectors has been split into individual member state targets (ranging from +20% to –20%), largely based on GDP per capita. It is important to understand that both reduction categories are independent of each other: for ETS, there is a cap-and-trade scheme among companies in the designated sectors (a market-based mechanism), while for the so-called "reduction sharing effort" in the non-ETS sectors, the countries are responsible (in the sectors mentioned).

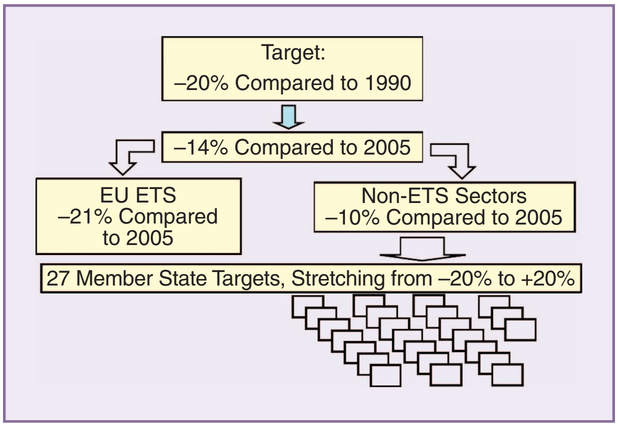

figure 2. EU GHG reduction targets following two separate philosophies, via companies (ETS) and by countries (non-ETS). (Source: Memo/08/34, "Questions and answers on the Commission's proposal for effort sharing," Brussels 2008.)

Energy Conservation

Although for almost half a century there has been much talk about energy conservation, energy savings, and energy efficiency, these appear to be among the most difficult targets to achieve. After an evaluation in 2014, the policy was adjusted, but it remains questionable whether the target will be reached. It is also not entirely clear what the reference baseline will be. In the future, it will become more important to clarify what is meant by the "consumption" of "prosumers" who avail of storage (which may have significant efficiency losses of up to 20–30%). Will only demand from the grid be taken into account?

Furthermore, many support schemes are not cost reflective, such as net metering and feed-in tariffs. The ensuing zero-marginal-cost electricity production by households may stimulate frivolous electricity consumption. As a consequence, the entire concept of "energy efficiency" may lose its meaning. In the end, a more generalized concept of "resource efficiency" (including investment cost, manufacturing and installation labor, fuel usage, if applicable, and so forth) and flexibility in consumption may be called for. This actually comes very close to the idea of economic efficiency, which may be the only meaningful concept in this context.

Interactions Among EU Energy Policies

The philosophy behind the cap-and-trade EU ETS system for GHG reduction is to achieve the GHG reduction target in the most economically efficient way by reducing first where it is cheapest. (Technically, this means that reductions take place first where the marginal abatement costs are the lowest.) The significant deployment of renewables (especially wind and PV solar, but also biomass) with substantial public support has not actually impacted Europe's CO_2 emissions, as they are capped under the EU ETS. They may have helped limit emissions to the cap, but at a cost higher than what could have been optimally the case. These RES will have reduced the CO_2 emissions in particular countries, but not in Europe as a whole. In other words, the avoided CO_2 emissions by these subsidized renewables will be replaced by other CO_2-emitting electricity-generating or heating sources in industry that also belong to the EU ETS. To put it bluntly, the subsidies for renewable energy have de facto made it easier for burning more fossil fuels in industry and coal for electricity generation.

A few comments are in order.

- ✔ The same reasoning would apply to new nuclear plants or to the enforced (premature) closure of coal-fired plants with regard to the local versus overall European CO_2 emissions.
- ✔ If the ETS had not existed, then the only alternative might be a combination of measures such as RES support and energy savings policies. Or, viewed positively, the contributions to reductions in CO_2 emissions due to RES may allow for a faster reduction of the CO_2 cap in the ETS.
- ✔ At present, the CO_2 cap in the EU ETS is hardly reached, and a massive surplus of allowances exists, so that it may seem that the previous reasoning is incorrect. However, if there were fewer emissions than emission allowances in the market, then the price of these allowances should be zero. The nonzero price means some actors withhold allowances from the market so that the cap of actually "available" allowances in the market is, indeed, be reached.
- ✔ A few exceptions exist concerning the statement made previously about CO_2 price reduction. For example, if locally produced PVs were to be dedicated to feed heat pumps that effectively replace (small-scale) CO_2-emitting boilers, then overall CO_2 emissions would be reduced, not because of the PVs as such—because that is still part of the electricity sector and thus the ETS—but because of the avoided CO_2 emissions for small-scale boilers, which belong to the non-ETS sector, as shown on the right-hand side of Figure 2. This last argument does not apply to industrial heat pumps replacing large industrial boilers because they are part of the capped ETS.

Another unintended policy effect is caused by the promotion of CHP, as the deployment of small-scale CHP units creates a shift of emissions from the ETS to the effort-sharing (non-ETS) sectors. While a small-scale CHP usually saves primary energy and replaces the emissions of a local boiler, the total amount of CO_2 emitted by the CHP is larger than the boiler only (due to the additional electric power that is generated). Because these local emissions are now part of the residential sector (the right-hand side of Figure 2), which is not under the CO_2 ETS cap, emissions have increased and are acting against reaching the country-specific target. The fact that emissions under the ETS have declined is not rewarded; it simply allows other facilities under the ETS to emit more.

For large-scale CHP, the same reasoning as for the RES deployment discussed earlier applies because the electricity sector and the heating sector for large industries are all part of the EU ETS (meaning that promoting large-scale CHP does not reduce GHGs in Europe because of the cap). Indeed, there are fewer emission certificates needed than would have been the case for separate generation. To summarize, it is almost certain that the promotion of CHP in both cases will turn out to have a higher CO_2 abatement cost than if only one GHG reduction target had existed; these cross-policy effects discourage an efficient route toward satisfying CO_2 targets.

The price evolution of EU allowances (EUA)— the price of CO_2 for the power sector and large industrial facilities—is depicted in Figure 3. As can be observed, the CO_2 price has fluctuated considerably over the past years and is quite low at the time of writing, around €5/ton CO_2 in the fall of 2016. The behavior we see in Figure 3—even with the sudden jumps and prices going to zero—is perfectly explainable by the modalities and rules of the setup of the EU ETS. This demonstrates that the short-term behavior of the trading scheme is as it should be. As an example, the zero price at the end of 2007 is due to the fact that the allowances were not "bankable" and became worthless as of 1 January 2008. For later periods of the EU ETS, the allowances were/are "bankable," avoiding "natural" zero prices but leading to a surplus of allowances after 2012 (the formal Kyoto period) as a consequence of the economic crisis, with much lower CO_2 emissions than originally anticipated and thus foreseen by the cap.

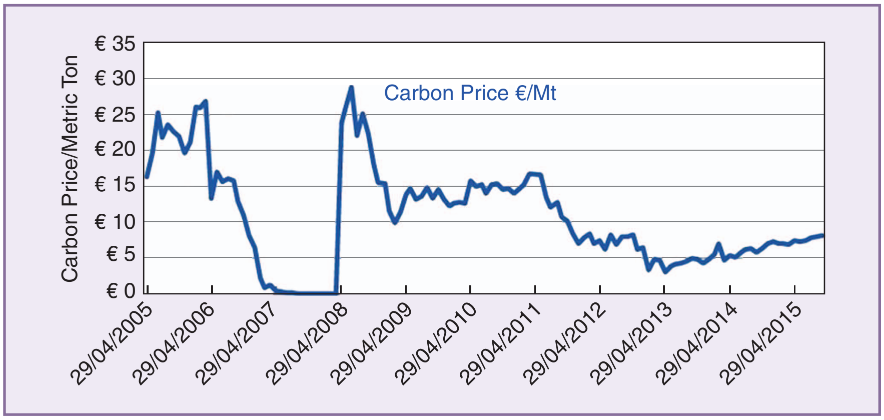

figure 3. The price of EU ETS allowances between 2006 and 2015. (Graphic based on data from Bloomberg and Sandbag, 2015.)

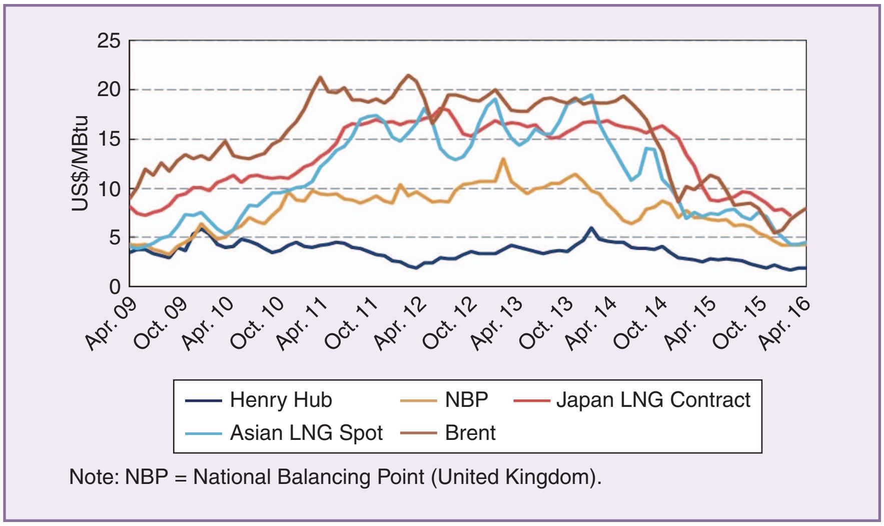

figure 4. The development of gas prices 2009–2016 in several parts of the world. Henry Hub represents U.S. prices, while NBP represents European prices. A comparison with Brent oil prices is given because many gas contracts in Europe are still linked to the price of oil. Since April 2016, prices have increased in the United States and worldwide. LNG: liquiefied natural gas. (Source: International Energy Agency, "Gas Medium-Term Market Report 2016," Organization for Economic Cooperation and Development, Paris, 2016.)

The current low CO_2 prices result from many factors, some of them straightforward consequences of the design of a cap-and-trade scheme, such as the lasting economic crisis (characterized by fewer emissions) that started in 2008, the inflow of international credits, and the bankability of allowances that makes the surplus persistent over time. However, in addition (and this is very important from a systems perspective) an unforeseen factor is that the EUA prices have been pushed further downward by the substantial injection of carbon-free renewables in the electric power sector. Indeed, the introduction of CO_2-free electricity has reduced the demand for allowances, leading to even lower prices (from which the other industries under the ETS umbrella and, e.g., coal-fired units have been able to take advantage). To put it in plain language, the high subsidies for electricity-generating renewables have not only not impacted CO_2 emissions on an EU level (because of the cap); they have affected the CO_2 prices, making it cheaper for CO_2-polluting units to generate electricity, while still meeting the cap.

To further understand the effects in the European energy markets, it is necessary to look as well at an important global interaction effect that, from an overall systems perspective, is of interest in its own right. The shale gas revolution in the United States—with gas prices that have been, and still are, much lower than in other parts of the world (see Figure 4)—has had (and is still having) consequences on the merit order for electricity generation in the United States, where cheap gas has pushed coal-fired units out of the merit order, leading to surplus coal on the world market and resulting, in turn, in depressed world coal prices.

A further system effect in Europe, then, is that marginal cost pricing in EU electricity markets is pushing efficient combined-cycle gas-fired units out of the merit order as a consequence of low world-market coal prices (due, as mentioned earlier, to the effects in the U.S. electricity market because of shale gas), the absence of a significant CO_2 price signal, and the injection of zero-marginal-cost renewable generation (see Figure 5). The green parties in the European Parliament wanted to see coal-fired units pushed off the wedge, which would have been the case if there had been no shale gas effect on coal prices and if there had been a high CO_2 price in the EU ETS.

From March 2007 until the summer of 2008, the wholesale forward electricity prices in the Central West European (CWE) region increased from about €50–55/MWh to €90–100/MWh, after which they gradually declined, with a small upsurge in the spring of 2011 (because of the Fukushima accident and related decisions in the German market) to levels of about €25–30/MWh in the late summer of 2016. The history from 2011 to 2016 is shown in Figure 6 for the CWE countries France, Germany, and the Benelux. This downward trend on wholesale prices makes it hard for gas-fired units to make a profit. Many European CCGTs are idle and being mothballed or kept as capacity reserve through a capacity remuneration mechanism. Discussions as to an appropriate market design ("energy only" versus "capacity remuneration schemes") are currently ongoing.

As previously mentioned, zero-marginal-cost renewables (with substantial installed capacity in many European countries) contribute to the downward drive of the wholesale electricity price when they are producing. In the absence of subsidies, this would lower their own return on investment, so they would effectively cannibalize themselves. Notwithstanding the decreasing wholesale prices, ordinary customers see increasing retail prices, mainly as a consequence of markups to recover the costs of the renewables' support schemes. This is illustrated in Figure 7 by the price evolution in Belgium for a typical end customer with annual consumption of 3,500 kWh. Similar retail price increases have occurred in Germany, with a steady increase from about €140/MWh in 2000 to a maximum of €291/MWh in 2014, after which there was a slight decline in 2015 and 2016 to about €287/MWh.

A final unintended effect of the rapid growth of renewables in the European system is that the convergence of cross-border electricity prices, which was a major goal of the common electricity market, has suffered from massive renewables penetration. The reason is that the cross-border high-voltage grid is currently not strong enough to ensure price convergence (i.e., by being congested) given the large differences in the generation portfolio among countries. This is illustrated by the decoupling indicated by the blue arrow in Figure 6 in the CWE market. The cross-border market coupling is very weak in situations of high wind and PV solar power production in this region. A further issue facing the European market is the so-called "loop flows" (or "unidentified flows") in certain regions such as CWE; these are also due to the lack of sufficient internal and cross-border transmission capacity.

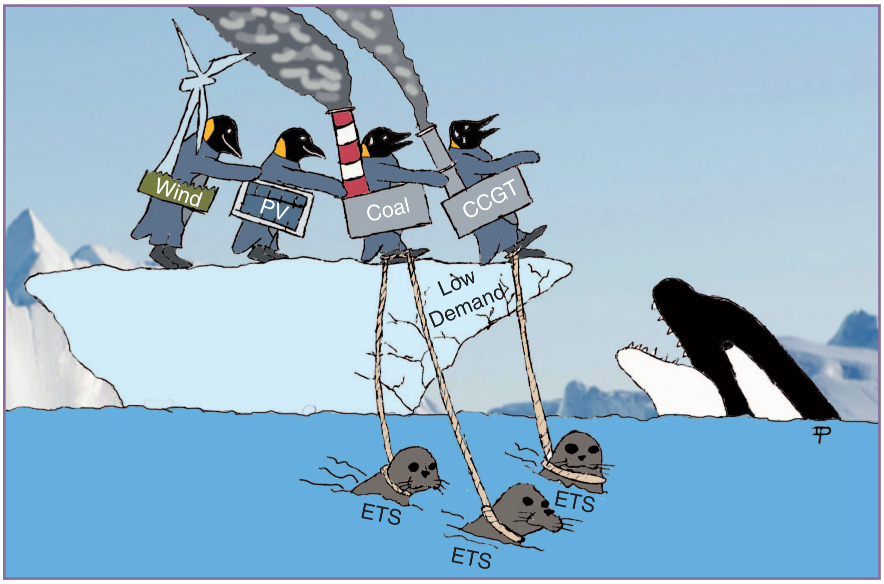

figure 5. The limited load factors of combined-cycle gas turbines (CCGTs) in Europe. Zero-marginal-cost renewables, together with low demand, push thermal generation units out of the merit order (or off the ice wedge). With current European gas and coal prices, and a very low CO_2 price penalty (via the ETS) represented by the baby seals, CCGT plants risk being the first victims. For higher CO_2 penalties, adult ETS sea lions would do the job of pulling coal-fired plants off the wedge first. For the relative coal-to-gas prices in the U.S., CCGTs are currently more economic regardless of a CO_2 penalty, and coal generation is the prey. In China, the demand is still sufficiently large so that coal and gas plants are called upon. (Image courtesy of D. Patteeuw, KU Leuven, used with permission; adapted image inspired by http://economicsforenergy.blogspot.be/2013/02/los-mecanismos-de-retribucion-de-la.html.)

The EU ETS Refurbished

Faced with low EUA prices in the ETS market, with the awareness that many market participants do not foresee a long-term CO_2 price and hesitate to make long-term investments, European policy makers have decided to "reform" the current EU ETS. Via market interventions (referred to as "backloading" and a "market-stability reserve"), a volume of allowances is being taken out of the market with the possibility of reintroducing them later. Whether these measures will alleviate the side effects of the EU energy and climate policies remains to be seen. The volume of the backloading seemed not to be large enough to have a significant impact. Whether the market-stability reserve will alleviate the side effects of the EU energy and climate policies remains to be seen; moreover, the final volume of allowances has not, in principle, been altered.

European Targets Toward 2030

In the meantime (and as part of European promises for the Paris COP21 Agreement), the EU has "sharpened" its commitments toward 2030—albeit in a different way, not unimportant for system interaction. The firmest commitment is the 40% reduction of GHGs with respect to 1990, again split between an ETS part with an annual reduction of 2.2 percentage points of the cap toward a 43% reduction with respect to 2005 and an EU-wide non-ETS part of 30% compared to 2005. For renewables, a 27% end-energy goal by 2030 has been set, as well as an efficiency-improvement goal of 30% compared to a baseline. For both the renewables and efficiency goals, there are no binding national targets but only an overall EU-wide objective.

Energy-System-Integration Observations on Flexibility Challenges in the United States and China

To illustrate that energy-system integration challenges are global and require careful consideration internationally, we include here a few examples from the United States and China. Due to lack of space, some elements/cases are only cited without a full discussion.

Energy-System-Integration Challenges in U.S. Markets

In New England, the past few winters have seen some interesting issues concerning the interaction between gas and electricity markets, whereby a stretched natural gas grid has translated into very high gas and electricity prices. Gas delivery occurs via pipelines from the south and the north (Canada), including liquefied natural gas (LNG). Average gas capacity suffices during the winter, but the system becomes stretched on particular peak-demand days. Because of market dynamics, which are a consequence of cheap shale gas in the United States since 2010 and thus gas price differentials with other world markets, LNG imports into New England have seen a reduction; therefore, the winter supply of LNG from Massachusetts's Everett and Canada's Canaport has declined, leading to winter spike prices. In addition, because of the low average U.S. shale gas prices and the environmental drive to reduce CO_2 emissions through the cap-and-trade system of the Regional Greenhouse Gas Initiative (RGGI), over the last few years natural-gas-fired electricity generation in New England has increased, along with the retirement of other plants (using nuclear, coal, and oil).

This increase in gas-fired electricity generation has, indeed, led to lower average wholesale electricity prices, but it transfers the physical stress in the gas network to fuel adequacy/reliability concerns in electricity generation, giving rise to sometimes very high electricity peak prices. The situation requires the full attention of system operators, who need to take both long-term and short-term actions, such as increasing gas-transmission capacity (although this is hampered by insufficient interest among capital investors desiring to see long-term commitments from shippers but hesitating to accept the financial liability, as well as by lack of public acceptance and complicated permitting), increased flexibility on the electricity-generation side by means of multifuel units (gas and oil), and demand–response programs, among others.

On the other side of the United States, major energy-system integration problems arose in 2000–2001 in California (later referred to as the "California electricity crisis"). As the first state to fully introduce liberalized markets (often inappropriately called "deregulation"), California experienced a combination of events and circumstances that led to the world's richest country's richest state having to "turn off the lights" (actually, cut all power—called *rolling blackouts*) to keep the system from collapsing. There are many reasons for this then unprecedented failure, but it was clearly a mix of many interacting factors, conditions, and regulations. We mention, among others, a regulated

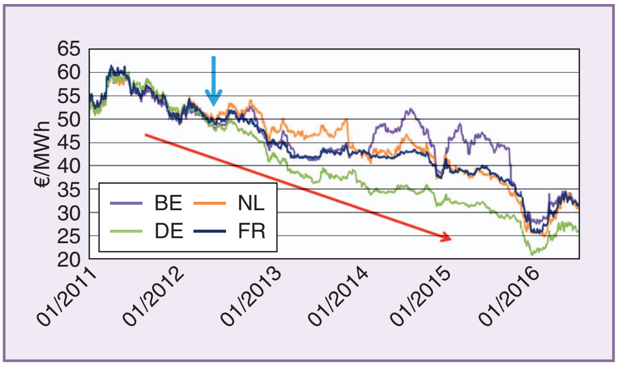

figure 6. The decreasing tendency of forward electricity wholesale prices in the CWE market (France, Germany, and Benelux). [Source: Commission de Régulation de l'Électricité et du Gaz (CREG), Belgium, Sept. 2016. The arrows have been added by the authors.]

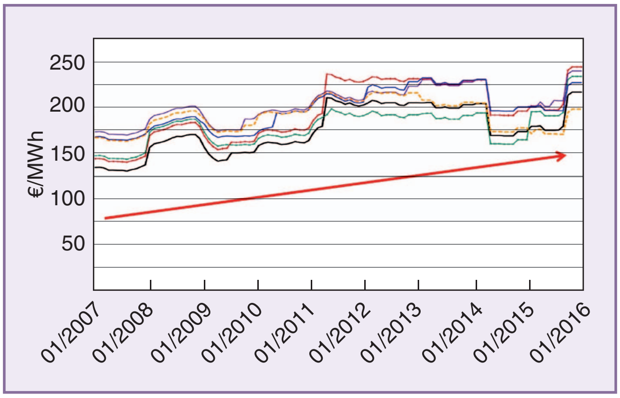

figure 7. Typical retail electricity prices in Belgium for average customers with annual consumption of 3,500 kWh/a. The different curves are for the same supplier (Electrabel) but different distribution-grid regions. The dip from April 2014 through September 2015 is somewhat artificial; it is due to a temporary reduction of the VAT from 21% to 6% and back (by different governments). (Source: CREG, 2016.)

cap on the retail price of electricity, while gas prices—and, thus, wholesale electricity prices—began to rise; increasing electricity demand; reduced imports of electricity from other states; a slowdown in the pace of granting permits to build new electric power plants, as a result of environmental regulations; and market-power problems, including market manipulation and even fraud. This crisis cost the California economy (consumers, shareholders, taxpayers, and laid-off employees, among others) several tens of billions of dollars and led to the drastic scaling back the energy-market liberalization philosophy in the state. Policy and regulation were major factors in the development of this crisis. In this case, system studies would certainly have pointed to the challenges and bottlenecks emerging from several types of interactions; such studies would likely have shown where greater regulatory flexibility could have alleviated, if not entirely avoided, the dire consequences.

Fast-forward 15 years, and California is preparing for another such energy-system challenge, with scientific–technical discussions of system integration currently ongoing to ensure that the necessary actions, preparations, and precautions are taken on the technological side; the economic, financial, and market environment; and an appropriate regulatory framework. With the rapid growth of PV solar capacity and given no corrective flexibility measures, it can be expected that, around 2020, stiff ramping rates by the non-PV remainder of the generation system—of the order of 13 GW in 3 h—will have to be coped with. This is illustrated by the so-called "duck curve" published by the California independent system operator CAISO, as shown in Figure 8.

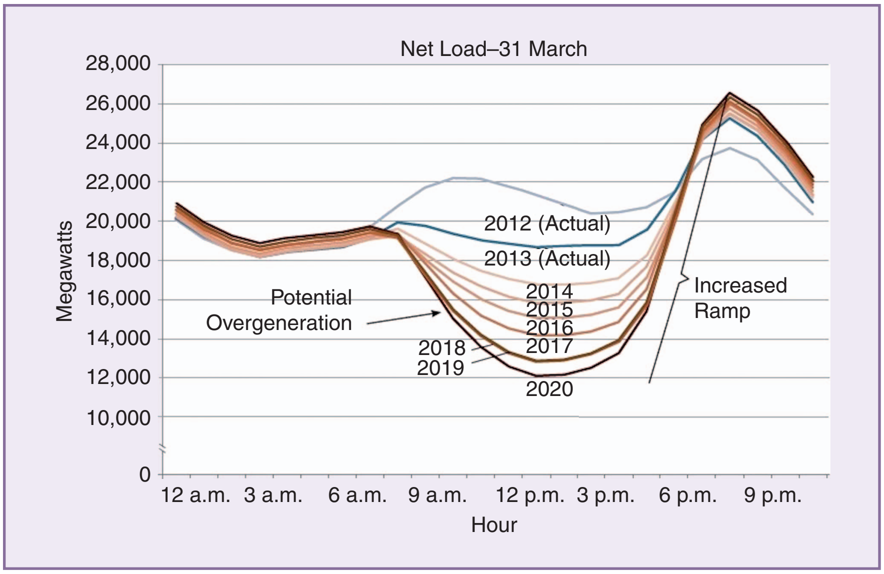

figure 8. The duck curve illustrating the "net" or "residual" load to be covered by the non-PVs remainder of the electricity system in California. After the sun has set in the early evening, electricity demand increases for air-conditioning, lighting, and cooking needs, leading to big ramping rates to meet electricity demand. (Source: CAISO.)

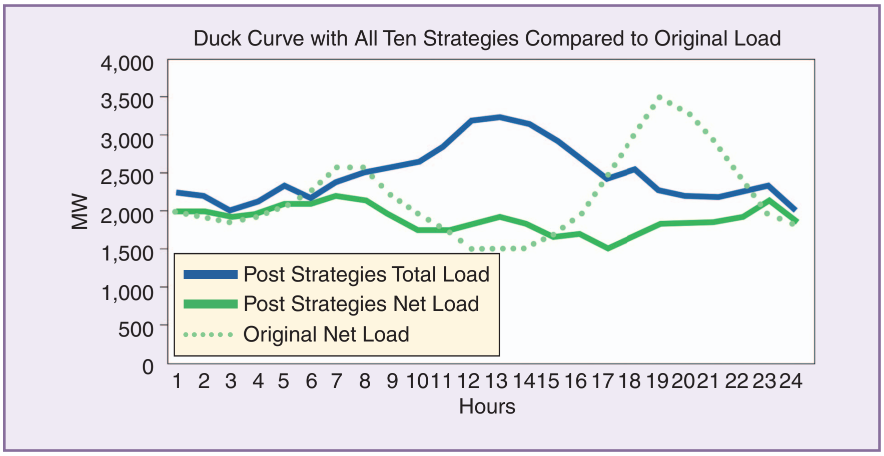

figure 9. Avoiding stiff ramping rates shown in Figure 8 (dotted curve) can be accomplished by well-chosen strategies to level off the net load (green curve). (Source: J. Lazar, *Teaching the "Duck" to Fly*, RAP, 2016.)

In reaction to this duck curve, studies have been initiated to demonstrate that appropriate flexibility measures, dealing with both the total demand and the net or residual demand, can "teach the duck to fly"—basically showing that stiff ramping rates can be avoided (see Figure 9). Whether the measures currently suggested will actually work remains to be seen, but the fact that the discussion has started is encouraging; by the time needed, appropriate soft solutions may be implemented.

Energy-System-Integration Challenges in China

China also faces considerable challenges in terms of energy-system inflexibility, especially for the integration of renewable energy. Renewable energy is growing in a nonmarket environment, where wind and solar generation is at the top of the merit order. However, large amounts of renewable energy are still being curtailed or dumped, despite the fact that it is scheduled with first priority. This is because it is obligatory for conventional generating units to offer flexibility (by reducing their output) but without any financial compensation. Because the flexibility is not priced in China, these conventional units do not have any incentive to improve their ability to provide grid flexibility.

However, China has instituted many ongoing attempts over recent years to meet the challenge of inflexibility. The government has been making great efforts on pilot projects and corresponding policies called the "Energy Internet," which consists of four major parts:

1) integrating multiple energy system (e.g., electricity, heat, and gas)
2) establishing a cyber-physical system and making use of big data toward a smarter energy system
3) deregulating the energy market
4) interconnecting power grids in multiple areas.

One of the most effective policies is the "deregulation" of the electricity market. Take the ancillary market for peak shaving in northeast China as an example. Conventional units, which offer flexibility for wind power, are now paid for by wind farms and other inflexible units. This policy has achieved great success as more than 77% of conventional units now offer a lower minimum output level than before the policy was established.

In addition, China is trying to solve electric power system flexibility issues by coordinating multiple kinds of energy. A typical example is the inflexibility caused by the linked electricity and heat production from coal-fired CHP plants. Due to the inflexible operation of the CHP units when forced to generate large amounts of heat, they also produce electricity so that the room left for wind generation is small, leading to wind curtailment. This also gives rise to the problem of severe air pollution, as coal-fired CHPs are notorious for large emissions of NOx, SO_2, and other pollutants. To avoid so much wind curtailment, as well as pollution, the government initiated a program called "heating by wind" to coordinate the electric power and heating systems. This program makes use of clean wind energy to serve heating demand, thus leaving more room for wind integration. However, it should be noted that "heating by wind" still needs special price policies in a nonmarket environment because the current central heating price from conventional CHP is only one-half to one-third the cost of the electricity heating. The wind farms that participate in the heating need to sacrifice some of their profit to make "heating by wind" economically acceptable to heat consumers. Many policy-related efforts are still expected to make wind power a cheap source for heating.

Regulatory Encouragement for Flexibility

Flexibility Options: The Possibilities

In this context of a fragmented and imperfectly aligned set of policy instruments, policy makers now face the challenge of encouraging flexibility options to improve overall energy-system integration and mitigate side effects. Flexibility means exist within energy sectors (in particular, the electric power sector), but it is also important to encourage interactions among different energy-carrier sectors (such as electricity, gas, liquid fuels, heat, and cooling) and end-energy sectors (such as industry, residential and service sectors, and transportation). We mention here the known flexibility possibilities (mainly originating in the electric power sector because of the absence of massive cheap electricity storage).

The most straightforward flexibility options are

- ✔ utilizing backup reserves from flexible dispatchable thermal plants (upward and downward)
- ✔ providing electric storage (short-term storage via multiple battery units; intermediate storage via pump-hydro storage; and long-term, large-scale storage via, perhaps, power to gas)
- ✔ expanding transmission grids
- ✔ encouraging active demand response or participation by customers (industrial, commercial and service sectors, and residential retail customers)
- ✔ encouraging interaction with other carriers/sectors (heating, transportation, etc.)
- ✔ curtailing superfluous RES production (because high "power" injection peaks can be avoided at the relatively minor cost of a bit of curtailed "energy"), which means that priority access for renewables should be reviewed and become part of a system-wide perspective.

A major question still to be addressed is how market designs, policies, and regulation affect these flexibility options.

Enabling Flexibility Options: Challenges for Policy and Regulation

As has been illustrated previously, policy and regulation often have unexpected—and, possibly. counterproductive—effects on overall system performance. It should, therefore, be a part of good policy making to first study the overall system by modeling its different parts, with much emphasis on the interactions among the different subparts as well as among different policies. As the behavior of the system—including the not-always-predictable behavior of customers and other market actors—will be strongly nonlinear, careful analysis is called for, well beyond the standard isolated "impact assessments."

First and foremost, policy makers should encourage correct system cost evaluation and, consequently, appropriate pricing to guide consumers. As a general rule, market requirements should provide sufficient freedom for market participants to play their roles while eliminating any loopholes overly creative individuals or organizations can abuse; this means that carefully considered boundary conditions and/or justified constraints must apply. Also as a rule, varying prices can influence customer behavior, and real-time pricing can steer markets in a desired direction. All customers connected to the electric grid need to contribute to its costs. Following the principle of cost-reflectiveness, a grid-connection tariff should be based (at least partly) on the connection capacity or maximum annual capacity used (in kW) rather than on energy consumption (in kWh). This applies, in particular, to customers with much self-generation.

An example of European energy policies with substantial side effects are the so-called 20-20-20 targets.

A proper price signal is key for good, active customer-demand participation; however, practical participation will likely require the help of aggregators, who will need to be allowed the freedom to act in the market and whose role should be facilitated by distribution-grid companies (which constitute a natural monopoly).

Particular attention should be paid to the challenging circumstances of a multitude of prosumers with rooftop PVs (possibly) assisted by local battery storage. What will be the appropriate pricing scheme for feeding back to the grid? Guaranteed feed-in tariffs and net metering do not appear sustainable in the long run. Also in this case, the intervention of aggregators, perhaps also employing local storage for grid ancillary services, may be called for. In this regard, specifications on products for ancillary services should be made as independent as possible of technologies, allowing for an open competition among providers of such services (coming from supply, demand, and/or storage).

One of the cheapest means to integrate intermittent renewables over large geographical areas is by allowing new high-voltage lines to be constructed (be it in open air or as cables, as ac lines, or as high-voltage dc). The crucial stumbling block of delayed or denied permits must be overcome. This is a typical case in which the collective benefit may supersede individual or personal desires (whereby the enforcing authorities must appropriately compensate the disadvantaged). The same applies to natural gas transmission grids. If there is insufficient grid capacity, there may not be enough transport of gas during heavy winter conditions (as in New England in the United States in 2014–2015) or because of geopolitically-inspired cuts (as on New Year's Day of 2006 and 2009 in Europe), with serious consequences for electricity generation and heating. Gas-compressor stations should operate bidirectionally where doing so can improve security of supply; in addition, also for gas-infrastructure projects, permits should be granted in a timely fashion.

Policy makers should anticipate (or avoid) conflicting or self-neutralizing targets, as we demonstrated in our discussion of the 20-20-20 case in Europe. One should identify the main problem (e.g., climate change and CO_2 emissions) and then impose one clear target. Because CO_2 emissions lead to external costs, these costs should be internalized, meaning that some sort of CO_2-related penalty on all CO_2-emitting sources may have to be considered (either by a simple CO_2 tax or via a single cap-and-trade system, with perhaps a CO_2 budget for all emitting entities, even up to the level of households). Renewables and CHP should take advantage of that simple CO_2-reduction scheme in a natural way, without extra (likely distorting) support mechanisms.

Through the interaction of the electric power sector with the thermal sector, ample attention is currently devoted to thermal grids (of the third and fourth generation). But a careful regulatory framework will be needed to guarantee a return on investment for the thermal grid and for customer satisfaction, especially in areas where natural gas distribution networks are also available. Who will own the thermal grid? Will it be a natural monopoly, with distribution/independent system operator characteristics? Will customers be forced to connect to thermal grids (and mothball efficient gas-fired condensation boilers)? Will there still be the freedom to install heat pumps and/or CHPs?

Transportation will likely see changes over the coming years. Whether very efficient combustion engines will survive or will be replaced by hybrid or battery electric vehicles or by hydrogen-fed-fuel-cell vehicles—and over what period—remains to be seen. It must be noted that in many countries, car engines already pay a stiff (CO_2) penalty because of high excise taxes (especially in Europe), meaning that cheaper options are available elsewhere in the energy economy. Also, current, seemingly cheap electric charging may change in many countries when authorities start levying excise taxes on electric charging (to compensate for missed revenues due to fewer fuel-consuming vehicles). Will such excise taxes be charged for self-generated electricity by prosumers? In the end, the revenue books of governments must balance the budget; it is important that energy-related taxes be imposed wisely without creating or aggravating side effects.

Long-term storage of electrical energy still needs to be resolved. A possible attractive candidate might be the so-called power-to-gas route, whereby "superfluous" renewable electricity is converted to hydrogen (via electrolysis) and then made to react with CO_2 (which, in turn, is captured somewhere) to produce "renewable methane." It is technically possible, but the overall cost picture in a market environment (and when all investment costs are appropriately accounted for) is not yet fully clear. In any case, "renewable methane" will have to compete in the common natural gas market.

As alluded to with regard to Figure 5, appropriate market designs will have to be developed, opting for capacity-remuneration mechanisms or energy-only markets for dispatchable units or other means of flexibility to provide the required balancing. If no satisfactory solution is found, there will be no firm means available. Conversely, remuneration for these balancing means must be fair and not over-reward them.

Finally, careful thought will be necessary for proper price-setting schemes in a (possibly) future all zero-marginal-cost generation environment, complemented by storage with finite losses. Appropriate market rules should allow prices to be based on the opportunity cost as seen by the market. Artificial pricing schemes will likely lead to economic inefficiencies.

Conclusions

The current set of energy policy instruments is characterized by varying degrees of effectiveness, and policies sometimes counteract one another. The full system costs of the resulting tangle of incentives often are not fully accounted for, and they are not well balanced and nontransparent, challenging system efficiency. Indeed, because of interacting policy choices and regulations, many energy markets are distorted by considerable hidden system costs, eventually to be paid by consumers, taxpayers, or shareholders (which often include pension funds). Because of a lack of economic bulk electricity storage, interactions within the electricity system and with other sectors, such as natural gas and heating, require increased flexibility for smooth operation and cost-effective performance.

A well thought-through and consistent policy framework is called for, ideally with some stability in the regulatory framework (and certainly without retroactive measures). Key will be clear, transparent, but comprehensive regulation, whereby market players (such as aggregators and energy-service companies) have the freedom to provide the services requested by customers. Furthermore, targets and specifications should be set to be as independent as possible from specific technologies, so markets can decide how to reach a certain target or meet a certain specification (whereby both supply- and demand-side actions, combined with storage, can truly compete across system levels and borders).

In any case, because of the complexities we have described, quick-and-dirty regulation will likely backfire, and even simple, positive-seeming measures may lead to unforeseen side effects because of negative feedback and system interactions. Policy makers are, therefore, advised to perform careful system-wide studies to simulate and understand the system's behavior and adjust draft legislation and/or regulation before any rules are implemented.

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