

Clean, affordable and reliable: Getting Spain's power system transformation right

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Executive summary

Spain has set clear and appropriate targets for increasing renewable energy sources in the power sector over the coming decade. The country has committed to some of the most ambitious renewable energy targets across Europe. According to its National Energy and Climate Plan (NECP), it aims to double the share of renewables in the electricity mix from around 37% in 2015 to 74% in 2030 while also increasing electrification of its energy system. Solar and wind power are expected to contribute the most towards achieving these targets.

As the use of renewable energy grows within the system, a question arises about whether the current market is fit-for-purpose to integrate these renewables and keep the lights on cost efficiently. Experience from across the world demonstrates that transitioning power systems must adapt to these new conditions to reap the full benefits of the transition for consumers.

This paper provides a review of the resource adequacy outlook in Spain and suggests measures that the country can adopt to achieve the desired levels of reliability at least cost while increasing the levels of renewables in its system. The paper focuses on the Peninsular Spanish system (hereafter referred to simply as Spain).²

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² Our paper hasn't considered the situation in the Balearic and Canary Islands nor in the autonomous cities of Ceuta and Melilla, that are effectively islanded systems.

Our key conclusions are:³

- The Spanish market suffers from an acute overcapacity problem, which is expected to continue at least in the medium term. The risks to security of supply are negligible even under the most extreme conditions.
- Spain needs to retire plants to establish an economically sustainable power market. Several coal plants are due to shut down in the short term, but even this would be insufficient. An incremental step in this direction, could take the form of a formal coal phaseout for the medium term. This would better align the resource mix with the Member States' emission targets, allow more flexible resources, including lower-cost demand-side flexibility options, to actively engage in the market and increase certainty and confidence in the market about the direction of travel.
- The resource adequacy outlook clearly demonstrates there is no need for an intervention in the market in the form of a Capacity Remuneration Mechanism (CRM) to support security of supply. Fossil-fuel generators in particular have substantially benefitted from the implementation of CRMs for over a decade. These mechanisms have retained unneeded fossil-fuel plants in the system, undermining the effectiveness of the wholesale energy market and burdening consumers with higher electricity bills. The adoption of a CRM, including any delay abolishing existing mechanisms, would be counter to the recently adopted Clean Energy for All Europeans (CE4All) package. It would only exacerbate market distortions by needlessly prolonging the overcapacity problem.

Looking into the future, flexibility will be the key to decarbonising the power system and meeting reliability targets, at minimum cost. The power system will need to be flexible enough to address volatility in net load (e.g., a rapid change in supply) over different time frames. There are several ways to achieve the required flexibility in the system — an improved wholesale energy and balancing services market design, the further integration of the Spanish market into the continental market and an enhanced role for demand response:

- The first priority for Spanish policymakers should be the implementation of administrative shortage pricing in the balancing market that will help reveal the true marginal cost of energy. In addition, introducing locational signals in price formation will support the development of flexibility, encourage new investments where most needed and help address grid congestion cost efficiently.
- Spain remains one of the most electrically isolated countries in Europe, with limited interconnection with the rest of Continental Europe. The country has commendably set plans to expand its interconnection capacity with the rest of

³ Research and analysis for this paper was undertaken prior to the COVID-19 pandemic. We expect that the conclusions of the paper remain valid even after considering the potential impacts of the pandemic. In fact, the impacts of the pandemic could reinforce some of the conclusions, for example magnify further the overcapacity problems in Spain, due to the potential reduction in demand.

Europe through France. At the same time, it will be important to ensure the economic potential of this capacity is fully utilised. Currently, interconnectors are underutilised, and there is significant scope for improvement. The country should also continue with its integration into the single electricity market across all time frames.

- The potential for cost-effective flexible demand must be further exploited, beginning with the elimination of surplus, uneconomic generation. While system operators traditionally forecasted demand and scheduled supply to meet it, the challenge will increasingly be to forecast variable power generation and schedule demand to lower costs and reduce curtailment. In this new context, it will be important to ensure that time-varying retail pricing — which is relatively well developed in the country — delivers efficient outcomes, and explicit demand response is enabled to participate in all markets with rules that facilitate its development. Spain could also improve the design of its network tariffs to further support cost-effective demand-side flexibility.

Introduction

Context: Spain's National Energy and Climate Plan

Spain has set one of the most ambitious National Energy and Climate Plans (NECPs) across Europe as part of the newly adopted governance regulation of the CE4All package.⁴ The country is planning to substantially increase the share of renewable energy in the electricity mix and reduce the greenhouse gas (GHG) emissions from the sector. The power sector is the leading sector across the economy in the reduction of GHG emissions, with a projected decrease of around 72% from 2015 to 2030. This corresponds to a doubling of renewables generation, from around 37% in 2015 to 74% in 2030. Final electricity consumption is projected to increase slightly in the same period (around 4% in the target scenario), driven mainly by greater transport sector electrification.⁵ It is an increase that is partially offset by greater efficiency across the economy. The plan is consistent with long-term objectives, out to 2050, including a goal for a fully decarbonised power sector by mid-century.

The key technologies driving renewable energy production growth are onshore wind and photovoltaic solar. The installed capacity of the two technologies is projected,

⁴ Spain is currently in the process of finalizing its NECP for 2030. A second draft of the plan was published for consultation in the framework of its strategic environmental assessment, initially until 25 March 2020. However, as a consequence of the enactment of Royal Decree 463/2020, declaring a state of emergency due to the Covid-19 pandemic, the initial deadline was suspended until the state of emergency was lifted. On 31 March 2020, the Spanish government sent the second draft to the European Commission, subject to changes that may eventually arise from its strategic environmental assessment. The second draft has retained the same key targets (e.g., renewable energy targets), although there are some differences in the details of the plan. See Spanish government. (2020, 20 January). *Integrated National Energy and Climate Plan 2021-2030*. https://ec.europa.eu/energy/sites/ener/files/documents/es_final_necp_main_en.pdf

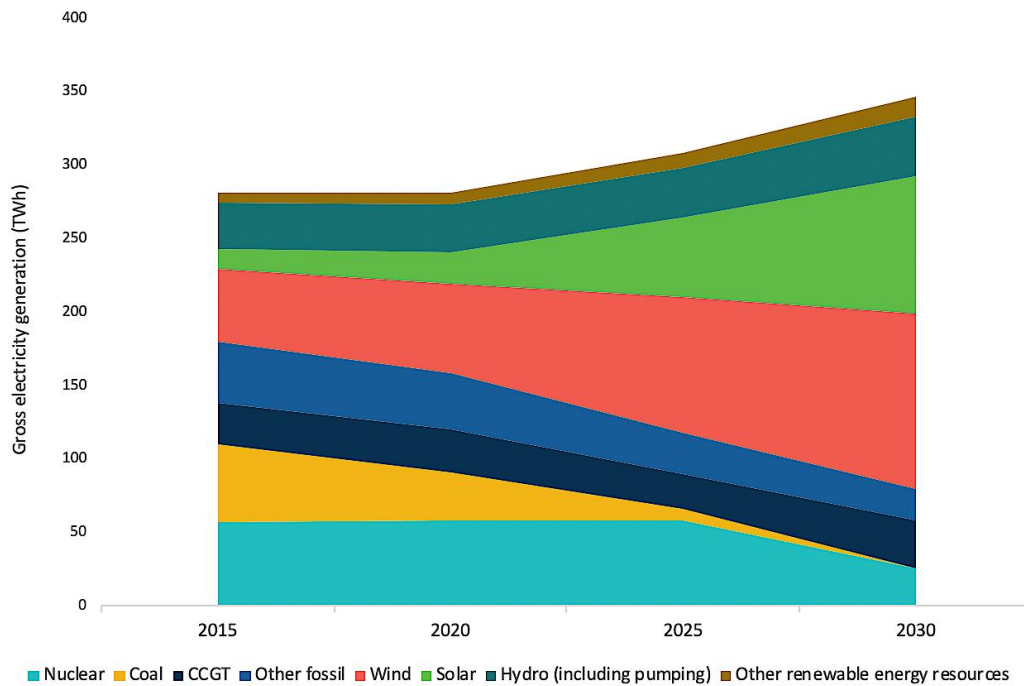
⁵ The Spanish NECP also projects a significant increase of electricity exports in the time frame of the analysis. Net exports amount to 40 TWh in 2030. Spain was roughly importing as much as it was exporting in 2015.

respectively, to more than double (from around 22.9 GW to 50.3 GW) and to increase almost sevenfold (from 4.9 GW to 39.2 GW), from 2015 to 2030.⁶ Wind is projected to contribute just over a third of total domestic generation in 2030 (or 120 TWh from a total of 346 TWh) and solar photovoltaic around an additional 20%. Other renewable energy sources, such as solar thermoelectric, hydro and biofuels, contribute to a lesser extent in the electricity mix. The growth of renewables is complemented by a reduction of electricity generation from fossil fuels and nuclear energy. In the target scenario, coal generation will decrease steeply in the first half of the decade, until it is phased out by 2030. Nuclear generation will decrease by more than 50% between 2015 and 2030, from 57.2 TWh to 25 TWh. At the same time, generation from combined cycle natural gas plants will broadly remain the same (around 33 TWh in 2030). Other fossil fuel technologies, like cogeneration or open cycle gas turbines, will have a relatively minor contribution to the generation mix. Figure 1 presents the evolution of the generation mix in the target scenario.

The NECP also contains a series of objectives and measures to secure electricity supplies, particularly given the level of penetration of variable renewables in the system. Some of the key strategies include:

- The expansion of Spain's interconnector capacity, primarily with France, as well as the better use of existing interconnection by reducing barriers to trading.
- Stronger regional cooperation as established in the recently adopted risk preparedness regulation.
- The development of storage technologies in the form of pumped-storage hydro and electric batteries, as well as the active participation of demand.

⁶ New wind and solar power installations have accelerated in the past couple of years (around 2 GW of wind and 3 GW of solar from 2018 to 2019), following a hiatus earlier in the decade. Red Eléctrica de España. (2020, 13 February). *Series estadísticas nacionales*. <https://www.ree.es/es/datos/publicaciones/series-estadisticas-nacionales>. In addition, a significant number of wind and solar projects are in the pipeline with 102 GW of projects having received grid access permits (and an additional 30.6 GW of projects whose grid access permits are currently being processed). Securing a grid access permit doesn't mean that a project will proceed, but the number of applications gives an indication of how lively the renewable energy market is in Spain. Red Eléctrica de España. (n.d.) *Actividades: Acceso, conexión y puesta en servicio*. <https://www.ree.es/es/actividades/acceso-conexion-y-puesta-en-servicio>

Figure 1. Gross electricity generation in the target scenario of the Spanish NECP

Source: Adapted with data from Spanish government. (2020). *Integrated National Energy and Climate Plan 2021-2030*.

Scope of paper

The goal of this paper is to address the question about how Spain can achieve its reliability targets cost effectively while at the same integrating increasing amounts of variable renewables. For this purpose, we review the resource adequacy outlook for Spain, aiming to identify whether the country is facing any security of supply concerns in the short-to-medium term. We then provide recommendations about market reforms the Spanish authorities could consider for integrating increasing amounts of renewable energy resources into the system and ‘keeping the lights on’ at minimum cost over the long term.

Resource adequacy in Spain

In the following section, we review the outlook to electricity security of supply in Spain. We first take a look at the historical evolution of the risks, followed by a review of the outlook towards 2025.

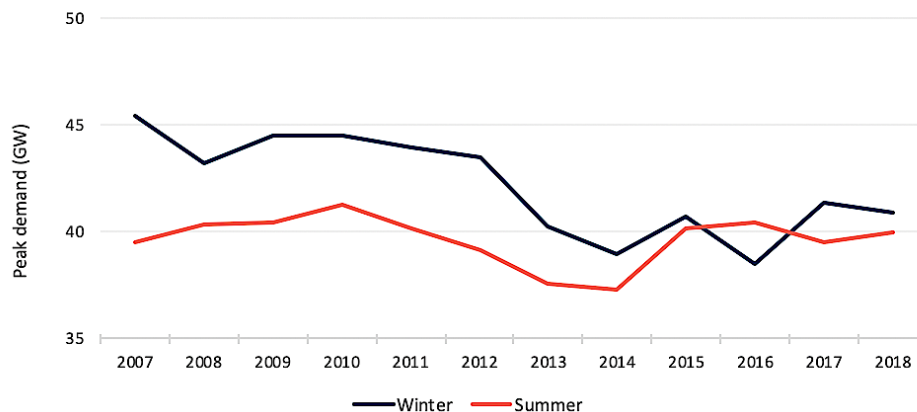
Historical evolution of risks to security of supply

The Spanish power system, similar with other systems in Europe, featured a significant overcapacity problem (i.e., a large surplus of supply over peak demand) over the past decade, from 2009 until 2018. While Spain went into 2009 in overcapacity, developments mainly on the demand side exacerbated the problem.

Peak demand dropped over this period and is still significantly lower than the highest demand ever experienced in Spain. This could be attributed to the financial crises and greater efficiency across the economy in this period.⁷ Figure 2 presents the peak demand from 2007 to 2018 for the winter and summer seasons. Peak demand has normally occurred in the winter season, although the gap between the winter and summer peaks has narrowed to the extent that the two were almost at the same level in recent years.⁸ In fact, summer peak demand was higher than winter peak demand in 2016. Peak demand in 2018 was around 41 GW, still about 4.5 GW lower than the all-time peak demand that occurred in 2007. It should be noted that these demand levels are the realised ones and aren't corrected for weather effects.

In contrast with the evolution of peak demand, annual demand has remained broadly flat across the past decade, as depicted in Figure 3. Annual demand in 2018 was slightly higher than the annual demand of 2009 by around 0.3%. Annual demand decreased significantly by 2014 before following an upwards trend. Although it is difficult to draw any conclusions about the relationship between annual and peak demand based on this information, it is worth noting that winter peak demand has followed a different trend to annual demand from 2014 onwards. The evolution of summer peak demand more closely resembles that of annual demand. Some of the potential reasons could include the effects of climate change leading to warmer winters and summers, changes in the nature of demand and other factors.⁹

Figure 2. Peak demand evolution in the winter and summer season from 2007 to 2018 (GW)

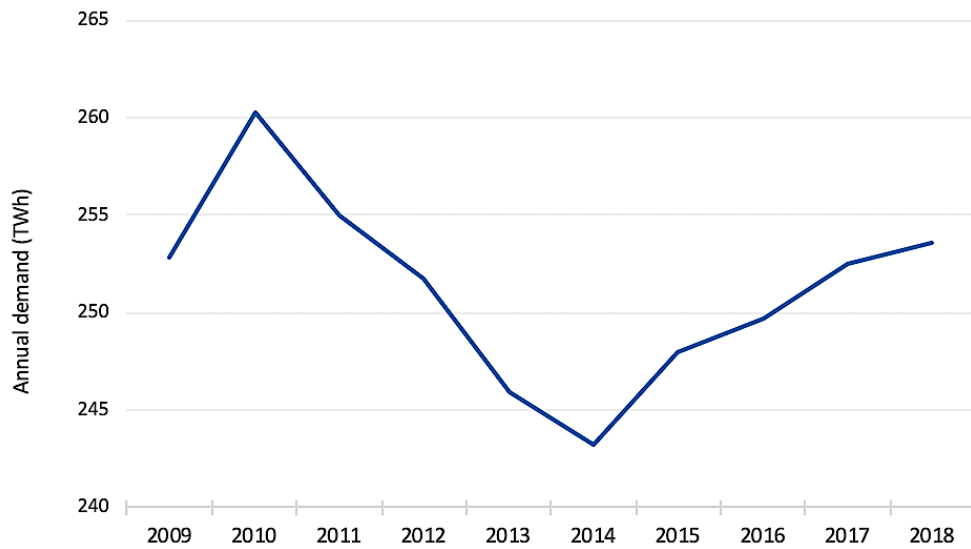


Source: Adapted with data from Red Eléctrica de España (REE). (2019). *Spanish Electricity System 2018 Report*.

⁷ IDAE. (2018, July). *Energy efficiency trends and policies in Spain*. Instituto para la Diversificación y Ahorro de la Energía. <https://www.odyssee-mure.eu/publications/national-reports/energy-efficiency-spain.pdf>

⁸ The gap between the two has decreased from 4 GW in 2009 to 1 GW in 2018.

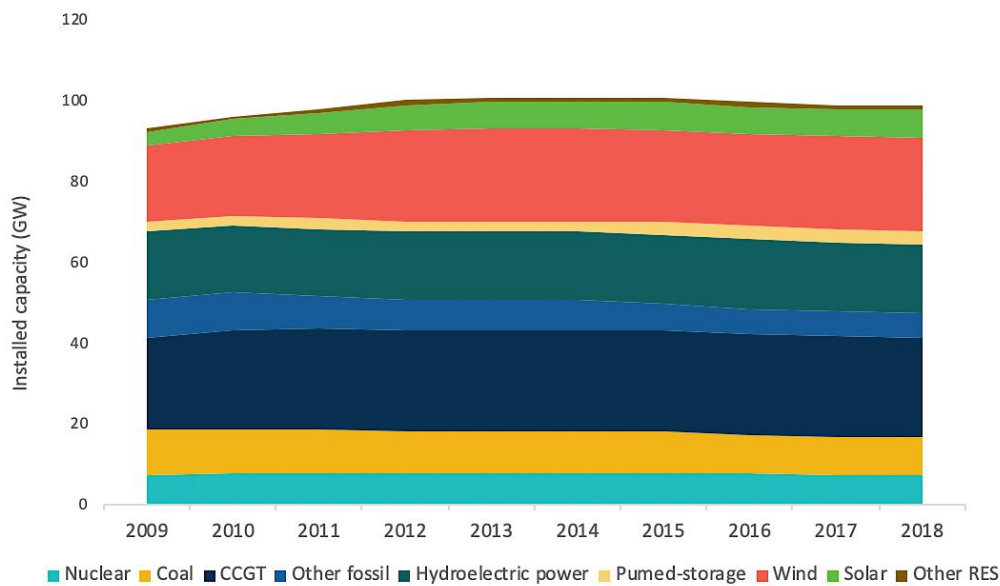
⁹ Weather-corrected peak and annual demands would allow for a more direct comparison of the changes of the two metrics.

Figure 3. Evolution of annual demand in the period 2009–2018 (TWh)

Source: Adapted with data from Red Eléctrica de España (REE). (2019). *Spanish Electricity System 2018 Report*.

The total installed capacity increased moderately between 2009 and 2018, from 92.9 GW to 98.6 GW, and the generation mix was altered to some extent. The installed capacity of renewable energy sources increased, driven primarily by wind (growth of around 4.4 GW) and secondarily by solar power (by around 3.3 GW for both solar photovoltaic and solar thermal). Other renewables, as well as storage in the form of pumped-storage hydro, experienced moderate growth.

At the same time, the installed capacity of thermal generation dropped (by around 3.4 GW), mainly due to the closure of older oil and gas generation plants. New combined cycle gas turbine plants (CCGT), which grew by almost 2 GW in the past decade, partly offset this reduction. Figure 4 shows the evolution of installed capacity over this period.

Figure 4. Evolution of installed generation capacity from 2009 to 2018 (MW)¹⁰

Source: Adapted with data from Red Eléctrica de España (REE). (2019). *Spanish Electricity System 2018 Report*.

As a result of these trends, the level of security of supply has been very high in Spain. Figure 5 presents the levels of realised margin at times of highest demand for every year from 2008 to 2018; in other words, the surplus of available generation over peak demand.¹¹ The black dashed line on the figure presents the target de-rated capacity margin in Spain, which is 10%.^{12, 13} While the realised margins aren't directly comparable with the de-rated capacity margin (the former are based on realised information while the latter is based on expectations for average type of conditions), the high differences between the two are still instructive: there is and has been a significant surplus of available generation over peak demand in Spain. Moreover, it should be noted that a 10% target capacity margin is significantly higher than the capacity margin indicated by modern, economically optimal reliability standards established in several countries across Europe. For example, Great Britain's reliability standard of three hours of Loss of Load Expectation (LOLE) per year is equivalent to a

¹⁰ Based on data from Red Eléctrica de España. (2019, 18 June). *Informe del sistema eléctrico Español 2018*.

<https://www.ree.es/es/datos/publicaciones/informe-anual-sistema/informe-del-sistema-electrico-espanol-2018>

¹¹ The Spanish transmission system operator, Red Eléctrica, defines the minimum coverage index (or the amount of available supply over peak demand) as $IC_{min} = \text{Min}(Pd/Ps)$, where IC_{min} means minimum coverage index, Pd means power available in the system, and Ps means peak power demanded to the system.

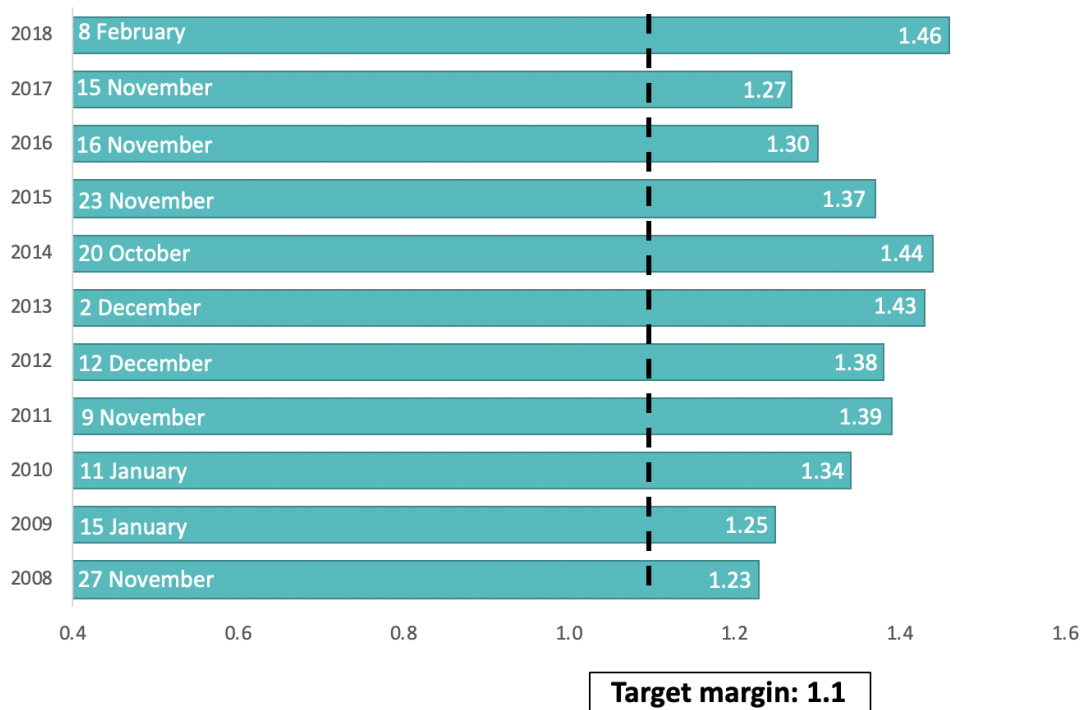
¹² ENTSO-E. (2018). *Mid-term adequacy forecast 2018: Appendix 1: Methodology and detailed results*. European Network of Transmission System Operators for Electricity.

https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2018_Methodology_and_Detailed_Results.pdf

¹³ The de-rated capacity margin is defined as the average excess of available generation capacity over peak demand, normally expressed in percentage terms. De-rating a resource's capacity reflects the proportion of it that is likely to be technically available to generate or reduce demand at times of peak demand.

target de-rated capacity margin of around 3.5%, which is about a third of the target de-rated capacity margin in Spain.¹⁴

Figure 5. Realised margins in the period 2008-2018 at times of peak demand



Source: Adapted with data from Red Eléctrica de España (REE). (2019). *Spanish Electricity System 2018 Report*.

Another indication of the significant surplus of available capacity over peak demand is the load factors for capacity. This is particularly true in the case of Spain, where CCGTs represent the type of thermal generation with the highest amount of installed capacity — 24.5 GW as of 2018. This has dropped significantly since 2013, as the economics for coal became more favourable compared to those for gas generation.¹⁵ In recent years the average load factor of CCGTs has been around 10% to 15%.

Future outlook of the risks to security of supply

Our review of the future risks is based on the 2019 Mid-term Adequacy Forecast (MAF), the most recent European-wide resource adequacy assessment of the European Network of Transmission System Operators for Electricity (ENTSO-E).¹⁶ The MAF 2019 assesses the risks for every European Member State (or bidding zones or islands

¹⁴ Baker, P., & Hogan, M. (2019, 13 October). *UK capacity market déjà vu: A solution that's still in search of a problem*. Euractiv. <https://www.euractiv.com/section/electricity/opinion/uk-capacity-market-deja-vu-a-solution-thats-still-in-search-of-a-problem/>

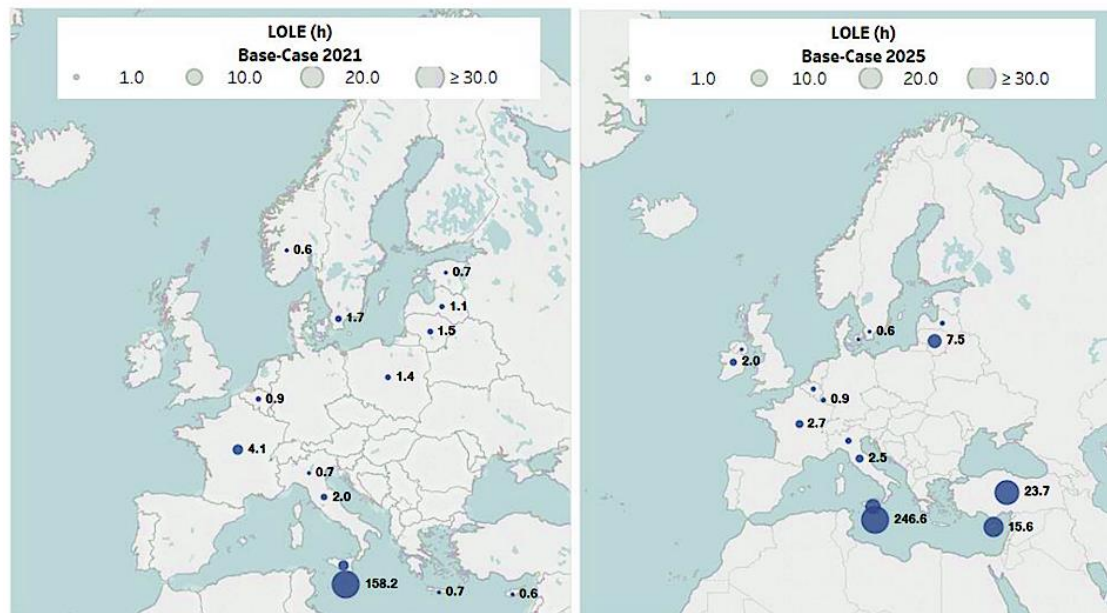
¹⁵ This was a result of decreasing carbon prices as determined by the Emissions Trading Scheme (ETS) in Europe and the relative prices of the two fuels.

¹⁶ ENTSO-E. (2019). *Mid-term Adequacy Forecast: Executive summary*. European Network of Transmission System Operators for Electricity. <https://www.entsoe.eu/outlooks/midterm/>

within a Member State) for the short term and medium term by estimating the relevant risk indicators for two snapshot years, 2021 and 2025.

The MAF 2019 contains a base case, a type of best estimate scenario for each of the two years. The results for the base case in 2021 and 2025 are presented on Figure 6. These show that the risks to electricity security of supply for Spain in both the short and medium term are negligible, as measured by the LOLE.¹⁷ The base case assumes that more than half of coal capacity has shut down by 2021 (around 4.3 GW of coal capacity remains operational for the two snapshot years of the study, down from 9.6 GW in 2018), while the amount of nuclear and CCGT capacity remains unchanged. At the same time, the installed capacity of renewable energy sources grows significantly. The MAF 2019 also presents the risks for the 95th percentile of potential outcomes; this is a subset of all potential outcomes and represents the 5% of the most extreme cases, that is, the ones with the highest risks. While this estimate provides a conservative view of the risks to security of supply, it is instructive to note that, even in this case, the risks for Spain are negligible.

Figure 6. Loss of load expectation for the base-case in 2021 and 2025¹⁸



Source: European Network of Transmission System Operators for Electricity. (2019). *Mid-term adequacy forecast*.

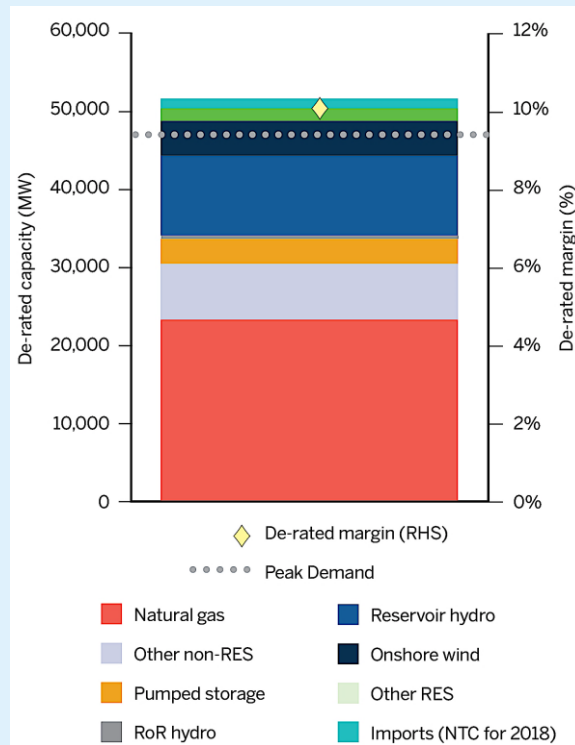
¹⁷ The projected LOLE for Spain in both years is so small that it isn't reported in the ENTSO-E map. The bigger the blue dot on the map the greater the risk, which a jurisdiction must take into consideration. LOLE below a certain level is a net cost to consumers because the value of lost load is lower than the cost of achieving such a low expectation of lost load through investment in new resources.

¹⁸ ENTSO-E, 2019.

Risks to Spain remain low even in the event of significant retirements

In addition to the ENTSO-E assessment, we have undertaken a simplified risk analysis for a scenario with additional closures of thermal generation. More specifically, we have estimated the de-rated capacity margin for the winter season in 2025, for a scenario where all coal and nuclear capacity retires.¹⁹ We have confined this analysis to the winter season, as we believe that the risks for the summer season will remain negligible as the deployment of solar generation accelerates in Spain.²⁰

Figure 7. De-rated margin analysis for winter season in 2025



For this analysis (see Figure 7 for results), we have used the MAF 2018 assumptions for peak demand and installed capacities of technologies.²¹ Peak demand is projected to increase roughly to 47 GW in 2025, or by 6 GW compared to peak demand in 2018.²² This represents a significant increase, especially considering that peak demand has dropped over the past decade (see Figure 2). We then applied some common real-life assumptions for the derating factors of generators.²³

¹⁹ A de-rated capacity margin is an inferior indicator to the statistical indicators of LOLE and ENS for a future power system. De-rating margins have been traditionally used by system operators to assess the security of the electricity supply. As the deployment of variable renewables in the power system increases, the statistical indicators offer an improved estimate of the risks, as they can better capture this variability.

²⁰ Solar generation should coincide with hot weather and the occurrence of peak demand in the summer and, as a result, contribute to a high degree towards securing supplies during the summer peak season.

²¹ In undertaking this analysis, we have also used some data from Red Eléctrica de España that offer greater granularity than the ENTSO-E assessment. At the time of drafting this paper, we only had access to the detailed 2018 data for some of the assumptions used for this calculation, such as the peak demand projections. The MAF 2019 lacks significant detail in the reporting of data, including peak demand projections.

²² Data provided by ENTSO-E. The future values represent the average peak demand across all the climatic years modelled by ENTSO-E in the Mid-Term Adequacy Forecast.

²³ With regards to resource availability, we have assumed the following de-rating factors for the most important technologies in the Spanish system: 95% for CCGT plants (same with the MAF); 95% for pumped-storage hydro (similar with the assumption made in Great Britain's capacity market); 60% for reservoir hydro and 40% for run-of-river hydro (based on the Italian CRM modelling, with a similar

We haven't considered the availability of any additional resources, for example in the form of demand response, storage or additional interconnector capacity.²⁴

The results in Figure 7 show that even in the absence of any coal and nuclear capacity in 2025, the Spanish market is projected to feature a high de-rated margin of around 10%. The resource adequacy risks to the Spanish system are projected to continue being negligible, even if an additional 12 GW of coal and nuclear capacity were to retire (compared to ENTSO-E's base case scenario in 2025).

Although this analysis is not a comprehensive risk assessment, it provides a strong indication that the Spanish system will be oversupplied even if a significant amount of generation capacity shuts down in the medium term.

Resource adequacy outlook: Conclusions

It is clear that the Spanish market suffers from an acute overcapacity problem and will continue to do so in the medium term under current expectations. Given these market conditions, the economic viability of several resources is unwarranted. The generation overcapacity means that the market is always oversupplied, as evidenced by the realised margins at times of highest demand periods in the past decade. Several resources are operating at levels way below the ones they require to be profitable. There are no instances nor risk of scarcity in the market, which in turn does not allow resources to recover their capital costs, especially resources that operate at the margin.

In order to establish an economically sustainable power sector, Spain needs to retire generating resources. Several power plants are planned and expected to shut down in the short and medium term; however, even this will be inadequate.²⁵ A formal coal phaseout in the medium term, similar to coal phaseouts being implemented in several other Member States across Europe, would be an incremental step in this direction. It would help Spain meet its carbon reduction targets faster, enhance certainty in the market about its determination to meet the set targets and allow for an orderly, just transition for the coal-dependent regions.²⁶ This would have the extra benefit that less flexible and inefficient resources make way for more flexible and efficient ones. On the contrary, the lack of a strategic and planned policy direction could hinder the delivery of much-needed societal benefits.

Alternatively, Spain could allow the market to freely decide whether resources exit the market or not. The country has effectively blocked this from happening through the implementation of CRMs in the past (see textbox below on the implementation of

climate zone); 15% for onshore wind; 90% for other-RES (e.g., biomass) and other non-RES technologies (e.g., OCGTs); and a contribution of 50% from interconnectors with reference to their Net Transfer Capacity in 2018 (or 1.2 GW of imports). We have de-rated solar generation at 0% as the analysis is for the winter period when the peak in the system normally occurs at nighttime.

²⁴ The projected NTC for imports for 2025 is 8.5 GW in MAF 2019 (consisting of 5 GW with France and 3.5 GW with Portugal), meaning that our assumption for the contribution of foreign resources is rather conservative.

²⁵ For example, nine coal plants are due to close later in 2020. Morgan, S. (2020, 3 April). *Spain finally sends 2030 climate plan to Brussels*. Euractiv. <https://www.euractiv.com/section/climate-environment/news/spain-finally-sends-2030-climate-plan-to-brussels/>

²⁶ This would also involve a transformation of the current economy and have a significant impact on employment. A planned phaseout will allow the timely design and implementation of just transition measures as the country phases out coal and potentially other resources. See, for example, E3G. (n.d.). *Just transition*. <https://www.e3g.org/showcase/just-transition/>

CRMs in Spain).²⁷ These interventions depress energy prices and undermine the development of demand-side flexibility options that will be crucial to Spain's decarbonised future. Such an approach won't necessarily drive the deep emission cuts that are required for a future that is compliant with the Paris Agreement.

It is also apparent that the Spanish market does not require any intervention to keep the lights on, from a resource adequacy perspective; that is, over investment time frames. Any intervention in the form of a CRM will likely exacerbate the problem by artificially retaining resources that aren't required in the market and thus prolonging the overcapacity problem. The Spanish authorities should also abolish any CRMs that are still in place. It is highly doubtful whether these mechanisms have provided any value to consumers given the excessive levels of security of supply in the past. On the contrary, they have costed Spanish consumers dearly, when they are already facing some of the highest wholesale prices across Europe.²⁸

Spain has a long history of support mechanisms for security of supply

Spain implemented its first support mechanism for security of supply purposes in 1998, with the implementation of the power guarantee (*garantía de potencia*). The scheme was terminated in 2007 and was replaced by new ones. The European Commission's sector inquiry on Capacity Mechanisms identified that Spain had four different mechanisms at the time of undertaking its analysis (2016),²⁹ the majority of which targeted fossil-fuel generators. We describe those briefly:

- An investment incentive scheme (*incentivo a la inversión*) for new nuclear, gas, coal, hydro and oil plants, in place since 2007.³⁰ The scope of this scheme was the remuneration of all power plants belonging to the aforementioned types that started operations from 1998; the scheme offers 10-year contracts to eligible resources. The Spanish authorities have changed the level of the incentive across the period; for example, the incentive was set at 20 k€/MW/year in 2007 and revised upwards to 26 k€/MW/year in 2011.
- An availability incentive scheme (*servicio de disponibilidad*) for new and existing gas, coal, oil and hydro with storage in place since 2007.³¹ The purpose of this scheme was to promote the availability of capacity from production facilities in the medium term. It consisted of making the contracted capacity available to the system operator for a predetermined time period. Coal and CCGT plants received around 4.7 k€/MW/year as of 2011.³²

²⁷ Such an approach has been followed in the US for example, where several GWs of coal plants have exited the market as a result of unfavorable economics.

²⁸ For example, Spain had some of the highest wholesale prices in 2018, alongside Greece, Italy and Great Britain, as measured by the average annual day-ahead (DA) electricity prices; the average Spanish DA prices were 57.3 €/MWh for 2018, higher by 10% compared to 2017. ACER. (2019, October). *ACER-CEER Market Monitoring Report (MMR) 2018*. <https://acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Current-Edition.aspx>

²⁹ European Commission. (2016, 30 November). Report from the commission: Final report of the sector inquiry on capacity mechanisms. https://ec.europa.eu/competition/sectors/energy/capacity_mechanism_sw_d_en.pdf

³⁰ For more information on the scheme, see, for example, the Spanish *Official State Gazette*: Ministerio de la Presidencia. (2011, 18 November). Legislación consolidada: Orden ITC/3127/2011. *Agencia Estatal Boletín Oficial del Estado*. <https://www.boe.es/buscar/act.php?id=BOE-A-2011-18064&tn=1&p=20111118>

³¹ Ministerio de la Presidencia, 2011.

³² CNE. (2012). *Propuesta del mecanismo por el que se establece el servicio de garantía de suministro*. Comisión Nacional de la Energía, predecessor of CNMC. https://www.cnmc.es/sites/default/files/1547950_8.pdf

- An environmental incentive scheme (*incentivo ambiental*) for coal plants with fitted sulphur dioxide filters, also in place since 2007. This scheme rewarded eligible coal generators (i.e., existing generators that fitted new sulphur oxide filters) for a period of 20 years with 8.75 k€/MW/year.³³ Payments are due to terminate in 2020.³⁴
- An interruptibility scheme designed for demand response (peak shaving) and, more specifically, large industrial consumers that was established in 2007 and substantially amended in 2013.³⁵ The scheme's participants reduce their consumption upon an instruction from the system operator in order to maintain the national balance between generation and demand. In return, they receive a financial reward for providing this service. The successful participants are selected through annual auctions on economic grounds.^{36, 37}

Spanish generators, in particular, have received abundant support in the past, on the grounds of security of supply. By one account, the total cost of CRMs in Spain amounted to around €18 billion in the period from 1998 to 2020.³⁸ According to information provided by the Spanish National Regulatory Authority or Comisión Nacional de los Mercados y la Competencia (CNMC), the total payments for CRMs (mechanisms supporting both generators and demand) between 2007 and 2017 were around €13 billion.³⁹ Information provided by the TSO suggests that the CRM costs for 2018 were around €1 billion.⁴⁰

At the end of 2018, the Spanish government abolished the availability service.⁴¹ This is consistent with the newly established Electricity Regulation, whereby Member States can only implement a CRM if they have identified risks to securing supplies based on the European-wide resource adequacy assessment.⁴² As we showed earlier, Spain has negligible risks in the short and medium term. At the same time, serious questions hang over the original decision to establish these

³³ CNE, 2012.

³⁴ The European Commission opened an in-depth investigation into the scheme in 2017 to assess whether it's in line with state aid guidelines. European Commission. (2017, 27 November). *State aid: Commission opens in-depth investigation into Spain's support for coal power plants*. https://ec.europa.eu/commission/presscorner/detail/en/IP_17_4965

³⁵ For more information, see, for example, the Spanish *Official State Gazette*: Ministerio de la Presidencia Relaciones. (2013, 31 October). Orden IET/2013/2013, de 31 de octubre. *Agencia Estatal Boletín Oficial del Estado*. <https://www.boe.es/buscar/doc.php?id=BOE-A-2013-11461>.

³⁶ The price paid to industrial consumers is determined by a descending auction, meaning an auction that starts with a high, initial price and is reduced at a predetermined rate until the resource requirement is met. The auction price is set by the marginal service provider, and all successful demand response providers receive the clearing price. The auction is run by the TSO (Red Eléctrica) and supervised by the national regulatory authority (CNMC). For more information on the scheme, see: Red Eléctrica de España. (n.d.). *Activities: Interruptibility services*. <https://www.ree.es/en/activities/operation-of-the-electricity-system/interruptibility-service>

³⁷ For some years, the use of the service has been extended beyond emergency situations (i.e., when there is a shortfall of supply over demand) to using it for balancing the system when this option is cheaper than other options. It would have been preferable to directly allow demand-side resources to participate in the wholesale market and extend their participation beyond industrial consumers alone.

³⁸ Greenpeace European Unit. (2018, 13 September). *Exposed: €58 billion in hidden subsidies for coal, gas and nuclear*. Greenpeace. <https://www.greenpeace.org/eu-unit/issues/climate-energy/1519/exposed-e58-billion-in-hidden-subsidies-for-coal-gas-and-nuclear/>

³⁹ CNMC. (2019, 6 February). *Informe de supervisión del mercado peninsular mayorista al contado de electricidad: Año 2017*. Comisión Nacional de los Mercados y la Competencia. https://www.cnmc.es/sites/default/files/2322298_0.pdf

⁴⁰ According to Red Eléctrica de España, the average cost for capacity payments and the interruptibility scheme were 2.7 €/MWh and 1.2 €/MWh, respectively, in 2018 and accounted for around 6% of total wholesale costs. Total peninsular demand stood at around 253 TWh in the same year. Red Eléctrica de España. (2019). *The Spanish electrical system 2018 report*. <https://www.ree.es/en/datos/publications/annual-system-report/spanish-electricity-system-2018-report>. The costs for the interruptibility scheme have dropped significantly in 2019, following a drop in the required volume.

⁴¹ The availability service was repealed in December 2018 by Ministerial Order TEC/1366/2018. Some of the main utilities have challenged the derogation and other aspects of the repealing Ministerial Order before the Spanish Supreme Court, which is yet to issue a decision.

⁴² For an overview of the relevant framework, see Appendix of the paper: Appendix: The European framework for securing supplies.

support mechanisms and their usefulness to consumers, when Spain had no real resource adequacy problems as evidenced by historical capacity margins.

Market reforms

In the previous section, we highlighted that the risks to security of supply for Spain are negligible in the short-to-medium term. As the power sector transitions towards a system increasingly dominated by low-cost, variable renewables, securing supplies will be about more than just generating capacity. As the output from variable renewables is largely uncontrollable (e.g., wind turbines will generate power when the wind is blowing unless deliberately curtailed),⁴³ flexibility will be key to achieving reliability and keeping energy affordable. The International Energy Agency (IEA) argues that power system flexibility has become a global priority for our transitioning power systems.⁴⁴ The agency's own modelling demonstrates that a flexible power system can 'keep the lights on' at significantly lower cost compared to an inflexible power system for the same level of variable renewables in the system.⁴⁵

The challenges system operators will face — the entities responsible for running the system safely on a second-by-second basis — will come in different forms and shapes. The kinds of flexibility the system needs will also evolve as the transition progresses. Traditionally, conventional power generators have been the main source of flexibility to the power system. Established practices include grid investments and expanding the geographical footprint of market and system operations (e.g., for transporting surpluses of variable renewables or netting off imbalances between balancing areas). The demand side, traditionally largely inflexible, is widely recognised as an increasingly valuable resource for flexibility. Its largely untapped potential⁴⁶ offers

⁴³ New technological advancements mean that variable resources can be controlled and also provide flexibility to the system. For example, the Californian Independent System Operator in cooperation with the National Renewable Energy Laboratory (NREL) and First Solar conducted a series of tests on a utility-scale solar photovoltaic plant to assess its capability to provide ancillary services, such as frequency response. The organisations concluded that the PV unit can provide all these services and, in fact, outperform conventional generators when complemented by smart technology (e.g., smart inverters). Energy and Environment Economics (E3). (2018).

Investigating the economic value of flexible solar power plant operation. <https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf>

⁴⁴ IEA. (2019, May). *Status of Power System Transformation 2019: Technology Report*. International Energy Agency.

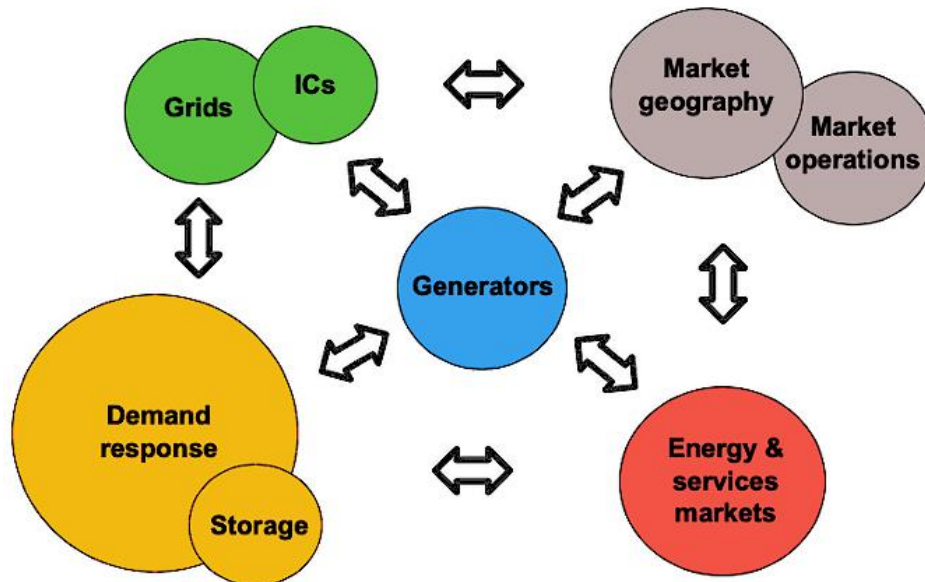
<https://www.iea.org/reports/status-of-power-system-transformation-2019>

⁴⁵ IEA. (2014, February). *The power of transformation: Wind, sun and the economics of flexible power systems*. International Energy Agency. <https://webstore.iea.org/the-power-of-transformation>. Other studies reach the same conclusion. See, for example: Energy Union Choices. (2017, November). *Introducing cleaner, smarter, cheaper: Responding to opportunities in Europe's changing energy system.* <https://www.energyunionchoices.eu/cleanersmartercheaper/>. The study assesses that a significantly higher deployment of variable renewables, compared to the CE4All package proposal, is feasible by 2030, at a lower cost, with smart electrification and smart coal plant retirement.

⁴⁶ ENTSO-E estimates the potential for demand-side response (DSR) to be around 17.1 GW for 2021, increasing to 20.6 GW in 2025 in MAF 2019. We interpret the 2021 potential to largely reflect the current situation. It is not clear from the publication what loads are considered in this estimation. Hans Christian Gils assesses the theoretical potential for DSR at around 121 GW in 2020 and 161 GW in 2030. Gils, H. C. (2014, April). Assessment of the theoretical demand response potential in Europe. *Energy Journal*, 67(1), 1-18. <https://www.sciencedirect.com/science/article/abs/pii/S0360544214001534>. Cowi et al. estimate the economic potential for demand-side

significant cost-effective opportunities. Emerging technologies — such as electric battery storage, electric vehicles and others — can also play a significant role in developing the necessary levels and types of demand-side flexibility. A key enabler for the development of these new flexibility resources will be updating the current market design and system operation framework to the new conditions. The different sources and enablers of flexibility are shown in Figure 8.

Figure 8. Notional representation of different sources of flexibility



In the following section, we provide recommendations about market reforms the Spanish authorities could consider for stimulating the necessary flexibility and achieving reliability at least cost in the future.⁴⁷

Wholesale market design

Price formation and administrative shortage pricing function

Wholesale energy pricing will be key to developing the necessary flexibility in the market, on both the supply and the demand side. Securing supplies in all time frames will require the right set of operational capabilities.⁴⁸ The value of investment in more

response to vary between 34 GW and 57 GW in 2030 between a business-as-usual scenario and a policy scenario that enables and promotes more actively its development; the latter reflects more closely the agreement in the CE4All package. COWI, AF Mercados EMI, ECOFYS, Thema, & VITO. (2016, July). *Impact assessment study on downstream flexibility, price flexibility, demand response & smart metering*. European Commission DG Energy.

https://ec.europa.eu/energy/sites/ener/files/documents/demand_response_ia_study_final_report_12-08-2016.pdf. Although the potentials for DSR are open to debate, it is clear that the currently realised DSR is only a fraction of the potential DSR and that this potential increases as the deployment of flexible loads and smart technologies increases.

⁴⁷ This is not meant to be an exhaustive list of recommendations but rather a highlight of some of the key areas that warrant attention.

⁴⁸ Although this has always been the case, new challenges surface as our power systems are being decarbonised (e.g., reduction in system inertia as synchronous generation is being replaced by asynchronous, renewable generation and batteries).

flexible resources can most clearly be seen and can only be properly compensated when energy prices correctly reflect real-time conditions on the electricity system. Therefore, getting the wholesale market price correct will be essential for developing the necessary operational capabilities and ‘keeping the lights on’ cost effectively.

Under legacy practices, wholesale prices are formed solely by the short-run production cost of the marginal unit in the merit order dispatch. The system operator takes actions to maintain the balance between supply and demand when the market is short, such as using operating reserves or calling emergency demand response from industrial consumers with interruptible contracts in place. Wholesale energy prices reflect the utilisation costs of these actions (e.g., the utilisation rate of a generator in the operating reserves) to the extent that they reflect them at all.⁴⁹ This practice disregards the true marginal costs of many system operator actions. It ignores or understates the marginal opportunity cost of energy when the combined demand for energy and the reserves necessary to run the power system within recognised security standards exceeds the supply of resources. In other words, it does not reflect the real marginal cost of energy, which is clearly problematic in a market that is meant to run on marginal cost prices.

The correct way to form wholesale prices is to consider the marginal costs of all operator balancing actions and the opportunity cost inherent in the competing demands for energy and reserves. When the system operator uses operating reserves to meet the demand for energy, it reduces the buffer available to the system to deal with any further imbalances. An example would be a plant failure or an unexpected decrease in variable renewable output. When the buffer is reduced below the level needed to comply with the demand for secure operation of the system, the opportunity cost (or the real value) of additional demand for energy is no longer the short-run operating cost of generation but is rather the cost associated with an increased risk of a power outages.

Ideally, it would be sufficient to co-optimize the competing demands for energy and reserves (in many markets this is current practice). The true opportunity cost would be revealed by the interaction between rising prices and price-responsive consumers. But we are still far from being able to rely on active competition from consumers to accomplish this reliably. To ensure that market prices better reflect full marginal cost — and to mitigate against the possibility of abuse by dominant market actors — several markets and regulators have implemented, or plan to implement, administrative reserve shortage pricing (also called administrative scarcity pricing or shortage pricing function). In Europe, this would be accomplished through the balancing market. For example, Great Britain has implemented this concept as part of the Electricity

⁴⁹ The procurement costs of these actions are often socialized in some way. Effectively, the full marginal costs of these actions are not reflected in prices, only the direct operational cost is, which ignores other opportunity costs where they exist.

Balancing Significant Code Review,⁵⁰ and more Member States are planning or considering doing so.⁵¹

Figure 9 depicts the formulation of this concept. When the system operator draws down operating (or balancing) reserves to meet the demand for energy, and the level of available reserves drops below the level deemed necessary to run the power system in compliance with established security standards, the probability of a power outage becomes material. This probability is measured by the Loss of Load Probability (LOLP), which is normally assessed by the system operator at regular intervals approaching real time.⁵² During periods of reserve scarcity, the price is set administratively as the product of LOLP and the Value of Lost Load (or ‘the maximum electricity price that customers are willing to pay to avoid an outage’).^{53, 54} When involuntary disconnections are unavoidable, the LOLP equals 1, and the wholesale price is set at the maximum price defined in the function.⁵⁵

⁵⁰ For more information on its implementation, see: ELEXON. (2019, June 27). *Imbalance pricing guidance: A guide to electricity imbalance pricing in Great Britain*. <https://www.elexon.co.uk/documents/training-guidance/bsc-guidance-notes/imbalance-pricing/>. For more information on the Electricity Balancing Significant Code Review, see: Ofgem. *Electricity Balancing Significant Code Review*. (n.d.). <https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review>

⁵¹ For example, the Belgian regulator, CREG, is examining the implementation of shortage pricing in Belgium since 2016, with a possible implementation at the end of 2021; CREG. (2019, September 12). *Note on the implementation of a scarcity pricing mechanism in Belgium*. Commission de Régulation de l'Électricité et du Gaz.

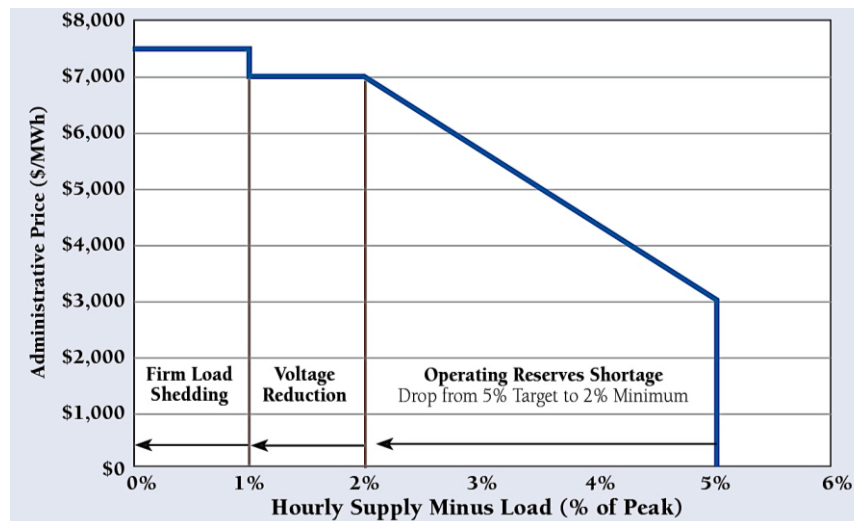
<https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986EN.pdf>. Other countries, like Poland and Italy, have committed to applying a shortage pricing function in their balancing markets as part of the agreed-on market reforms with the European Commission in the context of the approval of their capacity mechanisms. Administrative shortage pricing should be adopted in a market whether or not an out-of-market CRM is in place. Its effectiveness tends to be more significant in markets without out-of-market CRM in place.

⁵² For example, in Great Britain, the system operator assesses the LOLP at midday the day before the relevant settlement period, as well as eight, four, two and one hour(s) prior to the start of each settlement period. The one-hour-ahead (gate closure) value is used to determine the final LOLP.

⁵³ See EUR-Lex. (2019, June). Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (text with EEA relevance). European Commission. <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019R0943>. A number of jurisdictions have estimated this value; for example, a study for the UK Government estimated a value of £17,000/MWh.

⁵⁴ This is the price at which the market should be expected to clear when it reaches the point that the operator must resort to involuntary load curtailments to balance the system. That price should be as close as possible to, if not the same as, the VoLL.

⁵⁵ As shown in the figure, the need to begin reducing voltage or shedding load would typically occur when the reserve level reaches the minimum required quantity of one or more categories of frequency containment reserves.

Figure 9. Illustration of administrative scarcity pricing function

The application of administrative scarcity pricing in the balancing market is expected to feed indirectly into forward prices, given that these converge towards expected balancing prices as they approach real time. Scarcity pricing is necessary for all resources to be able to recover their capital and other fixed costs. It is especially important for resources with relatively high marginal costs that are expected to operate for only a few hours per year and depend on them to recover these costs. The use of administrative shortage pricing ensures the energy market supports investment in the resources needed to meet demand for reliable supply in two key ways:

- Through increased access to risk-hedging opportunities by wholesale market actors.⁵⁶
- Through higher prices during actual system stress periods (with lower prices during other periods and average prices being no higher and potentially lower).

Importantly, suppliers are incentivised to weigh the costs of underwriting investments in generation against the opportunity to develop the potential for cost-effective demand flexibility. In other words, by driving the incentives for needed investment through the energy and balancing services market rather than through various out-of-market mechanisms, administrative scarcity pricing can help ensure a more cost-efficient level of resource investment. At the same time, it will bring forward a more cost-effective mix of supply-side and demand-side solutions to meet flexibility requirements and security of supply (for more information, see the section below on Texas).⁵⁷

Spain would be wise to prioritise the implementation of administrative shortage pricing in its balancing market. The country is in an advantageous position to do so, given the almost complete rollout of smart meters and existence of dynamic pricing in

⁵⁶ These could take the form of bilateral contracting or forward trading of hedging products.

⁵⁷ Another benefit of implementing administrative shortage pricing is that it reduces the risk of market players exerting market power by setting administratively the price when there is a shortage of resources.

Spain (see section on demand-side flexibility on page 25). These conditions can help to reveal the true value that consumers place on an uninterrupted service, or on the option for shifting their consumption to different times. In doing so, administrative shortage pricing can stimulate cost-effective demand-side flexibility. Its implementation could bring significant benefits over the long term in the country.

Administrative Shortage Pricing has delivered least-cost reliability in ERCOT

The Electric Reliability Council of Texas (ERCOT) (the independent system operator for most of the state of Texas) runs an energy market complemented by administrative shortage pricing in its day-ahead market (the Operating Reserve Demand Curve or ORDC, in place since 2014), with energy and reserves co-optimisation at balancing time scales. The ERCOT market, which is not synchronized with the rest of the North American power system, has one of the highest penetration levels of variable renewables of any synchronized market in the U.S., and globally (wind and solar contributed 21.2% of generated electricity in 2019), most of it developed in the past decade.⁵⁸ Because ERCOT is electrically an island, the integration of variable renewables is all the more challenging. The state has seen a significant increase of peak demand over the past few years, mainly due to the expansion of oil and natural gas exploration activities and related petrochemical industrial activity. The increase in demand has occurred at the same time as the market has seen significant coal plant closures.

These developments led some to forecast difficulties in meeting summer peak demand, with projected capacity margins falling below the target level (e.g., the projected margin for the summer of 2019 was 8.6% compared to a target margin of 13.75%).⁵⁹ Despite these projections, ERCOT has been able to manage its system without shedding any load, despite setting a new record for peak demand in the summer of 2019 and experiencing a hotter than average summer. In the summer of 2019, the wholesale price reached VoLL (9,000 \$/MWh in ERCOT) for four hours and 10 minutes in total. The ERCOT market has for many years outperformed against the established loss-of-load expectation, which, at one event every 10 years, is comparable to or more stringent than most developed power systems.⁶⁰

The state's wholesale market design and general market arrangements have been more broadly successful in stimulating a response from the market. For instance, ERCOT has enabled the participation of demand response in the market. Some of the ways this response has manifested are:

- ERCOT has seen significant investment in new generation units. Analysis undertaken by Grid Strategies LLC shows that gas units recovered a significant margin in 2019 above what they require in an average year.⁶¹

⁵⁸ For more information, see: ERCOT. *Grid information: Generation*. (n.d.). Electric Reliability Council of Texas.

<http://www.ercot.com/gridinfo/generation>. For information across all U.S. synchronized markets, see: National Renewable Energy Laboratory (NREL). (2020, February 2020). *2018 renewable energy grid integration data book*. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. <https://www.nrel.gov/docs/fy20osti/74823.pdf>

⁵⁹ The target margin doesn't represent an economically optimal level but is rather based on traditional engineering thinking. The Brattle Group has estimated the economically optimal reserve margin for ERCOT to be about 10.2%. Brattle Group, (2014, 31 January). *Estimating the economically optimal reserve margin in ERCOT*. Public Utility Commission of Texas.

https://brattlefiles.blob.core.windows.net/files/7641_estimating_the_economically_optimal_reserve_margin_in_ercot.pdf. The level of margin is not directly comparable with the common way of reporting European margins, due to methodological differences in estimating the margin (e.g., the way reserves are accounted for in the methodology).

⁶⁰ ERCOT expects capacity margins to increase in the coming years, due in part to the development of new renewable resources, such as solar and wind power. See, for example: Behar, P., & Klump, E. (2019, 23 August). *How does Texas keep the lights on? It's complicated*. E&E News. <https://www.eenews.net/stories/1061038879>

⁶¹ Gramlich, R. (2019, October 15). *ERCOT 2019: Final proof of a successful market design?* RTO Insider: Stakeholder Soapbox. <https://gridprogress.files.wordpress.com/2019/10/ercot-2019-final-proof-of-a-successful-market-design.pdf>

- Suppliers hedged against the risks of price spikes, providing generators with predictable cash flow. For example, suppliers had hedged around 95% of demand prior to the start of summer 2019, which was expected to be rather tight.
- Generators increased their availability over the summer period in light of projected, tighter conditions. In 2018, the independent market monitor's analysis indicates that generators likely took longer planned outages during the shoulder months to ensure greater availability during the peak season, in line with market economics. Forced outages were only 2% in the months of July and August of 2018, when the highest demand in the state occurs.⁶²
- Most importantly, these market conditions have created a vibrant demand-response market. One key development is suppliers offering residential and small commercial consumers packages of wholesale price pass-through with load automation systems. ERCOT estimates that around 10% of demand — eligible through different demand-side and other programmes and through time-varying tariffs — shifted its load during the highest demand periods in summer 2019.⁶³

Unlike markets with CRMs in place, ERCOT has managed to exceed the desired level of reliability with a quantity and mix of resources dictated principally by the energy market, supplemented with administrative shortage pricing. By comparison, markets like PJM with long-established CRMs exhibit long-term and ever-increasing overcapacity, while the average prices seen by their consumers are significantly higher than those in ERCOT. In 2015, for instance, the average wholesale prices in ERCOT were around half of those in PJM and ISO New England, which had CRMs in place, with the cost of CRMs accounting for a significant share of this difference.^{64, 65}

Locational pricing signals

The current market design of a single bidding zone in Spain, as in most of Europe, determines one power price for the whole country. This effectively ignores the physical limitations of the network and masks the differences in marginal costs for delivering energy to different locations. In turn, this creates market inefficiencies and sends the wrong pricing signals to market participants. Ignoring the physical dimension of the network in the market can exacerbate congestion, leading to the scheduling of generation where network capacity is insufficient to deliver the energy to serve demand. As this is an infeasible outcome, the TSO (transmission system operator) must intervene to resolve the situation. It does this primarily through redispatching, meaning turning down lower-cost generation in the non-congested area and increasing

⁶² Potomac Economics. (2019). *2018 State of the market report for the ERCOT electricity markets*.

<https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf>. Potomac Economics is the independent market monitor for ERCOT.

⁶³ The maximum reduction was around 3.2 GW from a total of around 31 GW on 13 August 2019. The bulk of demand response was incentivised through the 4CP programme (similar to the Triad programme in Great Britain) and time-varying tariffs. ERCOT. (2020, March 9). *2019 demand and energy report: Monthly report on demand and energy use in the ERCOT region*. Electric Reliability Council of Texas. http://mis.ercot.com/misdownload/servlets/mirDownload?mimic_duns=000000000&doclookupId=707834561

⁶⁴ Hogan, M. (2016). Hitting the mark on missing money: How to ensure reliability at least cost to consumers. Regulatory Assistance Project. <https://www.raonline.org/wp-content/uploads/2016/09/rap-hogan-hitting-mark-missing-money-2016-september.pdf>

⁶⁵ Analysis undertaken for PJM shows that consumers have been paying excessively on an annual basis for nonessential generation resources due to the system operator consistently overforecasting demand. Gheorghiu, J. (2020, March). *PJM over-forecasting costs consumers up to \$4.4B for unneeded energy capacity: Report*. Utility Dive. <https://www.utilitydive.com/news/pjm-over-forecasting-costs-consumers-up-to-44b-for-unneeded-energy-capaci/574264/>

the output of higher-cost generation in the congested area. The resulting, increased costs are socialised amongst consumers.

In Spain, these costs are relatively high compared to other European countries. For example, ACER estimates that the costs for resolving congestions on the Spanish transmission level were around €370 million in 2017 (with an average cost of 1.6 €/MWh).⁶⁶ Information by the national TSO suggests that the congestion costs for 2018 were of similar order, at around 1.5 €/MWh.⁶⁷

Ignoring location-related costs in energy prices can exacerbate congestion and lead to valuable transmission capacity being held in reserve to account for increased uncertainty and risks. The growing deployment of variable renewables will lead to higher congestion on the network because generation will increasingly be located based on favourable wind and solar conditions rather than based on proximity to demand centres. At the same time, system operators will need to accommodate less predictable and more variable power flows.

Most organised wholesale markets across the world have implemented a different market design that incorporates locational information in the formation of prices. The prices in the market reflect the marginal cost for serving an additional MWh of load from a given location. This is called location marginal pricing (LMP) or nodal pricing.⁶⁸

LMP has both short- and long-term benefits. While it offered benefits in traditional power systems, they are amplified by the energy transition:

- It can increase the utilisation of existing energy assets, especially transmission lines. The system operator can anticipate fewer contingencies to operate the power system safely, thus freeing up more network capacity. In other words, a system deploying LMP will need less investment in transmission networks, while it can extract ‘more juice’ from the existing assets. This is evident for example in ERCOT, which recently moved from a system of small bidding zones to LMP. Following its

⁶⁶ The costs for 2017 were down compared to 2016 by 28% and generally followed a downward trend in the years from 2016 to 2018.

⁶⁷ According to Red Eléctrica de España, the average cost to resolve problems with the daily dispatching schedule due to network limitations was 1.47 €/MWh (Restricciones técnicas PDBF), and the average cost to resolve congestion problems at real-time was 0.07 €/MWh (Restricciones técnicas en tiempo real). Red Eléctrica de España. (2019, 19 February). *Servicios de ajuste e intercambios internacionales: Avance 2018*. <https://www.ree.es/es/datos/publicaciones/informe-anual-sistema/servicios-de-ajuste-del-sistema-avance-2018>

⁶⁸ It is not our intention to describe LMP in detail in this paper, but rather to provide a high-level overview of the benefits it can bring to the transitioning power system. The successful implementation of LMP would require a number of conditions, such as the development of robust trading in financial transmission rights, and a concrete framework for the development of liquidity and prevention of abuse of market power. For more information on LMP, see, for example: Newbery, D., Pollitt, M. G., Ritz, R. A., & Strielkowski, W. (2018). Market design for a high-renewables European electricity system. *Renewable and Sustainable Energy Reviews*, 91, 695-707. <https://www.sciencedirect.com/science/article/abs/pii/S1364032118302454>; and Neuhoff, K., & Boyd, R. (2011). *International experiences of nodal pricing implementation: Frequently asked questions*. Climate Policy Initiative. <https://climatepolicyinitiative.org/wp-content/uploads/2011/12/Nodal-Pricing-Implementation-QA-Paper.pdf>

introduction, utilisation of the most congested network corridor increased by 23% within two years.⁶⁹

- It promotes the use of the cheapest flexibility resources in the short term, both on the generation and the demand side, and incentivises the development of new flexibility resources over the long term.
- By revealing the location and value of congestion, it stimulates optimal investments in generation and networks. For example, owing to price transparency, it is easier to assess and demonstrate the value to stakeholders associated with new transmission investments between constrained and an unconstrained areas.

All in all, the implementation of LMP can lead to significant cost reductions over the long term and bring substantial economic benefits for the low-carbon transformation of the Spanish power system. The Spanish authorities could explore the potential for introducing LMP in the market.^{70, 71} Alternatively, the Spanish authorities could consider providing locational signals to market participants through electricity transmission charges.⁷² Revealing the locational value of energy in one way or another will be an essential part of a least-cost energy transition.

Regionalisation

Spain, and the Iberian Peninsula more broadly, is currently one of the most electrically isolated regions of Europe. Aside from its direct connection with Portugal,⁷³ Spain (and the peninsula by extension) is currently weakly interconnected to the rest of Europe through France. The total commercial capacity of the interconnection with France is around 2.8 GW, which is only a small fraction of the peak demand and installed

⁶⁹ More specifically, utilisation on the most constrained part of the network increased in the first year from 64% to 78% and in the next year to 87%. Hogan M., & Pandera, J. M. (2019, June). *Locational market in Poland: Security of supply, costs and the impact on the energy transition*. Forum Energii and Regulatory Assistance Project. <https://forum-energii.eu/en/analizy/rynek-lokalizacyjny>

⁷⁰ We recognise that the implementation of LMP would likely require a more coordinated EU effort. Although EU legislation doesn't block the implementation of LMP, it doesn't promote it as an option for the future either. Some Member States have considered or investigated the introduction of LMP. For example, the Polish TSO considers that LMP will be a better solution for the future and is planning to test such a solution in the future. See PSE. (2018, December). *PSE calls for electricity market design facelift*. <https://www.pse.pl/web/pse-eng/-/pse-calls-for-electricity-market-design-facelift>. The French NRA, Commission de Régulation de l'Energie (CRE), commissioned a study on nodal pricing recently, which concluded that a nodal approach is preferable to a zonal one. FT-Consulting Compass Lexecon. (2018, May). *Système de prix nodaux: expérience américaine et perspectives pour l'Europe*. CRE. <https://www.cre.fr/Documents/Publications/Etudes/Systeme-de-prix-nodaux-experience-americaine-et-perspectives-pour-l-Europe>

⁷¹ In our view, the key question for the implementation of LMP in Europe is whether and how this could work in a self-dispatch system, with the split of market and system operation. Systems with LMP in place use a central dispatch model, whereby the system operator is responsible for running the market and dispatching resources from the day-ahead onwards. Most of European countries run a self-dispatch system.

⁷² Great Britain has followed such an approach with Project TransmiT. For more information, see: Ofgem. (n.d.). *Project TransmiT*. <https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit>

⁷³ Spain and Portugal have been operating the Iberian Peninsula market (Mercado Ibérico de la Electricidad or MIBEL) since July 2007. For more information, see: MIBEL. (n.d.). *Premio del Consejo de Reguladores del MIBEL para estudios sobre integración de los mercados eléctricos*. Mercado Ibérico de la Electricidad. https://www.mibel.com/es/home_es/

capacity of the country.⁷⁴ This is evident by the significant day-ahead price differential between the two countries that stood at around 10 €/MWh on average over the period 2016-2018;⁷⁵ the average day-ahead price in 2018 in Spain was 57.3 €/MWh and in France 50.2 €/MWh.⁷⁶

The commercial capacity between Spain and Portugal is around 3.4 GW on average. The interconnection between the two countries was constrained for only around 6% of the time, and the average day-ahead prices were almost the same in 2018.

Recognising the benefits of greater interconnection to security of supply amongst other factors, the Spanish authorities are planning to increase its interconnection capacity mainly with France to achieve a 15% interconnectivity level by 2030.⁷⁷ The goal is to increase the interconnection capacity between Spain and France to 8,000 MW by 2030. The most advanced of the projects is the Bay of Biscay interconnection, with an installed capacity of 2,000 MW and a projected commissioning date of 2025.⁷⁸ It is worth noting that the French and Spanish systems are facing peak demand at different hours, which is a good indication that the French system could contribute to the security of supply in Spain during its tightest hours and vice versa.⁷⁹ Spain is also planning to expand its interconnection level with Portugal, though to a more limited extent given the already high level of price convergence between the two countries. The security of supply outlook for Portugal is also healthy, similarly to that of Spain.

Although it is essential that Spain continue to increase its interconnection levels with neighbouring countries, it is also essential that this capacity be utilised to the maximum economic extent. Analysis by the Agency for the Cooperation of Energy Regulators (ACER) suggests that the currently installed interconnection capacity is significantly underutilised. The interconnections with France and Portugal have been utilised at around 45% of the maximum power that can technically flow on them. The CE4All package dictates that the level of interconnection capacity made available to the market reach a minimum of 70% by 2025. This means that the available capacity of the existing interconnectors to the market should increase significantly in the coming five years, which would further enhance security of supply in the country. The Spanish authorities should pursue this target as quickly as possible and ensure that the level of

⁷⁴ Spain is also directly connected to Morocco through two submarine power cables with a total capacity of 800 MW.

⁷⁵ The aforementioned differential is for absolute price differences. The average price differential of actual prices was 5.8 €/MWh, which is still significant. The difference between the two metrics implies that there were price differentials in both directions. ACER. (2019, 11 November). *ACER market monitoring report 2018: Electricity wholesale markets volume*. Agency for the Cooperation of Energy Regulators.

https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202018%20-%20Electricity%20Wholesale%20Markets%20Volume.pdf

⁷⁶ ACER, 2019.

⁷⁷ Target established in the Spanish NECP.

⁷⁸ For more information on the Bay of Biscay interconnection, see, for example, the project's webpage: <https://www.inelfe.eu/>. For more information on other projects, see, for example, the Spanish NECP.

⁷⁹ Peak demand tends to occur at 7 p.m. in France and at 9 p.m. in Spain. Inelfe. (2017, August). *The electricity interconnection France-Spain across the Bay of Biscay*. https://www.inelfe.eu/sites/default/files/2017-08/Inelfe_INGL_04Agos_WEB.pdf

interconnection made available to the market exceeds the minimum threshold set by the CE4All package, if it's cost efficient.

It is also important that Spain and the Iberian Peninsula market continues working with other member states to further integrate its market in the single European electricity market. Spain and Portugal have been well integrated for over a decade with the formation of the Iberian market (MIBEL).⁸⁰ The MIBEL market is managed by a single operator for the peninsula, the OMIE,⁸¹ which incorporates the day-ahead and intraday markets. The balancing markets are managed by each national TSO separately. As of 2014, the MIBEL market is coupled at the day-ahead stage with the single area, which covers the bulk of the European countries. Spain and the Iberian Peninsula were part of the first wave of countries that implemented Single Intraday Coupling (SIDC) in June 2018, which is the continuous platform for trading in the intraday market.⁸² Spain is also a member of several initiatives associated with the balancing market, such as the Trans European Replacement Reserves Exchange (TERRE) and Manually Activated Reserves Initiative (MARI).⁸³

Demand-side flexibility

As the power system is transitioning, the demand side will need to play an increasingly active role in the power system to cost effectively achieve the goals of security of supply and decarbonisation. Under the traditional paradigm, demand was inelastic, and system operators would schedule generation to follow forecasted demand. The advent and increasing deployment in recent years of new technologies on the demand side — such as smart meters, automation controls and smart and more flexible appliances — is changing the status quo. These new technologies and services make it both possible and attractive for demand to play a more active role in the market, as long as the market affords fair access and compensation for doing so.

In the short-to-medium term, industrial and commercial consumers offer the main potential for demand-side flexibility.⁸⁴ In the medium and long term, we expect that the residential sector will become more active in the provision of demand-side flexibility, likely through automation or through energy or home services providers,

⁸⁰ The MIBEL became operational on 1 July 2007. See, for example:

https://www.ree.es/sites/default/files/electricity_interconnections_eng_2.pdf

⁸¹ For more information on the OMIE, see, for example, the operator's website: <https://www.omie.es/en>

⁸² More recently, the MIBEL market brought forward the gate opening time for the intra-day continuous market at 3 p.m. day-ahead (i.e., D-1), from 10 p.m. day-ahead. CNMC. (2019, October). *DCOOR/DE/003/19: Adaptación de las reglas de funcionamiento de los mercados diario e intradiario y de P.O.* Comisión Nacional de los Mercados y la Competencia. <https://www.cnmc.es/en/node/377402>. This is in line with recently established European rules. For more info, see: ACER. (2019, 24 January). *Establishing a single methodology for pricing intraday cross-zonal capacity.* Agency for the Cooperation of Energy Regulators. https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%202019-2019%20on%20intraday%20cross-zonal%20capacity%20pricing%20methodology.pdf

⁸³ For more information, see: ENTSO-E. (n.d.) *Electricity balancing.* European Network of Transmission System Operators for Electricity. https://www.entsoe.eu/network_codes/eb/

⁸⁴ In fact, industrial consumers can already offer services to the Spanish power system through the established interruptibility scheme.

especially as electrification introduces new, more flexible end uses, such as electric vehicles, to the system. Spain initiated the digitalisation process of residential demand over a decade ago. As of the end of 2018, almost all residential consumers (with up to 15 kW of contracted capacity) had smart meters in place.⁸⁵

Implicit demand response

Spain has so far focused mainly on implicit demand-side response, whereby consumers shift when they use electricity in response to the retail price at a given time. The Spanish government has established a voluntary, regulated, dynamic tariff called the Voluntary Price for Small Consumers (or PVPC), which is managed by the National Regulatory Authority (NRA) and administered by the TSO. The dynamic tariff, which offers three different configurations, only covers the energy component of the electricity bill and links the hourly wholesale prices with the retail tariffs seen by consumers.⁸⁶ Around 40% of all eligible residential consumers were on the PVPC tariff as of 2017.⁸⁷ Figure 10 shows an example of the PVPC tariff and the associated day-ahead prices for two random days. The energy component of the bill made up around 30% of the retail bill as of 2017, based on the most representative consumption band.⁸⁸ It is evident from this that the energy component represents only a fraction of the total cost that residential consumers are facing.

Alongside the regulated, dynamic tariff, the competitive retail market also offers time-varying tariffs, mostly in the form of time-of-use (ToU) tariffs, whereby the retail price is predetermined and differs for certain periods of the day, commonly two or three periods in a day. Some smaller suppliers also offer hourly dynamic tariffs, similar to the PVPC tariff; overall, their adoption in the free market is rather limited.⁸⁹ Only a

⁸⁵ As of the end of 2018, just over 99% of residential consumers with up to 15kW of contracted capacity had smart meters in place. CNMC (2019, June). *Acuerdo por el que se emite informe sobre el cumplimiento del último hito del plan de sustitución de contadores*. Comisión Nacional de los Mercados y la Competencia. https://www.cnm.com.es/sites/default/files/2520102_6.pdf

⁸⁶ The voluntary tariff offers three different configurations: (1) general or default tariff (resembling a flat tariff); (2) nighttime tariff (resembling a two-period time-of-use tariff); and (3) super-valley tariff (also called EV tariff). For more information, see, for example: Red Eléctrica de España & ESIOS. (n.d.). *Active energy invoicing price*. <https://www.esios.ree.es/en/pvpc>; and Red Eléctrica de España. (n.d.). *Activities: Voluntary price for the small consumer (PVPC)*. <https://www.ree.es/en/activities/operation-of-the-electricity-systemvoluntary-price-small-consumer-pvpc> [on first ref. name does not match website]

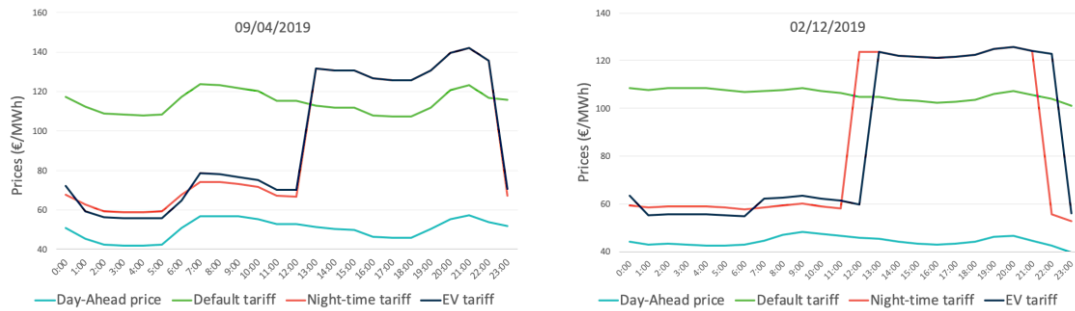
⁸⁷ CNMC. (2018, July). *Spanish energy regulator's national report to the European Commission 2018*. Comisión Nacional de los Mercados y la Competencia. https://www.cnm.com.es/sites/default/files/2168599_3.pdf

⁸⁸ European Commission. (2019). *Energy prices and costs in Europe*. Report from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions. https://ec.europa.eu/energy/sites/ener/files/documents/swd_v5_text_6_part_1_of_4.pdf. ACER and CEER estimate the share of the energy component somewhat higher at 44%, based on the incumbents' standard electricity offers for households in capital cities for the months of November and December. ACER/CEER. (2019, October). *Annual report on the results of monitoring the internal electricity and natural gas markets in 2018: Electricity and gas retail markets volume*. https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202018%20-%20Electricity%20and%20Gas%20Retail%20Markets%20Volume.pdf

⁸⁹ For example, a small supplier called Factor Energia offers dynamic retail contracts that are linked to the wholesale prices.

small portion of the domestic market segment was on dynamic, or hour-by-hour, tariffs as of the end of 2017.⁹⁰

Figure 10. Day-ahead prices and PVPC tariff for two random days (energy and network costs)⁹¹



Source: Adapted with data Red Eléctrica de España & ESIOS. (n.d.). *Active energy invoicing price*, along with data from ENTSO-E.

Overall, it is unclear what effects time-varying tariffs are having on consumer behaviour and whether they are delivering the expected behaviours and savings by shifting demand from periods of high prices to low price ones.⁹² The residential market segment is relatively concentrated, with the three biggest suppliers having a market share of 88% as of 2017.⁹³ In addition, the regulated tariff was around 15% lower than the average price by all suppliers in the liberalised market.

The current state of the retail market raises some important questions about the reasons that the market itself is only offering dynamic tariffs to a limited extent. One would expect that the provision of a regulated, dynamic tariff would incentivise suppliers to offer more cost-reflective retail products and undercut the established regulated tariff. It would therefore be prudent for the Spanish NRA to examine the reasons why this has not occurred.

Some relevant questions include:

- Whether the high concentration in the market acts as an impediment to the uptake of such tariffs.

⁹⁰ Thirteen percent of consumers with contracted power of less than 15 kW were subscribed to time-varying tariffs, linked to the hourly wholesale prices, at the end of 2017. CNMC. (2019, February). *Informe de supervisión del mercado minorista de electricidad*. Comisión Nacional de los Mercados y la Competencia. https://www.cnmc.es/sites/default/files/2322268_0.pdf

⁹¹ Data for day-ahead prices taken from ENTSO-E's transparency platform at <https://transparency.entsoe.eu/>; data for the three tariffs taken from <https://www.esios.ree.es/en>. The tariffs, in addition to the energy costs, include the costs for ancillary services, capacity payments, network access, and other cost elements. They don't contain costs for taxes and levies.

⁹² It is worth noting that the day-ahead prices show very little volatility, an effect that can be attributed, at least partly, to the significant surplus capacity in the system. This effect is more prominent on the default tariff of the PVPC, which follows more closely the day-ahead wholesale prices compared to the other configurations. Given the limited variation on day-ahead prices, flexible demand doesn't get the opportunity to respond more cost effectively than surplus generation, which is often being paid outside the energy market.

⁹³ CNMC. (2018, July). *Spanish energy regulator's national report to the European Commission 2018*. Comisión Nacional de los Mercados y la Competencia. https://www.cnmc.es/sites/default/files/2168599_3.pdf

- Whether the regulated tariff leaves room for the free market to offer more competitive products and undercut the former.

If the actual profitability of the regulated tariff is too low, or even negative (due to some of the associated costs being recovered elsewhere), then it would be very difficult for the latter to happen, effectively stifling competition. The above-mentioned difference between the regulated tariff and the average, retail tariff in the free market suggests that this might indeed be a problem. It is also important that the Spanish authorities monitor the effectiveness of the regulated tariffs and, more broadly, the retail tariffs in delivering demand-side flexibility.

The NRA's own research shows that the bulk of consumers were not aware of the difference between the free and regulated markets, and a third of consumers didn't know what tariff they are subscribed to (results based on a survey undertaken by CNMC in 2019).⁹⁴ Over 40% of the consumers that participated in the survey responded that they are on a time-varying tariff (either dynamic or ToU tariffs); however, the survey doesn't appear to contain any information about how consumers use these tariffs.⁹⁵

Explicit demand response

Spain has largely overlooked explicit demand response so far, as have most other European countries. Unlike implicit demand response, which affects the demand curve, explicit demand response represents a change in the supply curve. Customers flex their demand and sell it into the wholesale market in competition with offers from generators, in return for some financial reward. This is commonly facilitated and managed by an aggregator, especially for smaller consumers whose size prohibits them from direct participation in the market. An aggregator can be an independent entity or a supplier that uses demand-side flexibility to earn revenues in the market (e.g., by offering it in the ancillary services market) or to minimise its own or a market participant's costs (e.g., to manage a supplier's energy portfolio by reducing energy purchases at peak time and avoid imbalance charges). An aggregator delivers a share of the benefits accrued to the participating consumers.

As of today, the participation of demand response, either directly or through aggregation, is almost entirely prohibited in wholesale markets across all time frames.⁹⁶ In a positive recent development, the Spanish NRA has adopted a new regulation on

⁹⁴ CNMC. (2019, November). *Tres de cada cuatro hogares españoles desconocen la diferencia entre mercado libre y regulado del sector energético* [Three out of four Spanish households are unaware of the difference between free and regulated markets in the energy sector]. Comisión Nacional de los Mercados y la Competencia. <https://www.cnmc.es/en/node/377825>

⁹⁵ Other areas that might be worth exploring are the development of informational programmes to guide consumers about how to best use these tariffs and benefit from them and the potential to support the deployment of automated controls or other smart technologies.

⁹⁶ SmartEn. (2018). *The SmartEn map: European balancing markets edition 2018*. https://www.smarten.eu/wp-content/uploads/2018/11/the_smarten_map_2018.pdf. According to SmartEn, 'DR and aggregation is only allowed for generation and limited to pools of assets from the same technology'. Industrial consumers are also allowed to participate in the interruptibility scheme, as explained earlier in this paper.

the balancing market, as ordained by the European-wide Electricity Balancing Guideline (EB GL), that permits the participation of explicit demand response (and storage) in the balancing market. This includes the provision of different ancillary services, such as Frequency Containment Response (FCR) and manual Frequency Restoration Reserves (mFRR). The new regulation requires adaptation of the existing operational procedures that the TSO must implement by the end of 2020.⁹⁷

In developing these new rules for the participation of explicit demand response in the market, Spain should consider global best practices to fast-track its deployment.⁹⁸ Spain could usefully draw lessons from experience in the U.S. markets, where explicit demand response has a longer and more established history.⁹⁹ Other European markets that have successfully enabled participation in the wholesale markets, such as Belgium and France, can also offer useful experiences.¹⁰⁰ For example, the recently approved regulation for the Spanish balancing market stipulates that market participants should have a minimum offer threshold of 1 MW. Experience from the U.S. demonstrates that a lower minimum bid size of 100 kW is feasible and can significantly enhance the participation of demand response. Moreover, Spain can consider opening up the participation of explicit demand response in other wholesale markets, such as the intraday and day-ahead markets. It will also be important, as the new rules are taking effect, that the relevant authorities monitor their effectiveness through the establishment of a robust monitoring and evaluation framework.

Network tariffs¹⁰¹

CNMC, the Spanish regulator, has recently passed a new regulation for the determination of network tariffs, which will come into effect once the government finalises outstanding details.¹⁰² Network costs constituted just over 20% of the final electricity bill for households in 2017.¹⁰³ Combined with the energy component of the bill, they make up more than half of the final costs seen by consumers.

⁹⁷ Ministerio de la Presidencia Relaciones. (2019, December). Resolución de 11 de diciembre de 2019, de la Comisión Nacional de los Mercados y la Competencia. *Agencia Estatal Boletín Oficial del Gazette*. https://www.boe.es/diario_boe/txt.php?id=BOE-A-2019-18423

⁹⁸ The Spanish authorities should also consider whether there is a need to develop a comprehensive legal framework for aggregation and storage to the extent that European legislation is insufficient. Currently, there is no national legal framework for aggregation in Spain and only limited legislation about storage.

⁹⁹ See, for example: Hurley, D., Peterson, P., & Whithed, M. (2013, May). *Demand response as a power system resource: Program designs, performance, and lessons learned in the United States*. Regulatory Assistance Project. <https://www.raonline.org/knowledge-center/demand-response-as-a-power-system-resource/>

¹⁰⁰ Based on SmartEn, 2018.

¹⁰¹ The focus of this section is on the basic consumer network tariff designs and primarily the one for small residential consumers. Other tariffs, for example for consumers with self-generation, are outside the scope of this paper.

¹⁰² This includes, amongst others, setting values for certain parameters of the tariffs. CNMC. (2020, January). La CNMC aprueba la circular 3/2020 que establece la metodología para el cálculo de los peajes de transporte y distribución de electricidad. Comisión Nacional de los Mercados y la Competencia. <https://www.cnmc.es/en/node/378749>

¹⁰³ European Commission, 2019.

In brief, the design of the network tariffs consists of a capacity-based or power component charge (i.e., a charge based on a consumer's contracted capacity expressed in €/kW) and an energy or volumetric charge, whereby consumers pay according to their consumption (i.e., in €/KWh). The energy charge is time varying, meaning that a different price applies for different hours of the day; in other words, the energy charge is a ToU tariff. Consumers can also change their contracted capacity for certain hours of the day and be charged differently.¹⁰⁴

For low-usage residential consumers (with contracted capacity of less than 15 kW), the regulator has set three consumption periods across the day: peak, flat and valley.¹⁰⁵ For higher-volume consumers, six time periods will apply across the year (but only three on a certain day), following a similar logic. In addition, the legislation determines four seasons for all consumers except for the low-usage residential ones, varying from a high to a low season based on system-wide demand, with different applicable charges. Overall, the bulk of the network costs will be recovered through the capacity charges; the capacity component has a weight of 75% and an energy charge of 25%.

The new design is an improvement to the existing one (particularly for residential consumers that currently face only a capacity-based charge) in that it sends stronger signals about when to use the grid, that is, towards off-peak hours. At the same time, it fails to provide adequate incentives for a low-cost transition and is overly complicated. Below, we provide a brief analysis of the new design and more specifically the capacity-based charge, including some advantages and disadvantages of it:

- The capacity-based charge can incentivise consumers to shift consumption of new uses, such as electric vehicles (EVs), away from the hours of their individual peak demand, to keep the contracted capacity level as low as possible. It can also incentivise consumers to undertake permanent energy efficiency measures, such as buying a more efficient refrigerator to reduce their contracted capacity (we note, however, that these kinds of decisions are made infrequently).
- On the other hand, the proposed capacity-based tariffs are not reflective, in a meaningful way, of system costs. Companies size elements of the network based on the combined consumption of all consumers at peak time,¹⁰⁶ as there is significant diversity amongst loads.¹⁰⁷ Given any two consumers with the same level of

¹⁰⁴ CNMC. (2020, January 2020). *Las diez cosas que tienes que saber sobre la nueva factura de la luz*. Comisión Nacional de los Mercados y la Competencia. <https://blog.cnmec.es/2020/01/24/nueva-factura-luz-horarios/>. For residential consumers, the new regulation defines two periods, a peak period, from 8 a.m. to midnight, and an off-peak period for all other hours of the day. A consumer can sign up to a higher capacity requirement at off-peak hours and pay a significantly lower charge.

¹⁰⁵ The peak period corresponds to the highest demand hours in the day, around noon time (10 a.m.–2 p.m.) and evening time (6–10 p.m.), and the off-peak or valley corresponds to the lowest demand hours (from midnight to 8 a.m. in the morning). All other hours are considered flat hours.

¹⁰⁶ Certain elements of the network, such as one's line drop, are sized according to an individual consumer's demand.

¹⁰⁷ Traditionally, this exercise involves an assumption about the coincident peak demand coefficient per consumer (i.e., the average load consumed by every consumer at peak time). The size of the network would have been very different, indeed, if it represented the summation of the contracted capacity of all consumers.

contracted capacity, one may not be consuming at the time of system peak, while the other may be consuming at maximum, but under the proposed tariffs, both of them will pay exactly the same, even though they impose very different costs on the grid.

- Moreover, they do not incentivise cost-effective demand response, shifting demand away from peak, high-cost times to lower-cost times, or encourage conservation. Once you have decided on a certain connection capacity, your charge will be the same whether you are consuming at peak time or not and independent of whether you are consuming at all hours or nothing at all.¹⁰⁸
- The design of the networks tariff as a whole is overcomplicated and can result in unpredictable costs. For example, consumers can change the level of contracted capacity for predetermined hours of the day to minimise their bill. This appears to imply an expectation that consumers will optimise the level of contracted capacity they will normally use and then amend it for certain situations (e.g., when one wants to charge their EV and exceed the normally declared contracted capacity). This exercise, however, is too complex as consumers need to optimise across the entire year on parameters that are uncertain by nature (e.g., their consumption needs). Generally speaking, capacity is a concept that consumers find difficult to understand.¹⁰⁹ On the contrary, time-of-use tariffs are well understood and a tested, successful solution.
- All in all, most capacity-based charges do not empower consumers to save money nor send adequate signals for the cost-efficient use of the grid, that is, using the grid when there is spare capacity available.

To rectify these concerns, we recommend that the Spanish authorities shift the weight within the network tariff from the capacity-based charge to the time-varying energy charge (e.g., from 75%/25% to 25%/75%). This would be especially useful in cost effectively integrating new flexible loads, such as electric vehicles and heat pumps. Such loads generally have high withdrawal requirements relative to traditional loads.¹¹⁰ If their use overlays existing demand peaks, they can unnecessarily result in substantially higher network costs.¹¹¹ ToU charges, when designed well,¹¹² can send a

¹⁰⁸ Recognising this failure with capacity-based charges, the Dutch regulator is planning to phase them out as it doesn't consider them a good fit for the future power system (the current network tariff in the Netherlands is based on a 100% capacity-based charge).

¹⁰⁹ Norwegian Water Resource and Energy Directorate (NVE). (n.d.). *Consumer survey regarding capacity tariffs: English summary*. https://www.nve.no/Media/5355/summary_capacity-tariff-survey_tfou_qb_final.pdf

¹¹⁰ For example, home charging stations for EVs tend to vary between 3 and 7 kW.

¹¹¹ Hildermeier J., Kolokathis C., Rosenow J., Hogan M., Wiese K., & Jahn, A. (2019). *Start with smart: Promising practices for integrating electric vehicles into the grid*. Regulatory Assistance Project. <https://www.raonline.org/knowledge-center/start-with-smart-promising-practices-integrating-electric-vehicles-grid/>

¹¹² The most important design aspects are the ratio of the peak/off-peak prices and the duration of each consumption period. Experience shows that a 3-4 to 1 ratio tends to be effective in delivering demand response. Also, the shorter the peak period, the more likely that consumers will shift their more price-elastic consumption to another time. For more information, see, for example: Smart

strong signal to consumers to shift their flexible load away from peak demand hours and save on their bills.^{113, 114} In particular, the Spanish authorities should consider the implementation of critical peak pricing for these types of loads. A critical peak pricing tariff sets significantly higher prices for a limited number of pre-notified critical peak periods.¹¹⁵ CNMC has wisely decided on a similar price structure for EV charging points with output larger than 15 kW. In this case, the capacity-based charges will comprise 20% of the total network costs versus 80% for the energy charges.¹¹⁶ This structure will apply for the period from 2020 to 2025.

In addition, the network companies and regulator should monitor the utilisation of the networks and the effectiveness of any tariff network design in improving their use. The regulator could also consider applying an incentive to network companies to increase the utilisation of the networks; it will lead to better use of existing networks and thus a long-term reduction of investment costs.

Conclusions

Our analysis demonstrates that the Spanish market suffers from an acute overcapacity problem. The risks to resource adequacy are negligible over the short-to-medium term, even under extreme conditions, such as a scenario of significant plant retirements.

The power sector needs to retire plants to enhance its economic sustainability. While some closures are already planned in the short term, these will be insufficient to achieve this goal. An incremental step in this direction would be a formal coal phaseout, which would have the additional benefit of an orderly just transition for coal-reliant regions.

It's also clear there is no need for a CRM and that any existing mechanism should be abolished. This would be in line with the recently adopted CE4All package. Several resources have remained artificially in the market through the implementation of out-of-market interventions. Their added value to consumers is questionable, while they have cost dearly through higher electricity bills.

Electric Power Alliance. (2019, November). *Residential electric vehicle rates that work*. In partnership with E4TheFuture, Enel X, and The Brattle Group. <https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/>

¹¹³ For an example, see the Radius ToU network tariff in RAP. See Hildermeier, Kolokathis et al., 2019.

¹¹⁴ An important question relates to whether the proposed design should be the default option or opt-in alternative. In the latter case, consumers that wish to explore their flexibility could be given the option to opt-in to a largely time-varying network tariff. Over the medium-to-long term, time-of-use network tariffs will bring significant benefits as the deployment of variable renewables increases. It might be prudent to follow a step-wise approach to getting there and is a decision that needs to take consumer understanding of the market and preferences into account (e.g., the Sacramento Municipal Utility District has followed such an approach).

¹¹⁵ For an example of critical peak pricing, see the Tempo Tariff that is available in France. Kolokathis, C., Hogan, M., and Jahn, A. (2018). *Cleaner, smarter, cheaper: Network tariff design for a smart future*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/cleaner-smarter-cheaper-network-tariff-design-for-a-smart-future/>

¹¹⁶ A similar approach has been followed by utilities in California, recognising that the current system of high demand charges would likely make the business case for this type of charging points unsustainable, at least until sufficient EVs are on the road. For more information, see Hildermeier, Kolokathis et al., 2019.

As the power sector transforms towards a system increasingly based on variable renewables, the market will also need to adapt to reap the benefits of the transition and ‘keep the lights on’ at least cost, simultaneously. System flexibility will be key to achieving these goals. We recommend a series of measures to enhance system flexibility — an improved wholesale market design, the further integration of the Spanish market into the Continental market and an enhanced role for demand response.

The Spanish authorities should prioritise the implementation of administrative shortage pricing in the balancing market. This will help to reveal the real marginal cost of energy and incentivise a more cost-effective mix of supply-side and demand-side solutions to meet flexibility requirements and security of supply. Introducing locational signals in price formation will also support the development of flexibility, encourage new investments where most needed and help to address grid congestion cost efficiently.

Spain has commendably set a target to increase the level of interconnection with the Continental market. At the same time, existing interconnection capacity is significantly underutilised. It will therefore be important to increase the level of interconnector capacity made available to the market to the economically optimal level. Spain should also continue its efforts for further integration in the single electricity market.

The transitioning power system will require an enhanced role for demand-side resources. It will be important to ensure that time-varying retail pricing, which is relatively well developed in the country, delivers efficient outcomes and that explicit demand response can participate in all markets with rules that facilitate its development. Spain could also improve the design of its network tariffs to further enable cost-effective demand-side flexibility.

Appendix: The European framework for securing supplies¹¹⁷

The European institutions have recently adopted the Clean Energy for All Europeans (CE4All) package of legislation that, amongst other things, sets out the rules governing the wholesale electricity markets in Europe.¹¹⁸ More specifically, the Electricity Regulation sets out common rules that apply directly across all Member States of the European Union¹¹⁹ with the goal of creating a single electricity market across Europe. The regulation applies beginning January 2020.

The general principle of the regulation is to establish well-functioning, competitive and fast wholesale markets that reflect the true value of energy and balancing services.¹²⁰ The legislative file aims at removing regulatory and other distortions that are common in several European markets, such as the imposition of price caps that prohibit power prices from rising above a certain level. Ultimately, the regulation seeks to establish common rules across all Member States that would enable resources to compete against one another on equal terms and allow power to flow freely amongst EU countries based on market economics.

In this spirit, the regulation stipulates that Member States with identified risks to security of electricity supply should ensure that their wholesale energy markets are free of distortion and obstacles. Nations in this category must first identify the regulatory obstacles and market failures, such as the imposition of price caps, that are causing the risks. National policymakers must develop a market reform plan, detailing how they plan to remove the identified obstacles, and submit it to the European Commission for review. Member States with capacity remuneration mechanisms in place and those contemplating their implementation are also subject to this obligation.¹²¹

¹¹⁷ This section is taken from the following RAP paper: Kolokathis, C., & Hogan, M. (2019, December). *Market reform options for a reliable, cost-efficient and decarbonised Italian power system*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/market-reform-options-italian-power-system/>

¹¹⁸ The last step to finalise the CE4All package was completed in May 2019, with the adoption of the package. European Council and Council of the European Union (2019, 22 May). *Clean energy for all: Council adopts remaining files on electricity market and Agency for the Cooperation of Energy Regulators*. <https://www.consilium.europa.eu/en/press/press-releases/2019/05/22/clean-energy-for-all-council-adopts-remaining-files-on-electricity-market-and-agency-for-the-cooperation-of-energy-regulators/>

¹¹⁹ European regulations do not require transposition into national law, like European directives. They apply directly across the EU Member States upon entering into force.

¹²⁰ For example, the CE4All package stipulates the use of market-based procurement in the balancing market and ancillary services — where all types of resources, including demand-side resources, can participate — and promotes the introduction of shorter imbalance settlement periods of 15 minutes.

¹²¹ Following the Member States' submissions, the European Commission is tasked with issuing an opinion about whether a plan is complete within four months of receipt. It can then suggest amendments to Member States. EU countries already implementing a CRM are not permitted to sign any contracts until they have received the commission's opinion on their energy reform implementation plan. For Member States contemplating the introduction of a CRM, the energy reform implementation plan is part of the state aid submission to the European Commission. The Electricity Regulation also stipulates the prerequisites for annual monitoring and reporting on implementation of the plan.

The regulation also lists a series of measures that a Member State should consider when addressing the root causes of the risks to reliability. These include but are not limited to:

- Implementation of scarcity pricing in the balancing market.
- Further development of the transmission network, including interconnectors.
- Removal of any obstacles that disable the demand side from participating in the energy market.
- Establishment of market-based procurement for balancing and ancillary services.

EU countries may only apply capacity remuneration mechanisms if there are residual risks despite the energy reform plan they are implementing or are planning to implement (an energy reform plan and a CRM can be executed simultaneously). The CE4All package also stipulates that a Member State should investigate whether the outstanding reliability concerns can initially be addressed through a strategic reserve, as this is more consistent with the spirit of the regulation.¹²² A Member State is only permitted to apply a market-wide CRM as a last resort.¹²³

To monitor the risks to security of electricity supply, the European Network of Transmission System Operators for Electricity (ENTSO-E) is responsible for undertaking a Pan-European resource adequacy assessment. In addition, Member States can perform more detailed national assessments that are based on the EU-wide assessment (e.g., using the same reference scenarios), but they can also conduct sensitivity analyses on additional situations that might arise. The Electricity Regulation asserts that national assessments should apply a methodology and dataset consistent with the EU-wide assessment. They must have a regional scope and use a common methodology (to be established) for assessing the contribution of interconnectors to security of supply. If the resource adequacy assessments project acceptable levels of supply security as set by a Member State's reliability standard, the country will not be permitted to put a capacity market in place.

¹²² A strategic reserve is an instrument that sits outside the market and does not intervene in the energy market. It is, therefore, a more consistent solution to the vision of well-functioning wholesale markets. It is also much easier to abolish a strategic reserve, while the opposite is true for market-wide CRMs, as market players tend to rely heavily on them for their economic viability. Finally, strategic reserves are generally limited in size and, because of this, tend to cost only a fraction of market-wide CRMs. For example, the procurement cost for the strategic reserve in Great Britain for winter 2016-2017 was about one-third of the equivalent cost of the CM that replaced it the following year. Baker, P. (2018, 30 October). Britain's capacity market for electricity: Lessons for Europe. *Euractiv*. <https://www.euractiv.com/section/electricity/opinion/britains-capacity-market-for-electricity-lessons-for-europe/>

¹²³ A CRM is meant to be a temporary measure, can only be approved for a maximum of 10 years

and might need to be phased out even before the expiration of the approval period under certain conditions (e.g., if no new contracts are signed for three consecutive years).

Additional resources

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Market reform options for a reliable, cost-efficient and decarbonised Italian power system

<https://www.raonline.org/knowledge-center/market-reform-options-italian-power-system/> (2019)

Regional resource adequacy assessments: The key to ensuring security of supply at a reasonable cost

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