Renewable Electricity Integration: A Review of Policy Developments in Germany and Their Applicability to California

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Abstract

This paper describes the legal and policy frameworks governing the integration of variable renewable electricity generation resources (VREs) into the electrical systems and markets in California and Germany. It further seeks to provide quantitative or qualitative assessments of the outcomes of those respective frameworks in terms of the promotion of VRE deployment, cost of integration, and curtailment of VREs. Finally, the paper offers five potential lessons that the German experience may offer to California as it moves toward higher levels of VRE integration.

This paper is based upon a review of the literature and relevant public agency publications in both Germany and California during the Fall of 2017. The selection of sources for review and the synthesis of the literature review was informed by interviews in California and Germany with policymakers and academics who are recognized experts in the area of German energy law and policy. The author's familiarity with California energy policy and governance stems from more than eight years of energy law practice before the California Public Utilities Commission (CPUC) and teaching energy law focused on regulatory processes in California.

Based upon the review of contexts in each jurisdiction, the paper offers the following five potential lessons from Germany that may be applicable and beneficial to California as it seeks to integrate higher levels of VREs:

(1) Market design, including removing barriers to strong price signals, is key to incentivizing and deploying optimal integration solutions;
(2) Grid and market expansion are necessary to take advantage of resource diversity;
(3) The curtailment of renewable energy generators is inevitable, expensive, and ideally short-term;
(4) Central market design may be necessary but insufficient. Energy decentralization and democratization may be necessary to sustain a transition to higher levels of VREs; and
(5) Regulatory authority and responsibility may be too diffuse in California to enable quick, durable, and effective decision-making regarding VRE integration.

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1. Introduction

This paper describes the legal and policy frameworks governing the integration of variable renewable electricity generation resources (VREs) into the electrical systems and markets in California and Germany. It further seeks to provide quantitative or qualitative assessments of the outcomes of those respective frameworks in terms of the promotion of VRE deployment, cost, and the need to curtail VREs. Finally, the paper offers five potential lessons that the German experience may offer to California as it moves toward higher levels of VRE integration.

This paper is based on a review of the literature and relevant public agency publications in both Germany and California during the Fall of 2017. The selection of sources for review and the synthesis of the literature review was informed by interviews in California and Germany with policymakers and academics who are recognized experts in the area of German energy law and policy. The author’s familiarity with California energy policy and governance stems from more than eight years of energy law practice before the CPUC and teaching energy law focused on regulatory processes in California.

Section 2 provides a summary of lessons identified later in this paper from Germany’s experience that may benefit California.

Section 3 discusses the relevant background context in each jurisdiction. It begins with a discussion of California’s regulatory structure, its progress toward meeting its electricity demand with higher levels of renewable energy procurement, its market design and operation, and its current policies designed to help integrate VREs. Section 3 then discusses the relevant context in Germany, including the roots of Germany’s energy transition, the current status of renewable energy deployment, the legal framework governing VRE integration, its market design and operation, and its current policies designed to help integrate VREs.

Section 4 briefly assesses the outcomes for VRE policies in both jurisdictions in terms of reliability and cost.

Section 5 offers five lessons that California might learn from Germany’s experience integrating relatively high volumes of VREs.

Section 6 offers a brief conclusion. Acknowledgements, a brief vitae, a declaration of conflicting interests, a statement on funding, a list of acronyms, and a list of references follow the conclusion.

2. Summary of Conclusions

Having reviewed the policy contexts in both California and Germany, the paper discusses the following five potential lessons from Germany that may be applicable and beneficial to California as it deploys and seeks to integrate higher levels of VREs:

(1) Market design, including removing barriers to strong price signals, is key to incentivizing and deploying optimal integration solutions;
(2) Grid and market expansion are necessary to take advantage of resource diversity;
(3) The curtailment of renewable energy generators is inevitable, expensive, and ideally short-term;
(4) Central market design may be necessary but insufficient. Decentralization and democratization may be necessary to sustain a transition to higher levels of VREs; and
(5) Regulatory authority and responsibility may be too diffuse in California to enable quick, durable, and effective decision-making regarding VRE integration.

3. Discussion

In order to consider whether the German policies described in Section 3.2 may be applicable in the Californian policy context, this paper first briefly provides relevant contextual information concerning California in Section 3.1. In both sections, the paper reviews levels of renewable energy deployment, the operation of grids and markets, and current policies in place to integrate VREs.

3.1. California

3.1.1. Legal Jurisdiction over Integration of VREs in California

Several public agencies are charged with aspects of regulating the integration of VREs in California. Federal law in the U.S. has created an ever-more hazy jurisdictional dividing line between wholesale sales of electricity in interstate commerce, which are governed by federal law and regulated principally by the Federal Energy Regulatory Commission (FERC), and retail sales of electricity, which are generally governed by state law and, in California, regulated by the California Public Utilities Commission (CPUC).

At the federal level, FERC regulates the wholesale market in California primarily through review of proposals or actions by the California Independent System Operator (CAISO), a not-for-profit corporation whose Board of Directors is appointed by California's governor with the consent of the state legislature. CAISO operates a wholesale electricity market that includes most of the wholesale electricity sold and bought in California, as well as some electricity produced in neighboring states. As part of its operation of this market, the CAISO ensures the stability of the grid through procurement, as necessary, of ancillary services, as described more fully in Section 3.1. below.

Federal law also gives FERC the authority to regulate the transmission of electricity in interstate commerce. In practice, this means that new transmission-level interconnections and new transmission lines within most of California must be approved by the CAISO under its tariff approved by the FERC. Pursuant to this authority, the CAISO undertakes an annual transmission planning proceeding in which it considers proposals for new transmission projects that are needed for reliability, needed to reduce congestion costs, or are needed in order to further the states' policy objectives, including California's aggressive renewable electricity procurement requirements. As discussed more fully below, CAISO has also been proactive in revising its tariff to develop new market-based products to meet the need for increasing flexibility in the generation fleet to accommodate higher levels of VREs.

The State of California retains jurisdiction over the appropriate mix of electricity generation resources within the state. In that capacity, it has delegated authority to the CPUC to approve the integrated procurement plans of the State's retail sellers of electricity.[1] Among other goals, these long-term procurement plans are designed to ensure reliability of the electric supply in the state given the mix of resources expected to be available in the future.

Unlike other independent system operators in the U.S., the CAISO does not have a centralized capacity market. Instead, the CPUC and CAISO ensure reliability through a program called Resource Adequacy (RA), in which load-serving entities (LSEs) in California must demonstrate that they have adequate resources under contract to meet a prescribed minimum reserve margin during peak demand periods. The RA program includes CAISO tariff requirements that LSEs procure adequate generation capacity to meet 115 percent of their forecast peak demand in each month. (CAISO 2011 at 147). This capacity must then be bid into the market through a must-offer requirement. Load-serving entities provide these RA showings to the CAISO on a year-ahead basis. (*Ibid*). With regard to VREs, the amount of RA-qualifying capacity that these resources can provide is based on past output rather than nameplate capacity. (*Id.* at 153).

Due to the RA program requirements, CAISO has relied in the past relatively little on the two alternative capacity procurement mechanisms provided under its tariff: reliability must-run contracts and an interim capacity procurement mechanism. (CAISO 2011 at 147).

3.1.2. Status of Renewable Energy Procurement

3.1.2.1. California Renewables Portfolio Standard (RPS)

Under California law, each LSE in the State must meet at least 50 percent of its total retail sales of electricity through generation by RPS-eligible resources by 2030, with several increasing interim milestones.[2] As shown in Figure 1, below, about 29 percent of all electricity sold at retail in California in 2016 was generated from renewable resources.

Nearly all LSEs in California either met or exceeded the 2016 RPS requirement of 25% of retail sales served with eligible renewable energy resources. (CPUC 2017b at 1). The large investor-owned utilities (IOUs), which in 2016 served approximately 75% of California's retail

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[1] Cal. Pub. Util. Code § 454.52.

[2] Cal. Pub. Util. Code §§ 399.15, 399.30.

electricity load, are forecasted to achieve the 50% RPS target for 2030 ten years early, by 2020. (*Id.* at 1, 3). This is largely due to declining IOU customer demand due to the departure of customers from IOU service to service from Community Choice Aggregators (CCAs) or from the installation of customer self-generation, primarily rooftop solar. These CCAs also forecast that they will meet or exceed the existing 33% by 2020 requirement. (*Ibid*).

Publicly-owned utilities (POUs), which are regulated by the California Energy Commission (CEC) rather than by the CPUC, served approximately 20-25% of California's load in 2016 and are also largely in compliance with the State's RPS requirements. (*Id.* at 3).

The California Legislature is currently considering Senate Bill (SB) 100, which would require that 100 percent of the State's electricity be generated by clean energy sources by 2045, including interim goals of 52 percent from renewables by the end of 2027 and 60 percent by the end of 2030. To achieve the 2030 goal, SB 100 maintains the current list of eligible renewable energy resources defined in prior RPS legislation, which generally excludes hydroelectric generation facilities greater than 30 megawatts (MW). However, for the 2045 100% goal, SB 100 contemplates a different "zero carbon" requirement, which could make eligible large hydroelectric generation facilities and potentially other resources that did not count toward the RPS in the past. According to recent polling, a strong majority of Californians (76%)—including majorities across parties—support the goal of 100 percent renewably sourced electricity. (PPIC 2017 at 16).

California has an increasingly diverse retail electricity market, with competition in some areas. The State's three large IOUs still served approximately 75 percent of the State's retail electricity load as of 2017, while smaller and multi-state IOUs, CCAs,[3] and Electric Service Providers (ESPs)[4] collectively served approximately 25 percent of the retail load. (CPUC 2017b at 10). California's POUs served approximately 20-25% of the State's total retail electric load as of the same date. (*Ibid*). With very minor exceptions, all of these LSEs are subject to the same RPS requirements.[5]

The CPUC and the CEC have approved a number of what those agencies view as complementary programs in order to guide the State's LSEs to procure optimal portfolios of

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[3] CCAs are publicly-owned retail sellers of electricity. These entities offer the residents of their cities or counties an alternative to traditional utility service, and under California law they become the default provider after the date they are formed (residents who prefer to maintain electric service from the incumbent utility must opt-out of the CCA's offering). CCA service has grown quickly and at an increasing rate over the last decade, and the CPUC estimates that as much as 85% of retail customers could be served by entities other than utilities by the middle of the next decade. (CPUC 2017a at 3).

[4] ESPs are for-profit entities authorized under California law to offer alternative retail electric service in competition with utilities. ESPs were created during the deregulation of the 1990s, but the Legislature capped the total volume of retail sales that can be served by ESPs following an energy crisis in 2000-2001 due to concerns about the market manipulation in the deregulated market that had caused the crisis. That cap has been increased by a relatively small amount since that time, but ESPs continue to serve only a small portion of large commercial and industrial retail customers in California.

[5] *See* Cal. Pub. Util. Code §§ 380(e), 399.12(j).

renewable resources. These include a feed-in tariff program,[6] a Reverse Auction Mechanism,[7] a bioenergy carve-out program,[8] net-metering and direct subsidy programs to encourage the development of rooftop solar, and a general RPS solicitation program for large-scale renewable generation facilities. The CPUC has attempted to address integration cost concerns in part through the adoption of an "interim integration cost adder" that it ordered the large IOUs to add to the cost of wind and solar when evaluating bids received in certain renewable electricity solicitations, but the value of the adder was relatively low and has appeared to have little impact on the overall outcome of the solicitations. In response, the Legislature has considered but failed to adopt bills in recent sessions to create new mandatory procurement carve-out programs for "baseload" renewables (e.g., geothermal).

Although resource diversity has been a major goal of each of these programs, the procurement of VREs has increased at a much higher rate than new procurement from baseload renewable generation due to the rapid relative decreases in past years of the levelized cost of energy from wind and solar. These cost decreases have translated into similar decreases in the cost of wind and solar power purchase agreements (PPA), helped along by tax subsidies at both the state and federal levels.

3.1.2.2. California's Generation Portfolio

About 29% of the electricity that California LSEs served their customers in 2016 came from RPS-eligible resources, which represents a near tripling in the percentage of renewables in the generation mix between 2010 and 2016. (Penn 2017). While nearly all of the legacy renewable energy contracts serving California customers was with hydroelectric, geothermal, and wind producers, the percentage of total renewable energy from solar facilities has grown very quickly in recent years, as shown in figure 1.

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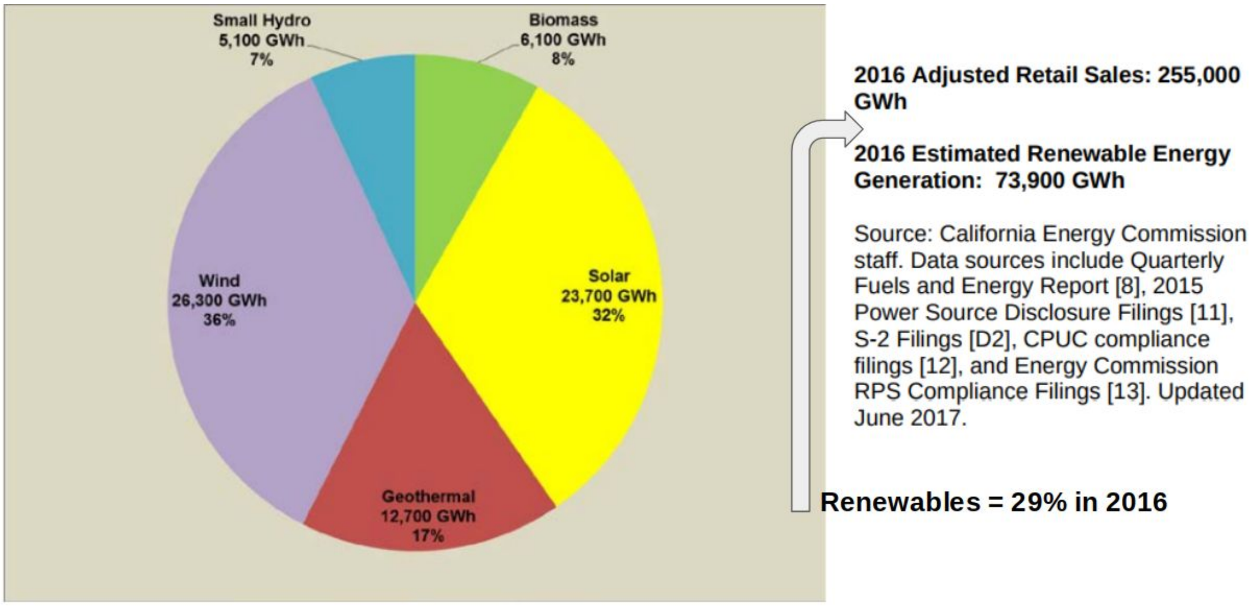
[6] In its most recent iteration, California's feed-in tariff program was called the Renewable Market-Adjusting Tariff (ReMAT) and featured a price that increased or decreased depending on supply conditions in order to avoid overpaying renewable generators as the cost of generation has declined. Another feature of the program was that solar, wind, and baseload resources were considered separately to avoid all of the Program's capacity going simply to the lowest-cost technology. A federal court ruling in 2017 found the ReMAT to conflict with federal law, leaving its future in doubt. *Winding Creek Solar LLC v. Peevey*, No. 13-cv-04934-JD (N.D. Cal. Dec. 6, 2017).

[7] The RAM operated as a typical reverse auction, establishing periodic and overall program capacity procurement targets and ordering the large IOUs to take the lowest-cost bids until each capacity target was achieved. It was designed to streamline and expedite the procurement process through the use of standardized contracts and eligibility criteria.

[8] A major motivating factor behind the bioenergy carve-out programs in California was a multi-year drought that caused a massive die-off of trees in California's mountains. Elected leaders sought to reduce fire danger through ordering the large IOUs to procure electricity from biomass generation facilities that could not otherwise secure power purchase agreements (PPAs) on the competitive market.

Fig. 1. Generation from Renewable Energy Facilities Serving California in 2016



Source: CEC, Tracking Progress, August 2017

3.1.3. CAISO Energy Market Design and Operation

The CAISO wholesale energy market is comprised of distinct day-ahead and real-time processes. The hour-ahead market forecasts demand and optimizes projected supply using 15-minute intervals. In real-time, demand and supply are balanced on a 5-minute basis.

CAISO, like other Independent System Operators in the U.S., has a nodal energy market design. This means that pricing and congestion management are based on locational marginal pricing. Locational marginal prices (LMPs) represent the additional cost of serving the next increment of demand at each point (or node) on the network, taking into account the bid prices of resources and transmission network constraints. LMPs are derived using a full network model that includes a detailed model of the physical power system network. Thus, the resulting prices are designed to reflect the physical system and market conditions and limitations. (CAISO 2011, p. 17).

Under locational marginal pricing, as congestion appears on the network, prices at each node area are adjusted to reflect congestion costs or benefits from supply or demand. Within areas where flows are constrained by limited transmission, local generation (which may be higher or lower cost than system average) is dispatched to meet demand. Hence, nodal prices in congested regions are often higher, but may also be lower (if local low-cost generation is greater than demand and cannot be exported from the region), than the price in unconstrained regions.

3.1.3.1. CAISO Ancillary Services

Ancillary services are energy products used to help maintain grid stability and reliability. There are four types of ancillary services products that are procured in the CAISO markets: regulation up, regulation down, spinning reserve, and non-spinning reserve. System-wide requirements are set for each ancillary service to meet or exceed the Western Electricity Coordinating Council's (WECC) minimum operating reliability criteria and the National Electricity Reliability Corporation's (NERC) control performance standards.

Regulation energy is used to control system frequency and varies as generators change their energy output. Resources providing regulation are certified by the CAISO and must respond to automatic control signals to increase or decrease their operating levels depending upon the need. The CAISO uses regulation up and regulation down to maintain system frequency by balancing generation and demand.

Spinning and non-spinning resources, collectively known as operating reserves, are used to maintain system frequency stability during emergency operating conditions and major unexpected variations in load. When economical, the market software will procure more of a higher quality reserve, such as regulation, to meet the requirement of a lower quality reserve such as the operating reserves. (CAISO 2011 at 139).

Spinning reserve is standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched. At least 50 percent of total operating reserves must be met by spinning reserves. (*Id.* at 141). Non-spinning reserve is capacity that can be synchronized to the grid and ramped to a specified load within 10 minutes.

The regulation capacity requirement is based on inter-hour changes in scheduled generation, intertie schedules, forecasted demand and the number of units starting up or shutting down. Therefore, the requirement can vary each hour. (*Id.*)

The operating reserve requirement is set by the maximum of 5 percent of forecasted demand met by hydroelectric resources plus 7 percent of forecasted demand met by thermal resources, or the largest single contingency. (*Id.*) At least 50 percent of total operating reserves must be met by internal resources. (*Ibid*).

Under the nodal market, 100 percent of the expected requirement for each of the four types of ancillary services is procured in the day-ahead market. All reserve requirements can be increased or decreased in the real-time pre-dispatch market based on updated system conditions. Additional capacity may be procured in the real-time pre-dispatch to replace capacity that is no longer available because of outages and derates. Also capacity may be procured to meet a market requirement increase resulting from an increase in the demand forecast. Units with day-ahead awards that are unable to provide the capacity in real-time are charged for the unavailable capacity at the real-time price for ancillary services. (*Id.* at 139.)

Resources providing ancillary services receive a capacity payment, normally the market clearing price, in both the day-ahead and real-time markets. (*Id.* at 144.) Capacity payments in the real-time market are only for incremental capacity above the day-ahead award.

The CAISO implemented scarcity pricing of ancillary services in both the day-ahead and real-time predispatch processes in 2010. This mechanism administratively sets the ancillary service price in the case of ancillary services deficiencies. The price level accounts for both the quality and location of the reserve and sets the price for each ancillary service product and region accordingly. (*Id.* at 142.)

3.1.3.2. Long-Term Capacity Procurement in CAISO

The CAISO, in conjunction with the CPUC, has created an RA capacity procurement mechanism in order to ensure that load-serving entities have a sufficient percent of their peak load requirements under contract in each quarter of the year ahead. This RA program and the "flexible RA" mechanism added by CAISO and the CPUC in recent years, is discussed in more detail in Section 3.1.4.1.1., below.

As relatively flexible gas-fired generators have threatened to retire in California in recent years, much discussion has centered on the need for a longer-term capacity procurement mechanism that would fill a perceived gap between the short-term (annual) RA program and the long-term (decadal) long-term procurement plans and related procurement required by the CPUC. In the absence of such a medium-term mechanism in 2012, the CPUC even ordered the IOUs to negotiate a short-term RA contract with a specific gas-fired power plant that had threatened to close.[9] That plant shuttered anyway in 2016 after the IOU contracts expired.[10]

3.1.3.3. Market Participation

Most energy sold into the CAISO market is generated pursuant to long-term (ie., greater than 10 years in duration) PPAs that are bilaterally negotiated between the generator and a California LSE. In the case of the IOUs, these contracts must subsequently be submitted to the CPUC for regulatory approval, and they only become effective upon receipt of that approval. This focus on long-term procurement is partially in response to California's energy crisis of 2000-2001, when deregulation combined with market design flaws and manipulation resulted in California LSEs paying exorbitant prices for the electricity they had to procure on the spot market. In response to that crisis, California passed new integrating/long-term procurement planning and RPS laws that require LSEs to demonstrate their ability to meet projected demand for at least

[9] *See* CPUC, Resolution E-4471.
[10] *See* CPUC, Resolution ESRB-6.

10 years into the future using contracts in their portfolios. Additionally, California's RPS law strongly disfavors short-term contracting in order to stimulate the development of new renewable generation facilities, which have been traditionally viewed as requiring a long-term contract in order for the developer to secure adequate financing. Long-term contracting for up-front capital-intensive wind and solar projects is common outside of California as well because of these financing requirements.

The LSEs solicit bids for primarily long-term PPAs based upon their projected retail sales. Alternatively, the IOUs have sometimes been ordered to offer various forms of feed-in tariffs for long-term PPAs. The structure of these PPAs has generally required the generator to sell all of its energy, capacity, and renewable energy credits (RECs) to the LSE. The transfer of title often takes place at the busbar of the generation facility, at which point the LSE must then schedule the sale of the energy or capacity into the CAISO. When structured in this way, the LSE becomes the "scheduling coordinator" and is subject to penalties for scheduling deviations (which may or may not be passed on to the generator, depending on contract terms).

The energy is therefore usually sold at a fixed price per megawatt to the LSE, which then sells the energy into CAISO at the then-prevailing LMP. The LSE must then schedule its load into the CAISO market as well and pay the then-prevailing LMP at the load aggregation point where it receives the electricity. The price difference that an LSE pays to the generator under a fixed, long-term PPA and the LMP where the electricity is injected into CAISO is the "green adder," or the cost of securing the REC for use in RPS compliance, under that PPA.

This high level of bilateral, out-of-market transactions has led to complications in the CAISO market. Many of these resources, especially the renewable resources, are "self-scheduled" into the CAISO market, meaning they become price-takers. Under this market design, a large portion of supply needed to meet demand is automatically scheduled in the day-ahead market. However, the marginal supply needed to meet demand is provided by resources that are bid into and scheduled through the market software.

On one hand, the high level of self-supply and forward contracting in California's wholesale markets has limited the incentive and ability for suppliers to exercise market power. (CAISO 2011 at 17). However, over the past few years, efforts have been made to begin economically bidding supply, including renewable supply, to allow the market to function better.

Another emerging issue related to the current market structure in California is that legacy PPAs do not tend to have terms and conditions that address the need to generate flexibly (e.g., to ramp up or down depending on market conditions and system needs) or that allow the participation of VREs in the ancillary services markets. If, for example, a generator has a long-term PPA with an LSE but schedules its own output into CAISO, that generator could choose to offer flexible capacity rather than self-schedule its generation into the market. In that case, if its bid is accepted to reduce output, then the offtaker under the long-term PPA with the generator will not receive the full output of the plant as provided in the PPA and does not get the expected RPS credit. The LSE may have a claim for breach of contract in this case, even though the public interest may have been better served by the facility offering a flexible capacity bid. This could lead to a sub-optimal outcome in which gas-fired generators provide the necessary integration services so that renewables can produce at any time and any cost. An alternative might be for future PPAs, or amendments to existing PPAs, to consider changes in a generator's output in order to provide ancillary services as "deemed delivered" output for both purposes of payment under the PPA and under the RPS counting rules.

3.1.4. Current Strategies to Integrate VREs

3.1.4.1. Ancillary Services Markets

CAISO sees "non-energy Essential Reliability Services" (i.e., capacity-related ancillary services) as critical market-based solutions to renewable integration through at least 2030. It also argues that the removal of price caps - allowing for price spikes during certain hours of the year for reserve capacity - will allow what it believes is necessary, flexible gas-fired generation to remain operational. (CAISO 2017c at 10).

CAISO also anticipates that capacity markets will cause photovoltaic (PV) generation to lose incremental value over time and will incentivize instead the installation of dispatchable clean resources like biomass, geothermal, storage, and voltage support technologies. (*Id.* at 12).

3.1.4.1.1. Flexible RA

CAISO recognized years ago the need to create a Flexible RA market product to provide flexible capacity to help integrate the rapidly increasing volumes of VREs generating and being imported into its boundaries. Accordingly, it created the first Flexible RA product and requirement in conjunction with the CPUC, and FERC approved that proposal in 2014. It called this initial proposal the Flexible RA Must-Offer Obligation (FRACMOO). Under the FRACMOO revisions to the CAISO's tariff, the CAISO develops Flexible RA capacity allocations and assigns those to local regulatory authorities like the CPUC. It also developed rules for backstop authority to procure additional Flexible RA in the event that the showings of regulated entities did not provide sufficient Flexible RA.

CAISO is currently working on a stakeholder initiative to introduce a revised Flexible RA capacity procurement framework. It views the original FRACMOO proposal as being over-inclusive in that it allows too many relatively non-flexible generators to participate and provide Flexible RA that does not adequately address system needs. (CAISO 2017b at 3). Currently, CAISO envisions that this revised framework will include the following elements:

(1) "Identify the ramping needs that Flexible RA should be procured to address
(2) Define the product to be procured
(3) Quantify the capacity needed to address all identified needs

(4) Establish criteria regarding how resources qualify for meeting these needs
(5) Allocation of flexible capacity requirements based on a sound causal principles"
(CAISO 2018 at 16).

In general, CAISO envisions the revised Flexible RA product closing gaps between the current market products and operational needs by defining products and rules that address both predictable and unpredictable variability in system conditions:

1) Predictable: known and/or reasonably forecastable ramping needs; and
2) Unpredictable: ramping needs caused by load following and forecast error.
(CAISO 2017b at 3).

If it is successful, CAISO views this new framework as providing market-based products that minimize the need to use out-of-market (e.g., penalty) solutions to balance supply and demand.

To address these needs, the CAISO is proposing to develop three Flexible RA products:

1) Five-minute Flexible RA;
2) Fifteen-minute Flexible RA; and
3) Day-Ahead Shaping RA
(CAISO 2017b at 4).

The CAISO envisions that Flexible RA product definitions will focus on ramping speed capability and will be location- and technology-agnostic, allowing both imports and VREs to bid to provide Flexible RA to the extent those resources can meet the technical requirements. The CAISO currently anticipates completing its Phase 2 Flexible RA proceeding in late 2018 in cooperation with the CPUC's RA proceeding. (CAISO 2018 at 4).

3.1.4.2. FERC Order 764

On June 22, 2012, FERC issued Order 764[11] to adopt reforms that would remove barriers to the integration of variable energy resources. Specifically, the FERC required each public utility transmission provider – including the CAISO – to make two revisions in a compliance filing:

(1) Revise its open access transmission tariff to include prescribed provisions that give customers the option of using intra-hour transmission scheduling at 15-minute intervals;[12] and

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[11] Integration of Variable Energy Resources, Order No. 764, FERC Stats. & Regs. ¶ 31,331 ("Order No. 764"), order on reh'g and clarification, Order No. 764-A, 141 ¶ 61,232 ("Order No. 764-A") (2012), order on clarification and reh'g, Order No. 764-B, 144 FERC ¶ 61,222 (2013).
[12] Order No. 764 at PP 97, 113, 373-74, Appendix B. The requirement to implement 15-minute transmission scheduling only applies to intertie transactions in organized wholesale energy markets like the Independent System Operator markets. *Id.* at P 113.

(2) Revise its pro forma Large Generator Interconnection Agreement to include prescribed provisions that define variable energy resources and require new interconnection customers whose generating facilities are variable energy resources to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting.[13]

In November 2013, the CAISO submitted tariff revisions to FERC to implement Order No. 764. It sought and received approval to implement a superior alternative to the FERC minimum requirements in the form of improvements to CAISO's market design. The key feature of this alternative market design was to create a new 15-minute market for both internal and imported resources so that they could be scheduled and settled on the same intervals. (CAISO 2013 at 4).

Previously, the CAISO had created a Participating Intermittent Resource Program (PIRP), which helped to reduce the exposure of VREs to schedule deviations by netting those deviations in all 5-minute periods across an entire month. With the introduction of the 15-minute market and implementation of FERC Order No. 764, CAISO phased out the PIRP program, as it was fundamentally inconsistent with the principle of cost causation. (CAISO 2013 at 5).

3.1.4.3. Curtailment

As part of recent integrated planning proceedings, the CPUC has found that curtailment of renewable generation, including VREs, has increased in California in recent years due to the sharp increase in solar generation. (CPUC 2017b at 54). The CAISO's data confirms the CPUC's conclusion. In 2015, CAISO was forced to curtail more than 187,000 total megawatt-hours (MWh) of solar and wind generation. (CAISO 2017a). In 2016, that number rose to more than 308,000 MWh. (*Ibid*). Most of these curtailments occurred when wholesale market prices fell sufficiently negative to cause generators, or their scheduling coordinators, to stop generating rather than to pay to put their electricity on the grid. (*Ibid*).

However, the CPUC does not necessarily view this as a negative development. The CPUC, CAISO, and the IOUs seem to be aligned in determining that curtailment of renewables can be a cost-effective strategy for integrating VREs, when compared to other integration options such as transmission upgrades or energy storage. (*See, e.g.*, CPUC 2017b at 54). The CPUC's recommendation, based on its initial modeling, is that "buying additional solar and economically curtailing renewable resources in the limited hours of the year when they are not needed is a cost-effective strategy to integrating more renewables into the grid and displacing natural gas generation." (*Ibid*).

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[13] *Id.* at PP 171, 210, 373, 375, Appendix C.

3.1.4.4. Export

An alternative to curtailing renewable generation to balance supply and demand within CAISO is to simply export the surplus electricity to other states. That's exactly what happened on 14 days during March 2017, when California paid Arizona utilities to take surplus power. In total, exports of surplus electricity from California saved Arizona consumers millions of dollars in 2017 alone. (Penn 2017). However, these exports do not necessarily reduce greenhouse gas emissions, as utilities in other states may curtail their own renewable generation in order to accommodate the imports from California. (*Ibid*).

3.1.4.5. Energy Storage

California has also sought to stimulate the demand for energy storage solutions, and hopefully drive down costs, through a 2010 state law, Assembly Bill 2514. Through implementation of that law, the CPUC has mandated the procurement of 1.3 gigawatts (GW) of energy storage, which the state's utilities are satisfying through various procurement solicitations and programs.

3.1.4.6. Expansion of CAISO

CAISO has identified regionalization of the electricity market as a key priority for integrating higher levels of renewable energy in 2030. (CAISO 2017c at 3). This is intended to drive down transmission needs, minimize generation costs, and provide greater reliability through geographic diversification. (*Id.*).

CAISO predicts that by 2030, many of the balancing authorities in other states in the Western U.S. will be absorbed into "Regional System Operators." This will remove transmission charges between these balancing authorities and, CAISO believes, facilitate the regional exchange of clean resources. (*Id.* at 19).

However, bills introduced in California in 2016 and in 2017 to put CAISO on a path to become more regional failed to be enacted due to the complicated tension between the labor unions' push to keep the renewable generation jobs within California and the policy goal of achieving decarbonization at least-cost. Regionalization of CAISO is also stymied by the seemingly intractable issues of: (1) how and whether each of the states should pay for the existing transmission infrastructure and the future transmission upgrades in each of the other states; (2) how political control of a regional CAISO would be apportioned among the states; and (3) how to integrate the differing states' energy policy goals.

3.1.4.7. Sector Coupling and Electrification

CAISO has identified electrification of the transport and building sectors as a necessary and key component of the energy transition toward 2030 and beyond in California. (CAISO 2017c at 4). Importantly, this helps not only from a greenhouse gas (GHG) perspective, but also from an integration cost and efficiency perspective: "The more of the economy we electrify, the easier and more affordable it becomes to manage total energy use." (*Ibid*). California is set in coming years to introduce mandatory time-differentiated retail electric pricing, and these new time-of-use tariffs, in combination with a push toward electrification of heating and transportation and the automation of control devices in these sectors, could provide strong incentives and the capabilities for retail customers to provide grid flexibility by changing their energy use practices when prices signal the need for that flexibility.

3.1.4.8. Using Renewables to Integrate Renewables

A 2017 study conducted by the CAISO in cooperation with National Renewable Energy Laboratory (NREL) and First Solar showed that a large (300 MW) PV facility can provide essential grid services to help integrate renewables through minor modifications to install sophisticated automatic "grid-friendly" controls. (*See generally* CAISO & NREL). While this is true from a technical perspective, the contractual and financial issues are legion. Most PPAs executed in the past between renewable energy generators and utilities in California require that the full available output of the facility be sold to the utility, leaving no spare capacity to be used to provide ancillary services. Moreover, the IOU offtaker is often the scheduling coordinator (the interface between the CAISO and the renewable generator) for facilities with which it has entered into PPAs, meaning that the IOU (rather than the generator) makes the decision regarding whether to curtail the facility for economic reasons. Generally speaking, generators are still paid for "deemed delivered" energy during such economic curtailments, and so an IOU could be expected to only curtail the facility where the negative price exceeds the value of the resulting RPS credit.

In light of these existing contractual arrangements, CAISO views a key part of the energy transition involving changes to PPAs that enable renewable facilities to provide a wide range of essential reliability services and to be compensated for doing so. (CAISO 2017c at 12). In order to maximize the opportunity for economic curtailments of renewables to help solve overgeneration situations, CAISO also recommends that future PPAs require that renewables be bid into the market rather than self-scheduled. (*Ibid.*)

3.2. Germany

3.2.1. Underpinnings of the *Energiewende*

Germany's *Energiewende* (roughly translated as "energy transition"), first envisioned and described as part of the anti-nuclear movement in the 1970s and brought into mainstream policy in the past decade, has been described as "a complex process of sociotechnical change, which requires destablIizing lock-in mechanisms in the existing system and shifts in behavioral patterns of consumers and producers as a well as technological, political, and social innovations." (Tews 2015 at 269). While the original overarching goals of the *Energiewende* were the reduction of GHGs and the closing of the country's nuclear power plants (*see, e.g.,* Expertenkommission 2012 at Z-2), this description fails to adequately capture the complexity and breadth of what many Germans hope to achieve with this transition.[14]

For some, probably a vocal minority of Germans, a key principle associated with the *Energiewende* is that of empowering ordinary citizens to exercise more control over energy production and consumption decisions through decentralization of the energy system. This concept is sometimes referred to as "*Bürgerenergie*," or "citizens' energy." It is a reaction to, and rejection of, large-scale, centralized energy development and has the fundamental goal of diversifying suppliers of energy (particularly those that are publicly-owned and/or local). For this group of Germans, the idea of local control and customer empowerment has value that justifies, if necessary, paying a higher price for energy commodities than what might be charged by larger, centralized production facilities. At the extreme, some communities in Germany have sought to create complete "energy autarchy."[15]

Although decentralization and local control are important concepts for some Germans, scholars have noted that Germany lacks a broadly-shared guiding vision regarding the direction of the energy system transformation in terms of system architecture, and specifically whether it should be more decentralized or more centralized. (Beermann and Tews 2016 at 130). So far, experimentation with a decentralized energy system has not been a major focus of major market participants or the federal government. (*Ibid*).

Another underlying goal of the *Energiewende* is to produce energy in a more sustainable way. Thus, ideally more-polluting forms of energy production like coal-fired power plants will be replaced by less-polluting forms of renewable energy production.

There are obvious potential conflicts between the goals of long-term environmental sustainability and energy security, the short-term financial incentives to produce and distribute energy in the most efficient manner given the current state of infrastructure and the industry, and the political desire of some Germans for local control over energy decision-making. These conflicts become particularly evident when considering the issue of integrating VREs since many potential solutions for lower-cost integration rely on large-scale, complex systems and geographic diversity of electricity producers. Complex markets and the building of a robust transmission grid to take advantage of geographic diversity can hinder the participation of ordinary citizens in energy production and can reduce local control over energy decision-making.

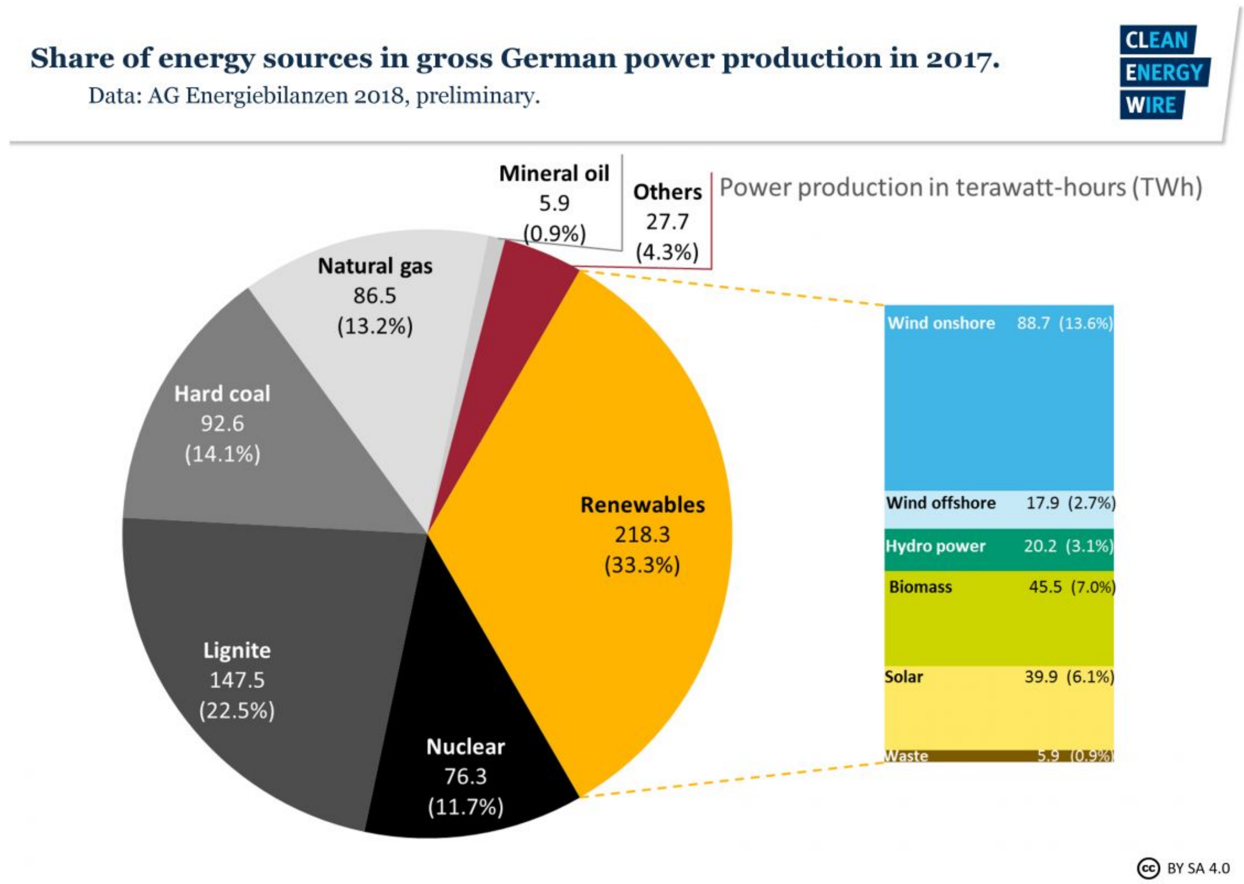
[14] For example, a 2016 survey of German energy policy experts found that while most associated climate protection as a top-level goal of the *Energiewende*, two-thirds found that the *Energiewende* would still be needed to meet up to 14 other policy goals even in the absence of climate change. (Joas et al. 2016).

[15] *See, e.g.,* https://www.buzzn.net/ueber/ (visited July 16, 2018) (noting that the goals of "Energy Groups" include self-sufficiency, autarchy, and local sourcing).

3.2.2. Status of Renewable Energy Procurement

As shown in Figure 2, renewable resources generated approximately 33% of total gross generation (including exports, losses and power plants consumption) in Germany in 2017. This corresponds to 36.2% of German gross electricity consumption in 2017. (BMWi 2018 at 43).

Fig. 2. German Gross Generation by Fuel Type, 2017



The 2017 Amendments to Germany's Renewable Energy Sources Act (EEG) reaffirm the objectives of previous amendments to the EEG. The EEG continues to call for a rise in the share of renewables in gross electricity consumption to 40-45 percent by 2025, 55-60 percent by 2035,[16] and at least 80 percent by 2050. (Agora 2016 at 6).

3.2.2.1. Generation Mix

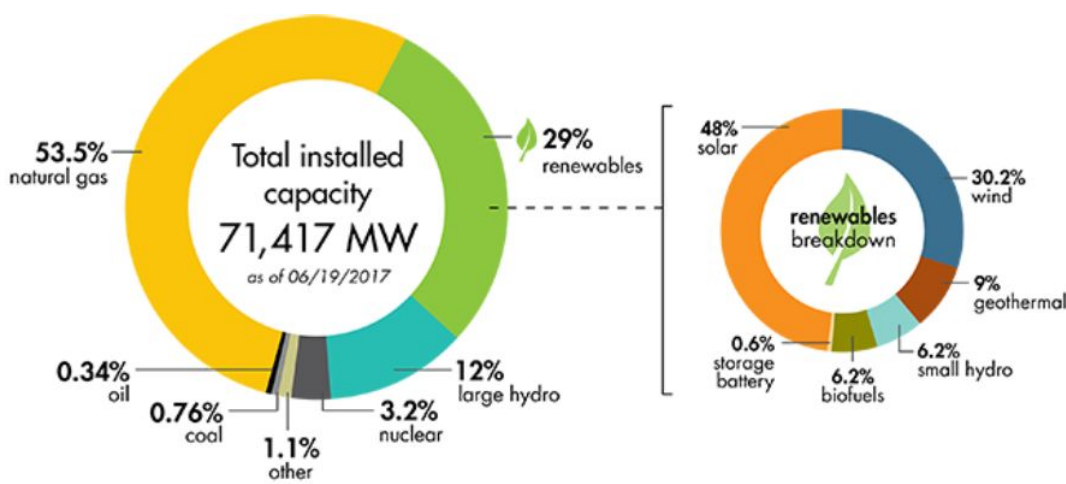
The total proportions of renewable generation resources in California and Germany in 2016 relative to all generation resources are very similar. Comparing Figures 1 and 2, above, it is

[16] An agreement between political parties to form a German coalition government in 2018 foresees raising this 2035 target to 65%.

also apparent that the total proportion of VREs as a percentage of total generation in each jurisdiction was similar in recent years (about 19.4% in Germany in 2017 and about 19.6% in California in 2016. It is likely that 2017 data for California would show a higher penetration of VREs). Interestingly, these figures demonstrate that VREs run at a much higher capacity factor (generation per installed MW) in California. As shown in Figure 3, below, total VRE generation capacity in California in 2016 was 16.2 GW, or about 23% of all installed capacity; in Germany, about 90.3 GW, or about 43% of all installed capacity in 2016 came from VREs. (BNA 2017c at 51, 65). Thus, total installed VRE capacity in Germany is about six times that in California and about twice the proportion of all installed capacity. The data suggest that in recent years, VREs in Germany were about half as efficient as those in California since they required double the proportion of installed capacity to produce the same proportion of energy.

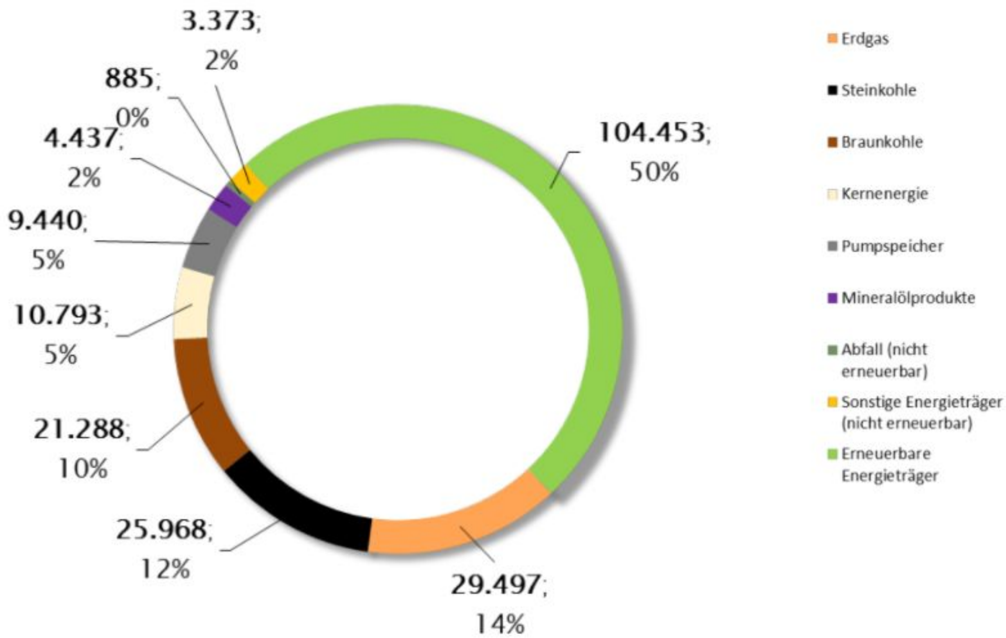
In comparing Figure 2, above, and Figure 3, below, it also is apparent that California's renewable generation portfolio is solar-heavy, while Germany's is wind-heavy. In theory, it should be easier to integrate a more diverse mix of renewable resources since the variability could be expected to be uncorrelated between the resource types. Accordingly, having more solar or wind may present different integration-related challenges and opportunities. For example, to the extent that California solar is more variable than German wind, this may create a better opportunity for the deployment of energy storage in California.

<u>Fig. 3. Installed Generation Capacity in CAISO - 2017</u>



Source: CAISO

Fig. 4. Installed Generation Capacity in Germany - 2016 (MW)



Source: BNA, Bundeskartellamt. 2017 Market Monitoring Report.

Figure 4, above, shows Germany's installed generation capacity in 2016 by fuel type. In 2016, coal-fired generation remained a significant portion of the power mix in Germany at about 22% of installed capacity. Nuclear power comprised another 5%, and gas-fired generation about 14%.

A major goal of the *Energiewende* is the phase-out of nuclear-based electricity production in Germany. In 2011, eight nuclear power plants with a total output capacity of around eight GW were closed down permanently, two further have been shut down at the end of 2015 and 2017, respectively, and German law foresees a complete phase out nuclear energy completely by 2022, resulting in a further reduction of 12 GW in nuclear generation from 2012 levels. (BMWi 2014 at 13).

As of 2016, the volume of natural gas-fired generation was rising quickly in Germany (but was still below volumes seen before 2012). According to the federal government, gas-fired power plants increased generation by nearly 40% compared to 2015. (BNA 2017c). While much of the increase may be attributed to weather and global macro-economic factors, this trend generally makes sense given that "[t]he overall need for fossil-fired power stations, and for base load and mid-merit power plants in particular, is decreasing while the demand for flexible peak load technologies and demand side management is rising." (BMWi 2014 at 13).

With regard to the addition of incremental renewable capacity, Germany is following a prescriptive model. It has created carve-outs for specific technologies in law:

- Onshore Wind: Starting in 2017, gross output is to increase by 2,800 MW per year. Starting in 2020, the annual increase target is 2,900 MW.

- PV: The gross increase of installed capacity is to be 2,500 MW per year. Of this, 600 MW are to be put out to tender. The remaining 1,900 MW are reserved for small- and mid-sized rooftop installations (no larger than 750 kilowatts (KW) each).

- Offshore Wind: Target increases the total installed offshore capacity to 6,500 MW by 2020 and to 15,000 MW by 2030.

- Biomass: From 2017 to 2019, the gross output of biomass facilities is to increase by 150 MW each year. Between 2020 to 2022, the increase is set to increase to 200 MW a year.

- Hydropower, Geothermal, and Biogas: The EEG exempts these technologies from auctions and maintains the fixed feed-in tariff without a cap. As a result, no added capacity targets have been set for these technologies. (Agora 2016 at 6).

3.2.2.2. Ownership of Renewable Electricity Generation

A fascinating aspect of the growth of renewables in Germany is the proportion of these new generation resources owned by small cooperatives or citizen-investors, rather than the large generation companies that tend to dominate the development of renewables in California. 34% of installed renewable capacity in Germany has been set up by "community energy participants," in which decision-making power is held by local communities or individual citizens, while the traditional energy utilities' share accounts for only 5% of the installed renewable capacity. (Energy Atlas 2018 at 16-17). In all, by 2016, only 12% of total renewable capacity installed in Germany was owned by large power generating companies. (*Id.* at 17). The number of citizen energy cooperatives in Germany climbed from just 86 in 2006 to over 1000 in 2015. (Beermann and Tews 2016 at 127).

One commentator has speculated that the German utilities simply considered the feed-in tariff returns too small to warrant engaging in the renewable market. (*Id.* at 4).

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3.2.3. Legal Framework Governing VRE Integration in Germany

3.2.3.1. Jurisdiction over Integration of VREs

Germany is governed by a multi-level federal system. Primary responsibility for the electricity sector lies with the Federal Ministry for Economic Affairs and Energy (hereinafter "BMWi" for its German acronym). Additionally, the Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety has some jurisdiction over energy-related policies, although not directly over the operation of the grids or the electricity markets. Under the authority of the BMWi, the Federal Network Agency (hereinafter "BNA" for its German acronym) is the primary utility regulator in Germany and ensures non-discriminatory access to the grids and the calculation of network charges imposed by grid operators. (*Id.* at 10). In 2012, the BNA employed 2,324 employees. (EC 2014 at 90).

While the regulatory framework for energy policy is developed at the European Union (EU) and federal levels, subnational authorities implement this policy and retain jurisdiction over specific legal, administrative, and budgetary questions. (Tews 2016 at 9). For example, states, counties, and municipalities can specify their own renewable energy policy targets and the adopt measures to achieve them. (*Ibid*). State and local governments have specific jurisdiction over land-use planning and siting. (*Ibid*). Additionally, the BNA shares with the German states responsibility for expansion and optimization of the electricity grids. (*Id.* at 10).

3.2.3.2. Federalism Considerations

The principle questions of federalism in German energy law and policy arise from the potential and actual conflicts between national and EU law. The EU has made market integration a driving principle of European integration. (Tews 2015 at 273). Therefore, conflicts arise concerning how much discretion member states should have to develop national energy policy approaches that are in tension with single-market principles. (*Ibid*). These conflicts and potential conflicts can often only be resolved through case law decisions from the European Court of Justice. (*Ibid*). The tension has not been fully resolved by any of the amendments of the EU's Treaty provisions. (*Ibid*).

The dual jurisdiction over energy issues between the EU and German national authorities has led to conflicts and legal proceedings to resolve them. The EU has been particularly interested in removing barriers to the functioning of seamless electricity flows and a single EU market for electricity. Toward this end, it has emphasized the importance of market-based solutions in solving the issue of VRE integration. For example, a European Commission (EC) document noted with approval that Germany's revisions to its EEG would ensure that "all new beneficiaries of the [EEG] support scheme will have to sell their electricity directly in the market and will be subject to balancing obligations." (EC 2014 at 88).

A proposed regulation on reform of electricity regulation and markets in Europe issued by the EC in 2016 further emphasized the Commission's preference for a market-based approach to integration of renewable energy:

> "[E]vidence has shown that isolated national approaches have led to delays in the implementation of the internal energy market, leading to sub-optimal and incompatible regulatory measures, unnecessary duplication of interventions and delays in correcting market inefficiencies. The creation of an internal energy market that delivers competitive and sustainable energy for all cannot be achieved on the basis of fragmented national rules where they concern the trading of energy, the operation of the shared grid and a certain amount of product standardisation. . . . Ensuring the stability of the grid and its efficient operation is increasingly difficult to do at national level alone, as rising cross-border trade, the uptake of decentralised generation and enhanced consumer participation, all increase the potential for spill-over effects. No state can effectively act alone and the consequences of unilateral action have become more pronounced over time. (EC 2017b at 9-10).

The EU formally took up the topic of energy policy first in the Lisbon Treaty of 2007. (Tews 2015 at 268). According to Article 194 of the Treaty on the Functioning of the European Union (TFEU), which consolidated and clarified the competences of the EU in the field of energy, the main aims of the EU's energy policy are to: ensure the functioning of the energy market; ensure security of energy supply in the Union; promote energy efficiency and energy saving and the development of new and renewable forms of energy; and promote the interconnection of energy networks.

EU primary law protects the "Member State's right to determine conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply." (TFEU, Art. 194). However, EU primary law also transfers national authority to the supranational (EU) level regarding the control of market integration principles. (Tews 2015 at 275).

3.2.3.2.1. Key EU Law Applicable to Renewable Energy Integration

With the objective of creating an internal energy market, the EU has adopted three consecutive legislative packages between 1996 and 2009, with the overarching aim of integrating markets and liberalizing national electricity and gas markets.

In the most recent adopted package, the EU adopted a comprehensive energy framework, including a goal (binding on member states) of increasing the share of renewable energy in gross final consumption to 20% by 2020 in order to support a reduction in GHG by 20% by the same year. (Tews 2015 at 268). The Internal Electricity Market Directive (2009/72/EC), adopted as part of the latest package, provided the common European market rules regarding the generation, transmission, and distribution of energy and the operation of the grid. Another part of the 2009 package was the Renewable Energy Sources Directive (2009/28/EC), which provides national discretion over the means and policies for achieving mandatory national renewable targets. (*Id.* at 274).

In 2014, the EU updated the energy framework to set targets of at least 27% renewables by 2030 to support a 40% reduction in GHGs by the same year. (Tews 2015 at 270). However, the 2030 renewable energy targets were non-binding on the member states; only the overall GHG targets were binding. (*Ibid*). "Instead, Member States will pledge contributions through the integrated national energy and climate plans that form part of the governance proposal to collectively achieve the EU target." (EC 2016 at 7). The EU has taken steps to increase the 2030 target for renewables to 32% of all energy consumption. (Vaughan 2018).

3.2.3.2.1.1. 2016 Proposed Reforms to EU Law

In 2016, the EC proposed significant revisions to the last major energy package as part of the EC's "Clean Energy for All" initiative. The EC has called portions of this proposed package a "Market Design Initiative" to emphasize its intent to use revisions to the EU-wide electricity market design to create a more conducive environment for renewable energy and customer control over energy choices. The EC's proposed package includes major revisions to the 2009 Directive on common rules for the internal market in electricity, the 2009 Regulation on the electricity market, and the existing Regulation establishing a European Agency for the Cooperation of Energy Regulators (ACER). If adopted, "those measures aimed at the integration of renewable energies in the market, such as provisions on dispatching, market-related barriers to self-consumption and other market access rules – previously contained in the Renewable Energy Directive –, [will be] integrated in the Electricity Regulation and the European Commission 2017." (EC 2017a at 8).

As of the time of drafting this paper, these proposals were still under debate in both the European Parliament and European Council and had received many hundreds of amendment requests from those bodies. Accordingly, it is only possible to speculate what the ultimate reforms will contain, but it is instructive to briefly outline the EC's current thinking and preferred direction.

In general, the EC's proposals would further centralize control of cross-border energy transactions and the harmonization of national energy regulatory programs. A revised energy regulation would specify more specific "network codes" that would apply directly to member states and would govern the cross-border flows of energy. In essence, these network codes are the mandatory protocols for internal EU trading of energy and dictate how the interconnected grids of Europe operate in practice.

The proposed energy package emphasizes the use of EU-wide market-based mechanisms to achieve least-cost dispatch and integration of VREs. "The physical nature of [VREs] – more variable, less predictable and decentralised than traditional generation – requires an adaptation of market and grid operation rules to the more flexible nature of the market . . . .The [proposed] electricity market design initiative thus aims to adapt the current market rules to new market realities, by allowing electricity to move freely to where it is most needed when it is most needed via undistorted price signals, whilst empowering consumers, reaping maximum benefits for society from cross-border competition and providing the right signals and incentives to drive the necessary investments to decarbonise our energy system." (EC 2017b at 2-3). Chapter II of the proposed Regulation provides a framework for more market compatible rules for the dispatch and curtailment of generation and demand response, including conditions for any exceptions that member states might adopt to those rules.

The proposed Regulation would take particular aim at out-of-market national capacity mechanism schemes, granting additional authority to EU authorities to assess and determine whether member states' claims for the need for capacity mechanisms are legitimate or merely protectionist. The EC's preferred "energy-only market' option for ensuring reliability in the long-term "would see European markets being sufficiently improved and interconnected that it provides the necessary price signals to spur investments in new resources and in the right places. In such a scenario, no capacity mechanisms would be required any longer." (EC 2017b at 14-15).

The proposed package would seek to make the EU energy market more technology neutral by removing barriers to entry to new products and services: "[A]ll market participants would bear financial responsibility for imbalances caused on the grid and all resources would be remunerated in the market on equal terms. . . .The [proposal] includes measures that would help pulling all flexible distributed resources concerning generation, demand and storage, into the market via proper incentives and a market framework better adapted to them and measures to better incentivise [distribution system operators (DSOs)]." (EC 2017b at 14).

A major focus is on revising energy markets within the EU to allow for demand-side solutions and VREs to participate more effectively in providing ancillary services: "In order to better accommodate the rising share of – mostly variable – renewables, wholesale markets have to further develop and in particular provide adequate rules allowing shorter term trading to reflect the necessities of variable generation. By allowing trading closer to the time of delivery well-integrated short-term electricity markets will also reward flexibility in the market both for generation, demand or storage. Moreover market rules will be adapted to allow renewable producers to fully participate and earn revenue in all market segments, including system services markets." (COM 2016(860) at 8). Unlike in California, where economic curtailment is currently viewed as a potential least-cost solution to overgeneration, the EC's new proposals are meant to ensure that curtailment of renewable VREs is "kept to a strict minimum." (*Ibid).*

A further key aspect of the EC's proposal is to eliminate artificial limits on market prices so that the market can provide flexibility solutions without the command-and-control approach of capacity mechanisms. "Wholesale price caps will be removed, making prices reflect the real value of electricity in time and location (scarcity pricing) in order to drive investments towards the flexible assets most needed for the system, including demand-response and storage." (EC Market Memo at 2). "An adequately interconnected, market-based energy system in which prices follow market signals will stimulate the necessary investments into generation and transmission in an effective manner and ensure that they are made where they are most needed by the market, thereby minimising the need for state-planned investments." (EC 2017b at 3). The EC views such market reforms as a catalyst for the participation of demand-side management in integrating renewables: "It is therefore critical to review any existing rules that distort price formation (such as rules prioritising the dispatch of certain installations) in order to activate and fully realise the flexibility potential that the demand side can offer." (*Ibid*). Thus, the EC's vision is for a market-based system that looks more like that of Texas, rather than a regulated capacity mechanism like that in California.

A primary focus of the "Clean Energy for All" proposal is to allow customers to participate more fully in the energy markets through aggregation of customer-side generation and demand response. "Consumers should be able to consume, store and/or sell self-generated electricity to the market. . . .All [] obstacles that prevent consumers from self-generating and from consuming, storing or selling self-generated electricity to the market should be removed while it should be ensured that self-generating consumers contribute adequately to system costs." (EC 2017a at 33). To facilitate this market participation, the proposed revision to the Energy Directive "entitles every consumer to request a smart meter equipped with a minimum set of functionalities." (*Id.* at 19). The proposal also "requires Member States to define frameworks for independent aggregators and for demand response along principles that enable their full participation in the market." (*Ibid*).

The proposed energy package would further define how national transmission system operators (TSOs) interact with each other. It would further define the roles of the existing TSOs, the voluntary standard-setting European Network of Transmission System Operators - Energy (ENTSOE), and the mandatory standard-setting ACER. In general, the EC has proposed giving ACER more responsibility for finalizing network codes, as opposed to ENTSOE. (EC 2017b at 32). It would also create new Regional Operational Centres (ROCs) that would further coordinate transnational flows of energy. Finally, the proposed energy package would create a new European entity to coordinate the activities of DSOs and would create detailed rules governing the cooperation between DSOs and TSOs with regard to the planning and operation of their networks.

If adopted by the EU Parliament and Council, the final energy Regulation, which is directly binding on Member States, would become applicable in all Member States on January 1, 2020. (EC 2017b at 90). The final energy Directive would enter into force shortly after its adoption by the European Parliament and Council, requiring Member States to implement its provisions through national legislation. (EC 2017a at 124).

3.2.3.3. Key German National Law Governing Energy Market Design to Integrate VREs

3.2.3.3.1. Electricity Market Act and Capacity Reserve Ordinance

In June and July 2016, after three years of talks and negotiation, the German parliament adopted the Act on the Further Development of the Electricity Market (a.k.a. The Electricity Market Act or Strommarktgesetz) and the Act on Digitalization of the Energy Transition (Digitalisierungsgesetz).[17] These Acts strongly reflect the 2016 proposals for European-wide electricity market reforms issued by the EC described above, suggesting that they may have been a model for the EC's proposal or at least developed in tandem with the EC's effort. In both cases, the primary goal is to reform the electricity market design to allow free competition between flexible supply, flexible demand, and storage to provide the ancillary services necessary to integrate increasing volumes of VREs into the grid. (BNA 2017c).

Germany refers to its new market design as the "Electricity Market 2.0," in reference to the fact that this was the first major revision to the electricity market design since Germany deregulated the market in the 1990s.

According to the BMWi, the new market design is intended to move strongly away from capacity mechanisms and toward market-based solutions to VRE integration: "The price signal will be the heartbeat of the further developed electricity market. . . .The measures taken will strengthen free, competition-based price formation and will permit price peaks to occur on the electricity markets." (*Id.*). The goal of the market reforms was to allow the BNA to recover the cost of ancillary services needed to balance the grid through new grid fees and charges, which should create short-term electricity market price spikes that incentivize the installation of new flexible capacity or demand response. (Agora 2016 at 19).

However, political consensus was impossible without the identification of near-term backstops in case the new market fails to deliver the needed flexible capacity. The Electricity Market Act therefore provides for three separate capacity reserves to meet market demand when power supply is low: a "grid reserve;" a "capacity reserve;" and a "lignite standby reserve." (Agora 2016 at 21).

The grid reserve, first enacted into law in 2012, provides extra power when congestion prevents enough electricity from passing from wind-heavy northern Germany to load-heavy southern Germany. (*Id.*). The grid reserve is made up in part of power plants in southern Germany and in neighboring countries that would otherwise be non-operational or shut down. (*Ibid*).

Similarly, Germany's capacity reserve consists solely of power stations which do not participate on the electricity market and do not distort competition and pricing. (BMWi 2015c at 32). The

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[17] The Digitalization Act provided for expanded use of smart meters to promote the *Energiewende*.

capacity reserve would only be called upon in emergency conditions and is meant "to provide additional 'belt and braces' security" against the failure of the market design reforms described below in Section 3.2.5.1. (*Id.* at 3). The BMWi proposed this capacity reserve as a political compromise rather than a capacity market because it found that "[c]apacity markets are susceptible to regulatory failure and make it more difficult to transform the energy system." (*Id.* at 4). Starting in the winter of 2018/19, 2 GW will be placed in the capacity reserve. (Agora 2016 at 21). Every two years after, the BMWi will review the quantity of reserve volume and adjust it when necessary. (*Ibid*). The costs of the capacity reserve are passed on to consumers via grid fees. (*Ibid*).

Finally, the Electricity Market Act contains a "security stand-by," sometimes also called the "climate reserve," that places 13% (about 2.7 GW) of Germany's lignite-fired generation capacity on cold stand-by (provisional shut-down). (*Id.* at 19). The idea is to gradually decommission these power plants from 2016-2020 in order to meet 2020 climate targets, but to not do so immediately in case the new market design fails to ensure reliability. The mothballed power plants must be able to start up again within 10 days and are considered the last resort for ensuring supply security. (*Id.* at 21). Like the other capacity reserves, the security stand-by plants receive a remuneration funded by grid fees. (*Ibid*). Many view it as highly unlikely that the stand-by reserve will ever be used and view it more as an "environmentally-motivated closure premium" for the coal industry. (*Id.* at 27).

3.2.3.3.2. Renewable Energy Act

The EEG of 2000 created a comprehensive framework for promoting renewables and marked a pivotal moment in Germany's *Energiewende*. (Tews 2016 at 3). Although the EEG's primary purpose was to increase the production of renewable energy within Germany through a feed-in tariff, for purposes of this paper the EEG's most important provision was the obligation it imposed on grid operators to interconnect and purchase the output of renewable energy generators. This essentially removed the risk of interconnection problems from developers and socialized the cost of interconnection of new renewables, which is a major component of grid integration costs. The broad socialization of interconnection costs was consistent with the EEG's general principle that the above-market costs of the EEG should be shared broadly (the "solidarity principle"). (*Id.* at 12).[18]

Following the massive increases in renewable energy capacity brought about by the EEG, regulators realized by 2009 that the ability of the grid to integrate the energy had not kept up. (*Id.* at 19). In response, the government introduced a "self-consumption bonus" as an amendment to the EEG, intended to stimulate on-site consumption of renewable energy

[18] California also socializes the cost of some policy-based transmission upgrades that are approved through the CAISO's Transmission Planning Process, but in general the rule has been that developers must at least initially cover the costs of interconnecting their facilities (including both reliability and deliverability distribution and transmission network upgrades), with some of the transmission network upgrades reimbursed over a period of years following the facility coming online.

generation in order to prevent grid stability problems. (*Ibid*). The self-consumption bonus provided a reduced feed-in tariff payment for energy consumed on-site, which, when coupled with the avoided cost from not having to buy electricity from a retail supplier, guaranteed that the PV investment would be profitable. (*Ibid*). The government reversed course in 2012 amendments to the EEG, when it phased out the self-consumption bonus in favor of a policy that required, by 2016, all renewable generation had to be offered in the central European Power Exchange (EPEX) spot market. (*Id.* at 20; Tews 2015 at 281).[19] This course-change is consistent with the general movement of German regulatory and legislative authorities toward market-oriented integration solutions.

The 2009 amendments to the EEG also introduced the first regulations on feed-in restrictions, allowing network operators to temporarily curtail power from renewable energy installations in case of grid congestion (and to compensate through socialized grid fees the cost of those curtailments). (Agora 2016 at 37).

Amendments to the EEG that came into effect in 2017 recognized that the massive increase in wind power generation in the North and East of the country was causing grid congestion issues because most of German load is in the South and West. Accordingly, the amendments limited the principle of guaranteed interconnection for renewables and restricted the amount of new wind that could be interconnected in congested areas until underway grid expansion efforts could be completed. (Agora 2016 at 39).

3.2.3.3.3. The Energy Industry Act

Germany's Energy Industry Act (Energiewirtschaftsgesetz or "EWG") was amended in 2016. The amendments implicitly recognize that it will not be cost-effective to build out the grid to ensure that all VRE generation will be able to be delivered via the grid to customers at all times. Grid operators will be able to plan their grid improvements assuming that projected annual power generation from VREs may be reduced by up to 3 percent. (Agora 2016 at 14). In theory, power unable to be delivered via the grid will be converted locally to heat and used in district heating networks. (*Id.* at 13). However, this recognition for the likely need for some curtailment of VREs appears to contradict the German government's insistence in other statements that curtailment should not be a solution to integration.

The EWG also seeks to ensure transparent and coordinated network expansion planning for the German high-voltage grid. The determination of the grid expansion requirements is carried out in a multi-stage process by the BNA in consultation with Germany's TSOs and the broader public.

[19] In fact, the reversal in policy was so complete that in 2014 German regulators introduced an EEG surcharge on on-site renewable energy consumption to avoid cost shifts. (Tews 2016 at 20).

3.2.3.3.4. The Power Grid Expansion Act

In tandem with Germany's focus on market-based solutions to VRE integration, the country has also emphasized the need to expand its power grid in order to ensure that all renewables can be delivered according to market outcomes. The first step toward building an improved power grid for the energy transition took place in 2009 with the passage of the Power Grid Expansion Act. This marked the first time that legislators formally required the individual German states to identify priority grid expansion projects and to complete those lines (which made up a so-called "start network") by a date certain. This start network was to be the basis for planning all other future transmission expansion projects in the country.

3.2.3.3.5. Further Grid Expansion Laws

The next major steps toward legislated grid expansion came with the 2011 Grid Expansion Acceleration Act Transmission Network and the Federal Requirements Plan Act (which came into effect at the end of December 2015). One of the major developments in these new laws was to provide a central, federal permitting authority (the BNA) for transnational extra-high voltage lines in order to reduce the fragmentation of permitting requirements across German states. The Federal Requirements Plan Act also set forth new rules for deploying high-voltage transmission lines underground in order to address the major public controversy that had stymied attempts to expand the overhead network.

3.2.4. Energy Market Design and Grid Operation in Germany

The purpose of this section is to briefly describe the practical, day-to-day functioning of energy markets and the operation of the electrical grid in Germany with a focus on how both markets and system operation seek to integrate VREs.

3.2.4.1. Key Market Participants

3.2.4.1.1. National Regulatory Authority

The BNA is Germany's national regulatory authority overseeing the transmission and distribution grid. In this role, the BNA would implement, subject to review by the ACER described in Section 3.2.4.1.2.1., the EU-wide network codes and guidelines adopted by the EC. (EC 2017a at 107, 115).

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3.2.4.1.2. Grid Owners and Operators

In Germany's deregulated market, and unlike in California, the grid owners are also normally the operators of the grid. TSOs own and operate the transmission-level[20] system and DSOs own and operate the grid at the distribution level.

3.2.4.1.2.1. TSOs and Their EU-wide Coordinating Bodies

In the transmission sector, the key players in Germany are the four regional TSOs: TenneT TSO GmbH; Amprion GmbH; 50 Hertz Transmission GmbH; and TransnetBW GmbH.

German TSOs have to be certified by the BNA following consultation with the EC. The TSOs coordinate with TSOs in other European jurisdictions through ENTSOE, which is described in Section 3.2.3.2.1.1., above. Thus, ENTSOE plays an analogous function in Europe to the North American Reliability Corporation in the U.S. If the EC's most recent energy package is approved as proposed, new ROCs would also be established to "complement the role of transmission system operators by performing functions of regional relevance. They shall establish operational arrangements in order to ensure the efficient, secure and reliable operation of the interconnected transmission system." (EC 2017b at 64). These ROCs, then, would be analogous to WECC in the Western U.S.

The EC has proposed that it be allowed to adopt delegated acts to create network codes and guidelines. (*Id.* at 77). This means that in practice, network codes in the future would be developed in the following way: (1) the EC would develop a priority list of topics impacting cross-border energy flows for which network codes to be developed; (2) ACER would propose a non-binding framework guideline for review by the EC; (3) the EC would approve the guideline; (4) the ENTSOE would convene a drafting committee of member TSOs to propose network codes based upon the non-binding framework guideline; (5) ACER would review and, as necessary, revise the codes in consultation with the ENTSOE and then submit them to the EC; and (5) the EC would adopt them. (*Id.* at 77-80). These codes include rules about what resources can be curtailed or re-dispatched. (*Id.* at 77). Network codes adopted by the EC are also proposed to address ancillary services and demand response. (*Id.*). Thus, these network codes will be central to the methodologies used in the EU, including Germany, to integrate VREs in the future.

3.2.4.1.2.2. DSOs and Their EU-wide Coordinating Bodies

Eighty percent of the electricity generated from renewables are fed into Germany's distribution grids, making these grids critical for the successful integration of VREs. (BMWi 2015a). Operation of the German distribution grids is complex and is currently run by about 900 private DSOs and around 700 municipal utilities. (Tews 2016 at 11). Historically, German law allowed

[20] Transmission in Germany is considered 380 KV and higher voltage.

“concession agreements” in which municipalities entered into contract with private contractors to allow those contractors to use and operate the local distribution grid for a defined period of time. (*Ibid*). These contracts typically ran for 20 years and have recently begun to expire, leading to a trend of re-municipalization. (*Ibid*).

Local grids in Germany are largely still operated by vertically-integrated entities (ie., entities that market electricity supply in addition to operating the distribution grid). The legal basis for this is an exemption from the statutory provisions on legal and operational separation of network and retail businesses that applies to DSOs with less than 100,000 connected customers. About 90% of Germany’s electricity DSOs fall under this “de minimis rule.” (EC 2014 at 91).

In its recent “Clean Energy for All” proposal, discussed above, the EC has advanced the idea of a new EU-wide coordinating entity made up of DSO representatives (the “EU DSO”). “The EU DSO Entity should closely cooperate with [ENTSOE] on the preparation and implementation of the network codes where applicable and should work on providing guidance on the integration inter alia of distributed generation and storage in distribution networks or other areas which relate to the management of distribution networks.” (EC 2017b at 31). Among other things, the EU DSO is proposed to be tasked with “integration of renewable energy resources, distributed generation and other resources embedded in the distribution network such as energy storage.” (*Id.* at 75).

3.2.4.1.3. Market Operators

There are two power exchanges offering the trading of electricity products in Germany: the EPEX spot market for day-ahead and intraday trading and the European Energy Exchange for any forward products. (EC 2014 at 91). Germany also has reserve (balancing energy) markets, which provide standby megawatt capacity for the energy-only market to avoid supply shortages. [21] Balancing markets in Germany are broken into five zones, each of which corresponds to one of the five major TSOs. Balancing energy has to be traded within each of the respective zones.

Germany does not have a nodal market like in California. Rather, one pricing/bidding zone covers the entire country, Austria, and Luxembourg. (EC 2017a at 3).[22] German legislators, and therefore regulators, are intent on maintaining this single-zone system for political reasons and have pushed back against the new EC energy package that may give more power to

[21] “Transmission system operators make a distinction between three different types of balancing capacity: Primary balancing capacity must be fully available within 30 seconds of being requested, secondary balancing capacity within five minutes and the minute reserve (tertiary balancing capacity) within 15 minutes. The transmission system operators also distinguish between positive and negative balancing capacity. Positive balancing capacity is delivered through higher production or lower consumption, while negative balancing capacity, in contrast, is delivered through lower production or higher consumption.” (BMWi 2014 at 11).

[22] German and Austrian authorities have agreed to a new congestion management scheme at the electric interconnections between those countries that is planned to replace the single price zone in those two countries as of October 2018.

European-wide entities to determine appropriate bidding zones within the EU. In response to the EC's proposal, the BMWi proposed an amendment to existing regulations to create a legal requirement that Germany retain its existing single bidding zone and follow a "copper plate" principle of building all necessary transmission to remove capacity constraints within the country: "The steady increase in cross-border electricity flows and the increased expansion of renewable energies, which are heavily used in existing transmission grids and require considerable effort in grid expansion, underline the importance of the uniformity of the German electricity bidding zone as the basis for equal conditions for grid access. In a single bidding area, the exchange of energy without capacity allocation is mandatory. This ensures that the basic condition for network access throughout Germany is uniform." (BNA 2017a).

The German electricity market is coupled with the electricity markets of 15 neighboring countries. The exchange price on the day-ahead market is determined jointly for coupled markets. Electricity providers and electricity purchasers submit their bids in their national day-ahead market zones (ie., price or bidding zones). In an iterative process, the demand for electricity in the market zone is served by the lowest price offers of electricity from all the market areas until the capacity of the connections between the market zones (cross-border interconnectors) is fully utilized. As long as the cross-border interconnectors have sufficient capacity, this process is intended to align the prices in the coupled market areas. (BMWi 2014 at 10). If there is limited interconnector capacity, the prices in different European bidding zones may diverge. In this sense, Europe's markets as a whole begin to act more like CAISO's nodal market, taking into account transmission constraints.

3.2.4.1.4. Balancing Responsible Parties

In Germany, grid stability is achieved through balancing groups. A balancing group is a type of virtual energy-volume accounting, managed by a Balance Responsible Party (BRP). Every producer and every consumer in Germany is assigned to a balancing group. As part of schedule reporting for each quarter hour for the following day, the BRPs report to the relevant TSOs both the volume and location of electricity they will both supply and draw from the grid. (*Id.* at 11). These schedules incorporate the results of trades in the market. (*Ibid*).

To the extent a BRP's actual injections and withdrawals differ from those scheduled, the costs imposed on the system are settled through the TSOs' imbalance settlement system and the BRP must bear those imbalance costs. (BMWi 2014 at 11; Agora 2016 at 17, fn. 11). These costs are similar to imbalance penalties paid by scheduling coordinators in the CAISO.

3.2.4.2. The Sale, Delivery, and Curtailment of VREs in Germany

Until 2012, VRE generators did not need to be involved in the marketing of their electricity. Under the Renewable Energy Law in place at that time, the generators were simply paid by the TSO the administratively-set price for their electricity. The TSO had an obligation to interconnect and accept the electricity, and it then sold the electricity on the market on behalf of the generators. (BNA 2017e). The difference between the administratively-set price paid for the VRE output and the market price received created the infamous "EEG surcharge" that has become a major component of residential electricity rates in Germany.

Germany introduced a new "direct marketing" option for larger VRE generators beginning in 2012 and made direct marketing mandatory for such generators beginning in 2014. Under this new rule, generators are no longer able to simply sell their electricity to the TSOs. They now have to market it themselves, or contract with another entity to market it for them. (*Id.*). Typically, larger renewable installations will have long-term PPAs with third-party marketers that buy the electricity from the generator and then put it on the market.

As of 2014, Germany's BMWi estimated that there was approximately 60 GW of excess generation capacity within the market in which Germany is located. (BMWi 2014 at 13). As in California, this has driven down wholesale market prices, forcing older fossil-fueled generation facilities to shut down. Germany sees this as a natural part of the *Energiewende* rather than a concern. (*Ibid*). As these plants retire and demand-side management increasingly provides the marginal flexibility in the future, the BMWi expects wholesale market prices to stabilize and recover to the point where they can adequately ensure reliability through the building of additional flexible resources. (*See ibid*).

As shown in Figure 5, prices in the German wholesale electricity market have begun to go negative. At the end of October 2017, the average wholesale electricity price in Germany for the entire day was expected to be negative due wind power production expected to meet approximately half of all demand. (Starn 2017). These negative pricing episodes mirror similar negative pricing events that are increasingly occurring in CAISO, although the magnitude of both the frequency and the extent of negative pricing appears to be less in Germany.

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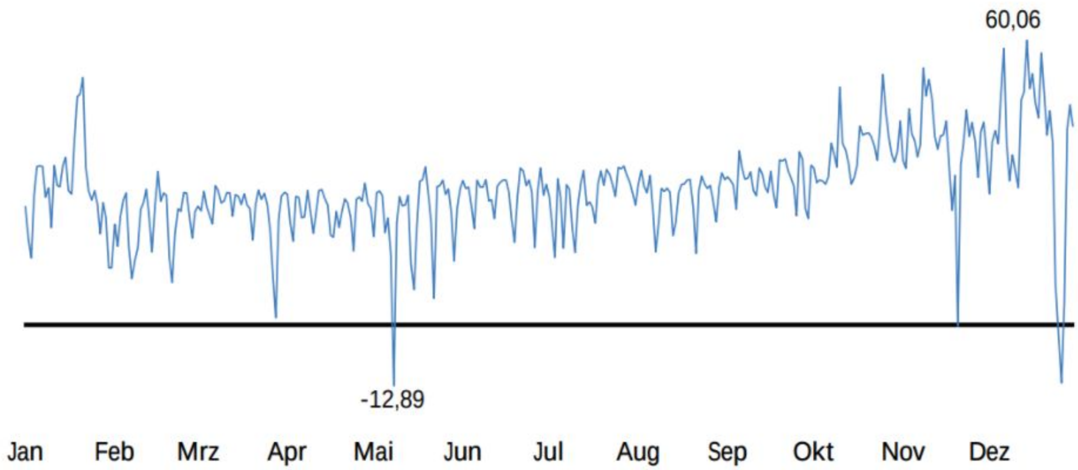
Fig. 5 - German Electricity Wholesale Market (Phelix-Day-Base) Prices - 2016 (Euro/MWh)



Source: BNA, Bundeskartellamt. 2017 Market Monitoring Report.

TSOs can, and apparently often do, “re-dispatch” resources due to constraints in Germany’s transmission system, particularly paths running from the North to the South. Re-dispatch therefore generally means ordering units in the South to generate to make up for shortfalls in the ability to deliver to load the generation that was scheduled from VREs (particularly wind) in the North. This “re-dispatch” is in addition to other grid reliability measures taken by TSOs, including the procurement and use of regulation reserves and “feed-in management” (Einspeisemanagement), which is compensated curtailment of renewable generators at the request of the network operator.

As a practical matter, it appears that re-dispatch works as a regulation-up order that applies mainly to fossil generation plants near load centers in the South of Germany. The feed-in management orders would be issued at the same time to VRE generation in the North of Germany where transmission constraints preclude delivery to load. Germany’s single bidding zone system means that suppliers serving load in the South contract for the cheaper VREs in the North, but these cannot be physically delivered, and the grid must therefore be manually balanced by the TSOs using these re-dispatch and feed-in management measures. Because both re-dispatch and feed-in management measures are compensated through fees on all grid users, these out-of-market balancing transactions are adding significantly to the overall electricity rates in Germany, particularly for those users who are not legally exempt from paying such fees.

More information related to the use and cost of curtailment to integrate VREs in Germany is provided in Section 3.2.5.6., below.

3.2.5. Germany's Policy Initiatives to Integrate Variable Renewables

3.2.5.1. Electricity Market 2.0: Creating A Level Playing Field for All Flexible Supply and Demand Providers

The current primary approach at the federal level in Germany to integrate higher levels of VREs has been to reform the electricity markets. The belief is that free markets will reveal the need for additional flexible capacity through unfettered short-term energy prices and that market participants on both the supply and demand side will create solutions in response to these market signals so long as they do not encounter barriers to participation. In this way, the German authorities hope to avoid a command-and-control approach that would involve prescribing the "right" technology and volumes needed in order to cost-effectively integrate the country's rising proportions of VREs. The Germans have termed this effort the creation of the "Electricity Market 2.0."

The BMWi kicked off a national debate on a new energy market design with the publication of a "Green Paper" in October 2014. Germany's robust civil society took a high level of interest in the topic, and the Ministry received some 700 comments on the Green Paper. Based on this consultation, the BMWi then issued a "White Paper" in 2015 laying out its proposal for the steps needed to create the Electricity Market 2.0. It made clear its belief that a new market design was the answer: "[W]e do not necessarily need more power stations, but rather flexible capacity. Flexibility is the answer to the weather-dependent renewable energy sources. By introducing the electricity market 2.0, we are permitting fair competition between all flexibility options." (BMWi 2015c at 3).

The White Paper ultimately resulted in the Electricity Market Act and the Capacity Reserve Ordinance discussed in Section 3.2.3.3.1., above. These new laws embraced the BMWi's vision that "[p]rice volatility on the wholesale market increases the value of flexibility and incentivises corresponding investment." (BMWi 2016 at 12). The Electricity Market 2.0 also appears to have been the blueprint for the EC's 2016 Market Redesign Initiative that was incorporated into its Clean Energy for All proposal, discussed above.

Under the revised market rules, the price for balancing energy can jump as high as 20,000 Euros/MWh during significant supply and demand imbalances. By comparison, the electricity price on the power exchange in 2015 averaged around 32 Euros/MWh. (Agora 2016 at 17). Thus, most commentators seem to think that the new laws will help in sending price signals regarding the need for additional flexible capacity.

However, there is less consensus that the new market design adequately removes barriers to entry to allow renewables and demand-side management to provide ancillary services. For example, Agora Energiewende, a key nonprofit participant in the public consultation process in Germany, notes that the ability of flexible demand to help meet integration needs is in jeopardy given the slow roll-out of smart metering in Germany. (Agora 2016 at 25). Under Germany's

2016 digitalization law, an average household of four persons will not be required to install smart meters until 2032, and even larger customers (up to 10,000 kwh/year) have until 2028 to install smart meters. (*Ibid*).

Additional key components of the Electricity Market 2.0 include:

- Introduction of 15-minute trading for certain products (BMWi 2016 at 12).
- Taking a European approach to security of supply: Monitoring of security of supply "will no longer focus solely on national output levels, but will give greater consideration to the contribution to security made by the European internal market in electricity. The electricity market 2.0 is to take a thoroughly European approach." (BNA 2017d).
- Increasing imbalance penalties applied to BRPs that fail to meet their balancing group commitments (*Ibid*).
- Extending the "grid reserve" capacity mechanism described in Section 3.2.3.3.1., above. "The grid reserve will be needed until key grid expansion projects have been finished." (*Ibid*).
- Improving transparency on the electricity market: "Transparent and up-to-date electricity market data can promote efficient generation, consumption and trading decisions. For this reason, a national information platform and a core market data register will be set up." (*Ibid*).
- Reducing and sharing more fairly the costs of grid expansion: grid fees that some, particularly large industrial users, could avoid in the past in order to maintain their international competitiveness will be abolished for new installations beginning in 2021. (*Ibid*).

3.2.5.1.1. Electricity Market Expansion and Coupling

As noted above, European energy markets have increasingly become coupled either directly or indirectly. This allows optimization of the entire European grid in terms of least-cost dispatch within the limits of the existing interconnectors.

The BMWi concluded that European market integration is a key goal of market re-design: "Thanks to large-scale smoothing effects, particularly for maximum peak loads and the feed-in from renewables, security of supply can be achieved more cheaply in the European internal market. The joint peak load is smaller than the sum of the national peak loads. As a consequence, less capacity (conventional and renewable power plants demand side management and storage) has to be maintained." (BMWi 2014 at 30; *see also* BMWi 2016 at 9). Creating a more integrated European internal market for flexible supply and demand products is viewed as a "no-regret measure" because it will reduce the total cost of integration regardless of the specific market design of individual Member States. (BMWi 2016 at 12).

3.2.5.1.2. Direct Marketing of Large Renewables

Similar to the movement in California away from "self-scheduling" of VREs, meaning that they will generate at any price, to the economic bidding of VREs so that they can be curtailed if prices go sufficiently negative, the German government has moved away from the original renewable energy scheme in which VREs received a relatively high, fixed price for any output they generated without any exposure to the actual market conditions. VREs larger than 100 KW in Germany must now be sold directly to the market, with generators receiving a subsidy equal to the difference between a "floating market premium" established in recent VRE auctions conducted by the government and the actual market prices they receive. (BMWi 2014 at 19). The government's theory in mandating such direct marketing was to make VRE operators "responsible for future production forecasts and for balancing any differences. In this way, they have the same responsibility as conventional power stations. They are incentivised to improve the forecast methodology and data that act as the forecast base, and thereby reduce any imbalances or balance them as efficiently as possible." (*Ibid*).

Since the calculation of the market premium is based on the average monthly price on the electricity exchange, those who are good at marketing their electricity directly and deploying their installation can theoretically earn more by strategically increasing and decreasing their output based on market signals: If a particularly large quantity of electricity is in demand on a certain day, so that the prices on the exchange go up, the generator selling electricity on that day will profit. But the opposite is also true: Those who sell their product when the price on the exchange is rock bottom earn less. The intention is to encourage the installation operators to align their electricity production with actual demand, thereby helping to integrate the VREs.

However, the reality is more complicated. In actuality, the price paid to the generator is often fixed for 10 years or more under a long-term agreement with a marketer. So the marketer is the one initially taking on the risk. In order to allow the direct marketing incentives to work, there must be mechanisms in the PPA to allow for flexible operation of the facility. It is unclear the extent to which these agreements contain such provisions.

3.2.5.1.3. Demand Response

A key focus of the electricity market reforms in Germany is the activation of demand response solutions. As one commentator notes: "The new Electricity Market Act [summarized in Section 3.2.3.3.1., above] allows special service providers to sell load shifting potential alongside energy providers in the balancing energy market. This could encourage new business models to emerge in the segment." (Agora 2016 at 32).

A specific example of demand response in the integration context is the curtailment of fossil-fueled combined heat and power (CHP) facilities during times of grid congestion. Germany's Energy Industry Act allows TSOs to sign agreements with CHP generators in grid expansion areas (as described in Section 3.2.5.4., below). Under these agreements, the generators are required to ramp down their facilities during periods of overgeneration and to instead generate the heat they need through power-to-heat applications using the excess VRE generation. (Agora 2016 at 14). As remuneration for their participation, the TSOs provide a subsidy for the CHP's investment in a power-to-heat facility and a rebate on the electricity they draw during overgeneration periods. (*Ibid*).

The focus on demand response as part of the new market design is fully in line with the EC's recent proposals for new EU laws, discussed in Section 3.2.3.2.1.1., above. As proposed by the EC, the EU's new regulations would require that Member States "ensure access to and foster participation of demand response, including through independent aggregators in all organised markets." (EC 2017a at 70). The Commission envisions that dynamic pricing contracts between final consumers and their energy suppliers will facilitate the use of demand response. (EC Market Memo at 2). However, as noted above, and in contrast to most other EU member states, Germany has elected not to pursue a large-scale rollout of smart meters. (Tews 2016 at 8). Rather, Germany planned to begin a gradual rollout of basic smart metering systems in 2017, prioritizing large consumers with greater energy saving and load shifting. (*Ibid*). The goal is to complete the installation of basic smart meter by 2032. (*Ibid*).

3.2.5.2. Energy Storage

As in California, energy storage is a technology that offers potential - if currently unrealized - promise for integrating increasing levels of VREs in Germany. Part of the market redesign in Germany is intended to allow up-and-coming technologies like storage to compete freely and fairly with other flexible energy providers to provide ancillary services.

One example of a storage-based flexibility application is the use of decentralized, blockchain-enabled local markets to link home energy storage systems to each other and the broader wholesale market. Although only at a pilot stage of maturity, TSO TenneT in Germany has successfully used this framework to provide redispatch services in Germany, rather than providing regulation up orders to fossil-fueled or nuclear power plants as has been customary. (TenneT 2017). In this pilot, which will continue until mid-2018, participating residential energy storage system owners can receive free electricity by offering their storage systems for grid services for just a few minutes a day, thereby creating a new revenue stream for those systems. (*Ibid*).

3.2.5.3. Capacity Mechanisms

As more fully described in Section 3.2.5.1., above, Germany has created three separate capacity reserve mechanisms to assure the security of the grid even in exceptional circumstances. As noted above, many commentators believe that these reserves will not be needed since the Electricity Market 2.0 reforms will create sufficient incentive to developers to build needed capacity. Germany has ruled out a capacity market as a way to ensure reliability. [23]

3.2.5.4. Limits on New VRE Interconnections in Grid-Constrained Areas

Despite the market orientation of Germany's federal policy toward integration, it has not completely set aside traditional regulatory tools to ensure grid reliability. The "belts and suspenders" insurance policy of capacity mechanisms was discussed in Section 3.2.3.3.1., above. Another of these policies that was codified in amendments to the Renewable Energy Law in 2017 created "grid expansion areas" (Netzausbaugebieten), where new VRE interconnections are capped until the grid can be expanded to accommodate the new generation. As might be expected given the bottlenecks in transmission from north-south in Germany, these capped areas are in the North, where wind generation is cheapest. In such areas, the capacity is auctioned off as a locally-constrained area. Thus, for example, in a 1000 MW auction for onshore wind, the government might declare that only 30 MW of this total could be awarded to new facilities that would be built in a particular area of the North. Assuming that bids from that area exceed this cap and that the cost of wind generation in that area is the lowest in the auction, this cap will increase the average price paid by consumers for new generation (although it may reduce the overall costs by reducing network charges associated with redispatch, as discussed in Section 3.2.5.5.).

This command-and-control regulation is necessary because the electricity market in Germany, like other European countries, does not take into account congestion and transmission bottlenecks. To align the market and grid conditions, either Germany will need to build out its grid to remove essentially all constraints (the so-called "copper plate" approach that is currently favored by federal regulators), or it would need to create separate pricing and bidding zones in the country, perhaps going so far as to introduce a nodal market like that in California.

The defined grid expansion areas and the initial limits imposed on new capacity in each such area will be reevaluated by the BNA at the end of July 2019 and then assessed every two years. (Agora 2016 at 14).

3.2.5.5. Grid Reconstruction and Expansion

Grid expansion is a key component of the Germany federal strategy to integrate VREs. In fact, the BMWi has declared grid expansion to be "the most cost-effective flexibility option" and has found that such expansion will be necessary in all future scenarios involving renewable electricity increases. (BMWi 2016 at 7). The federal government views grid expansion as a

[23] "An evolved Electricity Market 2.0 will only be able to deliver a stable basis for future investments if investors can rely on rules that are politically and legally stable. This therefore necessitates a clear and long-lasting fundamental political decision. This would not be compatible with a policy which kept open the possibility of a later shift to a capacity market, e.g. via a review clause. No-one would invest on such an uncertain basis." (BMWi 2015b).

precondition for the success of the Electricity Market 2.0, discussed in Section 3.2.5.1., above. (BMWi 2015c at 14). In contrast, the BMWi views decentralized generation solutions to be merely stop-gap measures to help ensure reliability and control of redispatch costs until the grid can be adequately built out. (BMWi 2016 at 7).

At the same time, Germany's vocal civil society has essentially blocked several of Germany's cornerstone grid expansion projects, objecting to the aesthetic and community impacts of new overhead transmission lines. This has led to a major disconnect between Germany's laws, which mandate grid expansion, and reality on the ground, where projects are often stalled. BMWi has recognized this disconnect and called for a "frank, all-encompassing debate" about the consequences of not completing the envisioned expansion of the grid. (*Id.* at 24). While the BMWi acknowledges that "[l]ocal acceptance for such additional [grid expansion] projects is absolutely essential," it seems entrenched regarding the need for such projects and appears to be looking simply for a tool to achieve such local acceptance. (*Ibid*). One such tool is the recent federal policy of requiring new direct current lines to be built underground and to test the ability to underground high-voltage alternating current lines. (BMWi 2016 at 2; BMWi 2015b). Undergrounding is likely to increase the cost to achieve the "copper plate" by many times, although it may achieve greater local acceptance.

Complicating the grid expansion strategy is the fact that about 90 percent of Germany's total renewable generation capacity is interconnected at the distribution level. Therefore, transmission grid expansion is necessary but not adequate; the expansion and digitalization of the distribution grids is a "key precondition" for the success of the grid expansion strategy for integration. (*Id.*). Of course, this means coordinating many more grid operators - numbering in the many hundreds - than the handful of Germany's TSOs.

The German regulators' instance on a single price zone for the country might be seen as a political strategy to ensure the continued focus on grid expansion as the key integration tool. Indeed, if the country were split into northern and southern price zones, as some have recommended, then it appears that incentives to build generation capacity in the North would decrease while incentives to build generation capacity in the South would increase. It is unclear the extent to which the local acceptability and the cost/benefit of the grid expansion policy have been assessed in comparison to an alternative policy that focused on decentralized generation and multiple price zones or nodes.

Finally, expansion of the grid as a policy is not limited to the national context. The BNA has recognized the view of stakeholders that "the pan-European expansion of the power grid is . . . a precondition for cross-border electricity trading and . . . a cost-efficient way to ensure security of supply." (BMWi 2015c at 15). For example, a planned submarine cable between Germany and Norway is expected to help integrate wind generation in Germany through the use of hydropower in Norway. (*Ibid*).

3.2.5.6. Curtailment

German regulators seem to recognize that the curtailment of renewables is a practical necessity to ensure grid reliability, even while they disavow any intention to rely on renewable curtailment as a strategy. Officially, the BNA has stated that renewable curtailment "is not a sensible alternative to reducing minimum generation," although it acknowledges that in "rare, extreme situations, it can make economic sense to impose moderate restrictions on the output of renewable energy installations so as to save on grid capacity and storage." (BMWi 2014 at 16).

German law mirrors the BNA's ambivalence toward curtailment. Statutes have traditionally provided renewable generators with "priority dispatch" (Einspeisevorrang), meaning that in the case of a grid congestion fossil plants will be curtailed before renewables (as long as this is technically possible, given that fossil plants often have minimum generation requirements). At the same time, German law requires grid owners to assume a certain level of curtailment of VREs (up to 3 per cent of the production volume from onshore wind and PV) to avoid over-building the grid at disproportionate cost. (Ecofys und Fraunhofer IWES 2017 at 22).

Perhaps the most important indicator is the practical reality that curtailment has become an essential tool to balance Germany's grid. "Curtailment was initially intended to be a measure of last resort for a few hours each year but curtailment and re-dispatch have now become everyday operations of the distribution and transmission system operators." (Ecofys und Fraunhofer IWES 2017 at 22). "Over the past five years, the costs for congestion management and curtailment have increased by a factor of ten, to about one billion euro per year. In 2015, more than three percent of Germany's yearly electricity generation was affected." (*Ibid*). Figure 6, below, shows this dramatic increase in renewable curtailment in Germany in recent years.

When compared with renewable energy curtailment in California (both the so-called "economic curtailment" in which renewable generators are bid into the market and fail to receive a reward because prices are sufficiently negative and instances in which the generators are manually redispatched by CAISO to avoid a system emergency) over a similar period, in Figure 7, below, it is clear that both jurisdictions are seeing general increases in curtailment as VREs increase. However, even if one considers only the compensated curtailment of renewables and cogeneration in Germany in 2016,[24] ignoring uncompensated emergency orders to curtail,[25] this amounts to about 12.5 times as much renewable curtailment in Germany in 2016 as in California. Normalizing for the larger capacity of the German electricity market, Germany's compensated curtailment of renewables was still more than double that of California on a

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[24] Compensated renewable curtailment in Germany totaled 3,743 gigawatt-hours (GWh) in 2016 at a cost of Euro 373 million charged to consumers through grid fees. (BNA 2017c at 105).

[25] Such uncompensated curtailment in Germany in 2016 added up to an additional 14 GWh. (BNA 2017c at 105).

curtailed GWh per installed GW of wind and solar.[26] Because of the different efficiencies of wind and solar generation in California and Germany, the difference in curtailment of VREs for each unit of VRE generation produced is even more stark: In California the volume of VRE curtailments equaled about 0.62% of total VRE generation in 2016,[27] while in Germany the volume of VRE curtailments equaled about 3.2% of total VRE generation in 2016.[28] This means that over five times as much VRE curtailment occurred in Germany compared to California in proportion to the amount of VRE generation that occurred in each jurisdiction. This makes sense if one assumes that curtailments increase with renewable penetration levels. Since Germany's penetration level of VREs is about equal to California's on a proportion of total energy produced basis, this might suggest that a pure application of Germany's historical approach to integration in California could result in as much as a 500% increase in renewable curtailment.[29]

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[26] In Germany, this is about 42 GWh curtailed per installed GW of installed wind/solar capacity. (3743 GWh / 90.3 GW). In California, it is about 19 GWh per installed GW of wind/solar capacity. (308 GWh / 16.2 GW).
[27] This represents the 50,000 GWh depicted from solar and wind in Figure 1, above, divided by 308 GWh of total curtailment in 2016.
[28] This represents 116,690 GWh of total wind and solar generation in Germany in 2016 (source: Frauenhofer ISE, at www.energy-charts.de) divided by 3743.2 GWh of wind and solar compensated curtailment shown in the figure immediately below).
[29] It is also important to recognize that 2016 may have been an unusually low volume of renewable curtailment in Germany. Overall, renewable curtailment in Germany in 2016 fell by about 20% compared to the level of 2015. (BNA 2017c at 115). The primary driver for the reduction in 2016 appears to be lower wind power generation due to lower wind speeds in the north of Germany in 2016 compared to the wind production in 2015.

Fig. 6 - Renewable Energy Curtailment in Germany, 2009-2016 (in GWh) (Note: period in the numeral indicates thousands, while comma indicates a decimal place)

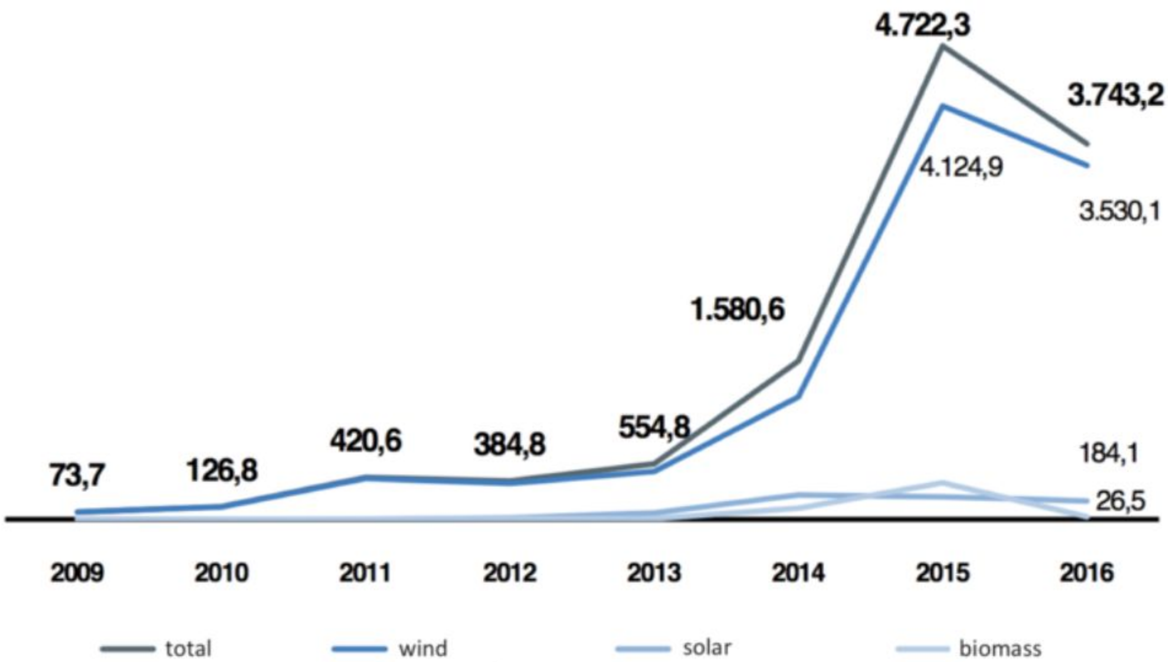
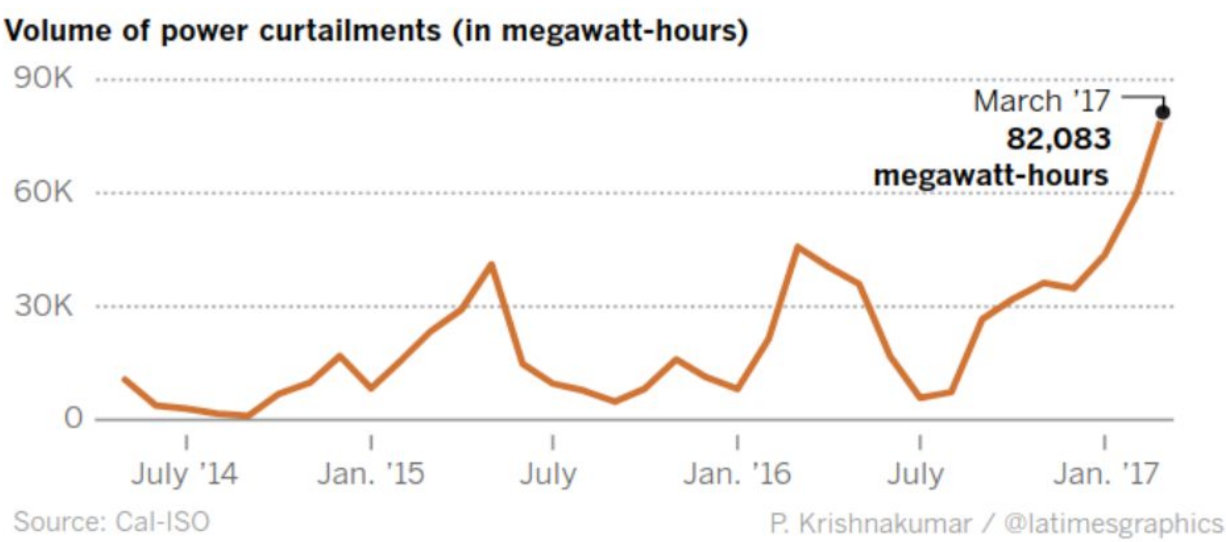


Figure 4: Curtailed electricity generation from renewable generators for the purpose of feed-in management in GWh (BNetzA 2017:p. 115)

Source: Bundeskartellamt, 2017 Market Monitoring Report.

Fig. 7 - Total Curtailment in California, 2014-2016



The EC has also taken a stance that disfavors renewable curtailment as an integration solution, but recognizes that up to 5% of installed VRE capacity could be curtailed if it is cost-effective to do so. (EC 2017b at 46). The EC's new proposed regulations would require any curtailment of renewables to be compensated by the grid operator and reported. (*Id.* at 45-46). Compensation for curtailed energy would have to be at least the greater of the higher operating costs incurred by the facility or 90% of the expected revenue (including subsidies like foregone production tax credits) if the renewable generator had not been curtailed. (*Id.* at 46).

4. Comparison of Reliability and Cost Outcomes in Germany and California

4.1. Reliability Metrics

Neither Germany nor California have experienced any significant increase in electricity outages due to increases in VRE generation. In 2016, the average outage duration (the System Average Interruption Duration Index, or SAIDI) in Germany was 12.8 minutes, and there were a total of about 178 power interruptions on Germany grid in the same year. (BNA 2017b). These numbers are close to those experienced in the prior year. (*Ibid*). The SAIDI score has fallen significantly since 2006, indicating increasing reliability even as VRE generation increased dramatically in Germany. (*See* BNA's overview of historic power outages at www.bundesnetzagentur.de/SAIDI-Strom).

The 10-year average of both outage durations and frequency in California have also declined from 2006-2015, in some service territories dramatically so. (CPUC 2016 at 10-11). These declines were achieved at a time when wind and solar generation were increasing very significantly in California. A large spike in outage duration in 2011 is related to a region-wide outage caused by human errors at a number of grid operators that violated legal standards and appears unrelated to higher VRE penetration levels. It is worth noting that while there has been a downward trend in outages in California, the SAIDI scores remain much higher than in Germany (12.7 minutes in 2015 for Germany vs. a range of about 70-150 minutes for the three major California IOUs in 2015). (*Compare* BNA 2017b *with* CPUC 2016 at 10).

In short, higher levels of VREs are not yet causing (and may never cause) system emergencies that result in power outages in either California or Germany. The integration issues raised by VREs are currently being resolved prior to system emergencies through economic and out-of-market dispatch tools, and therefore the impacts would be expected to be financial rather than operational.

4.2. Rate impacts

Given that the tangible result of integration policies in both jurisdictions has been primarily financial, it would be insightful to compare the cost of these policies on a common metric like the average electricity rates paid by classes of consumers. Unfortunately, such a comparison is challenging given differences in the design of grid fees and markets in California and Germany.

The incremental costs incurred by grid operators to accommodate incremental VRE generation is very difficult to isolate from the other components that contribute to changes in electricity rates, and neither the CAISO nor the BNA have attempted to identify and publish this data themselves. In addition to the feasibility issues with producing this data, the lack of even attempts at it may be in part political: German and California policymakers who are in favor of higher VRE mandates may prefer to focus public attention on the relatively small changes in total generation costs rather than the potentially more significant costs to the entire grid of integrating these new resources. From such a perspective, it could be politically convenient that integration costs are inextricably buried in larger rate components.

Additionally, fundamental differences in grid architecture (*e.g.*, a higher historic level of available distribution grid capacity in Germany) may make any identifiable historical grid integration costs unrepresentative of likely future integration costs and inapplicable to the costs that might be expected with similar VRE penetration levels in the other jurisdiction. As an example, the costs to interconnect new VREs is handled very differently in Germany and California. In California, interconnection costs are generally borne by developers and are subsumed within the total cost of the PPA paid by the offtaker, and therefore categorized as a generation cost. This makes it difficult to compare with German integration costs, since in Germany the principle is that the "grid follows generation," and therefore the costs to interconnect renewables are generally borne by the network operators and are therefore socialized through network charges (grid fees) that are lumped together with other costs of building and maintaining the grid. Thus, even if such integration cost estimates were available, it is uncertain whether they would be useful in a cross-jurisdictional analysis.

Despite the complications that make direct rate comparisons suspect, it is worthwhile for purposes of general context to review the significant difference in electricity rates between California and Germany. Average residential electricity rates in Germany as of April 2017 stood at €00.2986/kwh, or about $00.3165/kwh. (BNA 2017c at 231). This electricity rate is among the highest in Europe. (EC 2014 at 92). This followed an increase in electricity rates in Germany of about 39% between 2007 and 2015, or almost 5% per year. (Beermann and Tews 2016 at 6). The EEG surcharge, which represents the above-market cost of procuring renewable energy at the feed-in rates, made up 23% of the total average residential rate as of April 2017.[30] (BNA 2017c at 231). Network charges, which is presumably where much of the cost to balance VREs is found, made up another 23% of Germany's average residential rate.[31] (*Ibid*). These network charges are increasing at a fast pace - as of October 2017, they had increased by almost 9% in Germany in just the past year. Other integration costs may show up in the remaining two Germany rate components: generation, which likely includes the cost of new flexible capacity needed to fill in behind VREs; and taxes, the largest rate component, which predominantly provides non-VRE-related revenues for unrelated government objectives

[30] EEG Surcharge in 2016: €00.0688; Total Average Residential Rate in 2016: €00.2986/kwh. (BNA 2017c at 231).
[31] Network Charges (Netzentgelt) in 2016: €00.0699; Total Average Residential Rate in 2016: €00.2986/kwh (BNA 2017c at 231).

(thereby inflating retail rates), but also likely includes the cost of research and development programs designed to develop better VRE integration services.

This compares to an average electric retail rate in California in 2015 of $00.1523/kwh, or less than half of the average residential rate in Germany. (EIA 2016). While both jurisdictions' rates include numerous components that are not directly related to current VRE production and integration, and while cross-subsidization between rate classes (e.g., residential customers' subsidization of industrial rates in Germany), a large difference in the rates remains.

Although no conclusive determination can be drawn from the data, given the constraints noted above, it is intuitive that Germany's VRE integration policies are driving at least some of the higher electricity rates. As discussed in Section 3.2.5.6., above, compensated curtailment of VREs and re-dispatch of fossil plants in Southern Germany have become a mainstay of the German grid's operational reality. The costs for redispatch in Germany have resulted in about $1 billion Euro being added to grid charges borne by all consumers per year in 2015 and 2016, and the compensation just to the curtailed generators (generally, wind farms in Northern Germany) doubled in just one year from 2016-2017. (BNA 2017b; FAZ 2017).

It is also worth noting that in the first quarter of 2017, the level of Germany's out-of-market integration measures continued to climb steeply, in part due to weather and unit availability circumstances. The first quarter uncompensated emergency orders were already 14 GWh, equal to the entire volume of orders issued in 2016. (BNA 2017a at 4). The called-upon regulation reserve volume in the first quarter of 2017 was also already higher than the entire volume of reserves called in 2016. (*Ibid*). In sum, redispatch costs in Germany for just the first quarter of 2017 were already 84% of the total 2016 incurred redispatch costs. (*Ibid*). While no strict comparison can be made regarding the cost of integration policies in California and Germany, it is clear that policies in Germany have contributed to significant increases in rates, and this trend may be accelerating.

5. Potential Lessons for California from the German Approach to VRE Integration

This section of the paper seeks to derive lessons from the German experience in integrating high levels of VREs and to consider the applicability of those policies to California.

Although lessons for Germany from the Californian experience in integrating VREs are outside the scope of this paper, a question that deserves (and is currently receiving) academic and practical inquiry is whether Germany would benefit from splitting into multiple price zones or a nodal market, like the one created by the CAISO. Germany's current single-price-zone approach to market design appears to be the greatest near-term hindrance to the reduction in integration costs since it forces uneconomic, out-of-market redispatch and curtailment solutions in order to balance the mismatch between generation and load in the country. Creating a nodal, or at least a multi-zone, market would likely reduce overgeneration issues and incentivize the building of additional capacity in the South where it can be delivered without major new transmission investments. However, the question of whether such a system would be less expensive in the long run depends on the relative cost (and feasibility) of building the "copper plate" grid sought by German regulators versus the relative costs and locational benefits of new renewable generation in both Southern and Northern Germany.

5.1. Market Design is Key to Incentivizing and Deploying Optimal Integration Solutions

The German regulators (in line with the EC) are strong proponents of the idea that the proper market design can integrate VREs at least cost. The idea that the market is better at identifying and incentivizing the best solution to overgeneration and flexible capacity needs than administratively-determined carve-outs or mandates is seductive. The theory behind market-based solutions is logical and has the added benefit of absolving regulators of responsibility for picking winners and losers, which exposes them to enormous political pressure.

On the other hand, markets are notorious for failing. Perhaps the most relevant example is that of California's attempt to deregulate its electricity markets in the 1990s, when it ordered the utilities to divest much of their generation and instead to procure the electricity they needed to serve their retail customers through a spot market. The theory then, much like the theory of German regulators today, is that a free market and lower barriers to entry for new participants would result in an optimal resource mix and the right level of generation capacity. Of course, history showed that this new market failed spectacularly, resulting in an energy crisis in 2000 that is still being litigated today. Energy traders recognized flaws in the market design that allowed them to gain market power and to manipulate the spot market, forcing one major California utility into bankruptcy and requiring the state to become the energy provider of last resort. In the aftermath of the crisis, California largely re-regulated the industry, halting the sale of utility generation assets and ordering the California utilities to enter into long-term PPAs for nearly all of their forecasted long-term need. California also initiated its RPS program in the aftermath of the crisis, in part to provide long-term rate stability under the long-term contracts that new renewable facilities required for financing.

Given this experience, it is understandable that California would be reluctant to follow a purely market-based policy. But it may be that California's history with the energy crisis is causing it to rely too heavily on cumbersome command-and-control regulatory mandates that not only create sub-optimal outcomes, but which also may actively undermine the ability of the electricity market to function as intended.

5.1.1. California's RA Program May Be Hindering the Use of Market Mechanisms to Integrate Renewables

The path chosen by Germany, and further endorsed by the EC in its 2016 regulatory package, moves away from out-of-market capacity mechanisms like California's RA Program in favor of developing markets for essential reliability services that will send adequate price signals to developers to build needed capacity. From the perspective of Germany's approach, California's RA Program is a market-distorting overlay that impedes the optimal solution. The RA Program, recently augmented with new flexible capacity requirements as described in Section 3.1.4.1.1., creates administratively-set and relatively inefficient prices for new capacity by prescribing the levels of capacity that must be procured and by identifying specific characteristics that the capacity providers must meet.

By requiring the procurement of capacity under bilateral futures contacts, the RA Program may result in a glut of new capacity, which dampens any price signals in the spot market that could incentivize a better portfolio and amount of integration solutions. To the extent that the RA Program favors conventional generator characteristics in describing the type of capacity that energy providers must use to meet the Program requirements, the RA Program may also restrict the ability of new technologies that can provide flexible capacity (*e.g.,* demand response, energy storage, and renewables) from competing to provide these services. This can occur intentionally, through industry capture of regulators, or it can occur unintentionally simply through the inherent conservatism of regulatory agencies charged with ensuring grid reliability when they are forced to pick technological winners in advance.

CAISO has expressed understandable concerns about the potential for market manipulation, similar to what occurred in California in its 2000 energy crisis, in the absence of the must-offer RA Program. Specifically, CAISO worries that without the RA Program's requirement that generators holding RA contracts offer their capacity into the market, affiliated generators in transmission-constrained areas could withhold their capacity and thereby drive up prices artificially. (CAISO 2011 at 23). It seems, however, that this fear could be allayed through alternatives that identify and mitigate market power, but which, unlike the RA Program, allow the market to function as intended to incentivize the building of optimal integration solutions through clear and strong price signals. Germany's experience on this alternative path in coming years will be instructive.

5.2. Grid and Market Expansion Are Necessary to Take Advantage of Resource Diversity

Another insight from Germany's approach is the importance of grid investments and market expansion (through market coupling across regions) to allow the broadest reasonable set of supply- and demand-side providers to compete on the same market to sell flexibility services. Because of the geographic diversity of energy resources, especially VREs dependent on differing wind and solar resources, it is critical to achieve as large of a market as possible. The resulting diversity will tend to result in a self-integrating system (where, for example, wind generators with higher nighttime generation profiles balance solar generators). In the context of Germany, expansion of the market also means bringing in hydro-based storage resources in the Alps and in Norway. California may be able to take advantage of similar, cost-effective hydro resources outside of CAISO through grid and market expansion.

Germany's experience to date would suggest that CAISO is on the right path in its current efforts to expand throughout the Western Interconnection and suggests further that California should redouble its efforts to overcome the political obstacles to that expansion.

5.3. Renewable Curtailment is Inevitable and Expensive, But Ideally Short-Term

A third lesson from the German experience to date is that curtailment of renewable generation does not stop just because official policy prefers other integration solutions. In fact, the data indicate that renewable curtailment has become a major, and expensive, near-term tool used by Germany's TSOs to keep the grid balanced. While German regulators insist that curtailment and redispatch will be reduced in the future through grid improvement projects, these projects have been largely mired in political opposition and are behind schedule.

Luckily, CAISO, the CPUC, and California's IOUs all seem to be aware that renewable curtailment is a necessary and, potentially, cost-effective tool to help integrate VREs in the near-term. In fact, Germany's experience suggests that the volumes of curtailed renewables will increase substantially as VRE penetration in California increases.

At the same time, California may wish to take a page out of Germany's playbook on curtailment and recognize that while curtailing renewables may help in the near-term, this should not preclude developing more practical and cost-effective long-term solutions to integrating VREs. It makes little intuitive sense to curtail carbon-free energy resources when the goal is to decarbonize the grid. Even as California prepares to curtail higher volumes of renewable energy, it should develop the market and technological foundations to allow other flexibility solutions, including demand-side flexibility and storage, to reduce the need to curtail renewable generation.

5.4. Central Market Design May Not Be Necessary but Insufficient: Decentralization and Democratization of the Energy System

An intriguing and contradictory lesson that might eventually be taken from the German experience, depending on the success or failure of current policies, is that centralized solutions [32] ultimately impede energy transitions. A key driving force behind Germany's switch away from nuclear toward renewable energy has been the high levels of public acceptance and support for the *Energiewende.* That support, in turn, is at least partly due to the German public's perception that the *Energiewende* is a move away from the large, centralized, monopolistic electricity market of the past and toward a decentralized, consumer-oriented, and democratized energy system of the future. Though this thinking is very prominent in civil society and academia, Germany's grid regulators, TSOs, and legislators appear to pay only lip service to the notion of

[32] By "centralized," this paper refers to energy systems that seek to expand to the greatest extent possible both demand and supply in a single optimized grid, in contrast to a "decentralized" energy system like a micro-grid that can operate as its own island outside the bulk transmission system.

decentralization while focusing on improving the design of the central electricity market and expansion of that market through coupling and greater interconnections with neighboring countries. It remains to be seen who is right: Whether the German government's current centralized approaches to integration are able to be carried through and are cost-effective, or whether the focus on centralized and market-oriented solutions causes public support for the transition to falter.

It may be that Germany's *Energiewende* itself goes through a transition toward decentralized policy, and Germany's openness (or lack thereof) to such a course change may be one of its policymaking strengths or weaknesses. As transition management theory suggests, "setting up a predefined 'master plan' [for an energy transition] is neither meaningful nor feasible. Rather, adapting to the uncertainties of ongoing transition processes requires freedom for constant experimentation and innovation at various levels including the decentralised level." (Beermann and Tews 2016 at 126).

Germany's chief energy policymaking body has recognized in the context of efforts to build new transmission lines that public acceptance of centrally-determined, large-scale development projects to integrate VREs is lacking: "Despite a clear increase in efforts to encourage public participation and acceptance, and the increased use of innovative technologies (e.g. through underground cabling), the actual implementation of each individual project (route planning) remains a challenge." (BMWi 2016 at 24). While recognizing the challenge, the BMWi does not offer any new approach, but instead exhorts stakeholders to "rise to this challenge together and take a solution-based approach." (*Ibid*).

California policymakers may be in danger of falling into a similar trap, favoring economically-attractive, centralized, market-oriented solutions without engaging the public sufficiently to build the necessary support for the transition. For example, when it comes to demand-side flexibility offerings, CAISO seems to be focused largely on how customers can provide such flexibility without having to be active participants. (*See* CAISO 2017c at 14-15). The German model may suggest that this is exactly the wrong perspective to create a sustainable energy transition. Instead, Germany's incredibly successful approach to the early stages of the *Energiewende* was to empower end-use consumers to change the system from the bottom up in a decentralized manner. To date, this active involvement and broad participation has created a sustainable foundation for more radical changes to the system and a "willingness to pay" mindset. California will need to balance its technocratic instincts, in which highly-educated and capable government regulators and a small group of stakeholders develop economically optimal policy solutions, with the need to ensure the support, if not active participation, of California energy consumers who are increasingly demanding more control over their energy choices.

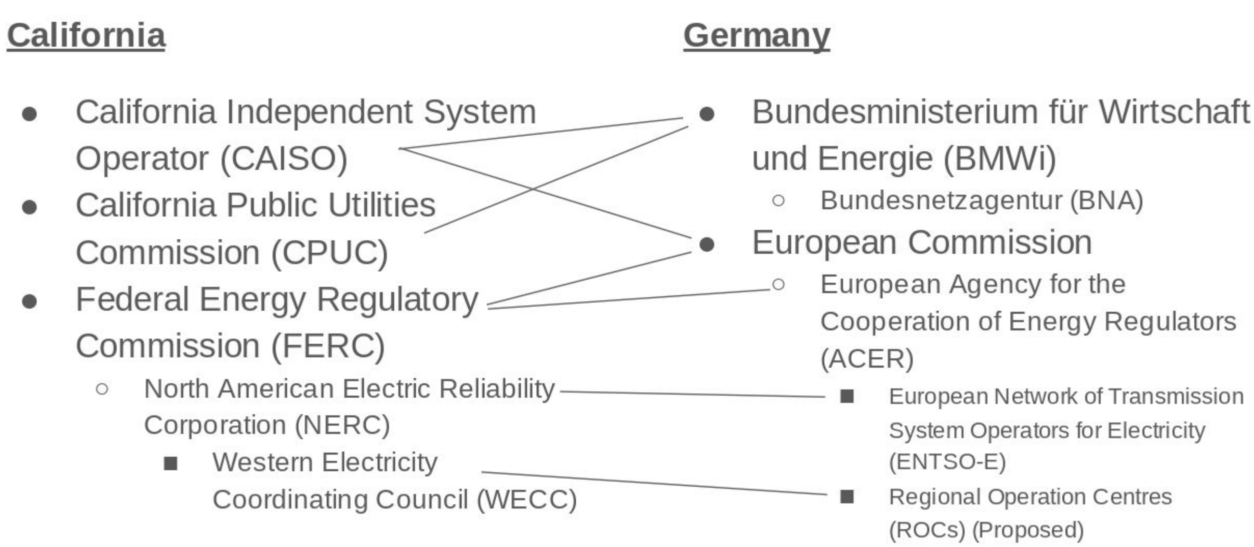
5.5. Regulatory Authority and Responsibility May be Too Diffuse in California

Finally, an obvious difference between the approach to energy policymaking in Germany and California is the relative concentration of regulatory authority within the BMWi in Germany, versus a diffusion of this responsibility between the federally-regulated CAISO and the state CPUC in California. Further, the CEC plays a coordinating and high-level energy policy role in California, and is independent of both the CPUC and CAISO. This diffusion of regulatory responsibility between so many agencies and actors, each with a slightly different core mission and set of legal obligations, makes policy and regulatory coordination more difficult.

In Germany, the BNA, which directly regulates the operation of the grids, sits within the BMWi, which is responsible for national energy policy, issuing regulations and making legislative proposals in that role. Thus, decision-making authority is fairly concentrated and streamlined within the BMWi, although this may be changing as the EC has proposed a more expansive role for itself and other EU-level institutions in cross-border energy policy issues. Figure 8, below, provides a simplified diagram showing the key regulatory bodies in each jurisdiction and identifying which of the bodies has similar authority.

In order to carry out a successful transition to high levels of VREs in California, the legislature may need to consider streamlining the regulatory structure so that policies can be implemented more quickly, durably, and effectively. This may include deferring more to the FERC-regulated CAISO as the lead regulator with significant consultation and participation by a single state-level regulator.

<u>Fig. 8: Regulatory Jurisdiction over VRE Integration in California and Germany</u>



6. Conclusion

This paper has surveyed the factual and legal contexts in both California and Germany that govern the integration of VREs into the electricity system. It has also assessed the outcomes of those respective policies in terms of reliability and cost. It concludes by identifying five lessons that California may learn from Germany's experience integrating high volumes of VREs.

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- Dr. Martin Schöpe, BMWi;
- Dr. Matti Supponen, EC, Directorate General for Energy

8. Vitae

I have practiced within the fields of energy and environmental law since 2003. I currently represent Pacific Gas and Electric Company ("PG&E") in regulatory proceedings, particularly those related to renewable energy policy, legislation, planning, and compliance. Prior to PG&E, I practiced air pollution law for the United States Environmental Protection Agency – Region 9, was in private practice with Latham & Watkins LLP, and served as a Luce Scholar and visiting fellow at the Thailand Environment Institute. I served as a law clerk to Judge (Ret.) Irma Gonzalez in the United State District Court for the Southern District of California.

9. Declaration of Conflicting Interests

I represent PG&E, a combined gas and electric utility company serving retail customers in Northern and Central California, as its attorney. Although I was on a leave of absence from my employment while writing this article and this research was neither funded by, nor solicited by, PG&E, I have an ethical duty of loyalty to PG&E, which includes advocating for the interests of the company and not creating actual or potential conflicts with those interests. To ensure that this work does not impinge on those ethical obligations, I have sought and received the consent of PG&E management to publish this article. Notwithstanding this consent, the opinions expressed in this article are solely mine based upon my independent research and do not express the opinions of, or reflect any endorsement by, PG&E.

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11. List of Acronyms

ACER: European Agency for the Cooperation of Energy Regulators

BMWi: Bundesministerium für Wirtschaft und Energie (German Federal Ministry for Economic Affairs and Energy)

BNA: Bundesnetzagentur (Federal Network Agency)

BRP: Balance Responsible Party

CAISO: The California Independent System Operator

CCA: Community Choice Aggregator

CEC: California Energy Commission

CHP: Combined heat and power

CLEE: U.C. Berkeley Center for Law, Energy, and the Environment

CPUC: California Public Utilities Commission

DSO: Distribution system operator

EC: European Commission

EEG: Erneubareenergiegesetz (Renewable Energy Sources Act)

ENTSOE: European Network of Transmission System Operators - Energy

EPEX: European Power Exchange

EU: European Union

EWG: Energiewirtschaftsgesetz (Energy Industry Act)

FERC: U.S. Federal Energy Regulatory Commission

FFU: Forschungszentrum für Umweltpolitik (Environmental Policy Research Centre)

FRACMOO: Flexible RA Must-Offer Obligation

GHG: Greenhouse gas

GW: Gigawatt

GWh: Gigawatt-hour

IOU: Investor-owned utility

KW: Kilowatt

LMP: Locational marginal price

LSE: Load-serving entity

MW: Megawatt

NERC: North American Electricity Reliability Corporation

NREL: National Renewable Energy Laboratory

PG&E: Pacific Gas and Electric Company

PIRP: Participating Intermittent Resource Program

PPA: Power purchase agreement

POU: Publicly-owned utility

PV: Photovoltaic

RA: Resource Adequacy

REC: Renewable energy credit

ROC: Regional Operational Centre

RPS: Renewables Portfolio Standard

SAIDI: System Average Interruption Duration Index

TFEU: Treaty on the Functioning of the European Union

TSO: Transmission system operator

VRE: Variable renewable electricity generation resource (ie., intermittent renewable generators, including wind and solar)

WECC: Western Electricity Coordinating Council

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