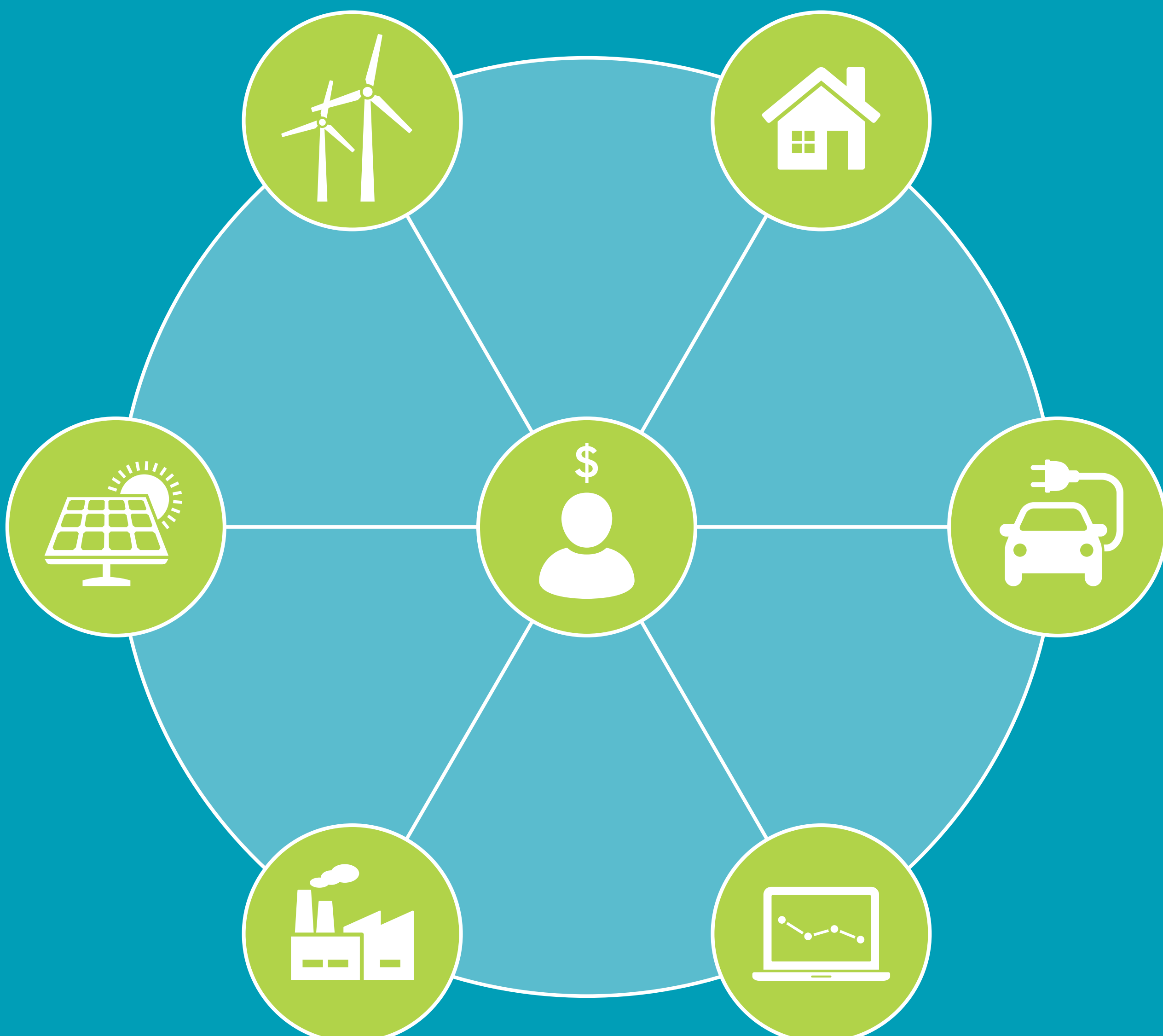
BUREAU OF ECONOMIC GEOLOGY UDDEN SERIES NO. 7

Net Social Cost of Electricity

Policy Smog and Waning Competitive Markets, Lack of Consumer Participation, Importance of the Grid, and Scalability Challenge

Gürcan Gülen



Bureau of Economic Geology

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Cover: Market-based solutions and demand-side participation are needed to achieve clean, affordable, reliable electricity at least cost.

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2019

For superforecasters, beliefs are hypotheses to be tested, not treasures to be guarded.

Superforecasting: The Art and Science of Prediction
Philip E. Tetlock and Dan Gardner

Acknowledgments

This report leverages more than 20 years of research that I conducted at the University of Houston and Bureau of Economic Geology of The University of Texas at Austin under the leadership of and in collaboration with Dr. Michelle Michot Foss. I have been fortunate enough to live through and study the electricity restructuring of not only the ERCOT system in Texas but also many others across a diverse geography, given my international work. The Bureau has been an excellent home to deepen my understanding of the natural gas resource base and markets. Participating on Bureau teams to develop Texas' FutureGen proposals and to analyze the economics of carbon capture and sequestration (CCS) for the Bureau's Gulf Coast Carbon Center was instrumental in developing proficiency in not only CCS but also comparison of alternative generation technologies in terms of their economics and environmental impacts.

My involvement in the Full Cost of Electricity project, an interdisciplinary effort managed by UT Austin's Energy Institute, exposed me to alternative expertise that deepened my understanding of the electricity sector and widened my awareness of additional dimensions. The list goes on. Learning never stops. Many research outputs from these joint efforts and many others not listed here are referenced in this report.

I would like to thank Dr. Foss and all collaborators for providing me with the opportunity to learn different aspects of the energy industry, which allowed me to write this report from a wide lens. Thanks are also due to all sponsors of research over the years for allowing the freedom to investigate issues of relevance to energy value chains. I also owe gratitude to the leadership of the Bureau—Dr. Scott Tinker, Mr. Mark Shuster, Mr. Eric Potter, Dr. Michael Young, and Mr. Jay Kipper—for their support over the years and their patience with the economist lingo. Special thanks to the Bureau publishing team, who made this report readable. Finally, I appreciate the feedback of several colleagues who were brave enough to peruse drafts of the report.

Needless to say, I alone am responsible for any errors and opinions in this report, which is written with the hope of contributing to a rational debate about the future of U.S. electricity. Given the rapid pace of developments in the electricity sector, it took me over a year and numerous revisions to call this version "final." Still, by the time it is published, I am certain that new data will influence some of the discussions and perhaps even alter some lessons. It is an increasingly uncertain environment, mostly driven by the political economy of energy. This heightened uncertainty obligates everyone involved in energy discussions, including this author, to fully employ their System 2 thinking and test their beliefs constantly rather than being influenced by the trends du jour.

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Executive Summary

Those who monitor developments in the U.S. electricity sector already know that competitive, or organized, electricity markets and traditional regulated, vertically integrated utilities both face a policy-driven energy transition that not only threatens the financial sustainability of many businesses across the electric power value chain but also causes concern about system reliability. There are many efforts to adapt markets to out-of-market policies and to reform regulatory frameworks. The literature on how to fix electricity markets and/or utilities is growing. Many of the proposed fixes, however, start with a prescription for a preferred mix of available technologies—rather than ultimate goals such as lower emissions, affordable electricity, and reliable service—and undervalue the role of consumers in reducing system costs and fueling true innovation.

The purpose of this report is to demonstrate that the time is ripe for a rational, multifaceted fresh look at the technology, economics, and negative as well as positive externalities of electricity service in the United States. The current uncoordinated, blunderbuss approach to energy policy across numerous jurisdictions has turned into a political competition that attempts to "level the playing field" for favorite technologies via subsidies and mandates. Many of these policies or attendant market design changes lead to litigation. This situation raises the cost of electricity for customers, who are still not full participants in the electricity market, and increases uncertainty for market participants, which in turn encourages further rent-seeking practices.

Fixing the existing competitive market structures according to economic principles is the obvious first choice to improve the current situation, but doing so appears politically infeasible in most jurisdictions, including many that restructured their electricity industry. Nonetheless, with apologies to those for whom these principles are obvious, I provide evidence for effectiveness of markets in achieving societal goals at least cost; these principles are not only worth repeating but also form the basis of the market-IRP, a hybrid system of competition and integrated resource planning (IRP). I discuss high-level principles of the market-IRP to improve upon today's cacophonous policy environment that induces rent-seeking and inefficient investments and handicaps technological innovation while challenging regulators who struggle to keep up with the changes and reconcile concerns of diverse stakeholders. Finally, I augment the levelized cost of electricity (LCOE), an imperfect but commonly used metric, with costs of externalities, electric power system costs, and subsidies to offer an improved tool for social benefit–cost analyses. A summary of key takeaways follows.

Competitive, or organized, electricity markets are facing existential threats.

Market designs have been flawed from day one. By definition, these are political failures, not failures of economic principles. Those flaws especially relevant to current technological transitions and discussions in the electricity sector include the following:

- Price caps undermined the price signals to market participants.
- Most consumers have not been allowed to respond to intraday dynamic price signals.
- Externalities have not been incorporated into market prices.

The long history of electricity as a public service never allowed for it to be seen as another commodity by the public and policymakers. Vertically integrated, regulated utilities continue to generate, transmit, and distribute electricity in many jurisdictions that never restructured their electricity industry. Although most utilities are investor owned, public power still serves about one-third of electricity consumers, including within the territories of organized markets.

Since the transmission and distribution (T&D) grid remains a regulated monopoly in restructured markets, investment in T&D is decoupled from competitive and, increasingly, incentives-driven generation investment decisions. This decoupling introduces inefficiencies into grid optimization and system cost management, especially with the rising penetration of remote intermittent and variable resources as well as of demand-side resources. Transmission and distribution utilities are incented to pursue unnecessary T&D investment under cost-of-service ratemaking.

Many states had priorities other than market efficiency, including environmental improvements and local jobs. Markets were not trusted to achieve these objectives because pricing environmental externalities, for example, would have visibly increased the cost of electricity. However, today, the retail cost of electricity is higher or, at best, stable in most regions despite historically low wholesale electricity prices.

A plethora of uncoordinated, often conflicting or duplicative, policies across jurisdictions distort markets, increase overall costs, and encourage rent-seeking. The several thousand policies across the country include familiar ones such as federal production and investment tax credits, renewable portfolio standard (RPS), energy efficiency programs, feed-in tariffs, net energy metering, and storage mandates. New policies are added constantly, such as the requirement of solar panels on new homes in California starting in 2020. New policies, regulations, or market design changes are needed to fix the problems created by the previous set of policies, which have no cohesive benefit–cost analysis. Benefit–cost analyses of individual programs are insufficient to capture all dimensions and ripple effects across industry segments and over time.

An increasing number of resources are supported by out-of-market compensation. Subsidized resources cause the competitive portion of markets to shrink and create a domino effect of subsidizing existing resources, which require further market design changes. The market design handicaps enhance the impact of out-of-market resources, especially intermittent and variable renewables. Price formation and capacity-market reforms have kept the Federal Energy Regulatory Commission (FERC) and stakeholders in several organized markets busy since the early 2010s. The recent saga of PJM reforms of its capacity and energy markets provides a good example of a cycle of confusion, litigation, and uncertainty.

Subsidies persist because they create interest groups and low-risk rent opportunities. This truism is seen in many sectors—perhaps most visibly agriculture and end-user prices of fuels and electricity—across the world, including the U.S. electric power sector. Financial interests seeking short-term growth and secure returns from risk-mitigating incentives perpetuate this policy volatility.

Properly designed markets would have delivered more cost-effective and innovative solutions to both economic and environmental goals.

Today, an increasing number of stakeholders and experts argue for allowing demand-side participation in order to promote a portfolio of technologies, such as the Internet of Things (smart appliances, energy management software), rooftop solar, and battery storage.

Energy markets without price caps (or at least with caps that represent the value of lost load) and with demand response by all consumers based on prices that reflect the true cost of electricity at different times of the day would have encouraged technology developers to serve customer needs for managing energy consumption or self-generation with innovative, more efficient technologies. Behavioral adjustments by consumers would have eliminated unnecessary investment in peaking capacity as well as T&D infrastructure.

The building industry could have responded to customer demands for more-efficient and energy-smart accommodations, providing an opportunity for large-scale change that would have attracted capital and talent into energy efficiency and conservation technologies and building designs.

Economists are nearly unanimous in their support of pricing externalities as the most cost-effective and impactful solution to environmental problems. For example, the sulfur dioxide cap-and-trade market is commonly accepted as successful in reducing acid rain. Similarly, a tax on greenhouse gas (GHG) emissions is economists' preferred solution to tackle climate change. The tax needs to be economy-wide since emissions from electricity generation account for only about 30 percent of total GHG emissions in the United States. But, as a global problem, some kind of adjustment to the cost of traded goods is needed to equate domestic cost of goods with costs in countries that do not have an equivalent tax on GHG emissions.

Supporting off-the-shelf technologies is inferior to taxing externalities if the main objective is to reduce environmental externalities. Even out-of-market policies can be made more cost-effective. For example, a national RPS is more cost-effective than a multitude of state RPS programs. Many jurisdictions seek local economic benefits such as job creation when they pursue RPS programs or other mandates. However, the evidence for such economic benefits is mixed. For example, most solar panels are imported. Installation jobs have lower value added than manufacturing jobs and technology innovation.

Alternative technologies do not eliminate the need for conventional infrastructure although they do change how such infrastructure is utilized. In fact, increasing penetration of wind and solar is dependent on the availability of a well-connected grid and sufficient dispatchable generation. Since 2010, about $200 billion has been invested in the T&D infrastructure, partially to facilitate integration of more renewable energy capacity. Some of these investments are certainly larger than needed, driven by the capital bias created by cost-based ratemaking for utilities. Nevertheless, intermittency and variability of wind and solar increase system costs, including the cost of new T&D infrastructure. These costs are not fully captured in market prices but find their way into electricity bills as T&D or other charges. As penetration of renewable energy increases, system costs also rise, and the market value of these technologies declines.

The trend of policy-driven resource addition seems irreversible. Nevertheless, realization of the higher cost of uncoordinated policies may be spreading.

Properly fixing competitive markets appears to be a Herculean task. Many still call the dynamic mishmash of policies, regulations, and design changes with constant battles at regulatory agencies and courts a *market*—but probably only for convenience. The de facto trend is away from competitive markets toward resource planning, but many market participants are feeling in limbo. There is, however, an opportunity to marry best practices in regulated IRP with competitive market principles to achieve society's goals at least cost and more quickly, minimizing time-wasting and costly regulatory and legal clashes as well as the influence of rent-seekers.

A hybrid approach should mimic the efficiency of a proper market. Let's call it *market-IRP,* or a planned market. A holistic look at the overall electricity system is necessary to capture the value offered by the T&D grid and demand-side participation. The least-cost option for achieving the objectives will differ across systems and can come from generation, T&D, demand response, or, most likely, a mix. Once system operators and regulators agree on the least-cost option, competitive procurement and performance-based ratemaking (rather than traditional cost-of-service ratemaking) should be pursued as appropriate. The United States has done some early experiments but still trails many international markets with advanced regulatory practices by decades. However, an agreement on objectives is a must, as is the elimination of technology-specific subsidies and mandates. Otherwise, the market-IRP would only add to total costs.

Conventional LCOE is inadequate for improved policy discussions. I offer an augmented LCOE that does not ignore the T&D grid and how it is managed by system operators while remaining reliable and delivering least-cost electricity in real time. Thus, it includes not only the traditional capital, operating, and fuel cost of technologies but also the costs of externalities and system-integration and of subsidies. This version of the augmented LCOE is still incomplete owing to paucity of consensus estimates on some externalities. There is also a range of uncertainty around system-integration costs since they are heavily dependent on individual system characteristics. Nevertheless, the augmented LCOE exposes the interdisciplinary effort needed to develop a metric that can capture costs and benefits of various energy policies. Even if a consensus cannot be reached about the value of the complete metric, the discussion of various dimensions within a policy or IRP benefit–cost analysis should be valuable.

I refrain from providing details on either the market-IRP model or augmented LCOE as they require the input of experts from a wide range of disciplines. No one is an expert in all aspects (technological, economic, legal, regulatory, environmental) of the electricity sector and fuels and technologies used. The scale of the electric power industry and macroeconomic setting are often ignored, and consumer preferences and behavior are taken for granted. Instead, many industry analysts and observers focus on impressive growth rates of wind, solar, and gas-fired generation capacity and the promise of emerging technologies and continuation of policies that support them. The extent of the larger energy industry; the supply chains for various fuels, minerals, and technologies; and connections to the rest of the economy are poorly understood.

In addition, the social media ills of information pollution and superficiality infect public opinion and undermine the all-too-important energy debate just as they do other issues in the political sphere. This atmosphere leads to cognitive problems such as confirmation bias and heuristic thinking. As research has amply proved, everyone is vulnerable to these psychological pitfalls, which are summarized in many books (e.g., Daniel Kahneman's *Thinking, Fast and Slow*). They can be mitigated, to a certain extent, via rational, fact-based, probabilistic analysis by those capable of doubting themselves and pursuing alternative lines of questioning. *Superforecasting: The Art and Science of Prediction* by Philip Tetlock and Dan Gardner, a neat summary of years of research, shows that individuals can improve their analyses by adopting principles of self-questioning and organized research and that, when averaged, forecasts of many such informed individuals become even more accurate. This larger context is important to acknowledge. The attraction of competitive markets, when properly designed, is their ability to garner the "wisdom of crowds" who have something at stake (often, money to lose) if they do not pay attention to market signals. In electric power and climate change, the crowd must include consumers who are fully exposed to the costs of their actions.

Prologue

One reason why organized electricity markets have been struggling in recent years is that most jurisdictions hampered competitive market designs from the day they restructured their traditional regulated, vertically integrated utility model. In fact, many jurisdictions never restructured, instead maintaining the traditional model. What some continue to call a market is not recognizable as such to economists and is not what the architects of competitive markets envisioned when the restructuring processes started more than 20 years ago. The following comment on renewables from a senior official at an energy infrastructure investment fund demonstrates the cognitive dissonance: "Economics, rather than policies or mandates, is now more often the driver.…But policies and mandates drive the economics" (Trabish, 2018b).

All markets are creatures of policy and regulation, economic or otherwise. As a corollary, a market failure often is policy failing to design the market properly (e.g., not pricing the cost of an externality, or capping the price of electricity). But when a growing share of investments and operational decisions are driven by out-of-market compensation such as subsidies and mandates, it is no longer possible to talk about a competitive market. Nor is it possible to defend all of these actions as effective mitigation of policy failures since many do not directly target a particular failure.

The problem is not the idea of competitive electricity markets but rather the politics of electricity. Kavulla (2017) provides insights from an experienced regulator on why the markets theorized by economists create difficult challenges for policymakers, such as their inherent price volatility. Parting comments from former Federal Energy Regulatory Commission (FERC) Commissioner Bay in early 2017 are also instructive: "The premise of the MOPR [Minimum Offer Price Rule] appears to be based on an idealized vision of markets free from the influence of public policies. But such a world does not exist, and it is impossible to mitigate our way to its creation. The fact of the matter is that all energy resources receive federal subsidies, and some resources have received subsidies for decades." [1]

1. For example, see https://www.powermarketstoday.com/public/Bay-picks-apart-MOPR-concept-on-last-day-at-FERC.cfm. I discuss MOPR later in this report and also provide some subsidy estimates.

Although electricity industry restructuring was flawed from the beginning, it was still able to deliver wholesale competition in many cases. However, subsequent market design changes or regulations were often done to accommodate socioeconomic or environmental policies rather than to improve competitiveness of the market. For example, political aversion to price spikes led to price caps on wholesale and retail electricity prices, which curtailed price signals to both developers of generation plants and consumers. In turn, concerned about not having sufficient capacity in the future (i.e., resource adequacy), policymakers created capacity markets to provide additional revenues. System operators also had to compensate load-following resources via uplift payments beyond what they earn based on market prices, which are not designed to reflect their full costs. At the time of writing, many markets continue to tweak their capacity markets and energy pricing algorithms. Some, including regulators, have started to question the effectiveness of capacity markets.

The lack of demand-side response to price signals by all consumers, the socialization of the cost of transmission and distribution (T&D) infrastructure, and the lack of retail competition in most states are legacies of the regulated industry that prevented a competitive market to thrive. Many of these constraints have been present even in the Electric Reliability Council of Texas (ERCOT) market, which is fully contained within Texas and is the sole restructured system in the country without a capacity compensation scheme.

A fundamental reason for this inhibited restructuring approach is that electricity has always been perceived as a public service rather than a commodity by most of its consumers and, thus, policymakers. Equally important is the large amount of rents across the electric power value chain that can be captured by influencing policy and regulation. The public service belief system naturally enforces the cozy relationship between rent-seeking and politics. As Kavulla (2017) puts it: "Electricity has never fit the paradigm of business versus regulation.…The utility sector clamors for government's involvement in its business decisions, and government is happy to oblige."

Moreover, there has always been a disconnect between individual state policies and the design requirements for an efficient market built around a physical infrastructure that crosses state boundaries. In the early 2000s, the FERC, with its standard market design proposal, intended to create a more efficient electricity market across multistate grids. But it was not able to overcome divergent state interests, which also prevented federal renewable portfolio standard (RPS) proposals in the U.S. Congress in the late 2000s. A federal RPS is shown by many researchers to be more cost-effective than state initiatives. Another casualty of jurisdictional misalignment has been multistate transmission lines that would have helped the expansion of renewables capacity in best-resource locations with little load by connecting them to large markets.

Often, local economic benefits are central to state RPS and other incentive programs that are built around locally available resources, such as biomass from animal farming or scrap railroad ties, or to attract manufacturing and/or installations jobs. In many cases, local resources are more expensive than alternatives. Governments have always pursued industrial policy to promote local economies and to reduce imports. It is easier to enlist bipartisan support when local economic benefits can be communicated. The macroeconomic question, as always, is whether these industrial policies, green or brown, are effective and yield a higher return on investment as compared to alternative approaches (i.e., achieving goals at least cost). The economic literature on inefficiency of such protective policies is abundant.

Regardless of one's views of the right balance among cheap energy, reliable power systems, clean environment, and a prospering local economy, the fact is that the current atmosphere undermines competitive markets. One piece of evidence is the poor financial health of the merchant generation segment relative to regulated utilities. Moody's Investor Services singles out merchant generation as a serious risk to utilities while those with mostly regulated operations are rated stable or better (e.g., Walton, 2018a). Similarly, S&P Global Ratings refers to energy efficiency and distributed generation policies slowing demand growth and to wind and solar curtailing peak prices as risk factors to merchant generation, while considering nuclear subsidies as a positive (e.g., Walton, 2018b). Gifford and others (2017) warn about another wave of bankruptcies among large generators, mostly merchants, after others that have occurred since the early years of the restructuring. Bushnell and Novan (2018) provide evidence of how large utility-scale solar in California undermines the economic viability of traditional baseload generation. Tsai and Gülen (2017c) demonstrate the revenue losses to thermal generators due to increasing wind generation in the ERCOT market.

Some studies expect renewables to drive more baseload retirement in the future (e.g., Tsai and Gülen, 2017b; Adelman and Spence, 2018). Indeed, the industry has seen many bankruptcies and ownership changes, as well as retirements, in recent years. Some retired plants were older, inefficient, high-emissions thermal plants that would have retired under most circumstances. Others were forced to retire before reaching the end of their useful life, or even before full amortization, making them stranded investments. Other plants, most notably nuclear assets, stayed online because states subsidized them.

Many studies point to low natural gas prices and low-cost renewables leading to historically and persistently low wholesale electricity prices in an environment of low to negative demand growth. However, these factors would not have induced the same level of concern regarding the sustainability of competitive markets if market design limitations and policies promoting out-of-market resources did not fracture the foundation of competitive markets.

Costs of the Current State of Limbo

The current environment leads to higher total system costs, which are eventually reflected in customer bills. Around the country, retail cost of a kilowatt-hour of electricity as seen by consumers in their electricity bills has been increasing or, at best, remained stable despite historically low wholesale electricity prices. Additional charges on customer bills reflect costs associated with new T&D investments, renewables, or, increasingly, storage mandates, as well as energy efficiency programs. Also, costs rise or shift for customers because of other policies, including net energy metering (NEM) for distributed resources such as rooftop solar, customer choice aggregation, and other utility programs mandated by state policymakers. Barbose (2018) estimates 2017 average RPS compliance costs at 2 percent (ranging from 0.5 to 4 percent) of retail electricity bills in RPS states. Wiser and others (2017) conclude in a literature survey that state RPS and NEM policies can increase rates, sometimes significantly but not everywhere, depending on the quality of the resource, penetration levels, and the design and target of the programs. Importantly, the authors note that incentives such as federal tax credits "reduce retail electricity rates by making [renewable energy] purchases less expensive." In other words, RPS programs would have led to increases in retail costs without federal subsidies, which are costs to taxpayers and belong in a wider social cost accounting.

California offers a sobering example as described in Borenstein (2018), who takes California policymakers to task regarding their "try everything" approach regardless of the cost. This article builds on Bushnell (2018), who criticizes the requirement that all new homes install rooftop solar starting in 2020; Borenstein (2017), who questions the effectiveness of California climate policy in terms of costs and global emissions reduction as the state "outsources its [greenhouse gas] emissions"; and Bushnell (2015), who points out the economic irrationality of geographically constrained net-zero policies such as the one the California Public Utility Commission (CPUC) initiated. As these articles highlight, total system costs are higher than they need to be because this multitude of policies are uncoordinated across and, as the case of California demonstrates, within states, and many target chosen technologies rather than societal goals such as lower emissions.

Costs in California and elsewhere also are driven by old laws, regulations, and standards that do not reflect today's realities, such as renewables that are intermittent and variable resources but may be cheaper in some locations and evolving demand-side technologies. For example, the Public Utility Regulatory Policies Act of 1978 (PURPA) continues to drive the cost of some renewables projects above that of competitively bid projects. Capacity-market schemes, and subsidies or mandates for certain resources, push reserve margins in some markets much higher than those considered sufficient by the North American Electric Reliability Corporation (NERC). Some reserve margins recommended by NERC are themselves considered higher than economically optimal. In fact, the concept of reserve margin—the amount of generation capacity needed to meet peak demand, accounting for historical rates of availability and system outages—needs a re-think as a measure of reliability; an effective market that induces larger consumer participation via dynamic price signals and the emergence of technologies such as rooftop solar and storage undermine its usefulness.

A competitive electricity market would have reduced emissions more efficiently and transparently via an appropriate Pigouvian tax or an equivalent cap-and-trade market. In a review of seven emissions trading systems implemented in the United States over the last 30 years, Schmalensee and Stavins (2015) conclude that cap-and-trade policies have reduced emissions more cost-effectively than traditional command-and-control approaches, including the SO_2 allowance trading program under the Clean Air Act Amendments of 1990, NO_X trading in the eastern United States, the Regional Greenhouse Gas Initiative in the northeast, and California's AB-32 market for greenhouse gas (GHG) emissions. These programs, however, remain the exception. Taxing externalities, especially GHG emissions, remains politically unpopular.

A competitive electricity market would have reduced emissions more efficiently and transparently via an appropriate Pigouvian tax or an equivalent cap-and-trade market.

Many state policies have subsidized investments in weathering and insulation, replacement of light bulbs, and other energy efficiency and conservation programs although many such programs have been shown to be ineffective or costly. Gerarden and others (2017), in a review of the energy-efficiency gap literature, find evidence for policy failures, such as the lack of dynamic pricing and noninclusion of externality costs, as well as behavioral explanations, such as the principal-agent problem, heuristic decisionmaking, and shortsightedness. Blonz (2018) provides cost estimates for the principal-agent problem in an energy-efficient appliance replacement program. Both studies support the general view of the need for careful assessment of existing programs' cost-effectiveness and effectiveness in increasing energy efficiency.

Consumers seeing the total cost of electricity at all times would have sought solutions to save money. For decades, many companies provided energy management services to large users that automated response and would have saved small consumers from having to actively manage their daily or weekly consumption. Some companies tried to bring these technologies to the residential and small commercial space in the early 2000s or sooner but failed because small consumers had little reason to pay attention since their bills would not have changed much without dynamic pricing. There is now growing interest in incorporating such demand response because availability of smart appliances, the Internet of Things, distributed generation, and battery storage technologies all make it easier for policymakers, regulators, and consumers to visualize the benefits. Industry surveys reveal these trends as well as the challenges they create for utilities (e.g., Black & Veatch, 2019; Utility Dive, 2019).

However, exposing consumers to the cost of electricity in real time is another idea that remains unappealing to policymakers. Instead, years of subsidizing and mandating certain technologies created interest groups and encouraged more rent-seeking behavior by these groups. Rent-seeking is the nature of business; it was part of the initial days of the regulated industry and was also common during the early days of competitive markets. Gaming in poorly designed markets, with Enron as the poster child of bad market actors, is a good example. While these problems have been resolved by the diligence of the regulatory process under pressure from competitors, regulators still need to remain vigilant because constantly changing market designs could create new gaming opportunities.

Today, the "smart money" seems to be tracking the next government mandate or subsidy without a restraint from a competitive market. The Clean Energy Technology Center at North Carolina State University documents several thousand programs on supporting renewables and energy efficiency across the United States. California leads all states with 229 programs.[2] In a review of 20 years of restructuring, Borenstein and Bushnell (2015) argue that "the greatest political motivation for restructuring was rent shifting, not efficiency improvements, and that this explanation is supported by observed waxing and waning of political enthusiasm for electricity reform.…[A] similar dynamic underpins the current political momentum behind distributed generation (primarily rooftop solar PV) which remains costly from a societal viewpoint, but privately economic due to the rent transfers it enables."

The financial sector plays an important role in perpetuating these policies as investors pursue fast-growing sectors or companies that will provide high returns to early movers regardless of long-term profitability and overall system costs. As such, capacity markets, uplift payments, subsidies, and mandates are favored by investors. However, the interest of investors is fickle, as seen in the shale gas industry, which continued to receive capital inflows despite the persistent lack of profitability. Savvy investors can realize high returns even in such an industry by strategically timing their entry and exit and targeting assets. There is opportunity in chaos.

Nevertheless, macroeconomic context is important to keep in mind. The president of the Federal Reserve Bank of Dallas attracts attention to the high level of debt in the U.S. economy (Kaplan, 2019). Government debt held by the public has reached 77 percent. The present value of unfunded entitlements is about $54 trillion. The U.S. nonfinancial corporate debt set a new record at about 46 percent of GDP in late 2018. The prior peaks coincided with recessions, most strikingly in 2008. The current record-high levels of government and corporate debt make the economy more sensitive to monetary policy (i.e., interest rates) and will likely increase the severity of the next recession, which will disrupt all sectors, including the energy sector. Already, as the Federal Reserve started to increase interest rates, capital markets started to adjust, which imposed a more disciplined approach to investment and cost management in the shale industry. Similarly, despite subsidies and mandates, the renewables industry also has struggled to be profitable. Capital will become more expensive for the developers of renewable energy projects, as well. Of note, subsidized low-cost renewables undermine their own profitability by lowering the price of the only product they sell, electricity (e.g., Sivaram and Kann, 2016; Sivaram, 2018).

Potential for Improvement of Benefit–Cost Transparency?

To the consternation of economists who yearn for efficiencies of competitive regional markets as dictated by the optimal operation of an electricity grid that does not recognize jurisdictional boundaries, neither the FERC nor Congress is expected to challenge the precedents of local policymaking, especially regarding choices of generation portfolios and retail competition. The importance of states' rights is clear in the history of federal legislation in the United States, especially the Federal Power Act. The lack of federal action on climate change has been a key driver of state policies. Recent 3–2 decisions by the

2. For details, visit http://www.dsireusa.org/.

FERC regarding capacity-market reforms are evidence of strong differences of opinion among the commissioners regarding the right balance between FERC jurisdiction and state prerogative. The PJM case is not settled at the time of writing (discussed later in the "Resource Adequacy, 'Out-of-Market' Support, Missing Money, and Market Reforms" section), leading FERC Commissioner Glick to call for an alternative to capacity markets (e.g., Bade, 2019b).

Thus, it does not seem politically feasible to fix competitive markets in a way that would lead to efficient solutions to society's problems in the energy–environment–economy space. No one openly talks about re-regulating, but the de facto trend is toward resource planning—without the benefit of the holistic approach of integrated resource planning (IRP) done by regulated, vertically integrated monopolies. As Kavulla (2017) puts it, "[F]or all of its obvious flaws, the cost-of-service regulatory model is not an abject failure." At least half of the country never left that model. But those "flaws" must be avoided this time around.

Can we improve the IRP process to mimic competitive market outcomes as much as possible while also capturing the value of the T&D grid and demand-side participation? Experiments around the country are trying to find out. Utilities meet their RPS requirement via competitive bidding by third-party developers. Some regulators pursue performance-based rate making to induce efficient investments by utilities, especially in behind-the-meter projects such as energy efficiency and distributed generation. Some T&D utilities develop interconnection maps to help developers of renewable energy projects optimize their site selection.

Such policies are often encouraged by the increasing availability and lower cost of wind and solar generation, battery storage, smart appliances, and control systems that can enhance demand response—all of which also fuel consumer expectations for cleaner, more efficient, and more distributed electricity service. Such expectations are probably misplaced in terms of the scale and pace of such a transition and are certainly not shared by all consumers. Nevertheless, the transition is happening. Improving the IRP approach requires stronger regulatory institutions that can stay abreast of rapid technological developments and mitigate past problems due to information and resource asymmetry. The regulators also need to be more engaged in consumer education.

This strategy, however, needs to be supported by the elimination of many redundant and wasteful programs. As CPUC president Michael Picker put it, "We have a renewables standard, and everybody is talking about 100 percent renewables, but that doesn't necessarily translate into GHG reductions.…Should we go to a GHG reduction standard?...What does California really want from customer choice? Is it bright and shiny technology? Is it decarbonization? We need clarity on those questions to avoid the mistakes of 2000–2001" (Trabish, 2018a). CPUC (2018) provides details of issues concerning the regulator, which result from "dozens of different decisions and legislative actions" that are being implemented without a plan. The CPUC report echoes the concerns raised by Borenstein (2017, 2018) and Bushnell (2015, 2018).

Can we improve the IRP process to mimic competitive market outcomes as much as possible while also capturing the value of the T&D grid and demand-side participation?

The lack of a coordinated plan is the underlying theme of this report. In Part I, I first provide a deeper discussion of issues in the electric power industry, the cost of current policy smog, and the trend away from the competitive market model toward a more prescriptive approach. Then, I provide some high-level principles of a planned market (market-IRP) approach as an alternative, although this approach is also politically challenging to advance. Objectives must be agreed upon, and the total societal costs and benefits of policies to achieve them should be transparent. Consumers should see these costs in electricity prices so that they, as well as policymakers, can make informed decisions.

Finally, in Part II, I focus on net societal costs associated with generation technology options. To that end, costs of externalities, subsidies, and system integration are added to the levelized cost of electricity (LCOE). The amplified LCOE is still incomplete but is more informative for policy discussions that need to investigate trade-offs across multiple dimensions.

Part I—Electricity as a Public Service and Competitive Markets

Early in the twentieth century, Samuel Insull and other electric power industry pioneers diagnosed that central generation and transmission of electricity over high-voltage wires yielded economies of scale and avoided wasting capital on duplicate infrastructure and that regulation at the state level by an independent entity, following standard rules and procedures, was better than capricious local oversight. Thus began the domination of the monopolistic but regulated investor-owned utility model with integrated generation, transmission, and distribution services. This model quickly electrified population centers, providing affordable electricity to most citizens and allowing utilities to capture rents, but it did not extend to rural areas where economies of scale were lacking. With the Rural Electrification Act of 1936 under President Franklin D. Roosevelt, public power expanded via federal entities such as the Tennessee Valley Authority, followed by rural cooperatives (co-ops) and municipally owned utilities (munis). Today, these public power entities serve about 28 percent of U.S. electricity customers.

Born during the Great Depression, the perception of electricity as a public good or service, or even as a tool for democracy, is still shared by many. That electricity is essential for a modern economy is even more patently evident in the twenty-first century. The multiplier effects of providing reliable and low-cost electricity service throughout the economy are significant. For example, the cost of the 2-day Northeast blackout in 2003 was estimated at about $10 billion.

The expansion of grids across state boundaries increased the role of federal regulation starting in the 1930s. Despite the statutory independence of regulatory agencies at both the state and federal levels, separating politics from agency rulings can be difficult in practice, especially during times of high prices or shortages. Also, over time, the asymmetry of information between the regulator and the regulated became a challenge. As publicly funded entities, regulators struggled to have as much expertise and resources as commercial businesses. In such an environment, cost-of-service regulation set the stage for unnecessary investments by utilities, which could pass those costs to their captive customers as long as they could convince the regulator of the necessity and convenience of the expense.[3]

Since the 1970s, environmental concerns added another dimension to policymaking and regulation. Pollution, especially of air and water resources, convinced the federal government to pass the Clean Air Act and the Clean Water Act, which have been amended over the years. Some states pursued additional regulations. Given the intensity of air pollutants per unit of electricity generated and the need for large amounts of cooling water, coal-fired generation was a primary, but not only, target of these regulations. Thus, environmental regulations influenced the functioning of the electricity sector.

In the 1990s, many jurisdictions started promoting renewables via subsidies (e.g., federal or local tax credits) or mandates (e.g., RPS programs by states). Increasingly, individuals and communities have been taking advantage of emerging technologies such as rooftop solar, battery storage, and smart meters and appliances such as programmable thermostats to become less dependent on the electric power grid or, at least, to be more efficient, conservational, and in charge of their consumption. A growing number of NGOs, think tanks, and consulting firms offer solutions to help those interested in making such transitions.

Demographically, it is possible that younger segments of the population, used to being in control of more aspects of their consumption with the help of information technology, may be more interested in generating their own electricity, managing their consumption in real time, or having it managed automatically by service providers. This grid independence seemingly undermines the importance of the public service factor and could favor a competitive market in which price signals nudge more consumers toward the most efficient solutions. In either case, such independence presents another political reality as policymakers cater to the voices of these newer constituents.

3. For a critical history of the electric power sector and its regulation and restructuring in the United States, see Lambert (2015), Tuttle and others (2016), and Kavulla (2017). For a history of restructuring in Texas, see Wood and Gülen (2009).

Principles of a Competitive Electricity Market

Inefficiencies associated with the regulated utility model encouraged the restructuring of the electricity industry. Equally important drivers were the results of several seminal energy sector reforms initiated in 1978. The Natural Gas Policy Act in 1978 started the process of deregulating natural gas prices and markets, which was completed by various orders of FERC. The PURPA and the Powerplant and Industrial Fuel Use Act (PIFUA) of 1978 encouraged non-utility generation, either as combined heat and power facilities built "behind the fence" by large consumers or as new renewable energy plants built by new businesses known as qualified facilities or exempt wholesale generators, which all can be classified as independent power producers or merchant generators.

By the 1990s, these developments led to gas-fired non-utility generation becoming an attractive option for meeting society's growing electricity demand. Merchant generators could build combustion turbine plants cheaper than the avoided cost of regulated utilities and quicker than other thermal plants fueled by coal or uranium. Improvements in gas turbine efficiencies and combined-cycle gas turbine plant designs rendered natural gas the most efficient fuel to burn for baseload generation. Wind and, later, solar facilities also have benefited from the PURPA.

Starting in the late 1990s, following earlier international experiments, about half of the states restructured their vertically integrated, regulated, monopolistic utilities and created a competitive market for generation of electricity and, in some cases, for retail choice of electricity suppliers. The economic principles of competitive electricity markets can be traced back to Joskow and Schmalensee (1983), who also pointed out the importance of regulation for the power industry, which had segments such as transmission and distribution networks that had to remain regulated monopolies to ensure reliable delivery of electricity to all customers at least cost.

Given considerations such as the diversity of generation portfolios, access to fuels and other resources, demand profiles, levels of grid integration across state boundaries, and state energy and environmental policies, market designs differed, sometimes significantly, although all targeted wholesale competition. With densely integrated grids across many states, interstate commerce laws allowed FERC to regulate independent system operators (ISOs) and regional transmission organizations (RTOs) and the markets they served, except for the ERCOT system (see "The ERCOT Market" sidebar). FERC ensures that competition in these territories is not undermined unduly by market participants or state interventions. Borenstein and Bushnell (2015, p. 4) consider the RTO/ISO model "the single most unambiguous success of the restructuring era in the United States."

Importantly, restructuring was not deregulation. In fact, it multiplied and complicated the job of regulators because competitive market designs grew increasingly more intricate as markets and their participants evolved along with technologies, and as energy and environmental policies of federal, state, and local governments induced changes.

One of the main driving forces of restructuring was to eliminate the inefficiencies of cost-of-service regulation, which induced utilities to invest in assets that were not needed to provide reliable electricity to their captive customers. Wholesale competition in generation worked remarkably well in most, albeit not all, restructured markets despite inaccurate price signals, partial market participation, and out-of-market resources.

A key design principle for a successful competitive electricity market is "[to] establish prices and pricing rules that are consistent with and reinforce the incentives for efficient operation and investment" (Hogan, 2014). With proper price signals, markets maximize welfare; properly incent market participants to follow commitment and dispatch orders of ISOs and RTOs; facilitate efficient investments in new generation facilities and equipment; and allow all generators to fully recover their costs of services while maintaining system reliability (FERC, 2014a).

Ideally, all consumers should participate in the market; their demand response (shifting consumption from high-price periods to low-price periods within a day or responding to unexpected price spikes by reducing load) can be as valuable a resource as any power plant. These responses can be automated. Generally speaking, real-time pricing is better than time-of-use pricing for maximizing the benefits of participation, but more-sophisticated price signaling can be developed. Together with energy efficiency and conservation, especially with the growing number of connected devices, demand-side management is a powerful and valuable resource. In fact, it can eliminate or, at least, postpone investment in new generation and/or T&D infrastructure, saving the whole

THE ERCOT MARKET

The Electric Reliability Council of Texas (ERCOT) grid system is located completely within Texas and serves about 90 percent of the electric load in the state. The ERCOT market design follows more of the competitive design principles. Generators receive revenues from the sale of electricity in the energy market. No separate capacity market compensates them for making capacity available to the system. Even the smallest (i.e., residential) consumer can shop around for a retail electricity provider. The fact that the ERCOT grid is fully inside Texas and has limited transmission connections to neighboring grids allowed the state to shape market design independently from FERC. See Kiesling and Kleit (2009) for a comprehensive discussion of the history of restructuring and market design in Texas.

There are exceptions to these tenets, however. First, a low energy price cap existed until 2011. Second, most retail customers do not have access to real-time pricing. Third, munis and co-ops (roughly 25 percent of the load within ERCOT) do not participate in the competitive market. Muni and co-op customers cannot contribute demand-side resources. Munis and co-ops still build generation based on utility planning and policies of governing bodies such as municipal governments. Fourth, out-of-market capacity undermined the market. Some munis and co-ops pursued renewables, signing long-term power purchase agreements encouraged by federal and Texas Tax Code Chapter 312 and 313 tax credits. Fifth, the state legislature supported the construction of transmission lines to West Texas to connect wind farms.

system money. This approach requires changing the cost-of-service regulation to provide compensation to T&D utilities equivalent to what they would have obtained from building new infrastructure.

In 2014, after years of experience with restructured markets around the country, industry experts and FERC had to reiterate competitive market principles because price caps, limited demand-side participation, and subsidized resources created concerns for revenue sufficiency and reliability in existing market designs.

Electricity Grid and Market: A Precise Balancing Act

Despite much excitement about new technologies that empower consumers and create the possibility of grid independence, a future when those kinds of distributed systems, or microgrids, dominate is still far away for most electricity consumers. The transmission network offers many benefits, including but not limited to increased reliability, reduced congestion, lower need for new generation capacity, integration of distant but higher-yield renewable capacity, and lower need for generation to back up renewables. Utilities are still investing tens of billions of dollars in the T&D infrastructure, and most electricity still comes from central generation facilities, including wind and solar farms. The efficiency and necessity of all of these investments are questionable given the tendency of cost-of-service ratemaking to induce large capital expenditures and the barriers to regional coordination in planning the transmission grid. Nevertheless, this grid is the dominant system described in this section.

The bulk electric grid functions mainly as a just-in-time inventory system. Electricity demand (load) and supply (generation) must match at all times at all nodes of the power grid. System operators dispatch electricity from a fleet of generation units across the high-voltage transmission network in order to maintain supply–demand balance in real time (i.e., instantaneously) at least cost while also maintaining reliability of the grid (e.g., via frequency control). To the extent demand-side resources are available, a system operator also can call upon their services. The system has many considerations that vary over time. For example, the transmission network can experience congestion if some generation units or transmission lines have unplanned outages and/or if certain locations have unexpected spikes in demand. Changes in generation portfolio also need attention since generation units employ different technologies with differing operational characteristics. The location of each generation unit also matters. In recent times, resiliency in terms of access to fuel has become another point of discussion.

This optimization problem has two complementary key components: security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED). The market produces locational marginal prices (LMPs) every 5 to 15 minutes at hundreds to thousands of nodes of the grid depending on system size. LMPs reflect the least-cost combination of prices needed to balance the system load, distributed across the nodes, with supply from available generation at various nodes and available transmission capacity across the network.

This optimization problem is challenging because electricity demand fluctuates across the hours, days, weeks, and seasons, sometimes unexpectedly as a result of extreme weather events. For demonstration purposes, load, wind generation, and energy prices in the ERCOT market for the week of August 7–13, 2016, are summarized in figure 1. The total load varies during each day (up to a 30,000 megawatt [MW] swing within one day) and across the whole week (a more than 11,000 MW difference between the peak load on August 11, which was also the annual peak in 2016, and the peak load on August 13, a Saturday).

A typical week in winter or shoulder months (e.g., March, April, October, November) would have a similar pattern but at much lower load levels. In recent years, the winter peak load has been less than 40,000 MW (about the minimum daily load experienced in the week of August 7–13) as compared with 70,000 MW in figure 1. The minimum load in winter or shoulder months has been as low as 30,000 MW in 2016. Note that the difference between daily peak and trough is smaller in winter and shoulder months than in summer months.

Typically, nuclear, coal, and/or natural gas combined-cycle (NGCC) plants operate as baseload plants, i.e., they run regularly to cover the minimum load at all times because they are technically capable of such operations and most efficient when run at relatively constant load. Some of these plants will run 24/7 during summer months. In recent years, the U.S. nuclear units averaged over 90 percent utilization (i.e., capacity factor [CF]) despite routine maintenance outages. Nuclear plants are relatively cheap to operate. The Nuclear Energy Institute (NEI, 2018) reported an average cost of $34/MWh in 2017. An existing coal plant can dispatch at less than $45/MWh in most of the United States, although since 2010 the average CF of the U.S. coal fleet declined from the mid–60 percent range to the low–50 percent range despite the large capacity of retirements. The NGCC plants are more flexible because they can cycle their secondary steam turbines but, again, this type of operation

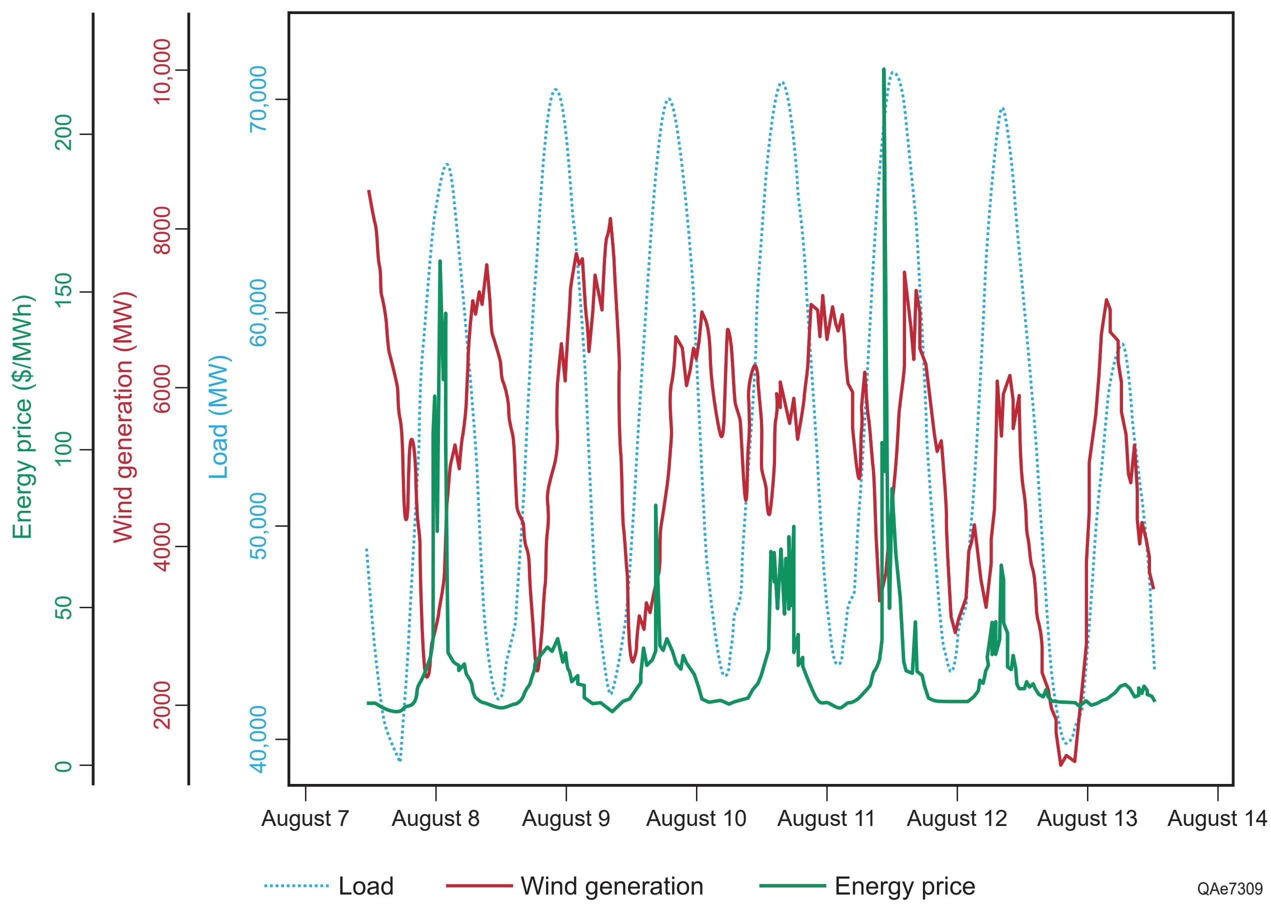

Figure 1. Fifteen-minute real-time load, wind generation, and energy prices in the Electric Reliability Council of Texas (ERCOT).

reduces plant efficiency. Some of these plants will not run 24/7 during winter or shoulder months since baseload during these months is much lower than in summer months. Routine maintenance of nuclear and coal plants is typically scheduled for these off-peak months.

Plants capable of ramping up and down in minutes to seconds are known as *peakers,* or fast-start resources. They can follow load, some even when load changes sharply and in large amounts. These plants are crucial for reliability of the grid although they run a limited number of hours in a year and have annual CFs at around 10 percent. These power plants have simple designs such as combustion or steam turbines that burn liquid fuels or, more common nowadays, natural gas. Some are dual-fuel capable. Peakers, though cheaper to build than most other plants, need to generate enough revenues from those few hours of generation in a year to cover their costs. Thus, their operators bid high prices for these few hours (e.g., the price spikes in fig. 1) to make these plants economic. Price spikes also can occur, albeit less frequently, at lower-demand hours if there are unplanned outages of generation or transmission facilities. Overall, these market prices are signals to market participants to evaluate new investments or retirements and, ideally, to consumers to adjust their consumption if they are allowed by policymakers to pay real-time prices. This is known as *scarcity pricing,* a crucial part of an efficient wholesale electricity market, which has unfortunately been curtailed by price caps and other design inexactitudes in all markets.

Although fast-start resources are best placed to follow system operator instructions, all thermal plants, including nuclear plants, can ramp their generation up or down, albeit over different time frames and at different economic and environmental costs. This technological and economic flexibility is known as *dispatchability.* In contrast, renewables that are dependent on natural resources such as wind speed and solar insolation, or irradiation, are not dispatchable because plants can generate only when those resources are available. In fact, other resources have to be available and ready to fill the gap when wind and solar resources stop generating. The dispatchability of thermal resources is what allows the addition of intermittent and variable resources. There is much excitement about battery storage as a substitute for thermal generators to provide the necessary backup to intermittent resources. Battery storage remains costly and marginal in terms of installed

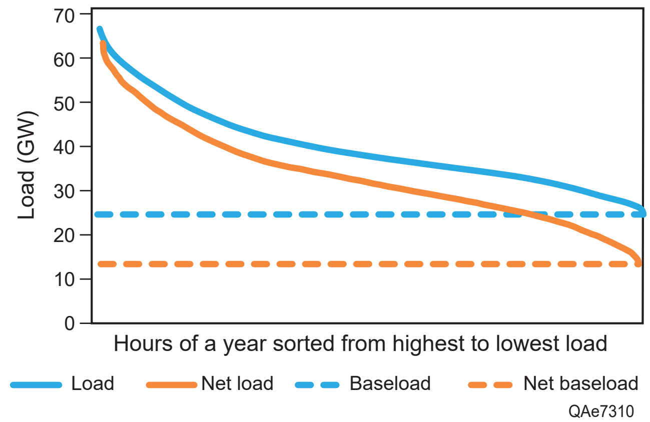

Figure 2. Load duration and net load duration with wind in ERCOT, 2017.

capacity (see discussion in the "Wide Range of Levelized Cost of Electricity Estimates" section in Part II).

When renewables are dispatched, they reduce the load to be served by thermal plants. The remaining load is known as *net load.* Figure 2 compares the 2017 ERCOT load duration and net load duration curves, which are hourly load and net load ranked from highest to lowest. In 2017, almost all renewable generation in Texas was onshore wind. Solar averaged less than 300 MW with a peak of almost 1,000 MW, as compared with 6,000 MW average and 20,000 MW peak for wind. Onshore wind is not coincident with load in ERCOT (fig. 1).

Note that peak load and peak net load are close in figure 2 (vertical axis). Overall, high-load hours between the two curves are much closer than low-load hours. As such, meeting peak load and following load during high-load hours requires about the same capacity of dispatchable resources. But these resources will dispatch fewer MWh the rest of the year, while incurring the same commitment, start-up, and/or ramping costs. The baseload has almost halved from almost 26 gigawatts (GW) to 14 GW in ERCOT. Ueckerdt and others (2013) call this displacement *full-load hour reduction,* a system-integration cost.

To the extent this development forces older, high-emissions plants out of the market, it is probably a net positive in terms of cheaper prices and lower emissions.[4]

4. Indeed, in early 2018, about 4 GW of coal capacity was retired in ERCOT. But one unit was only 33 years old, a historically young age for a coal plant to retire. Retired coal generation was mostly replaced by gas generation with lower emissions.

However, the system operator still needs some of the plants because of system reliability concerns. For example, the locations of some plants are critical to maintain reliable grid operations. Historically, ERCOT prevented certain plants from retirement via reliability-must-run contracts. Other systems have similar arrangements. The Midcontinent ISO (MISO) has been conducting a forward-looking renewable integration impact assessment (MISO, 2018). Not surprisingly, thermal generators are expected to produce less as penetration of renewables increases. Perhaps less intuitively, the number of thermal units needed during off-peak hours is expected to rise despite generating less on average. More units are needed because of increased ramping needs. Also, at some level of wind penetration, net load curve will cross the horizontal axis into negative territory, i.e., wind generation greater than the load in certain hours. Ueckerdt and others (2013) define this as *overproduction,* a system-integration cost. Overproduction already occurs in some European markets and California.[5] MISO (2018) predicts curtailment of renewable generation at high penetration levels.

Alternatively, remaining plants, especially NGCC plants, will replace retired baseload plants but will have to cycle more to accommodate wind and, increasingly, solar generation. That kind of operation is not commercially sustainable in the long run, especially if subsidized, low-cost renewables suppress wholesale electricity prices along with cheap natural gas. For example, in a global analysis, Bloomberg New Energy Finance (2018) predicts baseload gas generators losing market share as renewables and battery storage increase, while the need for load-following generators remains strong. In contrast, others see no need for peakers beyond the mid-2020s in a future with large capacities of geographically dispersed wind and solar backed up with large capacities of battery storage, at least in some regions (e.g., Merchant, 2017). On the other hand, the Los Angeles Department of Water and Power wanted to rebuild some gas-fired units as the cheaper alternative for maintaining reliability and avoiding outages. Comments from the department's senior assistant general manager for power system engineering are telling: "We're trying to maintain system reliability.…We could go to 100% renewables today if we want to accept more outages" (Roth, 2018). In early 2019, the Los Angeles mayor canceled plans for rebuilding gas plants in favor of pursuing clean energy alternatives.

The rising penetration of intermittent and variable resources also leads to longer and faster ramps in net load, which increase the need for fast-start resources. The MISO team found that net load ramps of different lengths (ranging from 5 minutes to an hour) increase significantly as a result of variability in wind and solar and that higher penetration leads to larger ramps (MISO, 2018). Geographic diversity and aggregation help with reducing wind and solar ramping, but the impacts can be in the range of 1 to 10 GW depending on the time scale and penetration levels. Geographic diversity often requires new transmission investment, perhaps in high-voltage, direct-current lines. For example, California pursues many long-distance transmission projects to import renewable electricity from a diverse set of regions from the Northwest to the Southwest.

In ERCOT, hour-to-hour changes between January 1, 2015, and December 31, 2017, are larger with net load than load about 60 percent of the time (fig. 3). More importantly, hour-to-hour shifts are also more volatile with net load than load and have been increasing over time along with the share of wind generation (fig. 4). Net load 24-hour volatility was 28 percent higher than load 24-hour volatility in 2015, but the gap increased to 44 percent in 2017. At higher frequencies (minutes to seconds), it is reasonable to expect the same trends with magnified force. Similar trends occur in other markets.

These are not existential threats to electric power grids. System operators have been able to manage the addition of intermittent and variable resources, at least so far. As before, fast-start resources along with other dispatchable resources have been used to balance the systems. Expansion of transmission grids and improvements in existing T&D infrastructure also help. But these are system-integration costs. For example, in January 2017, ERCOT added a new "Reliability Risk Desk" in its control room to address the evolving risks to grid operation, including renewable-energy forecast errors, net load ramps, low inertia, and need for variable ancillary services.[6] All other system operators with significant penetration of intermittent and variable resources deal with similar challenges.

5. In Part II, I will discuss system-integration costs in more detail. Refer back to figure 2 to help visualize some of these costs as defined by Ueckerdt and others (2013). Their figure 4 is an idealized extreme version of figure 2.

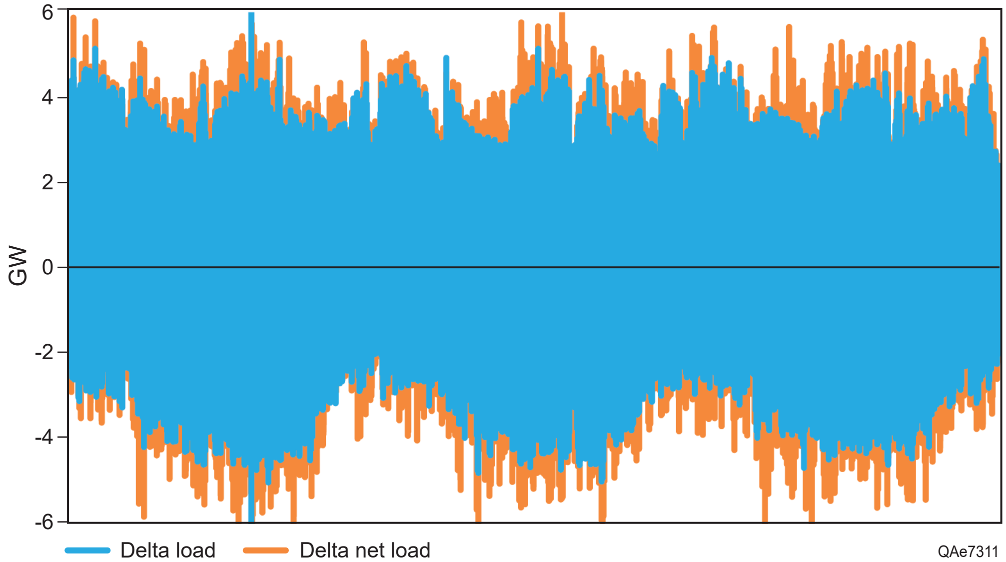

Figure 3. Hour-to-hour changes in load and net load in ERCOT, 2015–17.

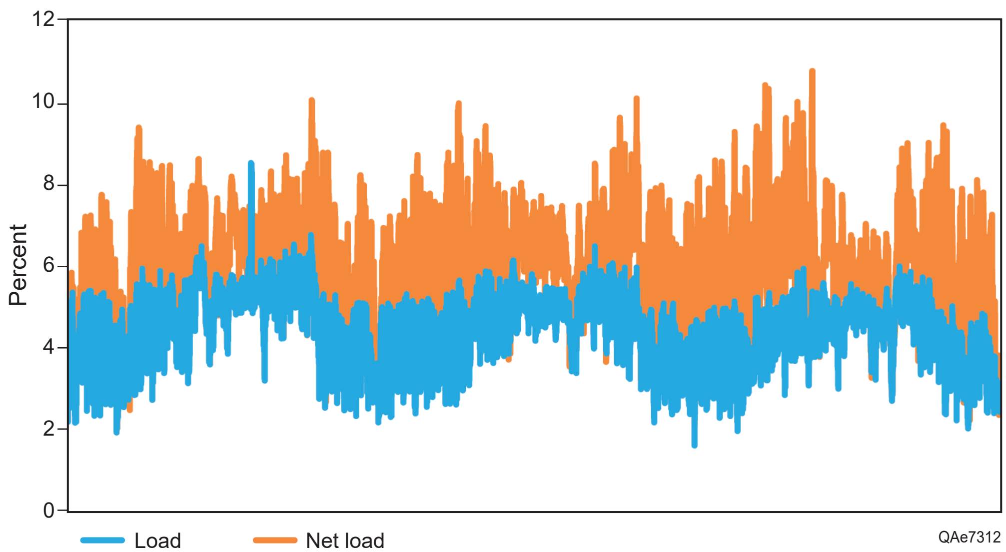

Figure 4. Twenty-four-hour volatility of load and net load in ERCOT, 2015–17.

Wind generation predictability is important for least-cost reliable system operations. Short-term wind forecasts have been improving but still have noticeable errors, particularly in shoulder months when wind penetration is higher. Between 2012 and 2017, mean absolute forecast error for day-ahead wind forecasts has improved from 8.5 percent to 5.8 percent on an annual basis, but the errors are larger during the off-peak season (October to May) than during the peak season (June to September). Hourly forecasts errors have been lower historically but also have improved from 5.6 percent to 3.8 percent on an annual basis, again with the off-peak season average greater than the peak season average (Magness, 2018). ERCOT also improved its short-term load forecasting, which is also important for SCED and SCUC.

6. Ancillary services are those deemed necessary by the system operator to balance demand and supply at all times by allowing the stable flow of electricity across the transmission grid. They are traded in their own markets and provide additional revenues to those facilities providing ancillary services. Among others, they include frequency control, reactive power, spinning reserves, and nonspinning reserves.

Despite improvements, these forecast errors translate into several hundred megawatts of discrepancy. When the total installed wind capacity in ERCOT reaches 25.5 GW by the end of 2019, the errors in thousands of megawatts can become more routine unless forecasts continue to improve. MISO (2018) expects the wind forecast error to stay within +/− 2 GW in a majority of hours, even at 40 percent penetration. Extreme cases reach +/− 8 GW at 10 percent penetration and +/− 12 GW at 40 percent penetration in a system where load fluctuated between 55 GW and 115 GW in 2018. These estimates depend on many assumptions, including wind profiles. The net load forecast error is driven primarily by changes in demand during high-demand periods and by increasing wind during the winter.

Other markets experience similar challenges. In all of them, other generators (often gas or coal fired) have to be available to either ramp up (when the wind/solar generation is less than forecasted) or ramp down (when the wind/solar generation is more than forecasted). Such ancillary services have a cost. For example, in ERCOT, the price of ancillary services, including regulation up, regulation down, nonspinning reserve, and responsive reserve, averaged about 4 percent of the energy price, ranging from as low as 2 percent to as high as 10 percent in February 2016 (on a monthly average basis). Spring and fall months of 2016 and 2017, when wind generation typically peaks, experienced more persistently high ancillary service prices.

As one of the design flaws of competitive electricity markets, real-time energy and ancillary services prices in most markets have not reflected all costs of fast-start resources such as those for commitment and start-up. System operators have been making these generators "whole" via out-of-market uplift payments. Increasing ramping needs necessitated by renewables expose this and other design flaws more strikingly. These price-formation challenges are discussed later in the "Resource Adequacy" section.

Erosion of Competitive Markets

Although competitive markets commoditize electricity rather than treating it as a public service, they do not contest the fact that electricity is essential to sustain a modern economy. Rather, via price signals to both producers and consumers that reflect the total cost of providing the last kilowatt-hour at any point in time, they offer efficiency gains and innovation across the electric power value chain, including generation, grid operations, and end use. These improvements should lower average prices and/or customer bills over the long-term. Markets also could have been enhanced to internalize externalities such as environmental impacts on air, water, land, and ecology.

Such a cost-reflective decisionmaking environment could eventually lead to a different paradigm on electric power generation, delivery, and use. For example, the most efficient and reliable system might ultimately be the one seemingly promoted by many today: smaller systems with distributed resources—such as rooftop solar and battery storage—in which all consumers have choices not only of electricity supplier but also of technologies to adopt, and can manage their consumption of electricity in internet-connected appliances via apps in their smart gadgets.

However, no competitive electricity market was allowed to incorporate all design principles that could have stimulated the transition from the vertically integrated utility model to a more efficient and clean future power system.

Price Caps and Limited Demand-Side Participation

Price volatility, an essential component of efficiently balancing an electricity market, as discussed above, has been politically unacceptable. Wholesale prices have been capped. Even allowing accurate price signals in the wholesale market would not have mattered because a great majority of consumers in most markets did not see dynamic real-time or even fixed time-of-use price signals. Ironically, with federal funding via the U.S. Department of Energy (DOE) and approval of state regulators, many utilities invested billions of dollars in installing smart meters at every home and business, which allow all consumers to see near real-time prices (e.g., in 15-min intervals). Smart meters reduce the operating costs of distribution utilities, which probably gets reflected in customer bills to a certain extent.

However, in its guide to public power utilities for creating smart cities, the American Public Power Association (2018) mentions that "many utilities are still grappling with what to do with the vast amounts of data coming in from advanced metering infrastructure (AMI)." Perhaps because of such data-management difficulties as well as a lack of policy support, most customers to this date do not have access to retail service with dynamic pricing although they pay for smart meters in their electricity bills. Despite the expansion of the Internet of Things and apparent interest from a growing segment of the population, some regulators are hesitant in approving new AMI investment in the absence of DOE funding, finding it hard to justify the convenience and necessity of such investments. Quite possibly, some utilities consider AMI and other popular demand-side investments attractive ways to sustain the rate base in an environment of low to negative load growth. Reforming the cost-of-service approach to incent utilities for efficiency rather than volume could reveal truly desirable and efficient projects.

No competitive electricity market was allowed to incorporate all design principles that could have stimulated the transition from the vertically integrated utility model to a more efficient and clean future power system.

The gap between wholesale and retail prices was one of the main components of the 2000–2001 crisis in the California market. Both prices were capped, but retail prices, especially for residential customers, were set at a lower level. In addition to a detailed discussion of the California power market crisis, Borenstein (2002) provides the rationale for real-time pricing in competitive electricity markets and shows that, if allowed, real-time pricing could have mitigated the perpetuation of the crisis by encouraging demand-side response.

Worse, price caps have been set too low. The economic theory of competitive electricity markets suggests the value of lost load (VOLL), a measure of demand-side willingness to pay, as a cap if one must be used. However, VOLL estimates differ by methodology and by customer class (e.g., London Economics, 2013). Typically, most residential customers do not want to pay anything if a blackout lasts an hour or less, but their willingness to pay increases sharply for longer outages. Small commercial and industrial users have the highest VOLL because they are more dependent on grid electricity than are large commercial and industrial users, which are more likely to invest in backup generators. The literature review in London Economics (2013) offers a VOLL range of \$9,000 to \$45,000/MWh for an industrial economy. Much lower caps restrain scarcity pricing, especially to load-following generators.

It was always unrealistic to expect competitive electricity markets to yield expected benefits when a large portion of load does not see the market, even with capped prices. As such, a feedback loop emerged: with such inelastic demand, price volatility is magnified. Energy price caps and nonparticipation of a large number of consumers in the market are the initial dominoes that set the stage for the fall of other pillars of the competitive market design, helped along the way by external policies.

Prices that fluctuated would have reflected true costs of balancing demand and supply in a dynamic system in real time, and could have incented the capacity of renewables to be built where they could compete. Inclusive of the cost of externalities, prices would induce the retirement of older, high-emissions plants, eliminate the need for ad hoc subsidies and mandates (see next section), and increase capital efficiency of renewables investment. In other words, the most reduction in externalities could have been achieved at least cost. This return on investment to achieve environmental objectives could have been higher if some consumers had switched to distributed resources, invested in energy efficiency measures, and conserved electricity during high-price periods. Importantly, the building industry and urban design professionals probably would have developed innovative solutions to meet customer needs. For years, artificially low energy costs encouraged customers to live in larger homes in distant suburban settings, with energy efficiency and conservation being promoted via administrative programs such as Energy Star and Leadership in Energy and Environmental Design.

Today, at least some proponents of emerging technologies, including utility-scale and distributed resources, recommend reforming markets to allow for dynamic pricing and demand-side participation (e.g., Kann, 2017). Burger and others (2019) suggest "time- and location-varying, marginal-cost energy pricing" and "more cost-reflective network pricing schemes" as a better way of deciding where distributed energy resources (DERs) can add value to the system beyond its integration costs other than through mandates. A senior vice president of ICF Commercial Energy Division argues that "customers… will no longer be viewed as passive load, but instead as flexible grid resources.…A more integrated approach to DSM [demand-side management] will ensure customer programs play an expanded role in supporting grid services, deferral of capital expenditures, and utility revenue streams. This shift will be enabled by a variety of behind-the-meter technologies, a modern grid and dynamic pricing or time-of-use rates working together to optimize the experience for the customer while supporting efficient grid operations" (Cook, 2018).

There is nothing new in these expectations. Faruqui and Aydin (2017) provide a succinct survey of various experiments since the 1970s with time-of-use and similar electricity-pricing mechanisms. Nevertheless, current policymakers and/or regulators may receive such recommendations more warmly than did their predecessors in the 1990s and 2000s because of increased familiarity with demand-side technologies, increased levels of concern about the environment, and changing views on grid independence. Nearly everyone praises the virtues of consumer choice, which can yield the largest benefit if consumers are fully informed about the value and cost of their actions. Faruqui (2017) discusses recent successful programs in innovative pricing for small electricity consumers. Perhaps, this time around, demand-side participation can contribute fully to the electricity system.

Subsidies

Since markets were not allowed to send accurate price signals, and many believed that environmental as well as local economic development goals could be achieved via renewables and energy efficiency, many technologies, especially wind and solar, have been introduced via subsidies and mandates across all levels of governments. PURPA contracts were instrumental until the 2000s, when other incentives and competitive procurement started to drive investment. The Clean Energy Technology Center at North Carolina State University documents several thousand programs on supporting renewables and energy efficiency across the United States.[7] California leads all states, with 229 programs at the time of writing. This number of programs helps us visualize the "try everything" approach criticized by Borenstein (2018).

Barbose (2018) reports that about half of renewable generation and capacity growth in the United States since 2000 is associated with state RPS requirements. The increasing role of corporate procurement and declining cost of onshore wind and utility-scale solar photovoltaic (PV) have reduced the significance of RPS mandates, but they continue to play a big role. Almost 60 percent of renewable capacity additions nationwide in 2016 (Barbose, 2016) and 34 percent in 2017 (Barbose, 2018) were driven by RPS policies. In the Northeast, West, and Mid-Atlantic, RPS has been the main driver. Gülen and Makaryan (2009b) show that the key driver for wind capacity expansion in Texas has been federal tax credits, in addition to some local incentives (e.g., Chapter 312 and 313 of the Texas Tax Code) and the high quality of wind in West Texas. MIT (2015) also acknowledges the importance of support for solar expansion.

Wind and solar are already competitive in some locations without subsidies or mandates and can be competitive in more locations with a tax on GHG emissions, the preferred solution of economists.

Although there have been many federal, state, and local incentives, federal production tax credits (PTCs) and investment tax credits (ITCs) have been most impactful since the 1990s. Figure 5 shows that every time PTCs were allowed by Congress to expire, wind-capacity additions fell significantly the next year (1999–2000, 2001–2002, 2003–2004, 2012–13). The most recent extension of federal tax credits was granted in the Consolidated Appropriations Act of 2016. These incentives encouraged a new wave of investments for both wind and solar. Importantly, four consultancies predict significantly lower-capacity additions after PTCs expire in 2020. A forecast is, by definition, imperfect and these four forecasts diverge, significantly in some cases, even for 2019. In addition to methodological differences, uncertainty about future policies and costs probably causes such discrepancy. Still, all forecasts agree that capacity additions will follow the historical pattern and decline after PTCs expire. This consensus suggests that, without tax credits, wind costs are not expected to decline sufficiently to render wind competitive against alternatives across all geographies.

The history of ITCs is different because solar panels remained very expensive until the early 2010s. The original

7. For details, visit http://www.dsireusa.org/.

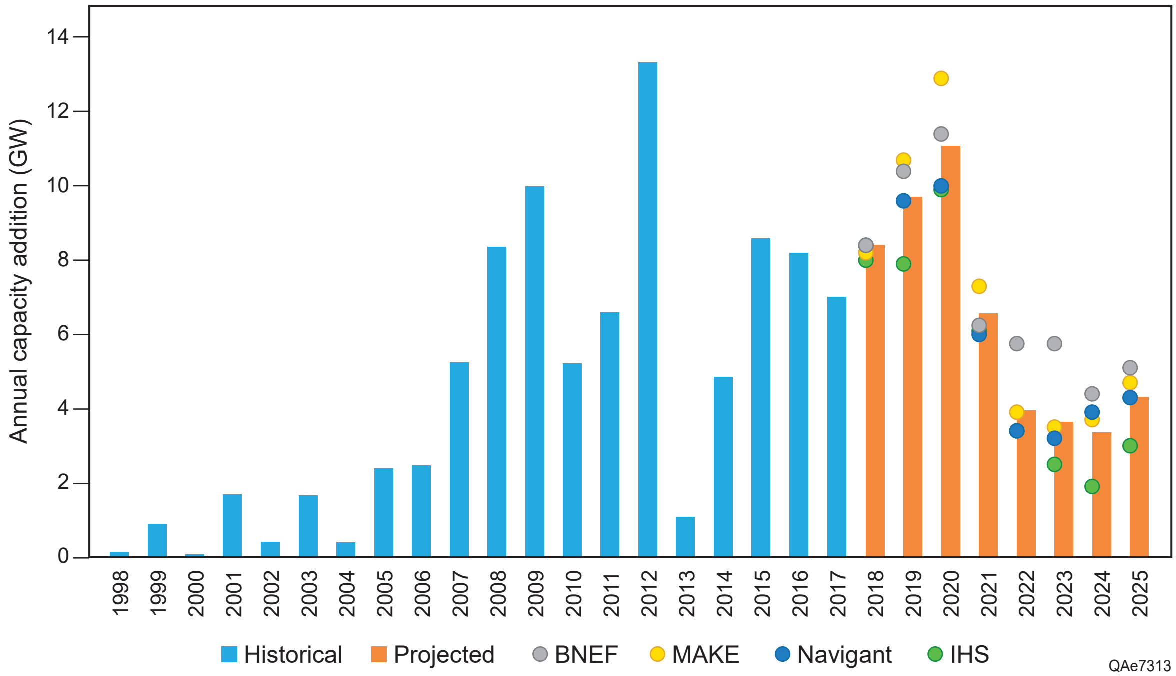

Figure 5. Historical and forecast U.S. wind-capacity additions. This chart re-creates figure 59 of Wiser and Bolinger (2018). Forecasts by Bloomberg New Energy Finance (BNEF), MAKE, Navigant, and IHS Markit (IHS).

ITCs in 2005, and their extension in 2007, had little impact. In 2008, ITCs were expanded—which had marginally larger impact, especially in rooftop installations—but they were still minimal until PV panel costs declined to levels that could compete with the help of ITCs as well as of state and local subsidies. However, the impact of the 2016 extension demonstrated the importance of ITCs, with installed capacity doubling from 2015 to 2016. Although installations declined in 2017, they were higher than in 2015.

In many states, renewable energy credits (RECs) or RPS mandates have been equally, and in some cases more, influential than federal tax credits. State RPS mandates often call for trading of RECs. In some markets, REC prices averaged as high as $60/MWh in the early 2010s. In other markets, REC prices fell to the $0–$2/MWh range once the RPS target was reached. But these targets are often reset at higher levels, which can elevate REC prices once again. Some states have specific targets for the share of solar. In New Jersey, solar REC prices in 2010–11 were above $600/MWh in response to aggressive targets of a state without high solar insolation, which caused solar panels to have a low CF and a high cost of solar panels. Despite lower panel costs in the second half of the 2010s, solar RECs remain expensive in some regions. In two other low-insolation regions, Washington, D.C., and Massachusetts, solar REC prices have been nearly $500/MWh (2013–2017), and between $300 and $400/MWh (2015–2017), respectively (Barbose, 2018).

In summary, after about 20 years of financial and policy support across various government levels, such support mechanisms are still seen as necessary to continue or grow investment in renewables. For example, the American Council on Renewable Energy (ACORE, 2018) highlights that financial institutions are interested in investing large sums in renewables as long as there are "technology-neutral" federal tax credits after PTC and ITC sunsets in the 2020s, "ambitious" state RPS programs, and carbon pricing in addition to improved "market-based signals that better reflect the values and services provided by energy storage and renewables to prevent our aging grid from hindering growth." Financial institutions' wish list of duplicative support mechanisms does not mean that all of these mechanisms are needed to render wind or solar competitive but rather demonstrates the wasteful rent-seeking behavior. Wind and solar are already competitive in some locations without subsidies or mandates and can be competitive in more locations with a tax on GHG emissions, the preferred solution of economists.

Cost of Subsidies

At the federal level, the dollar value of financial support to the electricity sector is small. For example, only 0.1 percent of U.S. GDP in 2013, a relatively high spending year thanks to American Recovery and Reinvestment Act funding, was spent on such subsidies according to Griffiths and others (2017), who identify 76 federal financial support measures to major generation technologies or their fuels in the 2010s, including direct and tax expenditures such as PTCs and ITCs.

The fossil fuel industry received roughly the same level of support as renewables from the federal government.[8] Focusing on the electric power sector only, renewables received considerably larger support as measured on a per-megawatt-hour basis. There are several reasons for this discrepancy between total dollars and per-megawatt-hour levels. First, wind and solar are used solely for power generation. Second, they have low CFs. Third, given the significantly larger capital costs of wind and solar in the early days of PTCs and ITCs, these credits have been fairly high and were kept high despite the declining cost of these technologies (although PTCs and ITCs have had their share of political strikes over the years). Given these three factors, when total dollars flowing to renewables projects are divided by their generation, per-megawatt-hour value is large. Fourth, only about one-third of natural gas is used for power generation. The rest is used for industrial, commercial, and residential purposes. Fifth, federal subsidies support upstream operations (exploration and production), not power generation. Coal has a similar story, albeit with a larger share being used to generate electricity. Finally, power generation from natural gas, coal, and nuclear individually is very large. Thus, when total dollars flowing to fossil fuels and nuclear value chains are divided by their generation, per-megawatt-hour value is small.

Griffiths and others (2017) concluded that during the 2010s, solar benefited the most (more than $300/MWh in 2013) and wind the second most (about $30/MWh) from subsidies. These amounts are expected to decline significantly by the early 2020s once the major support programs expire and solar generation increases. Federal financial support for coal, natural gas, and nuclear generation is in the range of $1–$2/MWh.[9]

The influence of federal support mechanisms on social costs is multiplied when state and local incentive programs are considered. Griffiths and others (2018) quantify state-level subsidies to specific generation technologies in the form of "direct expenditures, tax expenditures, mandates, and derivatives of these policies" in Texas and California. On a per-megawatt-hour basis, Texas subsidies to hydrocarbons (primarily natural gas based on severance tax exemption) ranged between $1.25 and $1.40 as compared with wind, which received support from $1.80 to $2.60 (primarily based on Chapter 312 and 313 benefits). Adding the cost of competitive renewable energy zone (CREZ) transmission lines for wind capacity expansion in West Texas pushes the support above $20/MWh during the peak of construction, but this amount declines over the years. Solar subsidies in Texas have been relatively low in dollars but high on a per-megawatt-hour basis (about $10) because of the low level of solar generation in the state. The per-megawatt-hour value will decline as more solar is built in southwest Texas, where high solar quality and demand from local oil and gas activity eliminate the need for any subsidy. California supports solar at about $140/MWh and wind at about $45/MWh. (These are at-minimum-level numbers; Griffiths and others [2018] were not able to decipher all the intricacies of California's multitude of programs.)

Expectation of local economic benefits, often more than environmental benefits, have induced state legislatures to pass RPS mandates (e.g., Gülen and Makaryan, 2009a). In many cases, locally available resources, regardless of their cost to end users, were favored to receive RECs under these programs. Economic theory suggests that a well-designed federal RPS program would have led to more efficient allocation of capital in technologies and

8. The history of subsidies for the fossil fuels industry is longer, but these subsidies did not target power generation. Rather, they targeted coal, crude oil, and natural gas extraction because of their large contributions to the U.S. economy across multiple sectors and industries. Here, too, industry lobbying sustained many of the support programs regardless of whether or not they were necessary. The persistency of subsidies, once granted, is a universal reality and a major handicap for reforms to rationalize energy, agriculture, and/or various manufacturing industries.

9. Many include the cost of externalities that are not charged to polluters as subsidies. Griffiths and others (2017) treat externalities as conceptually different from direct subsidies provided by the federal government. In Part II, I will consider the cost of externalities as well as system-integration costs and subsidies in developing a more complete comparison of overall social costs of generation technologies.

IMPACT OF FEDERAL TAX CREDITS ON GHG EMISSIONS

The value of PTCs and ITCs in reducing GHG emissions is disputed. For example, the National Research Council (2013) concluded that only "about 0.3 percent of U.S. CO_2 in the reference case" through 2035 is reduced as a result of federal tax credits. The report outlines difficulties of such modeling exercises, including those surveyed by the authors as well as the custom model developed for the report. Macroeconomic and energy systems are complex. The report provides several examples of interactions and chain reactions that may never be fully or accurately captured in such models. As such, it is not surprising that some models show larger GHG reductions thanks to PTCs/ITCs and others show an increase in GHG emissions. The results depend on model design and assumptions about interactions and future pathways. The bottom line is that it is difficult to consider federal tax credits as an unqualified success in reducing GHG emissions. The National Research Council report also concludes that "If the revenue lost as a result of the PTC/ITC is divided by the reduction in CO_2 emissions, just under $250 in revenues are lost per ton of CO_2 reduced. While this does not represent the social cost of reducing the ton of CO_2 emissions (because revenue losses are not a dead-weight loss…), the fiscal cost per ton of CO_2 reduced is high relative to other, more efficient approaches."

locations with lowest per-unit cost. If the objective is to reduce GHG emissions, Fischer and Newell (2008) rank a national RPS at fourth place after emissions price, emissions performance standard, and fossil power tax. Direct subsidies to renewables are ranked fifth. The authors find that a portfolio consisting of emissions price and subsidies to research and development (R&D) could be best. Davies (2010) offers strong legal and economic arguments for a national RPS. MIT (2015) recommends the replacement of state RPS programs by a "uniform national program." Oliver and Khanna (2018) show that a national RPS can induce the same share of renewable generation as the state RPS programs but "at a $61 billion lower welfare cost over the 2007–2030 period" and would "achieve greater GHG reductions, as it induces a larger decrease in coal generation." Young and Bistline (2018) concur, concluding that RPS mandates cost up to twice as much as, and displace less coal generation than, a technology-neutral GHG reduction strategy. Oliver and Khanna (2018) also confirm the near-consensus view among economists that a national GHG cap would be more efficient than even a national RPS. Adelman and Spence (2018) conclude that a GHG emissions tax (or an equivalent cap-and-trade market) would be by far superior to even a national RPS. Schmalensee and Stavins (2015), among others, demonstrate the effectiveness of cap-and-trade policies in reducing certain emissions more cheaply than command-and-control approaches.

Unfortunately, opposed by state interests, federal RPS proposals failed to advance in the U.S. Congress. In contrast, corporations that started to pursue aggressive renewables targets in recent years increasingly favor procuring most efficient resources, regardless of their location, via virtual contracts or direct investment, unless they install rooftop solar. While trying to be socially responsible corporations, the financial bottom line is still important for many companies. Some of these projects are still diverted to less-efficient locations in order to take advantage of state and/or local incentives in those locations, but overall the increase in corporate procurement of renewables has the potential to bring more rationality to site selection for renewables. System operators and utilities can help renewables developers in selecting the best sites in terms of best resources that are easy to interconnect to the grid (e.g., Walton, 2019a). Still, the question of what level of corporate procurement will be sustained in the absence of federal tax credits remains open. Power purchase agreement (PPA) prices still reflect the benefits of a collection of support measures (see next section).

In addition to being costlier than alternatives, RPS programs did not always lead to expected local economic benefits. For example, solar panels from China have dominated the market since the early 2010s. China followed a very pragmatic strategy of initially subsidizing its solar PV panel industry to take advantage of all the subsidies offered to solar in Europe and the United States rather than diversifying at home because solar was too expensive for Chinese consumers. Chapter 2 of Sivaram (2018) provides a detailed account of how Chinese subsidies to panel manufacturers led to China dumping panels into global markets, causing a price war, which led to the bankruptcy of many European and U.S. solar equipment manufacturers. Since 2010, several trade cases have been filed with the World Trade Organization against Chinese dumping

SOLAR EMPLOYMENT IN CONTEXT

The U.S. labor force had over 160 million people in 2017 according to the Bureau of Labor Statistics. The unemployment rate declined from nearly 10 percent in 2010 to 4 percent in 2017, but the civilian labor participation rate is significantly lower than its pre-2008 levels (63 percent since 2014 versus 66–67 percent before). In comparison to the 250,000 mostly installation jobs in the solar sector, more than 2 million people are employed in the upstream, midstream, and downstream activities associated with oil, natural gas, coal, nuclear, and electric utility sectors. Many of these jobs require college degrees in STEM and pay high salaries.

of solar panels. Tariffs were imposed on several occasions (most recently in early 2018 by the United States), but Chinese panels continue to dominate the world market. Platzer (2015) provides details on these trade conflicts and questions the ability to sustain a solar manufacturing base in the United States. Since manufacturing accounts for a very small portion of solar-related jobs, the wider U.S. solar industry opposed the petition that led to a 2018 tariff, which starts at 30 percent and declines 5 percent a year until it reaches 15 percent. A reduction in solar installations of 11 percent (or about 7.6 GWDC) through 2022 is expected (e.g., Pyper, 2018).

According to the Solar Foundation's 2017 census of national solar jobs, about 250,000 Americans worked along the solar supply chain, roughly 4 percent less than in 2016.[10] Only about 37,000 of these jobs, or 15 percent, were in manufacturing, and 7 percent in R&D and finance. The rest are mostly installation (more than half), sales, and project-development jobs. Most companies do not require a college degree for new hires. These data suggest that solar jobs are sensitive to policy changes. More importantly, they indicate that intellectual property is not created in the United States. The RPS mandates, supplemented by federal ITCs and possible local incentives, induce developers to buy the cheapest technology, which, so far, has been the Chinese-manufactured crystalline–silicon panels, rather than investing in R&D to innovate the next generation of solar technology. Sivaram (2018) identifies this lack of technological innovation as an inherent obstacle to solar's share going beyond 20–30 percent as its intermittency and low CF undermine its own market value.

Wind and solar have low operating costs. Sometimes, they get dispatched at negative prices either to take advantage of tax credits or to avoid curtailment. This suppression of wholesale prices will increase as the share of renewable generation increases. Low prices undermine revenues to levels insufficient to recover capital costs. It is difficult to envision new generation capacity investment in such a low-price environment without continuation of tax credits or mandates, or as part of an IRP approach where costs can be incorporated into regulated rate bases. In the meantime, these low prices distort markets and create uncertainty for unsubsidized resources, both existing and new investment. In other words, the volatility of the policy environment across technologies, jurisdictions, and time represent a political risk factor, for which there is no insurance.

Manufacturers in China and elsewhere improve economies of scale as much as they can to remain profitable in an increasingly competitive industry with the threat of declining subsidies or import tariffs and a macro environment of higher interest rates. The same scenario repeated in the battery market, with many states introducing storage mandates and China investing heavily in the manufacturing of lithium-ion batteries and in supply chains of critical minerals such as cobalt. Capital from institutional or private sources chasing fast growth and secured returns have been flowing to subsidized sectors, perpetuating investment in technologies such as decarbonization that are inadequate to meet long-term goals. Figure 6 depicts this cycle of subsidy dependency in the solar industry.

Many are concerned about inefficient or unnecessary investment in gas-fired generation (e.g., Dyson and others, 2018). Indeed, historically, much gas-fired generation operated below ideal CFs and commercially faltered. Some plants in the current wave of gas generation expansion may face the same fate. The crucial difference, however, is that most investment in gas-fired plants is made by merchant generators in proven technologies at their own risk without subsidies. Most renewable investment also is made by merchant developers, but it would not occur without subsidies or mandates. As such, private investors mitigate their market risk with the help of subsidies, but taxpayer dollars are invested in more expensive and inefficient technologies.

10. https://www.thesolarfoundation.org/national/.

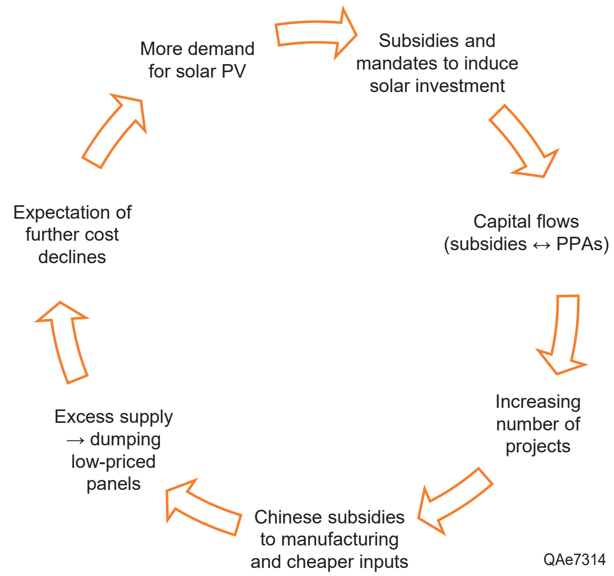

Figure 6. Cycle of subsidy dependency in the solar industry. PPA = power purchase agreement; PV = photovoltaic.

Power Purchase Agreement Prices, Levelized Cost, and Market Value

Sometimes not fully appreciated are the reinforcing impacts of these support mechanisms on the financing of renewables and energy efficiency projects. These incentives have been encouraging the signing of long-term PPAs by utilities, including munis and co-ops, because they provide long-term guaranteed prices, which are artificially lowered thanks to tax credits, RECs, and/or other local incentives. Prices are lowered further because tax credits and mandates mitigate market risk and facilitate raising capital with terms more attractive than otherwise would be available. Tax-equity investors have played an important role by providing renewables (especially solar) developers with sufficient tax liability to take full advantage of federal tax incentives, including ITCs, accelerated depreciation, and bonus depreciation.

Yet, many PPA prices have been higher than average wholesale prices. Figure 7 duplicates figure 52 of Wiser and Bolinger (2018). The market value of wind is calculated using hourly wind-generation profiles at different locations and LMPs at those locations. Black diamonds represent the generation-weighted national average PPA price for wind, which is typically closer to the 10th percentile than the 90th percentile. Wind-PPA prices were higher than wind's market value in almost every market until 2013 or so. The decline in wind costs and continuation of PTCs reduced wind-PPA prices further, and wind has become more competitive despite declining wholesale prices. But even in 2017, wind-PPA prices were higher than the market value of wind in many regions.

The decline in market value of wind is also driven by the increasing penetration of wind resources in the same location increasing the mismatch between system load profile and wind generation—the natural outcome of intermittency of renewables. The issue can be larger with solar. Sivaram and Kann (2016) report that when solar reaches 15 percent of generation in a system, its value falls by more than one-half. At 30 percent, a California simulation implies a value loss of more than 67 percent. Solar generation is highest closer to peak hours and curtails the peak prices. The daily peaks shift to early evening hours, but prices are not as high during that time. The challenge is universal. Hirth (2015) concludes that solar value is higher than average wholesale price at low penetration, but this benefit turns into a penalty as, in the case of Germany, penetration surpasses 5 percent. Hirth (2015) also suggests that this value drop is steeper than wind's value drop because solar generation is more concentrated and coincides with high demand periods. Hirth (2013, p. 218) finds "the value of wind power to fall from 110% of the average power price to 50%–80% as wind penetration increases from zero to 30% of total electricity consumption."

Sivaram (2018) offers the shift away from generous feed-in-tariffs (FiTs) to reverse auctions as an example of how consumers can benefit more from competitive bidding by solar developers. Globally, winning bid prices lower than \$20/MWh have been reported in recent times. Although good news for consumers and government coffers, these lower prices squeeze profitability of the solar industry and eventually will curtail investment. Recent years have witnessed bankruptcies, cost-cutting, Security and Exchange Commission investigations, and consolidation across the solar value chain (manufacturers, installers, developers). In 2018, China's decision to limit FiTs availability for new solar installations and U.S. tariffs on imported panels reduced investments not only in the United States but globally, highlighting the tightness of margins.

That most investors are looking for government subsidies and guarantees, which mitigate market risks, is not surprising. But the demand for continued support is almost universal among renewable industry groups and their supporters. This request is inconsistent with

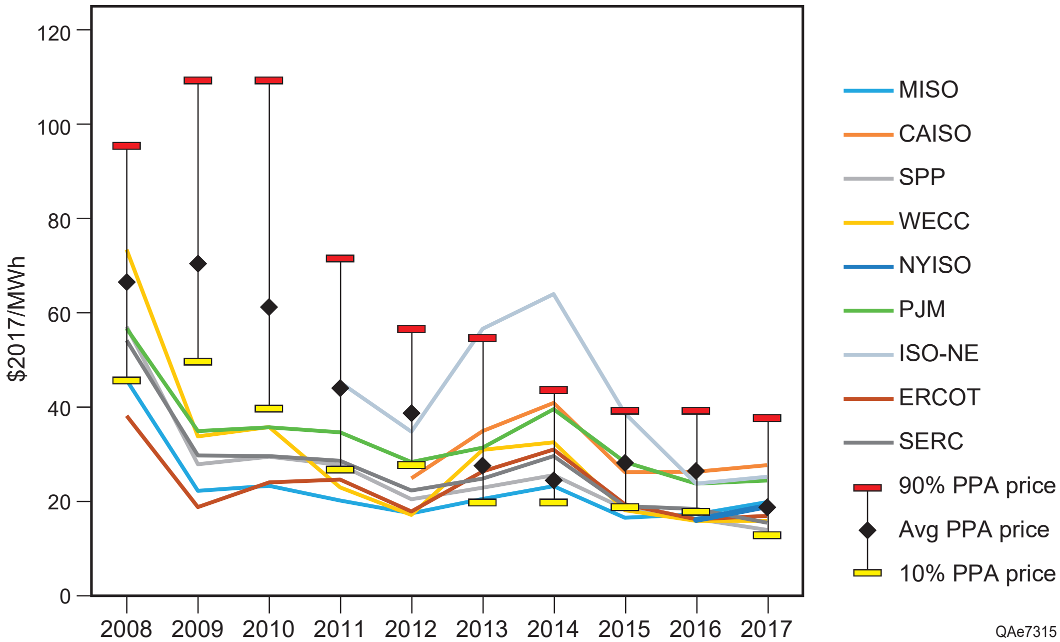

Figure 7. Regional wholesale energy market value of wind (colored lines) and generation-weighted national average levelized wind-power purchase-agreement prices ($2017/MWh). Modified from figure 52 of Wiser and Bolinger (2018). The average power purchase agreement (PPA) price for 2017 shown here is about $6–$7 lower than the value shown in figure 52.

the reports on wind and solar becoming cost competitive with conventional resources (e.g., Lazard, 2018a). Indeed, as one would expect, years of capacity expansion driven by subsidies and mandates along the supply chain of wind and solar started to yield economies of scale. In recent years, declines in costs of solar panels and windmill equipment led to average cost estimates for onshore wind and utility-scale solar PV that are competitive with NGCC plants.

As I will discuss in detail in Part II, however, this comparison is accurate for some locations but not in all geographies. A corollary to this conclusion is that in locations where onshore wind and utility-scale solar are competitive on their own merits, subsidies are unnecessary. In fact, as MIT (2015, p. xii) suggests, "the current array of federal, state, and local solar subsidies is wasteful." Jensen (2018) demonstrates that Chapter 313 subsidies were unnecessary for most of the capital investment projects (energy and non-energy) in Texas. Finally, the PURPA requirement of compensating developers on the basis of avoided cost leads to costs that are higher than competitive bids. Some developers sue state regulators for not accepting their project priced based on the PURPA while the state already received sufficient capacity bid competitively at lower prices. Kavulla and Murphy (2018) document the issues and urge FERC to use its authority to align the PURPA with competitive bidding practices.

Vicious Cycle of Level-Playing-Field Arguments

A common argument in favor of continued support to renewables is the need to level the playing field across all fuels and technologies, all of which have either received subsidies over the years and/or somehow been treated favorably by market designs. Supporting the fight against subsidies is easy. Generally speaking, economists disapprove of subsidies of any kind because they distort markets. The tax reform in 2017 missed a big opportunity to rid the federal tax code of incentives to all kinds of industries, including fuels and power-generation technologies. But the level-playing-field argument perpetuates a vicious cycle, with more subsidies and mandates for disadvantaged resources and/or next favorite technology. In the absence of proper competitive markets, the political economy of electricity avails itself to constant lobbying by various interest groups. As the literature cited earlier shows, the current plethora of support programs is not only costlier than other alternatives but also less efficient in reducing GHG emissions.

Since the early 2010s, cheap natural gas and, in some markets, larger shares of subsidized, low-cost renewables lowered the cost of electricity across all hours and seasons of the year. Combined with the shortcomings in energy, ancillary, and capacity markets, the generation sector started experiencing a "missing money" problem. Between 2010 and 2018, utilities and merchant generators retired about 67 GW of coal, 38 GW of gas, and 5.3 GW of nuclear capacity. Not all of these retirements can be tied to any one reason. A great majority of retired coal units were older, less efficient units that probably would retire under new environmental regulations. Most retired gas units were older steam turbines, continuing the transition that started in the late 1990s. Between 2001 and 2009, the industry replaced almost 26 GW of older gas-fired units and nearly 6 GW of liquid-fuel plants with combined-cycle gas plants and, toward the end of the decade, some wind.

The transition increased speed in the 2010s, amplified by uncoordinated policies across multiple jurisdictions. More retirements are expected. Adelman and Spence (2018, p. 274) conclude that "renewables pose a much greater threat to the viability of baseload generation in the longer-term than natural gas-fired generation." Clemmer and others (2018) is the latest in a series of studies warning about the early retirement of many nuclear units. About 22 percent of existing capacity is unprofitable, and some units are already scheduled to close. Feaster (2018) reports 21.4 GW of coal-fired capacity to retire between 2019 and 2024. This rapid transition has led to concerns about resource adequacy in electricity systems, whose reliable and efficient operation should not be affected by political boundaries.

In reaction, coal and nuclear generators have been petitioning for their own support programs in this uncertain, commercially challenging environment. Some powerful examples from the last several years demonstrate the vicious cycle of out-of-market interventions. At the time of writing, the frequency of industry news about a government official somewhere across the country saving a coal or nuclear plant appears to be increasing. Saving local jobs is often the central argument but sometimes maintaining reliability or resiliency, or zero-emissions benefits in the case of nuclear plants, is also named.

Ohio regulators approved PPAs for existing coal and nuclear assets of First Energy and AEP Ohio, a process blocked by FERC in early 2016. In 2011, concerned about generation shortage in the future, Maryland signed a contract with a company to build a new gas-fired plant, a rare instance where gas-fired generation was the intended beneficiary of an out-of-market support mechanism. In early 2016, the Supreme Court overturned Maryland's contracting program because it disregards interstate wholesale markets. However, the Supreme Court was careful to allow states to pursue other energy policies such as RPS programs. From a competitive market perspective, different treatment of various generation technologies is a major setback.

In August 2016, New York regulators approved a new Clean Energy Standard program that includes zero emission credits (ZECs) for nuclear plants. Without nuclear plants, New York cannot achieve its emissions goals within the target time frame, nor can the state allow for negative economic impacts of plant closures in nuclear towns. The value of a ZEC will be determined on the basis of social cost of carbon (SCC) used by the U.S. Environmental Protection Agency (EPA). This approach of valuing emission-reduction benefits is a way to avoid the challenges similar to those faced by Ohio and Maryland approaches, which were deemed to interfere with wholesale markets governed by FERC. The Future Energy Jobs Bill in Illinois, passed in December 2016, provides ZECs of roughly $235 million per year (or about $10/MWh) for 10 years to nuclear plants. As the name of the Illinois bill suggests, saving local jobs and economies is a strong driver for keeping these nuclear plants open.

Interestingly, Tsai and Gülen (2017a) report that keeping the New York and Illinois plants online does not necessarily lead to GHG reduction within the larger region. Uncoordinated local interventions, however well-intended, cannot solve global problems such as climate change. In early 2019, the Electric Power Suppliers Association (EPSA) together with two of the largest merchant generators, NRG and Calpine, asked the Supreme Court to consider whether or not New York and Illinois subsidies to certain nuclear plants violated the Federal Power Act after lower courts upheld these state programs (e.g., Bade, 2019a). The plaintiffs claim that these subsidies are equivalent to the Maryland program overturned by the Supreme Court.

In August 2017, a DOE Notice of Proposed Rulemaking sought revisions to market rules to boost "resiliency" by saving some fuel-secure plants—an obvious attempt by the Administration to save not only coal but also some nuclear plants. The evidence in support of the proposed changes was practically nonexistent. Opposition to it was widespread across system operators, environmental groups, merchant generators, and consumer groups with the obvious exception of some coal and nuclear interests. FERC rejected the DOE proposal in early 2018 but asked ISOs and RTOs to study the resiliency question. In 2018, while system operators were working on their alternative solutions, the Administration issued a directive to save coal and nuclear plants. The proposed solution is for the DOE to use its emergency powers under section 202(c) of the Federal Power Act, an unpopular idea with threats of litigation. Because there has not been a power shortage or serious reliability issue around the country, the DOE has not used such powers at the time of writing, but the concerns of the coal and nuclear industries remain.

Once the genie of the level playing field is out of the bottle, it is difficult to put it back, especially if the competitive market is off the table.

In 2018, New Jersey and Connecticut were the latest to join the group of states saving select nuclear assets with various subsidies. In late 2018, the U.S. Senate considered the Reinvigorating American Energy Infrastructure Act, which would reignite the DOE loan program to support high-efficiency, low-emission coal generation plants. One senator supporting the bill stated that it was necessary to ensure that coal "is competing on a level playing field while also keeping up with advances in technology" (e.g., Walton, 2019a). Once the genie of the level playing field is out of the bottle, it is difficult to put it back, especially if the competitive market is off the table. As MIT (2016, p. ix) puts it, "the only way to put all resources on a level playing field and achieve efficient operation and planning in the power system is to dramatically improve prices and regulated charges (i.e. tariffs or rates) for electricity services."

The threat to the nuclear fleet alarms not only the nuclear industry but also those who realize that the premature retirement of nuclear plants will lead to an increase both in GHG and local emissions. Tsai and Gülen (2017b) report conclusions from long-term capacity expansion and dispatch modeling showing that, on an economic basis, gas-fired plants will be the main substitute for premature nuclear retirements, and emissions will increase with nuclear retirements through 2030. Despite all the federal, state, and local support, renewables cannot be developed fast enough at sufficient scale and in the right places to compensate for possible nuclear retirements. This fact must have played a role in multiple states' decisions to save some of their nuclear plants. According to data from the Energy Information Administration, between 2010 and 2018, more than 80 GW of gas-fired capacity was built, compared with 56 GW of wind and 30 GW of solar. Projects under construction or with necessary permits and expected to be online by 2022 include 35 GW of gas, nearly 17 GW of wind, and a little over 9 GW of solar. Despite the large nameplate capacities of wind and solar, when adjusted for their intermittency with a generous national average CF of 45 percent for wind and 26 percent for solar, the capacity of wind and solar reliably available to the power system is much less.

Clemmer and others (2018) argue for a national GHG price[11] to save nuclear plants, consistent with proposals from most economists and at least some nuclear industry leaders. The CEO of Exelon—one of the largest nuclear fleet operators in the country with many plants benefiting from various state subsidies, and one of the architects of the Illinois nuclear subsidies discussed earlier—came out, albeit belatedly, in favor of a GHG price over "band-aid" state subsidies (e.g., Bade, 2018a).

Market reforms are under discussion or being implemented to enhance energy and capacity prices to address resource adequacy concerns. I discuss them in detail to demonstrate the needed market fixes and challenges such reforms face. I fear, however, that they will be only stopgap measures because of the lack of consensus around them. Many states continue to pursue out-of-market solutions, which will undermine whatever fix is put in place.

11. In much of the literature and media coverage, the term "carbon price" is used to represent a tax on GHG emissions or the price of "carbon" in the cap-and-trade market. A tax is imposed on or an equivalent cap-and-trade market is created for carbon-dioxide-equivalent emissions of GHGs, which include carbon dioxide, methane, nitrous oxide, and fluorinated gases. I use GHG price when referencing studies using carbon price or discussing cap-and-trade market prices but prefer to use GHG emissions tax when discussing general policy.

Resource Adequacy, "Out-of-Market" Support, Missing Money, and Market Reforms

Having 10 to 20 percent more installed capacity than the predicted annual peak demand (reserve margin) is the best-known measure of resource adequacy in electric power systems. The reserve margin is primarily an engineering construct to avoid outages. It depends on system characteristics such as generation mix, grid topography, and load profiles across the year. Historical data and technical assumptions on these variables are used to develop probabilistic analyses of the risk of not meeting estimated peak load. The dispatchability of plants matter, as they are required to ramp up to follow load up to its peak. Wind farms are credited for only a portion of their installed capacity because they are typically not able to generate much during traditional peak periods. In contrast, solar farms, which have generation more near traditional peak load periods, are assigned higher peak credits by system operators.

The specific percentage for each system is calculated based on NERC guidelines. Long-term and short-term reliability assessments published by NERC have consistently reported reserve margins significantly above reference reserve margins, with the consistent exception of the energy-only market of ERCOT, where the reserve margin has been at or below the reference level for many years.[12] Among the other organized markets, PJM has had a reserve margin between 30 and 35 percent in recent years, with a prospective margin of 60 percent by 2022–23. The comparison between ERCOT and other markets suggests that a combination of capacity markets, federal tax credits, and state policies has been inducing more investment than necessary.[13] It is also possible to argue that the energy-only market in ERCOT with its price caps has failed to encourage sufficient investment, especially as wind and, more recently, solar resources entered the system and lowered wholesale electricity prices beyond the decline caused by low natural gas prices. These interpretations are discussed later in more detail, but it is important to note that despite low reserve margins, ERCOT has not experienced a major reliability event.

In regulated and most restructured systems, the reserve margin is mandated. Some restructured markets provide only a target reserve margin. Changes in the industry (e.g., increasing share of variable and/or distributed resources, retirement of traditional baseload generators, and demand-response technologies) challenge the appropriateness of the technical reserve margin as the proper metric of resource adequacy.

As discussed earlier, in competitive markets, energy price caps significantly below VOLL undermine price signals to potential investors in new generation facilities as well as to consumers who, ideally, also should be resources to the power system. The concerns about resource adequacy led ISOs and RTOs to implement capacity markets while keeping price caps in their energy markets low. As such, capacity markets can be seen as out-of-market compensation schemes. Depending on their design, these markets can be costly, keep older units online, or, conversely, force premature retirement of baseload generators and/or encourage less-efficient units to be built. Since the early days, each capacity market suffered from one or more of these afflictions and has been continuously modified to correct design mistakes and/or to adjust to changing industry conditions. The PJM capacity market has been modified about 30 times in the last 10 years. As mentioned earlier, capacity markets are at least partially responsible for overinvestment in generation in PJM and other ISO/RTO territories that yield a reserve margin much larger than levels considered necessary for system reliability.

At the time of writing, the distortionary effects of subsidized resources are being tackled in several markets. In early 2018, FERC approved the proposal of ISO New England (ISO-NE) to separate its capacity market into two segments, one for subsidized resources (mainly wind and solar) and another for conventional thermal resources. In contrast, in early July 2018, FERC rejected a similar proposal from PJM. The PJM region also includes subsidized nuclear resources. More states within PJM are considering subsidies for nuclear facilities. The ISO-NE proposal compensates for the market impacts of new subsidized resources while the rejected PJM proposal covered existing subsidized resources, as well. I discuss these reforms in more detail in the ISO-NE and PJM sections that follow.

While capacity markets are struggling, scarcity pricing in energy markets remains a challenge. The simple example in the "Energy Price Information" box can help

12. For an example, see figure 1.1 in North American Electric Reliability Corporation (2018).

13. FERC Commissioner Glick appears to agree that capacity markets induce excess capacity development (e.g., Bade, 2019b).

ENERGY PRICE FORMATION

Although not fully representative of the complexity of electricity markets, a simple, single-period example with four generators, each with three blocks of megawatts with different prices (block-loaded), allows us to investigate price formation concepts and compare several alternatives: locational marginal price (LMP); convex-hull pricing or extended LMP (ELMP), a version of which is implemented in MISO; and PPLMP, a solution proposed by a market participant during the FERC price formation docket but not implemented in any market. Unlike LMP and ELMP, PPLMP is an accounting adjustment that does not require any changes in current economic dispatch and unit commitment procedures (SCED and SCUC). It aims to set the price, when warranted, at the "full cost" (i.e., inclusive of start-up and no-load costs) of the highest cost block of energy dispatched at any given hour to internalize out-of-market uplift credits that are currently not transparent. Key assumptions of the example are summarized in (a). Block 1 is the economic minimum for each generator. All generators are dispatchable for Blocks 2 and 3. Block bidding and minimum dispatch requirements lead to a nonmonotonic, nonconvex total cost curve.

(a)

Gen.	Min. MW if committed	Max. MW if committed	Block 1 MW; $/MWh	Block 2 MW; $/MWh	Block 3 MW; $/MWh	Start-up cost
G1	200	260	200 MW; $50/MWh	30 MW; $53/MWh	30 MW; $56/MWh	$10,000
G2	100	180	100 MW; $60/MWh	40 MW; $65/MWh	40 MW; $69/MWh	$2,000
G3	50	150	50 MW; $200/MWh	50 MW; $221/MWh	50 MW; $241/MWh	$50,000
G4	150	270	150 MW; $300/MWh	60 MW; $333/MWh	60 MW; $353/MWh	$5,000

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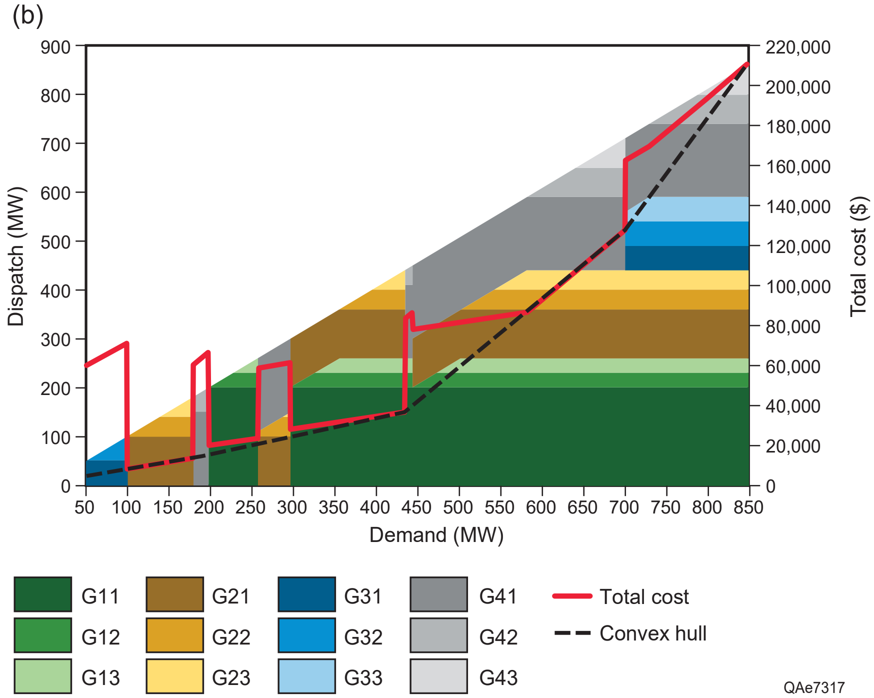
Note: Adopted from ISO-NE Real-Time Price Formation Technical Session #3, April 30, 2014.

(b)



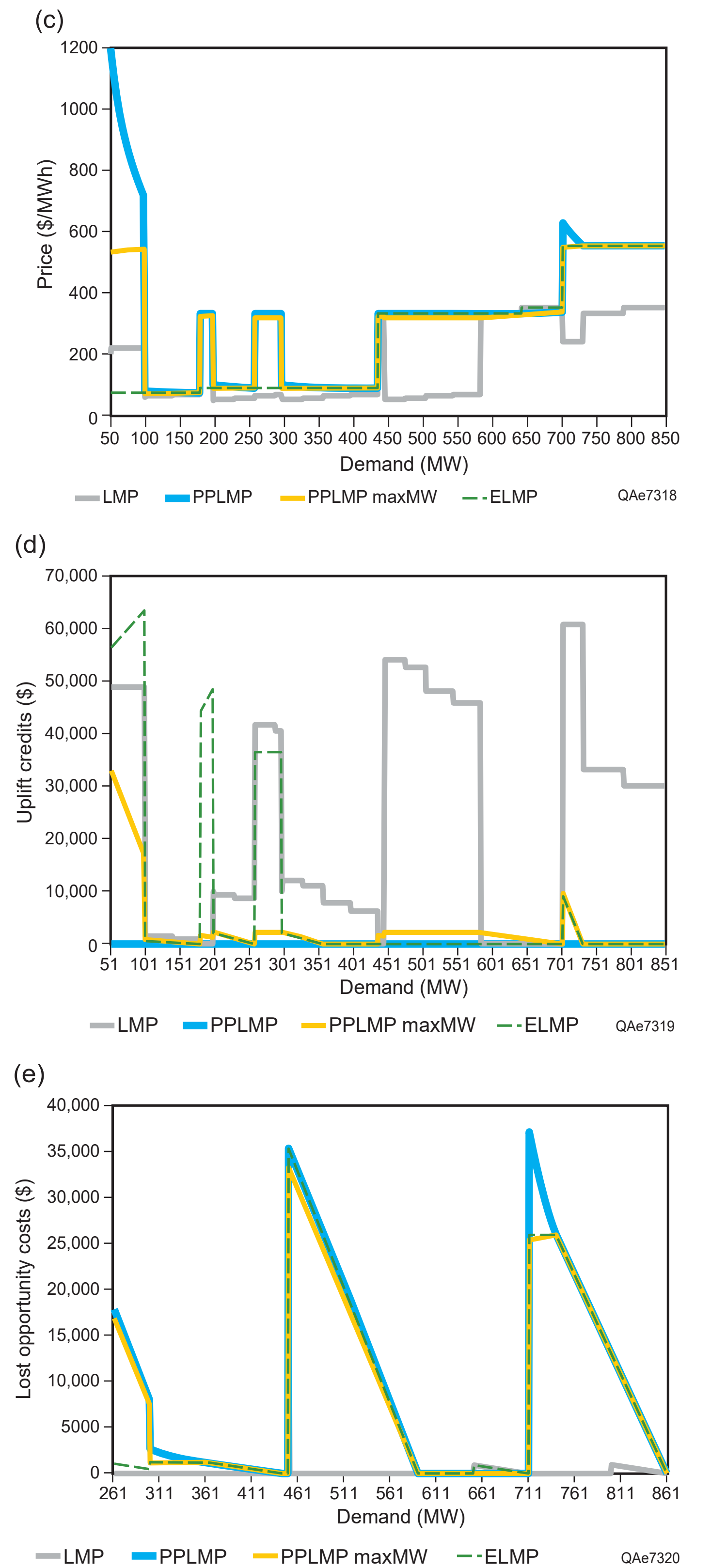
The single-period context is prone to nonmonotonic increases in the set of committed generators with increasing load (b). For example, a load of 260 MW can be met at minimum total cost of $23,270 by dispatching all three blocks of the first generator (G11, G12, and G13). If load rises to 261 MW, the option that yields the lowest total cost is to dispatch the fourth generator at its minimum output level of 150 MW (G31) and use G21 fully and G22 partially, not running G1 at all. Total cost now jumps to $58,715. ELMP can be calculated as the slope of a piece-wise linear convex hull of the total cost curve (dashed line in [b]).

PPLMP is mostly higher than LMP, significantly so in some intervals (c). Block offers and minimum output requirements increase both LMP and PPLMP in those intervals but much more aggressively for

PPLMP because the start-up cost of the highest average cost generator dispatched in those demand levels is very large in this example. ELMP increases with demand and is higher than LMP in most demand levels; PPLMP converges to ELMP at maximum dispatch of the highest cost unit. These difference in prices translate into revenues. Total revenue is highest with PPLMP, but the difference between PPLMP and ELMP is reduced as load levels are increased.

In terms of out-of-market payments, PPLMP eliminates uplift credits (d). ELMP reduces uplift credits significantly, especially at higher load levels. In fact, ELMP and PPLMP maximum megawatts yield roughly the same results. Lost opportunity costs (LOCs) increase under all alternative pricing schemes relative to LMP (e). Note, however, that the increase in LOC is relatively small because there are fewer megawatts available from other generators that are not already dispatched. In reality, one could expect that LOC is not that significant during high-demand periods, such as summer afternoons in most systems, as most committed units are probably dispatched in full. However, in other demand periods, the PPLMP potential to increase overgeneration incentives can be significant if LOCs are not separately compensated.

See Gülen and others (2016) for more information.



familiarize readers with some of the concepts discussed in this section and offer a preliminary comparison of various pricing designs. Gülen and others (2016) discuss this example and others in detail, and Gülen and others (2015, 2016) provide a more in-depth assessment of price formation issues and their evolution in different markets and at FERC.

Capacity markets do not address real-time operation challenges and proper compensation of flexible units. Ancillary services are used to provide additional compensation, but system operators still make out-of-market payments known as *uplift credits* or make whole payments to some generators. Based on empirical evidence in the California Independent System Operator (CAISO) and ISO-NE markets, FERC (2014a) found that existing market rules and protocols do not always reflect the full costs of a resource, including start-up, particularly of fast-start resources; the resulting energy and ancillary service prices are artificially low. According to FERC (2014c), additional drivers of uplift credits are system constraints that are not modeled, and the dispatch and commitment of inflexible resources or the commitment of resources are ineligible to set price. Wind and solar are inflexible in that they are dispatched in full capacity when available, subject to transmission constraints.[14] As discussed earlier (figs. 3, 4), faster and longer ramps in net load caused by intermittency and variability of wind and solar increase the need for system operators to arrange for larger megawatts of fast-start resources than in the past. In several systems, FERC identified sustained patterns of specific resources or specific regions receiving a large proportion of total uplift credits over long periods of time. Administrative uplift payments do not always incent appropriate short- and long-term actions by resources and loads (FERC, 2014b).

Lost opportunity cost (LOC) is the compensation made to generators if they were not dispatched as much as they economically could have been. For example, if a generator is committed in the day-ahead market but is not called upon or is partially curtailed in the real-time market, it is entitled to LOC uplift. Curtailment occurs for operational reasons, such as congestion or need for a generator to provide an ancillary service, or renewables dispatching more than forecasted. In some markets such as PJM and ISO-NE, the LOC is also considered an uplift payment.

In response to these challenges, in January 2015, FERC initiated Docket No. AD14-14-000 on Price Formation in Energy and Ancillary Services Markets to seek input from system operators and other stakeholders. No consensus was reached on the best approach to address fast-start pricing logic or on whether or not to expand the set of costs included in the energy component of LMP to cover start-up and no-load costs. System operators considered uplift payment an inherent element of wholesale energy and ancillary markets and expressed concern that design changes to eliminate uplift could lead to unintended consequences and undermine the market. ISO-NE identified the lumpiness and inflexibility of some generators, especially fast-start resources needed for load following and peaking, as among the main causes of uplift payments. Most system operators (e.g., CAISO, ISO-NE, MISO, New York Independent System Operator [NYISO], PJM) had already put certain "cost causation" or "beneficiary pays" principles into practice for allocating uplift payments. However, at least some operators (e.g., ISO-NE, PJM) believed that it was difficult or nearly impossible to determine causality of uplift payment of an individual transaction with reasonable accuracy. Some operators (e.g., ISO-NE, NYISO, PJM) questioned the value added by introducing a significantly complicated allocation methodology, considering the small level of uplift relative to total energy market value. For example, PJM (2014) reported that, via certain changes to its market design, the system operator was able to reduce the share of total uplift in total gross billing to about 1 percent in mid-2014 from 2.5–3 percent in 2013. However, the size of uplift and its market impacts differ across regions and over time as generation mix and load profiles change.

The EPSA, frustrated with the lack of urgency by FERC on the price formation issue, recommended that "all ISOs/RTOs should employ a dynamic approach to fast-start resource pricing based on convex hull pricing." The EPSA offered the examples of MISO's approximate extended LMP (ELMP) and NYISO's treatment of block-loaded units as dispatchable for the purposes of determining real-time prices and recommended their

14. Technically, wind and solar have flexibility in adjusting their output, but economic incentive to operate flexibly is lacking. For example, wind operators collect their federal PTC only when dispatched. The system operator would have to compensate the wind operators more than the value of wholesale electricity price plus PTC plus REC. Often there are cheaper providers of such services.

expansion (e.g., to include offline resources). Regional associations of independent power producers, companies, and financial players expressed similar opinions. Financial market participants considered uplift allocation as one of their primary concerns and urged FERC to order all ISO/RTO markets to adopt and maintain a set of best practices, preferably ELMP and demand-side participation.

The following are more-detailed discussions of some of the market issues and conflicts among various stakeholders in individual regions.

New York Independent System Operator (NYISO)

The NYISO has a nuanced "hybrid pricing" methodology to permit certain fast-start and block-loaded resources to set LMPs. Although NYISO is concerned about efficiency impacts of including start-up and no-load costs in prices, it allows start-up costs of offline, fast-start resources to be included if they are committed and their dispatch is economic in real time. Similar to ISO-NE, NYISO does not allow price setting by fast-start resources unless their dispatch is economically useful (i.e., system costs would be higher without the fast-start resource). The NYISO determines if a block-loaded natural gas combustion turbine (NGCT) is economic and could be dispatched in the first ideal pass. If economic, this NGCT plant is eligible to set price in the second ideal pass, either modeled as block-loaded at the NGCT's upper operating limit or fully dispatchable from zero (ISO relaxing the minimum operating limit) to the NGCT's upper operating limit. In its uplift allocation methodology, NYISO also distinguishes uplift costs relating to statewide reliability from costs due to local reliability issues.

New England Independent System Operator (ISO-NE)

ISO-NE used to allow commitment costs of pool-committed fast-start resources (not limited to block-loaded units) in LMP calculation only during the initial commitment interval (5–10 min) by relaxing their minimum output to zero in the real-time pricing process. This practice leads to at least a couple of suboptimal outcomes. First, more generation than demand is scheduled since these generators actually must be scheduled to operate at least at their minimum; this process leads the ISO to ask other generators to reduce their generation and compensate them via ancillary services known as *regulation-down* at additional cost to the system. Second, the fast-start resources do not recover their start-up and no-load costs for the remainder of the time they get dispatched, which increases their net commitment period compensation—out-of-market uplift in ISO-NE—and encourages fast-start resources to inflate their offers to cover these commitment costs.

With FERC approval, in early 2017, ISO-NE implemented changes to address these suboptimal outcomes and eliminate net commitment period compensation. Changes also included providing compensation to resources that, in certain circumstances, incur LOC for following the ISO's dispatch instructions when a fast-start resource sets the LMP under the new pricing method. Fast-start pricing with these modifications is allowed when a fast-start unit's generation is "economically useful," i.e., total system production costs would be higher without it.

In addition to fixes in energy-price formation, in early 2017, ISO-NE proposed a reform of its capacity market to accommodate subsidized resources without undermining price signals to unsubsidized resources. The reform introduced a two-round capacity auction. The primary goal of the reform was to facilitate the addition of more renewables while forcing retirement of thermal generation. The first round would work as in the past, with an MOPR and administered capacity-demand curves, which is higher than the price low-cost renewables could offer. During the second round, without MOPR or administered demand curves, resources with retirement bids that received capacity supply obligations during the first round could transfer those obligations to new, subsidized resources that did not clear the auction during the first round.

The MOPR is critical to understanding the debate around these capacity-market reforms; it is fundamentally a tool to prevent capacity-market manipulation by artificially low bids. It sets a minimum price, typically the cost of new entry of a new NGCT or NGCC. However, it also is seen as a tool to mitigate the negative impact of subsidized, or state-sponsored, resources. But states see it as a threat to their clean energy policies unless these resources are exempted from it. The ISO-NE capacity-market reform tries to solve this impasse (as do the proposals from PJM Interconnection, discussed later).

In early 2018, FERC approved the ISO-NE proposal with a 3–2 decision. The narrow decision demonstrates the reflection on the commission of the battle between market efficiency and state policies of pursuing subsidized resources. As has been the case with recent conflicts, legal challenges will follow. Some commissioners argued that the bifurcated capacity market had only delayed the inevitable price-suppression impact of subsidized resources. On the other hand, even some commissioners approving the proposals objected to MOPR as the standard approach to state policies imposing out-of-market resources on wholesale markets.

At the time of writing, the ISO-NE market continues to suffer fundamental challenges of resource adequacy in the short-term, which is the result of years of uncoordinated state policies undermining markets and preventing development of energy infrastructure, such as natural gas pipelines and power transmission lines. ISO-NE is now considering further reforms to its capacity market to value resources with secure fuel supplies. Although FERC rejected ISO-NE's request for a waiver to provide cost recovery for the 1,700 MW Mystic Generating Station in Boston, which has access to natural gas via an adjacent liquefied natural gas import facility, the federal regulator allowed for a short-term cost recovery option while ISO-NE reforms, yet again, its capacity market. In recent winters, liquefied natural gas imports have been critical to meeting the natural gas needs of New England for heating and power generation. ISO-NE's interim solution of treating the Mystic plant as a price-taker in the capacity market raised concerns about reduced compensation to other resources and premature retirements, which would further hurt resource adequacy (e.g., Bade, 2018b).

PJM Interconnection

PJM Interconnection is the largest RTO, serving parts or all of 13 northeastern U.S. states and the District of Columbia. Given its size, the fact that it hosts many market challenges is not surprising. PJM does not allow offline resources to set LMPs, and does not include start-up and no-load costs in price calculations because the RTO is concerned with encouraging resources not to follow dispatch instructions. PJM relaxes the minimum operating limits of block-loaded fast-start resources, including demand-side resources, and limits the degree of relaxation of the minimum operating limit to 10 percent during the commitment period. In comparison, NYISO, ISO-NE, MISO, and CAISO relax the limit to zero.

PJM's LOC compensation criteria have been evolving, as well. FERC approved PJM's proposal to switch from compensating LOC based on a single point of a unit's offer curve to calculating LOC payments based on the entire incremental offer curve to avoid over- or under-compensation. This approach has been used for calculating uplift in ERCOT since the opening of the ERCOT nodal market. In the same order, FERC also approved the consideration of start-up and no-load costs in the calculation of LOC payments to NGCT units that are scheduled in the day-ahead (DA) market but do not run in real time (RT) per PJM instructions (start-up costs will continue to be excluded if the unit operates in RT). Previously, LOC was calculated as (RT price – DA incremental energy offer price) × (curtailed MW). This approach led to NGCT operators getting paid more via LOC by not operating in RT (curtailed MW = DA commitment) than if the unit ran in RT because, if dispatched, it would incur start-up and no-load costs. To close this loophole, PJM's proposed change calculates the lost opportunity as [(RT price – DA incremental energy offer) × (curtailed MW) – start-up – no-load]. The change is expected to reduce LOC payments, eliminating incentives for gaming. PJM also created pockets, called *closed-loop interfaces,* to limit the reflection of no-load costs in the LMPs only within these regions (PJM Interconnection, 2014).

Capacity market reforms probably are a bigger challenge for PJM. In early 2018, PJM filed with FERC two proposals to reform its capacity market. Like the ISO-NE reform approved by FERC, the goal was to eliminate the price-suppression effect of state-sponsored resources, renewables, and, increasingly, nuclear on other resources that the grid still needs. The fear in organized markets is that subsidized resources push unsubsidized plants to retire early because of lost generation and lower energy prices (thus, lower revenues) and prevent new entries by suppressing capacity prices. One proposal developed by PJM staff created a bifurcated market with two rounds like the one by ISO-NE. The first round would operate like the current capacity market. During the proposed second phase, PJM would replace offers from subsidized resources with PJM's estimate of a competitive offer. The other proposal was put forward by PJM's independent market monitor and followed a more familiar, albeit also contentious, path of adjusting MOPR for subsidized resources.

In June 2018, FERC rejected both proposals with another 3–2 decision, again demonstrating the disagreement among the commissioners, and asked for alternatives within 90 days. One of the main disagreements appears to be between those who believe that the market, and in particular traditional generation assets, are undermined by subsidized resources and those who believe that states have the right to pursue policies regarding generation portfolios for their own purposes. Just like the decision in the ISO-NE case, this decision stated that "the integrity and effectiveness of the capacity market administered by [PJM] have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market."[15] As noted, two commissioners dissented from this language.

In the background of these capacity-market reforms is the August 2017 DOE Notice of Proposed Rulemaking that sought market-rule revisions to boost "resiliency" by saving some fuel-secure plants. FERC rejected the DOE proposal in early 2018 but asked ISOs and RTOs to study the resiliency question. While opposing federal action to save specific power plants, a recent PJM study acknowledges the new risks caused by changing generation portfolios, including resiliency based on secure fuel supplies. As the president and CEO of PJM writes in Ott (2018), PJM sees market-based solutions based on fuel-security criteria developed via the stakeholder process as the most effective approach.

PJM returned to FERC with two new proposals, trying to find the middle ground between generators who are under threat of the "price suppression" effect of subsidized resources and consumer advocates who believe that proposed fixes will increase costs. PJM criticized both sides for ignoring the realities of the state clean energy policies and the price suppression effect of the subsidized resources (e.g., Bade, 2018c). Both proposals would carve out subsidized resources from the capacity market and have a price floor for remaining resources. The resource carve-out (RCO) excludes only the resources subject to MOPR and those receiving a state (but not federal) subsidy. In its filing, PJM acknowledged that if the carved-out capacity becomes too large in the future, the robustness of the residual market would need to be assessed.[16] The Extended RCO "addresses a concern that led the Commission to reject Capacity Repricing in its June 29 Order—namely, a concern that paying subsidized resources the reconstituted capacity price amounted to an unfair windfall" by "completely isolating the subsidized resource from PJM's capacity market, and thus not paying the resource a capacity payment out of the PJM market" (PJM filing, p. 10).[17]

Nonsubsidized generators do not like the carve-outs, preferring the MOPR approach, or the Extended RCO as a second-best option, with some recommended changes. Comments filed with FERC in response to PJM proposals are instructive. NRG Power Marketing wrote, "Adopting [RCO] would signal a retreat from the competitive markets that the Commission has espoused since its landmark Order No. 888. Like all massive government interventions in the market, [RCO] would stifle the efficient allocation of private capital, shift costs and risks to consumers, and replace private, at-risk investment with ratepayer-backed investment."[18] In its filed comments, also favoring Extended RCO as the best option available with shortcomings, Calpine makes another important point: "Competitive generators have invested tens of billions of dollars in the PJM market since RPM was introduced. They did so with the understanding that competitive markets will be protected and the Commission will ensure just and reasonable pricing.…If the Commission fails to take the necessary action in this proceeding to shore up the structure of PJM's capacity market, then the Commission must be prepared to develop mechanisms to provide stranded cost recovery for these investors who were otherwise tricked into investing capital in a market with no meaningful opportunity to recover that capital, and a fair return with it."[19] The stranded cost concept is discussed in Part II.

15. ZECs and RPS programs were out-of-market payment examples included in the decision. For details, see the order at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14961693.

16. https://www.pjm.com/-/media/documents/ferc/filings/2018/20181002-capacity-reform-filing-w0172181x8DF47.ashx.

17. As Helm (2017) points out, the UK practice is similar, as it excludes wind from the capacity market: "National Grid had no reason to auction wind in the capacity market, for example, because it is already given the separate subsidies, but it does deduct the [equivalent firm power] contribution by existing wind from the capacity auction procurement level."

18. Page 1 in https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15092093.

19. Page 13 in https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15092084.

It is easy to dismiss these comments as complaints from fossil fuel–based generators, but that would be prejudicial. Most economists filing comments either on behalf of generating or marketing companies, PJM, the EPSA, or as the independent market monitor agree that RCO would result in significant price suppression. Some suggested that this suppression may result in failure of competitive markets (e.g., see the link to comments by Robert B. Stoddard on behalf of NRG Power Marketing in footnote 18). These are legitimate arguments, as this report tries to demonstrate. Another observation by Mr. Stoddard is also incisive: "Because the states do not see the full cost of their policy choices, they have incentives to grant ever increasing rounds of subsidies to save preferred resources—preferred for their environmental attributes, local job creation, or acumen of their lobbyists—from the consequences of the resulting price suppression." Consumers do not directly see the full cost of the policies, either. In Part II, I will provide estimates for system-integration costs, which are mostly socialized. But it is also important to keep in mind that individual state or even local policies can induce costs in neighboring jurisdictions if they are all part of the same power system. Such costs are negative externalities.

Electric Reliability Council of Texas (ERCOT)

Even in ERCOT, without a capacity market, price caps in the energy market used to be $1,000/MWh until the tight market conditions of summer 2011 proved the irrationality of price caps significantly below VOLL. Since then, the energy price cap has been gradually increased to its current level of $9,000/MWh. This value is loosely based on London Economics (2013), which was commissioned by the Public Utility Commission of Texas (PUCT), although the report did not recommend $9,000 specifically for the ERCOT market. Newell and others (2014) estimated the economically optimal reserve margin for ERCOT as 10.2 percent, as compared with the 14.1 percent implied by NERC technical criteria.

Although the higher energy price cap sends a better signal, there are other price formation challenges. Currently, the ERCOT market has no features analogous to ELMP to specifically treat fast-start resources or minimum load issues. Uplift credits are paid to resources that are committed by ERCOT but do not recover their total costs from energy or ancillary services prices. In September 2013, PUCT approved another solution, the operating reserve demand curve (ORDC), setting the VOLL at $9,000, the current energy price cap. The ORDC is a shortage pricing mechanism reflecting the loss of load probability (LOLP) at a predetermined level of operating reserve (2,000 MW in ERCOT; fig. 8) times VOLL. Operating reserves for quick start (e.g., spinning reserves) are a subset of the total installed capacity in a system. As seen in figure 8, predetermined curves for numerous 4-hr blocks change across seasons, which leads to some jumps between blocks for the same reserve level.

The ORDC has been implemented since June 2014. The value of ORDC adders is expected to change across the years and, within a year, across seasons as shortage conditions change in response to fluctuations in load and available resources. According to Potomac Economics data, independent market monitor for ERCOT and many other ISOs and RTOs, annual average ORDC adder contribution to annual average price has been relatively low: $1.41/MWh, or 5 percent of the annual average real-time price of $26.77/MWh in 2015; $0.27/MWh, or 1 percent of the annual average real-time energy price of $24.62/MWh in 2016; and $0.24/MWh, or <1 percent of the annual average real-time energy price of $28.25/MWh in 2017. However, annual averages hide the fact that the value of the ORDC adder can be much higher during active hours. For example, in February 2017, the value of the ORDC adder was $182.1/MWh in hours when it was active (Potomac Economics, 2018). In early 2019, PUCT allowed for real-time co-optimization of energy and ancillary services, a long-time ask of market participants to improve price signals. PUCT also directed an increase in the standard deviation of LOLP used in ORDC calculations, primarily to account for increased uncertainty due to intermittent and variable resources. This change should trigger adders to kick in more often and, hence, increase revenues to resources that provide short-term reserves. Finally, an average LOLP curve will replace multiple seasonal and time-of-day curves seen in figure 8.

These reforms are partially necessitated by the increasing penetration of wind, which is negatively correlated with load and leads to faster and longer ramps, as discussed before. Because most ERCOT customers have retail choice, higher prices also can induce demand-side response in terms of energy efficiency and conservation,

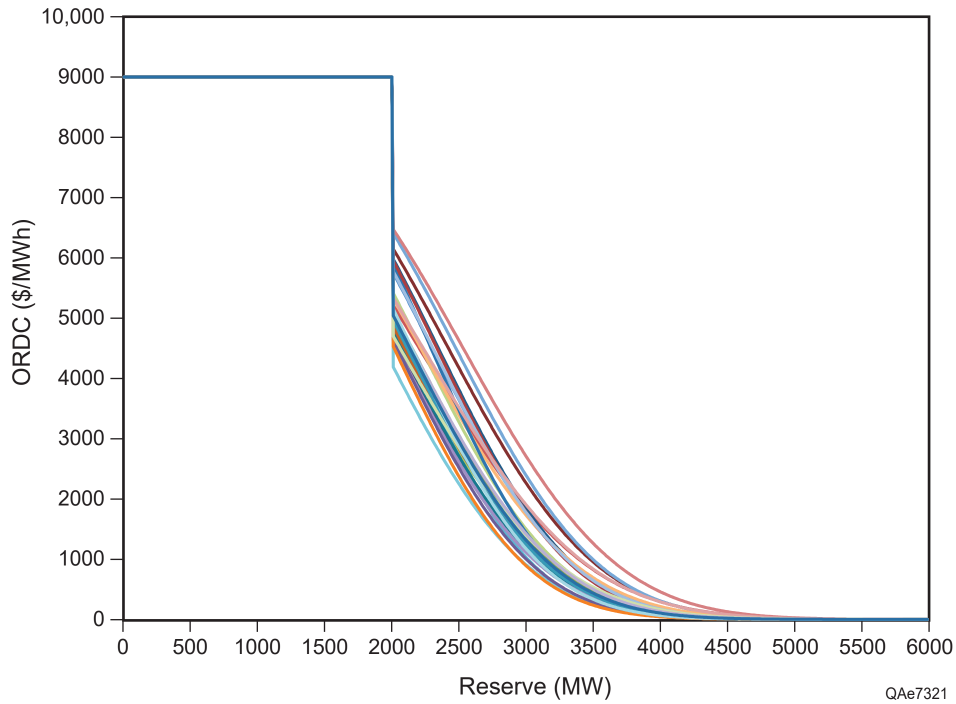


Figure 8. 2017 operating reserve demand curves (ORDC) in ERCOT triggered at 2,000 MW (source: Potomac Economics, 2018). Different colors represent predetermined curves for numerous 4-hour blocks that change across seasons.

managing the load throughout the day, or investing in distributed generation and/or storage assets. However, retail electricity providers offer only a limited number of real-time or time-of-use pricing products to residential or small commercial customers.

Midcontinent Independent System Operator (MISO)

Simply put, convex-hull pricing (CHP), also known as ELMP, is a mathematically elegant way of including commitment costs (e.g., start-up, no-load) in the calculation of market-clearing LMPs in order to minimize out-of-market uplift credits. Gribik and others (2007) laid out the principles of CHP, which builds on the cost-minimization objective of SCED and SCUC and is based on the same mathematical optimization structure. ELMPs at any demand level can be calculated as the slope of the envelope (i.e., convex hull) of the total cost curve. This envelope is depicted as a dashed line in (b) of the "Energy Price Formation" box.

Without the commitment costs, these prices would be LMPs; with them, they are the convex hull prices, or ELMPs. The underlying commitment and dispatch algorithms remain the same. In practice, the ELMP allows for units operating at their economic minimum or maximum and demand-side resources to influence the energy price when appropriate.

Despite its theoretical soundness, CHP has not been implemented in any market, presumably owing to computational challenges. A simplified version of it, known as "approximate ELMP," was executed in MISO on March 1, 2015. Approximate ELMP limits the participation of resources that can be included in ELMP calculations to fast-start resources—including those that are not block-loaded and some that might be offline—and emergency demand response. While some ISOs and stakeholders want to limit fast-start pricing to block-loaded resources because of overgeneration concerns, MISO is concerned that restricting price setting to only block-loaded resources could reduce system flexibility: even dispatchable fast-start resources may prefer to submit block-loaded offers if they would otherwise not be allowed to set the price. There is a concern, even with only block-loaded fast-start resources, that fast-start pricing will lead to higher prices that would encourage flexible units that were backed down to generate in excess of their dispatch signal. Allowing more units than just block-loaded units could aggravate this problem.

Delivering ___?___ Electricity

The discussion of price formation and capacity-market reforms in the five ISO/RTO regions might be confusing to many readers. Already very complex electricity market designs have been getting more labyrinthine as a result of a dynamic policy environment in support of certain technologies. Policies differ, sometimes significantly, across jurisdictions and lead to a cycle of conflicts with attendant attempts to fix the market.

These issues are not easy to decipher, even for the experts. What should be clear to readers, however, is the existential threat posed by the current state of affairs to competitive electricity markets. The fixes to energy and capacity markets are contentious and unsatisfactory to many market players. The financial health of merchant generators, especially those who do not receive any subsidies, are increasingly uncertain. Financial markets are looking at state subsidies and mandates to allocate capital to mitigate the risks associated with policy uncertainty. Industry surveys (e.g., Black & Veatch, 2018, 2019; Utility Dive, 2019) demonstrate increasing concerns in the utility sector regarding policy and market uncertainty. All of these so-called fixes are pushing the industry away from the principles of competition and toward more planning (fig. 9).

As Bill Hogan of Harvard University put it at the FERC conference in May 2017, "The avowed purpose of capacity markets is to correct for defects in energy pricing.

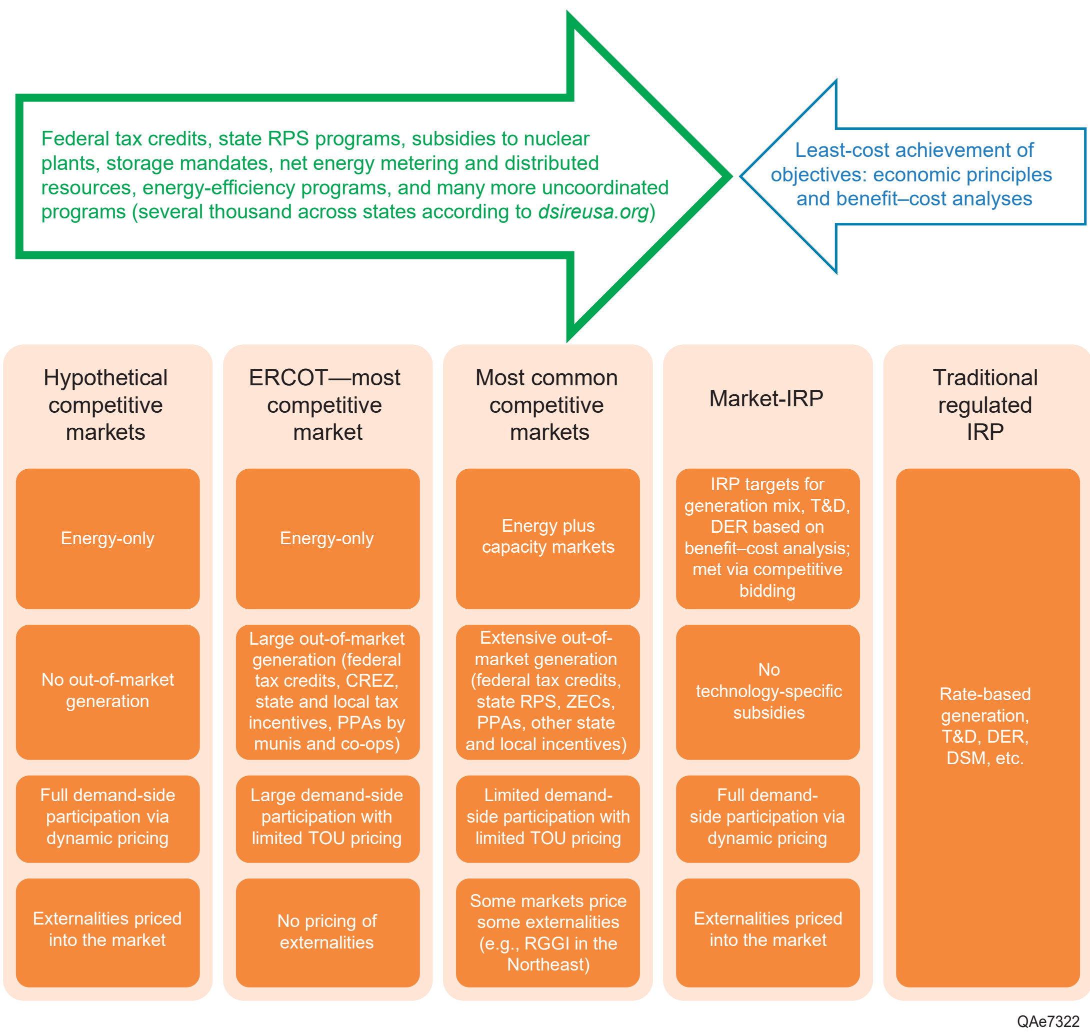


Figure 9. Options for organizing electric power sector. CREZ = Competitive Renewable Energy Zone; DER = distributed energy resource; DSM = demand-side management; IRP = integrated resource planning; munis = municipally owned utilities; PPAs = power purchase agreements; RGGI = Regional Greenhouse Gas Initiative; RPS = renewable portfolio standard; T&D = transmission and distribution; TOU = time-of-use; ZECs = zero emission credits.

WHY AN ECONOMY-WIDE GHG EMISSIONS TAX?

A GHG tax should be economy-wide because electricity generation has accounted for about 30 percent of GHG emissions in recent years. Transportation has been responsible for another 30 percent, followed by industry (22 percent), agriculture (10 percent), and residential and commercial sectors (each with about 6 percent). These are still aggregate numbers. Each industrial or commercial activity contributes to emissions at differing rates, which also vary across regions.

Importantly, as consumers, we all are ultimately responsible for buying goods and services, the supply chain and consumption of which cause emissions. As such, rapid progress in emissions reduction is only possible if consumers can see the negative impact of emissions on their pocketbook. Consumers, including businesses, with the most GHG-intensive activities should be expected to react quickest to manage costs. The same principle applies to all negative externalities.

If this is the case, the commission should have no obligation to accommodate subsidized resources that, in effect, make the problem worse. The commission can and should limit access and discriminate against those subsidized resources that are adding to the problem of inadequate pricing in energy markets" (as quoted in Heidorn, 2017). These economic principles are universal. It is worth repeating the quote from Helm (2017, p. 115) in regard to the UK practice: "National Grid had no reason to auction wind in the capacity market, for example, because it is already given the separate subsidies." Unsurprisingly, this economist view is not shared by everyone, as amply demonstrated before, during, and after the same conference by state representatives.

A truly competitive market could have achieved environmental goals at lower cost, as discussed earlier. No conflict among clean, reliable, and affordable need exist. I call this market "hypothetical" in figure 9 because such a market does not exist. Most regions have capacity markets, limited demand-side participation, and plenty of out-of-market generation. Externalities are rarely priced, partially because of a prisoner's dilemma: pricing an externality in one region while neighboring regions ignore it undermines economic competitiveness and creates losers.

Greenhouse gas taxes are discussed in more detail in Part II, but it is useful to cover the topic here briefly because it is central to the clash between competitive electricity markets and out-of-market incentive policies. Economists are almost unanimous in their recommendation of an economy-wide GHG emissions tax if the goal is to reduce GHG emissions (see sidebar "Why an Economy-Wide GHG Emissions Tax?"). In the past, cap-and-trade markets have been used to internalize costs of SO_2 and NO_X emissions, which were, as a result, reduced significantly. On January 17, 2019, the *Wall Street Journal* published a letter supporting an economy-wide GHG emissions tax signed by nearly 50 economists, including 27 Nobel laureates, 15 former chairs of the Council of Economic Advisers, and 4 former Federal Reserve chairs. This letter reflects the pillars of the Climate Leadership Council plan: a gradual increase of the GHG emissions tax, replacement of less-efficient carbon regulations, a border carbon adjustment to prevent international free riders, and return of all revenues to U.S. citizens via lump-sum rebates.[20]

Fischer and Newell (2008) rank a national RPS at fourth place and emissions price first as the most economic approach to reducing GHG emissions. The National Research Council (2013) underlines the ineffectiveness and high cost of federal tax credits as instruments for reducing GHG emissions. Oliver and Khanna (2018) demonstrate that a national RPS would be more efficient than a combination of state RPS programs but still inferior to a GHG emissions tax. Young and Bistline (2018) estimate RPS to be twice as costly as alternative ways of achieving the same level of GHG reduction. Adelman and Spence (2018), though supporting the superiority of a GHG emissions tax over a national RPS, suggest that regional approaches via ISOs or RTOs can be superior given regional differences in generation portfolios. However, such a "cooperative federalism approach" does not seem practicable. For example, New England states do not seem to agree on a GHG emissions tax or tightening

20. The Climate Leadership Council has brought together a diverse group of supporters, including major oil and gas companies and NGOs, around a simple plan: https://www.clcouncil.org/economists-statement/.

the cap in the Regional Greenhouse Gas Initiative market. Other multistate systems do not cooperate around either a GHG emissions tax or RPS policies. In fact, only NYISO, a one-state system operator, is considering a GHG emissions tax.

On the other hand, Meckling and others (2015) argue for a "green industrial policy" with the support of instruments such as FiTs and RPS policies, which would allow renewable energy firms to develop scale and eventually sustain a lobbying force large enough to counterbalance that of traditional industries and support carbon pricing policies. As the authors put it, "carrots buy sticks." Indeed, such policies—shown within the green arrow in figure 9—have been enacted in varying degrees around the country and globally. Meckling and others (2015) note that 35 out of 54 jurisdictions with carbon pricing had green industrial policies first. The authors also correctly point out that current carbon pricing (either via a direct tax or a cap-and-trade market) has not provided strong signals. But, again, this is a policy failure rather than a market failure because of the difficulty of agreement on the right tax on GHG emissions or emission reduction targets, given the influence of incumbent interests on the politics and the fear of public backlash at elections if the price is set too high. Empirically, Young and Bistline (2018) argue that green industrial policies such as RPS programs can reduce the cost premium over least-cost alternatives but do not eliminate them.

Although Meckling and others (2015) acknowledge the problems of rent-seeking and regulatory capture because of green industrial policies, the only defense they offer, based on Rodrik (2014), is that it is possible to prevent regulatory capture and rent-seeking (and, I would argue, inefficient allocation of capital) via institutional improvements. This is an obvious recipe for fixing the ills of regulatory capture. I also argue for improving the policymaking and regulatory institutions, as do many others on every side of the energy–environment debate—much easier said than achieved. In fact, the capture is often happening at the head of the food chain with policymakers.

The devil is in the objectives. If politics is the art of the possible, a policy based on market efficiency with an economy-wide GHG emissions tax does not seem attainable today. Not even a federal RPS is likely to get much traction. Costs of green industrial policies are becoming increasingly visible, partially because such policies promote currently available technologies regardless of their operational and capital efficiency, fit for the energy systems, and sustainability from a supply-chain perspective. Improved institutions may conclude that the benefits of such policies are lower than their costs. Unlike pricing externalities economy-wide, green industrial policies leave consumers—who always bear the cost as ratepayers or taxpayers but do not fully participate in decisions—out of the equation.

Already, consumer groups are voicing concerns about the rising cost of energy despite low wholesale prices of electricity, which has become an equity issue for some politicians and is certainly a contributing factor to divergence even among states that individually support renewables (e.g., New Hampshire blocking the transmission line from Québec, Arkansas and other states forcing the cancellation of DOE support for Clean Line Energy, and the failure to grow the Regional Greenhouse Gas Initiative). If these concerns gain traction among policymakers, more-rational policies may follow. So far, though, the idea of least-cost achievement of societal objectives based on economic principles and benefit–cost analyses (blue arrow in fig. 9) is mostly overwhelmed by this "green" steamroller.

Therein lies the challenge for a GHG emissions tax. A GHG emissions tax today can avoid wasteful use of limited productive and financial resources only if it substitutes for all other out-of-market incentives such as federal tax credits and direct expenditure programs, federal regulations such as the Clean Power Plan, and nonfederal support programs such as state RPS programs and ZECs. Despite their costs, green industrial policies around the globe developed economies of scale and lowered the cost of wind and solar panels sufficiently enough so that, according to many estimates, they are competitive in some regions without any support mechanisms (see Part II for a detailed discussion of social cost of generation resources).

The demand for these technologies is growing, with many customers willing to pay higher prices because of the positive environmental attributes. In such a setting, providing incentives is unnecessary; those resources can be better used for other purposes, including R&D of more-efficient clean energy technologies. The four pillars of the Climate Leadership Council include replacing inefficient regulations such as the Clean Power Plan but not any of the other market distortions—a gaping hole in an otherwise rational proposal. The social cost of support programs will not only remain a burden for consumers but also undermine the technological innovation and economy-wide efficiency improvements expected from the tax because many programs support specific existing technologies, even in regions where they are less productive, and others are duplicative.

Market-IRP: A Planned Market

With sociopolitical forces pushing most competitive markets toward a more planned approach—with mandates and subsidies determining not only the generation mix but also the deployment of demand-side technologies—we should remember that the inefficiencies of cost-of-service regulation have been a major driver of industry restructuring since the 1990s. As such, going back to the traditional regulated IRP world (rightmost column in fig. 9) should be avoided.

No one seems to be arguing for re-regulation. Even the regions that never restructured and kept their regulated, vertically integrated utilities are experimenting with market-based solutions to achieving state goals. Some programs considered successful in lowering costs are not without their problems. These experiments may be useful in reforming markets and regulatory frameworks. For example, Cross-Call and others (2018) offer a guide for reforming regulatory design to improve economic efficiency of utility investments with associated case studies that highlight lessons learned and recommended improvements.

Annual surveys of the electric utility industry by Black & Veatch and Utility Dive, among others, track the changing market, policy, and technology environment and register the growing concerns of utilities as well as their solutions for accommodating new technologies and customer expectations. Importantly, all of these surveys and studies are implicit recognitions of the continuing importance of the T&D grid and the utilities that own and operate them. Forecasts of T&D infrastructure investment are in tens of billions of dollars per annum, which will be a continuation of the investments observed in the 2010s. Under scenarios with more electrification (e.g., faster penetration of electric vehicles), annual transmission investment alone can be $20 to $40 billion, higher with penetration of more renewables (e.g., Weiss and others, 2019).

As valuable as utility experimentation could be, in the absence of consistent market and regulatory reforms that establish standards, or best practices, and leverage the value offered by interconnected regional grids, some of these investments will turn out to be unnecessary while others that would have been more cost-effective are not made. The uncertainty surrounding future policy and market reforms only feeds such investment inefficiency. There is an incentive for each utility to build the rate base up while the cost-of-service regulation is still the norm. Concerned with the rising cost of electricity to end users, some regulators do not approve some of the utility proposals, even if they are for popular technologies such as smart meters.

COMPETITIVE SOLICITATION

With the 1978 policy changes that encouraged non-utility generation, seeds for competitive solicitation of generation resources were sown. Especially since the early 2000s, many states—including California, Oregon, Arizona, Montana, Utah, Georgia, Florida, Illinois, Oklahoma, and Pennsylvania—have been pursuing competitive solicitation, mostly for RPS compliance. Similarities and differences of these experiences offer lessons on best practices.

A recent example is illustrative of benefits and remaining issues. In 2017, Xcel Energy and a diverse group of stakeholders proposed the Colorado Energy Plan, which calls for replacing coal capacity with wind, solar, and natural gas as long as the cost of electricity to customers does not increase. In August 2017, the Public Service Company of Colorado, a subsidiary of Xcel, issued a competitive solicitation for all sources and received 430 bids, including many wind and solar projects, some combined with storage. Median bids for wind and solar were about $20 and $30/MWh, partially reflecting the benefits of PTCs and ITCs. These very low bids suggest that even without federal tax credits, wind and solar projects can be competitive.

The success of the solicitation was marred by a losing bidder seeking an avoided-cost rate based on PURPA, which would have been higher than awarded bids. This perverse result, and others like it, led the National Association of Regulatory Utility Commissioners to propose that FERC bypass PURPA when competitive solicitations exist (Kavulla and Murphy, 2018).

A higher-level conversation is necessary to improve on this uncertain environment. **Responsible public policy requires a more transparent, consistent, and predictable approach to determining societal objectives, prioritizing them, and comparing various ways of achieving them through benefit–cost assessment.** Following are some high-level principles that might start such an interdisciplinary dialogue. They are intended to incorporate as many competitive market principles as possible into the IRP model.

- Focus on the objectives (e.g., lower emissions, increased consumer choice, affordable electricity) rather than on the technologies. This is a necessary, albeit insufficient, condition to ensure least-cost solutions and to encourage sustained innovation for the future.
  - Represent the cost of externalities in market prices.
- Procure resources competitively. The practice of competitive bids for resources has been expanding nationwide as well as globally, leading to least-cost penetration of renewables (see "Competitive Solicitation" sidebar).
  - Unbundle generation, T&D, and retail functions. This principle of restructuring is still well-founded. In fact, the increased number of market participants and technologies across the electric-power value chain strengthens the case for unbundling.
    - All generation can be developed by merchant generators.
    - Even merchant transmission may be preferable in certain cases.
  - Encourage retail choice and ensure that retail prices reflect all costs (i.e., inclusive of externalities and system costs) at all times to all consumers. This is essential for incorporating the demand side, a large resource, in the calculus. The time is opportune to take advantage of a large and growing portfolio of smart technologies and a growing demographic that is more comfortable with them. Many analysts advocate for customer choice and talk about the emergence of prosumers, but customer choice is hollow in the absence of consumers making decisions based on accurate price signals.
    - Established consumer-protection practices are still needed and can be improved upon to protect low-income consumers, those who live in multifamily dwellings without the ability to fully control their energy consumption, and other vulnerable segments of the population.

REGULATORY REFORM

Internationally, many jurisdictions have tested incentive-based rates, such as the revenue-cap regulation in the United Kingdom, in place since the early days (late 1980s) of restructuring. Benchmarking and yardstick competition, used to set performance targets, have been common across the world in not only electric power but also other network industries. All of these approaches have evolved over time with experience and changing conditions. Lessons learned from international experience include the following:

- Do not overexperiment; best practices can already be apparent.
- Do not overburden the utility and regulators with too many targets. Focusing on objectives rather than favorite technologies should keep the regulatory design simpler.

Overall, the United States has lagged in implementing performance-based rate making, but several states are leading the way. To support its goal of 100 percent renewable by 2045, the Hawaii PUC is developing performance-based regulations expected to induce the utility to improve energy efficiency, facilitate DER, and enhance customer choice. The PUC already decoupled utility earnings from higher electricity sales in 2010. In Rhode Island, an interagency team issued guidelines for power-sector transformation, which include a shift away from the cost-of-service model that rewards the utility for capital investment and toward a pay-for-performance model. In late 2018, after several years of work under the e21 Initiative, the Minnesota PUC started the work of identifying performance metrics for Xcel Energy, the state's largest utility.

In addition to such state efforts, there is Renovate, a new regulatory innovation initiative convened by the Smart Electric Power Alliance in partnership with the American Public Power Association, Edison Electric Institute, National Association of Regulatory Utility Commissioners, National Association of State Energy Offices, National Conference of State Legislatures, National Governors Association, and National Rural Electric Cooperative Association, as well as think tanks and nonprofits.

REGIONAL COORDINATION

The Northwest Power and Conservation Council is a rare example of regional resource planning. The Council was established by federal law, the Northwest Power Act of 1980, mainly in reaction to a costly and failed experiment to build nuclear plants in Washington State in the 1970s. The Council has professional staff and resources to develop an independent 20-year least-cost power plan, updated as necessary but at least every 5 years. Demand response, energy efficiency, and conservation have been part of the least-cost resource plans since the early 1980s. The Council is also responsible for mitigating the impact of hydroelectric dams on fish and wildlife. It has eight members, with two members each appointed by the governors of Washington, Oregon, Idaho, and Montana.

The Council's power plan is mostly advisory. Each state and utility has deviated from its recommendations from time to time, often driven by provincial politics. Still, this regional least-cost resource-planning approach is promising. An independent regional entity with the requisite legal support of its member states to avoid politically expedient interference can develop a mandated regional-IRP, for which resources should be procured via competitive solicitation. The regional-IRP needs to be provided with sufficient resources to recruit competent staff and acquire data and modeling tools necessary for the IRP development. Where they exist, ISOs and RTOs already have the capabilities to develop these resource plans. Secondment of staff from utilities and regulatory agencies could be valuable.

- Reform utility regulation to ensure least-cost achievement of policy goals (see "Regulatory Reform" sidebar).
  - Replace cost-of-service rate making that encourages new capital investment regardless of need with performance-based regulation.
  - Allow utilities to obtain a return from third-party investment so that they are indifferent between building assets themselves and procuring merchant generation, transmission, or other services.
  - Eliminate policies and regulations that undermine competitive procurement (e.g., PURPA requirements, mandates or subsidies for specific technologies).
- Leverage the value offered by the T&D grid via IRP.
  - Employ least-cost solutions to achieve objectives, realizing that they can come from any segment: generation, transmission, distribution, demand-side (behind-the-meter), or a combination.
    - Co-optimizing via IRP can avoid the problem of overbuilding for peak demand (e.g., via demand response) and can help induce wind and solar development in best locations (e.g., via high-voltage, direct-current transmission).
  - Enhance coordination across jurisdictions. The reliable and efficient flow of electricity across the transmission grid does not recognize state boundaries. The optimal expansion of the grid to integrate more renewables with higher CFs and to enhance system reliability requires a regional approach. ISOs and RTOs are best placed to optimize grid operations. FERC, state regulators, and system operators (with their stakeholders, including utilities) need to agree on a regional-IRP, along with its objectives and constraints (see "Regional Coordination" sidebar).
- Strengthen regulatory capabilities with access to the same data as private-sector participants, state-of-the-art modeling tools, and human resources to conduct an independent assessment of IRP recommendations while staying current on technological developments and protecting and educating end users.

The electricity sector is complex across many dimensions: economic, policy, regulatory, environmental, and technological. Dynamic socioeconomic priorities multiply the complexity. The principles discussed in this section are neither complete nor final. Most are not new as economic principles of restructuring, and competitive markets have not changed. But the principles do need to be reevaluated with the current slate of technologies and societal priorities. The list in this section offers numerous ideas for an **interdisciplinary expert assessment** to develop a market-IRP model that can modernize electricity systems across the United States and cost-effectively achieve objectives. Importantly, the process of developing this model should be transparent and acceptable to major stakeholders. Achieving such reconciliation, however, has been difficult even during the best of times. Today's polarized environment makes it even harder, but initiatives such as Renovate, which brings together key decision makers from state governments as well as utility interests, gives hope.

Part II—A Fresh Look at the Social Cost of Generation Resources

Electricity from generating plants of all types is delivered to our homes and businesses via an integrated grid of high-voltage transmission and low-voltage distribution lines, with associated infrastructure such as substations. Although distributed generation resources, such as rooftop solar with or without battery storage and reciprocating engines that burn natural gas, have been increasing their penetration, the large grid-based power system still dominates. In fact, existing dispatchable resources and the T&D grid are what allow utility-scale and distributed intermittent and variable resources to be added, since they need backup when the wind does not blow and the sun does not shine.

Balancing supply of and demand for electricity is done in real time because large-scale energy storage in batteries is still not available. Pumped hydrofacilities have been around for a long time, but their expansion is constrained by the availability of appropriate geography. System operators manage the challenging task of real-time balancing via SCED and SCUC, as discussed in Part I. Each system is different in terms of portfolio of generation assets, demand-side participation, load profiles, and grid layout. Moreover, policy and regulatory differences influence these factors and market design. As such, each system presents unique challenges in terms of dispatch dynamics and proper compensation of each resource, whether generator or demand-side.

Wind and solar capacity have been expanding across the United States, albeit sensibly more concentrated in regions with the best resources (e.g., solar in the Southwest, wind along the wind corridor east of the Rockies). This expansion would not have been possible without the help of federal tax credits, state mandates, and local incentives. Declining capital costs have been a more important factor in recent years, but the reduction in cost is partially driven by subsidized manufacturing of equipment (e.g., solar PV cells and panels in China). The impact of subsidies on power systems is indirect and both positive (renewables have low operating costs and thus lower electricity prices) and negative (displacing other generators can force retirement, raise reliability issues, destroy investor returns). Large-scale wind and solar projects can generate cheaper electricity than thermal generation in some locations with the highest wind speeds or solar insolation and existing grid access, especially if there is no natural-gas delivery infrastructure and/or the price of natural gas is relatively high. However, this cost competitiveness is not generalizable. With current technology, wind and solar cannot be developed competitively in locations with poor wind speed or solar insolation, especially if there is a need for new investment in long-distance transmission lines.

Generation Costs

LCOE, typically on a per-megawatt-hour basis, is the metric commonly used to compare the cost of generation technologies for a new plant. It is important to note that LCOE is primarily used for high-level policy-discussion purposes. Power plant developers do not use LCOE in their assessment of investment opportunities or in IRP, for which existing resources and the T&D network are an integral part of the evaluation process. Investors consider many region-specific factors, including but not limited to the following: subsidy policies at state or local levels; existing generation portfolio, including expected retirements and other potential new builds; load growth potential; grid topography and access to grid; access to fuel infrastructure; ability to contract; environmental policies and regulations; share of distributed generation; and demand response. For policymakers and the analysts who influence them, the following discussions should be of highest value.

The conventional formula for LCOE captures overnight capital cost and its financing costs (capital recovery factor [CRF]), operating and maintenance costs (fixed O&M [FOM] and variable O&M [VOM]), fuel costs (product of fuel price and efficiency of plant in converting energy content of fuel into electricity plant, known as heat rate [HR]), and annual expected generation (product of 8,760 hours in a year and ratio of net electricity generated in a year to energy that could have been generated at continuous full-power operation during the same period, known as the capacity factor [CF] of a technology).

$$LCOE = \frac{CRF * capital + FOM}{8760 \times CF} + VOM + HR \times fuel\ price$$

However, LCOE estimates based on this formula are often misused. This representation of LCOE is an incomplete indicator of competitiveness and social costs of different generation technologies because it ignores many factors that can lead to significantly different values for the LCOE of any technology. To begin with, there are significant regional differences for each component of the LCOE formula: capital costs, FOM, VOM, fuel price, HR, and CF. Also, in many studies using historical averages for thermal plants versus technical maximums for wind and solar, CF values are inconsistent across technologies. Renewables have been subsidized for many reasons, but the nominally most important driver has been their environmental benefits. And subsidies were needed because, with a few exceptions, policymakers have been unwilling to price the cost of externalities—such as environmental impacts on air, water, and land, as well as waste disposal—into the market. This is a legitimate argument.[21] The cost of externalities should be included in LCOE calculations to render them more useful for comparing alternative generation technologies based on their technical and environmental costs.

The plug-and-play standard: LCOE estimates for different technologies can only be compared with each other for locations where it is feasible to build any type of facility without additional investment in related infrastructure.

By the same token, system-integration costs of intermittent and variable resources must be included. These include balancing and backup (or, resource adequacy) costs, grid costs such as the T&D infrastructure needed to accommodate remote or distributed renewables, curtailment costs caused by capacity overbuild, and stranded costs of existing assets forced to lose revenues or even retire early because of subsidized resources.

Even in the best locations, wind and solar are intermittent and variable, needing backup and balancing from dispatchable resources. Their generation does not always match load profiles. For example, in most onshore locations in North America, wind generation reaches its maximum in the morning hours of spring months and is very low during summer afternoons. This generation profile does not match the load profile and reduces its usefulness to the grid and, thus, its market value. This mismatch between load profile and generation from nondispatchable resources has led Joskow (2011), among others, to declare LCOE flawed.

Regional Differences

Not all types of generation facilities can be built at any given location. All facilities need access to infrastructure such as natural-gas pipelines, coal railways, and power-transmission lines, as well as to water for cooling, land for coal ash disposal, and so on. Although wind and solar do not need a fuel supply chain, unlike most thermal plants that can be sited near an existing power grid, wind and solar often do need new transmission lines because the best resources (e.g., high-enough wind speeds and solar irradiation) are located away from load centers. There are also natural obstacles such as earthquake zones. In short, LCOE estimates for different technologies can only be compared with each other for locations where it is feasible to build any type of facility without additional investment in related infrastructure. One might call this the "plug-and-play standard." Otherwise, all related infrastructure costs should be considered as part of the LCOE of any facility. To address this location challenge, Rhodes and others (2017) use exclusion zone maps from Mays and others (2012) that are based on 11 different criteria: population density, wetlands, protected lands, lands with landslide risks, high-slope land, 100-year floodplains, water availability, EPA nonattainment zones, access to fuel (> 40 km [25 mi] from gas pipelines or railroads), proximity to suitable saline formations for carbon sequestration, and ability to build CO_2 pipelines.

At varying degrees, every single component of LCOE can be different across regions. Differences can be particularly large for some components, such as the CF of wind

21. However, as discussed in Part I, the studies assessing the benefit–cost accounting of subsidies in terms of environmental benefits offer evidence that federal tax credits and state RPS programs are less-effective direct taxation of the externality or an equivalent cap-and-trade market.

and solar and the price of natural gas. Rhodes and others (2017) use regional multipliers from the U.S. Energy Information Administration (EIA, 2013) for capital and fixed operating costs, historical data from various sources on average annual generation as a proxy for CF, and natural-gas-hub prices to estimate LCOE for each technology across all counties in the United States. Since any of these assumptions can change over time and some interested parties may have more-accurate data on their region, two online calculators are provided.[22] In addition to capturing regional differences across traditional LCOE components, calculators also allow for adding the cost of externalities. One calculator also allows users to add the cost of new transmission. Users can change many of these inputs if they have more-accurate information. Overall, these county-level LCOE estimates are significant improvements over the single-LCOE estimates provided by other sources. There is room for further improvements.

Capacity Factor

The CF changes significantly for all technologies across geographies. The range is much wider for wind and solar because the quality of wind speed and solar insolation varies widely across different geographic areas (fig. 10). LCOE estimates by Lazard have been referenced most frequently in recent years. Only recently, Lazard started offering regional estimates. Version 11 (Lazard, 2017) offers wind and solar LCOEs for five aggregate regions in the United States, which is not granular enough to capture the variability of the CF.

Thermal generator CFs used in LCOE calculations are typically based on historical utilization, which is a function of system characteristics such as electricity-demand (load) profiles, mix of generation assets, fuel prices, and transmission bottlenecks. As such, historical CFs do not reflect the "technical" capability of those plants. For example, in many regions, NGCC plants were utilized at an average CF of 50 percent or less because of overbuilding of generation capacity, lack of load growth, higher fuel prices at times, the increased penetration of subsidized renewable resources, or a combination of these along with other potential market, policy, or regulatory factors. For example, after the retirement of 67 GW of coal, 38 GW of gas, and 5.3 GW of nuclear capacity between 2010 and 2018, the utilization of many gas plants in regions with a lot of retirements started to increase.[23] In short, using a historical CF value in calculating the LCOE of an NGCC leads to a higher LCOE than that warranted by the technical capability of an NGCC. This is also true for all dispatchable resources (e.g., coal and, to a lesser extent, nuclear).

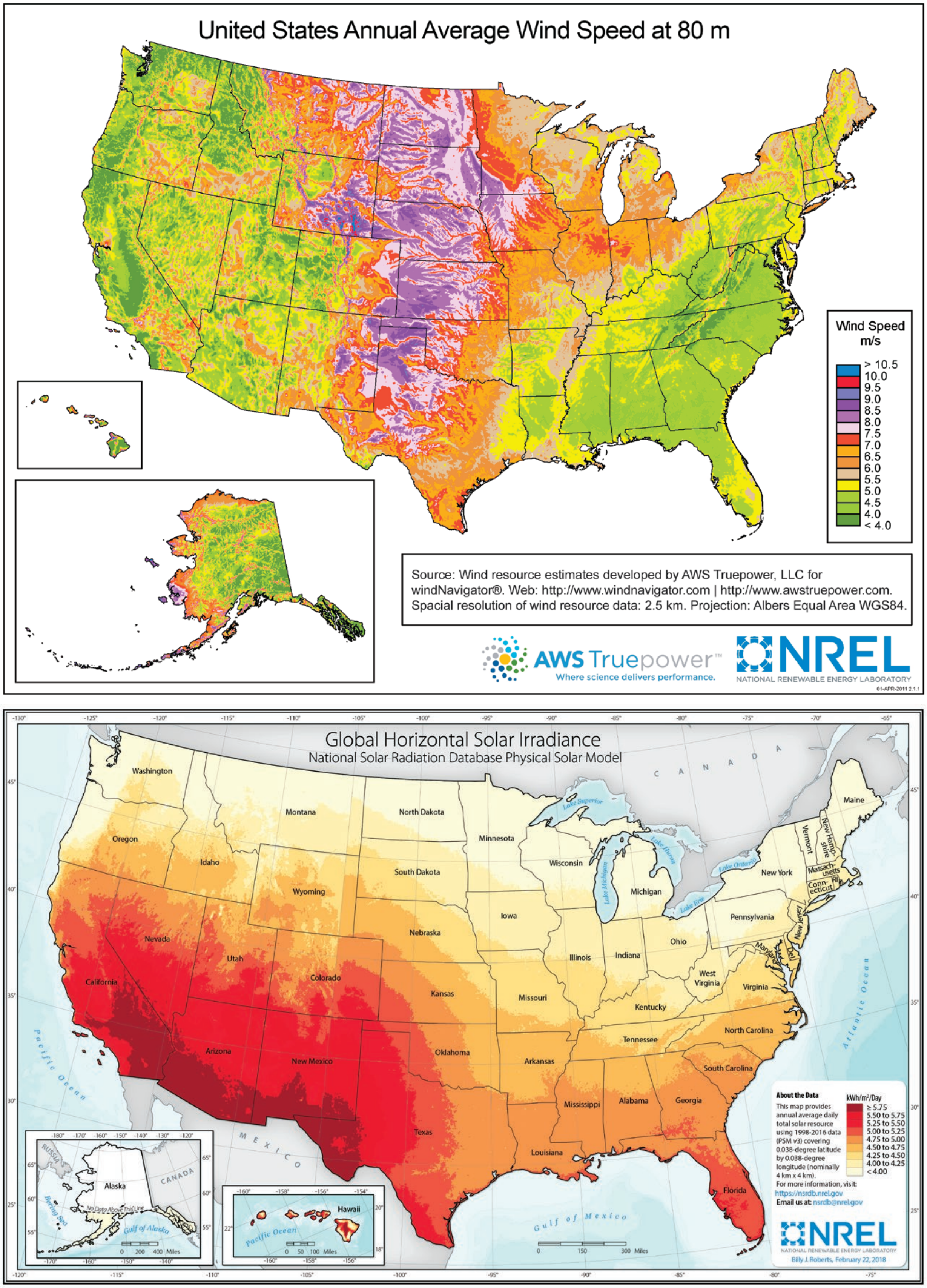
In contrast, a technical CF is often used for wind and solar mainly because these intermittent resources get dispatched in full when they are available, as long as there are no transmission constraints. Wind and solar technical CFs are often based on annual generation profiles developed by the National Renewable Energy Laboratory (NREL), AWS Truepower, General Electric, or others via engineering analysis. Increasing historical data allow for developing more-accurate annual hourly generation profiles and average CFs. But one can still use a wide range of estimates in calculating the LCOE of wind and solar. In table 1, I compare CF assumptions from EIA (2018c) and Lazard (2018a), results from a technical assessment of power densities in commercial-scale wind and solar facilities in the United States (Miller and Keith, 2018), and historical data in EIA's Electric Power Monthly (EPM) report.

Miller and Keith (2018), using U.S. data from most grid-connected commercial-scale facilities in operation between 1990 and 2016, estimate power densities for wind and solar facilities. Mean and 90-percentile CFs corresponding to their power-density estimates are, respectively, 32.9 and 43 percent for wind and 22.1 and 27.5 percent for solar.

EIA (2018c) assumptions are equal to or larger than the 90-percentile estimates from Miller and Keith (2018). Importantly, EIA's Electric Power Monthly reports annual average CFs that are consistent with Miller and Keith (2018): between 32.2 and 34.6 percent from 2013 to 2017 for wind, and between 25.1 and 25.9 percent from 2014 to 2017 for solar. Wiser and Bolinger (2018) report U.S. average annual CF for wind improving over the years and averaging about 35 percent without curtailment, with

22. Calculators are a product of the Full Cost of Electricity project (https://energy.utexas.edu/policy/fce), an interdisciplinary effort managed by The University of Texas at Austin Energy Institute, and can be found at https://energy.utexas.edu/calculators.

23. It must be noted that with current market structures, risk-taking investors see profit opportunity even at medium CFs and are building new gas-fired plants in the same regions. They also may be counting on more retirements. In the meantime, new plants will compete away some of the CF increase of existing gas plants.



Source: NREL

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Figure 10. Wind speed and solar resources in the United States. Source: National Renewable Energy Laboratory.

Table 1. Capacity factor assumptions, technical estimates, and historical data

	EIA (2018c)	Lazard (2018a)	Miller and Keith (2018)	EIA EPM
Onshore wind	43%	33%–55%	32.9%–43%	32.2%–34.6%
Utility-scale solar PV	33%	21%–34%	22.1%–27.5%	25.1%–25.9%

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Note: Lazard (2018a) range for solar is a mix of crystalline (minimum) and thin film (maximum) PV. Values from Miller and Keith (2018) represent mean and 90-percentile values corresponding to their power-density estimates. U.S. Energy Information Administration (EIA) Electric Power Monthly (EPM) is from https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b (accessed January 12, 2019).

significant regional variability. The 2017 net CF for wind projects built between 1998 and 2016 ranged from 18.3 percent in Tennessee to 43.8 percent in Nebraska (from the data file associated with Wiser and Bolinger, 2018).

The minimum values of Lazard (2018a) ranges agree with the mean values from Miller and Keith (2018), which suggests that Lazard ignores 50 percent of CFs that have been lower historically. In addition, the maximum values of Lazard are significantly larger than the 90-percentile estimates of Miller and Keith. Without a doubt, technological improvements (e.g., solar panel efficiencies) and operational improvements (e.g., better site selection and plant design to maximize power density and avoid curtailment) have been boosting average CF, especially for solar farms. But Lazard ranges ignore a large portion at the lower end of the distribution and emphasize the higher tail of the distribution. Miller and Keith (2018) also show wind CF improving at an average of 0.7 percent per year between 1998 and 2016, but their box-whisker plot (their fig. 4b) indicates that only in 2016 were there plants with a CF of 55 percent.

The use of a technical CF for wind and solar is inconsistent with the use of a historical CF for dispatchable plants and, given that these technical CFs tend to be higher than historical averages, their use unrealistically reduces the LCOE of wind and solar. Technological improvement may improve CF, but only incrementally unless there are advances in fundamental design or chemistry is enhanced. These improvements are also counteracted by other factors. For example, as shares of wind and solar increase, they are curtailed more regularly because of either transmission congestion or generation in excess of demand. Wiser and Bolinger (2018) estimate a 1 to 2 percent reduction in average wind CF since 2008. In addition, Miller and Keith (2018) show that wind power density, and thus CF, decreases with increasing plant size (area). Altogether, it is difficult to believe that the CFs of EIA (2018c) and the upper half of Lazard (2018a) ranges can be representative of most new facilities in the United States.

Ideally, LCOE calculations for all technologies should use technical CFs determined by engineering design. In locations with transmission constraints, an adjusted LCOE (with a lower CF) would be more accurate. Or, alternatively, LCOE with technical CF can be increased by the cost of transmission expansion that is necessary to connect the new resource. In systems where transmission costs are not uplifted to the whole system (i.e., socialized), these additional costs sometimes prevent project development, indicating the lack of competitiveness of those projects.

Wide Range of Levelized Cost of Electricity Estimates

Ranges of LCOE estimates from Lazard (2017, 2018a) and EIA (2018c) are summarized in figure 11. Based on a survey of the literature, I provide ranges that are typically larger than those from other sources because I use the most extreme U.S. values for each component of the LCOE formula from multiple sources. For many components, the extreme values are either from Rhodes and others (2017) or Lazard reports. These extremes represent feasible ranges given location-specific values for CF and all cost components. Some very expensive projects were built because of incentives. But, as the industry matures and subsidies are reduced or eliminated, investors will not build in locations with the high end of the LCOE range, although irrationally enthusiastic solar RPS programs in some northeastern states have for years led to REC prices of up to \$500–\$600/MWh. The low end of LCOE ranges is improbable because such low estimates reflect a perfect alignment of lowest capital and operating and financing costs, and, importantly, highest CFs.

Different assumptions regarding technology (e.g., thin-film versus crystalline silicon PV, single-axis tracking versus fixed-tilt, baseload use versus load following, including versus excluding storage, with or without carbon capture) also influence these estimates because they impact some of the components of the LCOE formula, such as capital and operating costs and CF values. Financing cost assumptions also can differ across sources.

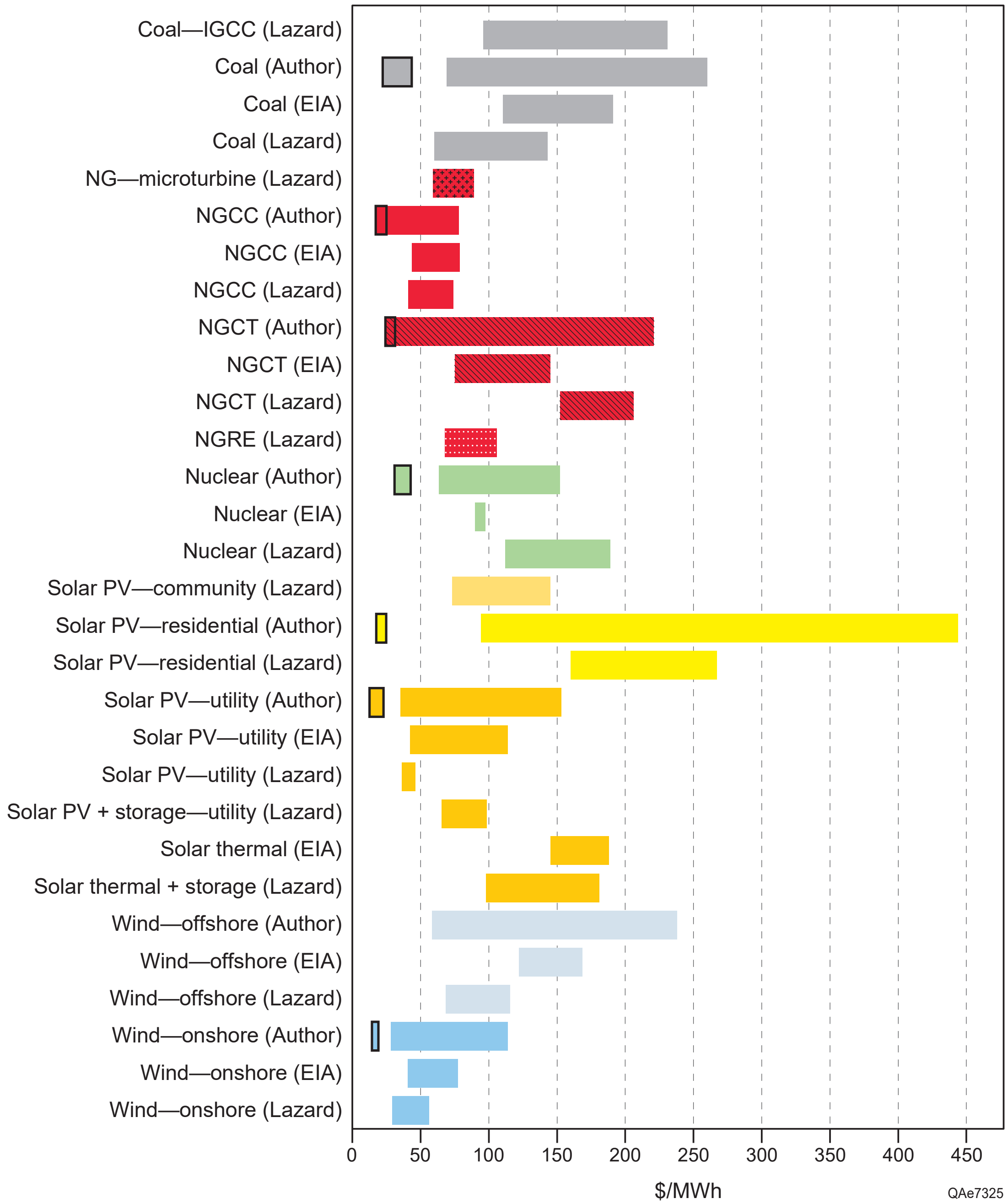

Figure 11. Wide range of recent LCOE estimates, excluding externalities, system-integration costs, and subsidies ($/MWh). Sources are Lazard (2017, 2018a), EIA (2018c), and author's survey of literature. Gas-peaking estimates from Lazard (2018a) are reported as natural gas combustion turbine (NGCT). Lazard (2017) provides $82/MWh as midpoint of solar photovoltaic (PV) + storage, which was transformed into a range via +/– 20 percent. Coal integrated gasification combined cycle (IGCC), natural gas (NG) microturbine, and natural gas reciprocating engine (NGRE) are from Lazard (2017). LCOE estimates for existing assets (outlined black) are by the author, except for nuclear from the NEI (2018).

Following are some of the key differences across the assumptions used in various studies:

Natural gas price is important for the LCOE of gas-burning generation plants. Lazard (2018a) assumes \$3.45/MMBtu, while I use \$2.33/MMBtu for the minimum estimate and \$5.00/MMBtu for the maximum estimate. Nationwide, the price of natural gas delivered to electric power plants has stayed mostly below \$3.8/MMBtu since 2012. In certain regions, such as near the Marcellus Shale play, natural gas prices have been lower. For example, in Pennsylvania, the price of natural gas delivered to power plants remained below \$2.70 and averaged \$1.83/MMBtu between April 2015 and November 2016, much lower than the national averages. Only in one scenario (low oil and gas resource and technology)—of the *Annual Energy Outlook* 2019—is the real price of natural gas at Henry Hub expected to surpass \$4.35/MMBtu by 2030 (EIA, 2019). In most scenarios, the price does not reach \$4/MMBtu until 2030.

Lazard (2018a) maximum CF for onshore wind (55 percent) and utility-scale PV (34 percent) are the highest CFs reported in the literature. As discussed earlier, such high CFs are historically unjustified as a national average. Going forward, with technology improvement, such CFs would still be limited to best resource locations without transmission congestion or overgeneration challenges. Maximums from Rhodes and others (2017) are 51 percent and 26 percent for onshore wind and utility-scale PV, respectively. Keeping all other assumptions, these differences lead to a more-than-\$2 increase in minimum LCOE for onshore wind and an \$8 increase in minimum LCOE for utility-scale PV.

Capacity factors for NGCC cover a wide range. The Lazard (2017) range is from 40 percent to 80 percent, but Lazard (2018a) uses 80 percent. Technical CFs for NGCC can be 80 percent or higher on a routine basis in a system where gas plants form the baseload and are not forced to cycle. EIA (2018c) has the range as high as 87 percent. However, in recent years, NGCC CFs fluctuated from low- to mid-40 percent during the winter trough and 65–70 percent during summer peak, indicating that NGCC plants do not serve baseload on a consistent basis. Although these numbers vary from region to region, the national average CF increased to about 56 percent in 2015 and 2016 as gas-fired generation replaced retired generation before falling back to about 51 percent in 2017, probably because of too much new gas capacity and low demand growth.

Weighted average cost of capital (WACC) assumptions vary significantly. Lazard (2018a) uses 9.6 percent (7.7 percent after tax) for all plants (60 percent debt at 8 percent interest rate and 40 percent equity at 12 percent). EIA (2018c) uses 8.5 percent (7 percent after tax, 4.5 percent real after tax) with some variations across technologies (60 percent debt at 6.7 percent interest rate and 40 percent equity at 11.2 percent, which is calculated based on the capital asset pricing model). I use a range from 5.5 percent to 9.6 percent, depending on plant type and minimum versus maximum estimates. The higher the WACC, the greater the LCOE increase for higher-capital-cost technologies. For example, if the WACC increases from 6.4 percent to 9.6 percent, keeping all else the same, the LCOE for NGCC will increase by 11 percent, while the LCOE for onshore wind will increase by 21 percent and the LCOE for utility PV will increase by 24 percent, given their higher capital intensity. Lazard (2018a, p. 5) provides a more detailed description of this sensitivity. This comparison highlights the importance of tax credits and other subsidies provided to wind and solar because they allow for more-attractive financing terms.

Existing Plants

Adding new resources to a power system has an impact on existing resources, especially if the new resources are subsidized. Some existing resources offer value to the system, often at lower cost since most of them are fully amortized. They are considered as part of the overall resource needs of an electric power system by grid operators and utilities that conduct integrated resource planning. As discussed in Part I in the "Resource Adequacy" section, many market-design changes around the country focus on full-cost compensation of all assets, including existing generation plants in energy and capacity markets, while accommodating the price-suppression impact of subsidized resources.

Boxes outlined black in figure 11 indicate how much it costs to produce from existing power plants. These LCOEs are much lower, which is expected because they exclude capital costs. Admittedly, this approach is simplistic because some existing plants are still paying their financing costs. Others may also need new capital spending to upgrade, to install environmental controls, or to fix structural issues. On the other hand, such plants might already have retired or will retire in the current environment of low wholesale prices and a pipeline of subsidized resources. As such, the existing plant LCOE is probably a fair representation of many plants in U.S. power systems, having fully amortized capital costs but still young enough to operate without additional capital spending.

These numbers are consistent with those of Lazard (2018a): \$24–\$31 and \$27–\$45 as the marginal costs of operating fully depreciated nuclear and coal facilities, respectively. In fact, the Lazard (2018a) range for existing nuclear facilities is less than the range in figure 11 (\$31–\$43). Existing nuclear units also have very low LCOE, despite operating costs increasing for many existing plants through the early 2010s before stabilizing (NEI, 2018). Many nuclear plants are retired or saved by state subsidies, which also suggests that their costs probably are not as low as LCOE estimates suggest. Finally, existing NGCC units have low LCOE depending on the price of natural gas being low. The average capacity-weighted age of the U.S. gas-fired power plants was 22 in 2016 according to EIA (2017). With the rejuvenation of the gas fleet continuing, the gas fleet will be younger, with more than 70 percent of the fleet built after 2000 by 2022.

Existing onshore wind and solar PV have the lowest LCOE, given the lack of fuel costs and low operating costs. Some wind farms are approaching the top end of the equipment warranty range (8–20 years), with attendant decline in CF and increase in O&M costs. Industry reporting suggests that most wind farms will require retrofitting to replace aging parts and to increase their CFs. The net impact of the new capital costs, reduced O&M, and improved CF is likely to be favorable in locations with better wind resources, where most retrofits are expected. In some cases, old wind farms can be fully replaced by new facilities at the same site, often with larger-capacity windmills. In other cases, the old facilities may be retired, especially in the absence of federal PTCs. There is less data on solar refurbishments because the large-scale facilities are very young. However, with wear and tear over time, solar panels lose efficiency and O&M costs increase. Similar to wind, some locations will be refurbished with newer panels (possibly using more-efficient technologies) while others may be decommissioned, especially in the absence of federal ITCs.[24]

NGCT plants require special attention. New NGCT plants have a wide LCOE range, mainly reflecting their utilization as load-following or peaking units. In fact, it is rare and increasingly unlikely that NGCT plants reach the 70 percent CF that allows for low-end LCOE estimates for new plants. Existing NGCT plants have very low LCOEs, even lower than the lowest LCOE estimates for new wind and solar plants. NGCT plants play an important role in electric power systems, providing the fast-start and ramping capabilities that are necessary for balancing demand and supply in real time. This role has become even more critical in many systems as the penetration of intermittent and variable wind and solar generation increased ramping needs, as discussed in Part I. Although system operators increasingly ask NGCC plants and coal plants to cycle to accommodate wind and solar, those units are not able to provide the same fast-start and ramping services. As a result, more NGCT plants will be needed in a system with growing renewables, regardless of the high LCOE of NGCT plants.

At the least, existing NGCT plants can offer a cheaper alternative under reasonable assumptions, as seen in figure 11, especially if price-formation reforms in many ISO/RTO regions allow for more transparent and fuller compensation of real-time costs of running these plants. An existing NGCT has an LCOE of less than \$75/MWh, even at \$4/MMBtu natural gas and 10 percent CF (roughly the average of the U.S. NGCT fleet in 2017 and 2018). For battery storage as peaker replacement in wholesale markets, Lazard (2018b) reports a cost range of \$257 to \$390/MWh (flow batteries) and \$204 to \$298 (lithium). Industry reporting suggests that combining batteries with utility-scale solar farms reduces the cost to below \$200/MWh or more in some cases. For a utility-scale solar PV plus storage-system cover, Lazard (2018b) estimates a range from \$108 to \$140/MWh, which is larger than the \$82 midpoint estimate in Lazard (2017).

These are evolving estimates because the number of such projects started to increase only recently. Some expect that with the expansion of battery storage, especially when combined with solar systems, dispersed wind and solar generation interconnected with a large transmission network will eliminate the need for new NGCT

24. We did not offer an existing plant LCOE for offshore wind because there is only one 30 MW U.S. offshore wind facility, which started operating in December 2016.

DEMAND SIDE: ANOTHER CHEAP EXISTING RESOURCE

Existing generation resources are often the lowest-cost suppliers of electricity. There are also demand-side resources that offer an opportunity to reduce energy costs, negative environmental impacts, and new capital investments if policies focus on energy efficiency and conservation via allowing consumers to see full costs of their energy consumption in real time.

EIA (2018b) reports that about half of the 28 percent of CO_2 reductions in the U.S. power sector since 2005 are due to demand growth lower than the historical average. The main driver of the flat demand since 2005 probably has been the loss of industrial demand. Energy efficiency and conservation are part of the reduction picture but likely trail the changing of industrial mix and increased self-generation. Nevertheless, the numbers demonstrate the potential on the demand side, a potential supported by various case studies of the American Council for an Energy-Efficient Economy.

Cook (2018) argues that, with the rapid expansion of "smart" technologies and the high comfort level of younger generations with them, the time may be ripe for much-larger-scale and price-driven incorporation of the demand side into the market via dynamic or time-of-use pricing. Yet, state regulators have not always approved utilities' requests to invest in advanced metering infrastructure (e.g., Walton, 2019c).

plants as early as the mid-2020s, at least in some regions (e.g., Merchant, 2017). However, such predictions have several challenges. Batteries have limited duration, and longer duration usually means higher cost. Batteries cannot be run continuously as long as needed, like NGCT or other thermal plants. But they can offer fast ramping and can be used to shave the peak, either the traditional afternoon peak or the new early evening peak due to penetration of solar PV. Denholm and Margolis (2018) show that in California, 4-hr storage can shave traditional afternoon peak demand by up to 3 GW without hitting diminishing returns to additional storage capacity. With solar PV, however, shifting peak to afternoon hours changes the conclusion. In fact, as solar penetration gets above 11 percent, load profile becomes peakier (in the evenings, this time). With 17 percent solar PV penetration in California expected for 2020, up to 7 GW of 4-hr storage capacity can be added. If California relaxes its 4-hr storage rule, batteries with shorter or longer duration can be used to shave different segments of the peak (e.g., Hohenstein, 2018). This fast-ramping, peak-shaving storage will displace generation from NGCT plants, forcing some to shut down and eliminating the need for new plants. Whether this scenario is feasible or desirable by 2025, aside from systems such as CAISO, is highly uncertain. Not many states have been implementing transitional energy policies as aggressively as California for such a long time.

EIA (2018b) reports about 620 MW and 800 MWh of large-scale, grid-connected battery storage power and energy capacity, respectively, in the continental United States. With the help of state mandates and economies of scale in manufacturing, 338 MW were installed in 2018. Wood Mackenzie Power & Renewables estimates order backlogs for about 660 MW in 2019, 1,700 MW in 2020, and more than 3,850 MW by 2023 (IEEFA, 2019). The growth rate is increasing.

However, scale matters. In comparison to storage capacity of about 1,200 MW at the end of 2018, there were about 1.1 million MW of installed net summer generation capacity of all types in the United States. Total generation from utility-scale facilities was more than 4 billion MWh in 2017 and roughly 4.2 billion in 2018.[25] Assuming that batteries can charge and discharge once a day and are all used for supplying electricity to the grid,[26] the 2017 large-scale battery fleet could have supplied about 292,000 (800 × 365) MWh a year, or 0.007 percent of annual consumption. Assuming all backlogged orders are built, more than 10,000 MWh of battery energy capacity may be online in 2024, accounting for 0.09 percent of total consumption, assuming the same technology and same annual electricity consumption. Admittedly, these are rough calculations but they demonstrate that scale matters. Although the dispatch from batteries is minuscule at the national level, it can be more impactful in California, where most of the new capacity is expected to be built.

25. All of these data are taken from EIA electricity pages: https://www.eia.gov/electricity/data.php.

26. Many existing batteries are typically not used to back up renewables but rather for grid services such as voltage regulation.

A more localized example exposes other challenges to replacing existing gas resources with battery storage. Consultants who advised the Los Angeles Department of Water and Power to rebuild three gas-fired plants suggested that to replace all three plants with clean energy, the city could need 1,800 MW of energy storage (almost double the installed nationwide capacity at the end of 2018) plus hundreds of miles of new transmission lines to import solar and wind power, possibly from outside California (Roth, 2018). Stakeholders in the ERCOT market continue to debate whether or not T&D utilities can build a storage facility, who can own such a facility, and how to treat inflows and outflows of electricity from it (e.g., Gheorghiu, 2018). In an energy-only market with tight margins, generators probably see storage by T&D utilities as another threat to their bottom line.

In early 2018, FERC Order 841 asked ISOs and RTOs to develop rules for energy storage participation in energy, capacity, and ancillary services markets. Responses filed in December 2018 varied significantly. The lack of a standard approach and reactions from market participants and other stakeholders might slow down the expansion of battery storage (e.g., Maloney, 2018). But states and utilities are not waiting for market solutions. State storage mandates encourage utilities to include storage in their IRP process. In states without a storage mandate but with a strong RPS, backing up renewables with storage is a strategy for some utilities. The solar–storage combination is particularly attractive because it works well for the grid and can take advantage of the federal ITCs available to solar projects. The IRP approach lowers market risk and enhances access to capital at lower cost, in the same way that PPAs signed by utilities improved renewables financing. IEEFA (2019) reports nearly 35 GW of utility-scale storage projects in the interconnection queues of system operators around the country. Roughly 25 GW of this queued capacity is in CAISO, with about 6 GW as solar–storage projects. Note that this storage capacity is much higher than 7 GW, with a 17 percent solar share estimate of Denholm and Margolis (2018). Being in the interconnection queue does not guarantee deployment at any particular time, but these numbers demonstrate the high level of interest in battery storage and also the potential for inefficient (unneeded or wrong duration) capacity expansion.

Mostly missing from the discussion about battery storage are the geopolitical and environmental ramifications along the supply chain of battery-minerals mining, processing, and manufacturing. In addition to electric power grid demand, there is increasing demand from the transportation sector for lithium-ion batteries for the manufacturing of electric vehicles. Demand for batteries has been growing much faster in the automotive sector than has grid storage. Although global resources are currently sufficient, supply chain and production bottlenecks exist. For example, the price of lithium tripled between 2015 and 2017. Similarly, the price of cobalt tripled between 2016 and 2018. For a variety of reasons, including the additional investment in mining, processing, and transportation capacity, prices have declined again by the time of writing (early 2019). The key point is that prices of lithium, cobalt, and other minerals critical for battery chemistries will be more volatile in the future, just like other energy and industrial commodities that are essential to the world economy.

China is duplicating its solar PV manufacturing strategy for battery manufacturing. The country already has the largest cobalt refining and lithium-ion battery manufacturing capacities in the world, importing almost all of the cobalt from the Democratic Republic of the Congo (DRC), which is home to 60–65 percent of global mine production. Rising prices and geopolitical concerns around the DRC and China have been encouraging changes in battery chemistry. Unless researchers succeed in replacing cobalt without loss of battery performance and/or mining and refining capacities increase outside the DRC and China, these concentrations could create disruptions along the supply chain of cobalt and batteries. Geopolitical and environmental impacts of these mining operations and manufacturing strategies will become more visible as the battery industry grows. For example, the two key ingredients in today's favorite battery chemistry, lithium and cobalt, also exist in coal ash, which is a major concern for communities near coal plants. Recycling depleted batteries can become an environmental hazard if not managed well. There are similar concerns for other minerals. For example, MIT (2015) finds that increasing solar PV penetration beyond 5 percent of world electricity would require unprecedented growth in supply of certain minerals such as tellurium, indium, and gallium. O'Sullivan and others (2017) consider the dependence on new minerals a potential "new" resource curse, especially if critical mineral resources are concentrated, as in the situation with cobalt.

A More Complete Levelized Cost of Electricity

The LCOE ranges in figure 11 represent only the costs of building and operating power plants. They do not capture system-integration costs, which are particularly significant for wind and solar because their lowest LCOEs can be realized in only the best resource locations without transmission constraints, and because they are intermittent and variable. These LCOEs also ignore the cost of externalities, avoidance of which is one of the main reasons for pursuing clean generation from wind and solar resources. To render the LCOE broader and more useful to discussions on costs and benefits of various policies, these costs should be added to the base LCOE.

The extremes of the ranges in figure 11 are unlikely to persist as technologies and developers mature. Rationally, one should expect the policies and capital allocation to focus on locations that are most attractive, especially in the absence of tax credits and other incentives. In the short-term, lowest-cost locations are likely to be pursued. As these are depleted, developers may move up the cost curve to locations with lower-quality resources. By that time, technological improvements may reduce the cost of equipment per unit of output, and/or economies of scale and experience may reduce building costs.

Carrying forward a range of estimates for the rest of this analysis is difficult. It is unnecessary to include technologies that are deemed expensive by most studies and/or that have achieved marginal penetration, if any. However, I also exclude NGCT plants, which, per earlier discussion, remain best positioned to provide balancing and fast-ramping services that are in rising demand as intermittent and variable resource penetration increases. Instead, I use point estimates, mostly average LCOEs from Lazard (2017, 2018a) and EIA (2018c), as reported in table 2. Given the discussion on CF assumptions, I added alternative onshore wind and utility-scale estimates based on mean CFs from Miller and Keith (2018). **As I will remind regularly, however, readers must always remember that (1) these point estimates cannot be taken as universally applicable, (2) regional differences can alter the ranking of least-cost technologies, and (3) an IRP approach ignores LCOE.**

Externalities

Economists consider the impact of market transactions on third parties that are not reflected in the price of the good or service exchanged as *externalities,* which can be positive or negative and come from either production or consumption of the said good or service. For decades in the power sector, the focus has been on negative externalities associated with the production of electricity, e.g., emissions of particulate matter (PM), mercury, sulfur dioxide (SO_2), nitrous oxides (NO_X), pollution of nearby water resources or land resources, and the disturbance of the ecology. Since the 1970s, some, but not all, of these issues have been addressed with federal and local legislation. In recent years, greenhouse gases such as carbon dioxide (CO_2) and methane (CH_4) have attracted more attention because of climate change concerns.

Traditional energy sectors dependent on oil, natural gas, coal, and nuclear have been fueling the world economy not only as providers of energy but also, and equally importantly, as feedstock to manufacture almost everything each of us uses to improve our standard of living. As such, their supply chains represent an infrastructure complex that is orders of magnitude larger than that of the still-emerging renewables industry despite its remarkable growth in the recent decade. Thus, not surprisingly, carbon-intensive fuels and materials that are omnipresent in our lives account for more negative externalities and attract more attention. Coal burning causes more pollution because it is the most carbon-intensive fuel, is solid, and contains other harmful elements such as mercury. Methane is the cleanest fossil fuel because it has only one carbon atom, is gas, and combined-cycle technology can generate more megawatt hours per unit of fuel.

Although free of emissions during electricity generation, renewables also have environmental impacts on water (e.g., solar thermal facilities using water), land (e.g., utility-scale PV having a larger footprint per megawatt than conventional energy technologies), and species (e.g., avian, desert, coastal, or offshore ecology). As renewables scale up to the capacity levels necessary to replace conventional generation technologies, these impacts will necessarily become more visible. In many areas with large renewables development, we already observe local opposition similar

Table 2. Representative levelized costs of electricity (LCOEs)

Plant Type	LCOE	Source	Comments
Coal CCS—30%	$130	EIA (2018c)	Simple average. EIA estimates range from $117 to $191. EIA assumes a 3% increase in cost of capital to represent risk associated with higher emissions.
Coal CCS—90%	$119	EIA (2018c)	Simple average. Less than $143, high end of Lazard (2017) range, which incorporates 90% CCS. EIA estimates range from $111 to $140.
Coal	$60	Lazard (2018a)	Low end of range, conventional: "Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal."
Coal (existing)	$44	Author	High end of existing-plant range in figure 11. Lazard (2018a) offers range of $27 to $45.
NGCC	$49	EIA (2018c)	Simple average. Closer to lower end of Lazard (2018a) range of $41 to $74 but very close to author's average of $52.
NGCC (existing)	$33	Author	High end of existing-plant range in figure 11. Low end is $17. Low end of new NGCC is $25.
Nuclear	$93	EIA (2018c)	Simple average. Lower than Lazard (2018a) range of $112–$189. Lowest capital cost in Lazard (2018a) is $6,500 versus $5,946 in EIA (2018c). Author's range is $63 to $152.
Nuclear (existing)	$34	NEI (2018)	U.S. average for existing nuclear fleet in 2017. Lazard (2018a) offers range of $24 to $31.
Solar PV—utility	$41	Lazard (2018a)	Midpoint of total range of thin film and crystalline ($36 to $46). Lower than EIA (2018c) average of $63 but higher than EIA (2018c) minimum of $42. Author's range is $35 to $153. Miller and Keith (2018) 90-percentile CF of 27.5 percent yields $44, keeping all other Lazard minimum assumptions the same.
Solar PV—utility (alternative)	$55	Author	Using minimum capital and FOM cost assumptions from Lazard (2018a) and mean CF of 22.1 percent from Miller and Keith (2018).
Solar PV + storage—utility	$82	Lazard (2017)	Midpoint. No range is provided. No EIA (2018c) estimates. Within the EIA (2018c) range.
Wind—onshore	$41	Lazard (2018a)	Midpoint of range, which is lower than EIA (2018c) average of $59 but same as EIA (2018c) minimum. Author's range is $28 to $114. Miller and Keith (2018) 90-percentile CF of 43 percent yields $38, keeping all other Lazard minimum assumptions the same.
Wind—onshore (alternative)	$49	Author	Using minimum capital and FOM cost assumptions from Lazard (2018a) and mean CF of 32.9 percent from Miller and Keith (2018).
Wind—offshore	$92	Lazard (2018a)	Midpoint. No range is provided. EIA (2018c) range is $122 to $169 with a simple average of $138. Author's range is $58 to $238. Roughly midpoint of the EIA (2018c) range.

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Note: Unadjusted for externalities, system-integration costs, or subsidies. All values are rounded up or down to avoid decimals. CCS = carbon capture and sequestration; CF = capacity factor; FOM = fixed operating and maintenance; NGCC = natural gas combined cycle; PV = photovoltaic.

to that against development of conventional energy projects, including electric power transmission lines.[27] Such local opposition, known as *not-in-my-backyard* (NIMBY), is a growing problem for modern societies. As they scale up, renewables will not be immune from NIMBY impacts, such as legal costs and project delays or cancellations.

All fuels and technologies also have environmental footprints along their supply chains: drilling for oil and

27. The most notorious example of local opposition to a renewables project is probably the Cape Wind offshore wind farm that, after 16 years of arguments, was canceled because of opposition from "wealthy property owners like the Kennedys, Mr. Koch, and Rachel Lambert Mellon" and economic concerns of many local officials, businesses, residents, Indian tribes, and environmental activists because of the high cost of offshore wind power or impact on the local environment (e.g., Seelye, 2017). Similar groups, including some national environmental NGOs, objected to solar farms in Joshua Tree National Park and Mojave National Preserve, offshore wind farms along the Texas Gulf Coast, wind or solar facilities in New York City, and many more.

POSITIVE EXTERNALITIES

Positive externalities associated with electricity include increased productivity, easier access to more education, and better health. These benefits are mostly visible in regions of the world that have recently gained access to reliable and affordable electricity, but they exist in modern economies, as well—albeit mostly taken for granted unless a major event, such as the 2003 blackout in the northeastern United States, exposes our dependency on reliable electricity service. Other positive externalities can include energy security and the development of local economies via domestic manufacturing. They are often key drivers of RPS policies and tax incentives, but these subsidies confound benefit–cost accounting because they represent "internal"costs to the society itself.

gas; mining for coal or mineral inputs of solar panels, windmill equipment, and batteries; transporting fuels; manufacturing and transporting wind, solar, and battery equipment; disposing waste from these supply chains; disassembling or recycling at end life; and so on. For example, Alvarez and others (2018) report methane emissions from the natural gas supply chain (oil and gas production, processing, and transport) equivalent to 2.3 percent of total U.S. production. Such detailed analyses are needed for all environmental impacts of all supply chains, from mining operations to final consumers.

Within the electricity sector, generation of electricity accounts for the majority of emissions costs. Other activities in the electricity cycle also emit pollutants, albeit less significant once distributed across a lifetime of generation. Based on a literature review, Mai and others (2012) report some average estimates for one-time GHG emissions for all technologies. Upstream activities include "raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, and on-site construction." Downstream activities include "project decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the equipment and other site materials." There are also ongoing noncombustion emissions such as fuel-cycle and other O&M activities.

For one-time upstream GHG emissions, solar is most intensive, with 1,630 kg of CO_2-equivalent (eq) per kilowatt for PV panels (2,970 kg for solar thermal) versus 315 kg for old coal, 257 kg for new coal, 160 kg for NGCC, 350 kg for nuclear, and 619 kg for onshore wind. For one-time downstream, solar thermal is most intensive, with 239 kg of CO_2-eq per kilowatt. But there are only a small number of these facilities. Nuclear, with 175 kg, is the second-most intensive, because of the wide scope of the nuclear decommissioning process. Solar PV follows with 38 kg.[28] Noncombustion emissions during the lifetime of assets are very small. Since there are no GHG emissions during power generation from wind and solar facilities, over the lifetime of these plants, per-megawatt-hour GHG emissions are very small. Nevertheless, scaling up the capacity would induce significant increases in one-time upstream and downstream emissions.[29]

Electricity markets do not automatically price externalities, either negative or positive (see "Positive Externalities" sidebar). But economic theory suggests that competition would lead to efficiency and innovation if we internalize external costs and benefits. For example, economists are almost unanimous that taxing GHG emissions across the economy rather than targeting any particular industry is the most efficient solution to addressing the climate change challenge. As discussed in Part I, this approach has been successfully used before in reducing the impact of environmental externalities such as sulfur dioxide.

In the absence of internalizing externalities via a Pigouvian tax (balancing negative and positive externalities via benefit–cost analyses) or a comparable cap-and-trade approach, concerned parties currently pursue policies to support alternatives such as renewables subsidies and mandates, subsidized energy-efficiency programs, or mandates for technology-du-jour (lithium-ion battery storage at the time of writing). According to the Clean Energy Technology Center at North Carolina State University, several thousand such support programs exist across the United States. As discussed in Part I,

28. See Mai et al., 2012, appendix C and table C-1 for details on these emissions estimates.

29. For example, given the differences in CFs (say 51 percent NGCC, 2017 average for the U.S. fleet, versus 25.5 percent for solar PV, mean from Miller and Keith, 2018), replacing 1 kW of NGCC with 1 kW of solar PV would lead to about 20 times larger upstream GHG emissions (1630/160)*(51/25.5).

there is strong evidence that these options are costlier than market-based approaches. It is thus important that a more useful LCOE captures negative and positive externalities. Given the paucity of estimates on positive and many negative externalities, the current analysis is limited to air emissions. But one must acknowledge that a more complete assessment of externalities is a highly desirable future area of work.

Cost of Emissions

Cost of emissions can be calculated on a per-megawatt-hour basis and added to conventional LCOE estimates. I adopt the approach of Rhodes and others (2017), who capture the externalities associated with air emissions on a regional basis:[30]

$$LCOE = \frac{CRF * capital + FOM}{8760 \times CF} + VOM + HR \times fuel\ price$$
$$+ \sum_{j \in \theta} R_j \times D_j + E_{GHG,\ one\text{-}time} \times D_{GHG,\ one\text{-}time} + R_{GHG,\ NC,\ ongoing} \times D_{j,\ CO_2}$$

Where R_j is the rate of emission in tonnes per megawatt-hour, NC is noncombustion, E is the total one-time emissions from upstream and downstream, and D_j is the economic value of the damage caused by emission measured in dollars per tonne (t).

The literature widely discusses potential net economic damages of non-GHG emissions such as PM, SO_2, NO_X, and mercury to human health and the environment. Such estimates were used since the 1970s to legislate the Clean Air Act and its amendments and to develop associated regulatory or market structures. Although these estimates on damages of air emissions are peer tested, it is important to note that there is no consensus on some of the assumptions used in calculating externality costs (e.g., discount rates, value of human life at different ages or locations).

The literature on the social cost of carbon (SCC) calculations is more recent. The SCC, like cost estimates of other emissions, is an economic metric of net damages, i.e., "monetized value of the net impacts, both negative and positive" as defined in National Academies of Sciences, Engineering, and Medicine (2017), a report of the Committee on Assessing Approaches to Updating Social Cost of Carbon. See the summary of the report's recommendations in the "Social Cost of Carbon Estimates" sidebar to appreciate the complexity of the modeling exercise and the wide room for disagreement on the assumptions, especially the discount rate.

Using new versions of the integrated assessment models (IAMs) reviewed in National Academies of Sciences, Engineering, and Medicine (2017), the EPA provided SCC calculations for different asset lifetimes and discount rates and for upstream, downstream, and ongoing operations. There have been several updates, probably following some of the recommendations of the National Academies' report. Table 3 of Rhodes and others (2017) indicates that the 2013 EPA SCC estimates range from \$14 to \$129/t in addition to reporting a range of \$1,034 to \$2,562/t for methane emissions in CO_2-equivalent terms, based on the work of Marten and Newbold (2012).

Others offer their own estimates of SCC or an appropriate GHG emissions tax based on their assumptions and models. The Climate Leadership Council, a new international policy institute, suggests starting with a GHG emissions tax of \$40/t.[31] Others argue that European GHG prices need to be higher in order to make emissions-trading permits more valuable, thus encouraging investment in emissions-reducing projects, referencing \$30/t from an International Monetary Fund (IMF) staff paper.[32] The IMF (2016), issued after the 21st Conference of the Parties in Paris (COP 21, December 2015), notes that \$30/t is a 2010 EIA modeling estimate of cost to achieve a 10 percent reduction in emissions but that \$50/t may be required for countries to reach Paris targets of roughly 56 Gt by 2030 (UN, 2015, p. 9). The IMF (2016, p. 19) further notes that \$60/t could be a more effective price for emissions reductions to meet 2030 targets based on current modeling.

In the current analysis, I avoid these discrepancies and use \$20/t, \$62/t, and \$88/t, which correspond to 5 percent, 3 percent, and 2.5 percent discounting, respectively, of damages in future years for a plant life of

30. For example, the severity of local emissions is not the same in urban versus rural areas, or in industrialized versus less-industrialized regions. Although the cost estimates are dynamic numbers in that costs presumably decline as the emissions of a particular pollutant decline, the calculations do not use different costs for different years of a generation asset's life. This is an area worth exploring in future research.

31. https://www.clcouncil.org/.

32. https://www.bloomberg.com/view/articles/2017-02-20/europe-needs-a-higher-price-on-carbon.

SOCIAL COST OF CARBON ESTIMATES: TO DISCOUNT OR NOT TO DISCOUNT

The Interagency Working Group on the Social Cost of Greenhouse Gases asked the Committee on Assessing Approaches to Updating Social Cost of Carbon to examine integrated assessment models (IAMs) used by the Working Group. The Committee suggested "near-term improvements" and "long-term recommendations for comprehensive updates…to improve the scientific basis, characterization of uncertainty, and transparency of the [SCC] estimation framework within the federal regulatory context." It also recommended a modular approach with socioeconomic, climate, damages, and discounting modules, each reflecting the current state of knowledge updated every 5 years to capture evolving understanding of the science and economics of climate change.

Specifically, near-term changes include (1) using statistical methods and expert judgment for projecting distributions of economic activity, population growth, and emissions into the future; (2) using a simple Earth system model that captures CO_2 emissions, concentrations, temperature changes, and sea-level rise; and (3) improving formulations of climate change damages, making calibrations transparent based on recent empirical estimation and process-based modeling of damages.

The fourth near-term recommendation, on discounting, deserves more attention. Discounting is indeed central to estimating damages from all environmental externalities. For decades, regulatory processes and environmental impact assessments across many industries used discount rate guidance (of 3 and 7 percent) from the U.S. Office of Management and Budget. Chapter 6 of the Committee report provides a detailed discussion of the use of discount rate in IAMs. Stern (2006), a study by Sir Nicholas Stern on economic effects of climate change, showcases the centrality of this assumption. He assumes a very low discount rate (1.4 percent), which leads to higher present value of estimated future costs. Weitzman (2007), while agreeing with Stern's sense of urgency, argues that his discount rate is based on time preference and marginal utility assumptions that "are more like theoretically reasoned extreme lower bounds than empirically plausible estimates of representative tastes." Tol and Yohe (2006), Mendelsohn (2007), and Nordhaus (2007) are among the other studies that critique the discount rate assumption of the Stern review. The debate on the appropriate discount rate to use for calculating climate change damages over the next century continues.

35 years. These cover the GHG prices discussed so far. GHG prices in existing cap-and-trade systems have been mostly lower than any of these estimates. The European emissions allowances fluctuated around $15 in 2009 and 2010, $5–$10 between then and 2018, but surpassed $20 during the last quarter of 2018 and were close to $25 in early 2019. Prices have been much lower on this side of the Atlantic: $3–$8 with the Regional Greenhouse Gas Initiative in the U.S. Northeast and $12–$13 in California.

With the addition of emissions costs, existing nuclear facilities and renewables look more competitive (fig. 12). As discussed in Part I, ZECs or similar subsidies offered to nuclear facilities by several states range from $10 to $20/MWh. Adding to the $34/MWh average operating cost of an existing U.S. nuclear plant still makes those facilities cheaper or equivalent to new onshore wind or utility-scale solar builds when using the alternative estimates (i.e., based on mean CFs from Miller and Keith, 2018). Otherwise, new onshore wind and utility-scale PV are cheaper than subsidized nuclear. At certain locations, such as the Marcellus region, an existing NGCC can beat a subsidized nuclear plant as long as GHG emissions tax is less than $20/t.

Based on alternative estimates, new onshore wind and utility-scale PV can compete with an existing NGCC as long as there is a GHG emissions tax of about $17–$20/t. The ones based on relatively high-end CF estimates are cheaper than an NGCC even at a GHG emissions tax as little as $5/t. It is important to keep in mind that locations yielding those high CFs for wind and solar are limited to certain regions and may not overlap with where conventional facilities are or may be located.

System-Integration Costs

Intermittent and variable resources such as wind and solar impose costs on electricity systems. Some—such as those added to power systems via subsidies or mandates, or those located far away from load centers without ready access to the transmission grid—impose higher costs. Many of these costs are not visible to consumers except as additional charges on their electricity bills because they are often socialized, i.e., uplifted to the power system rather than being charged to responsible parties following the cost-causation principle. However, as the penetration of wind and solar increase, these costs increase and attract more attention. The literature on system-integration costs has been growing accordingly.

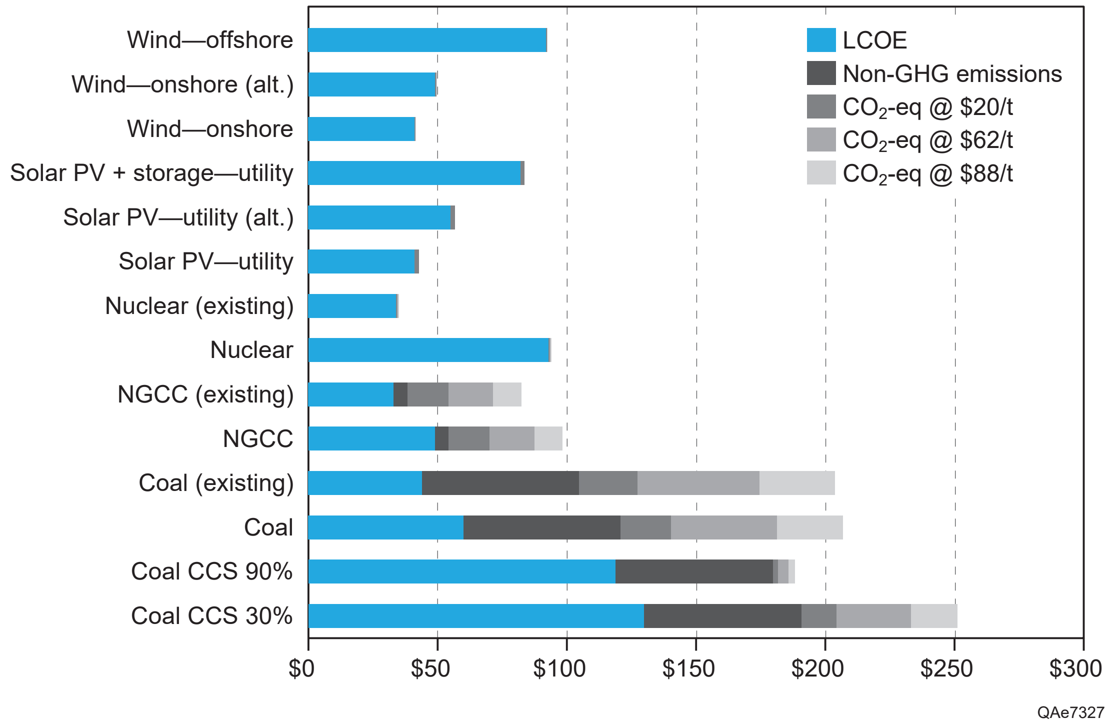

Figure 12. Representative U.S. LCOE, including air emissions ($/MWh). Excludes negative externalities associated with water, land, and ecological impacts; system-integration costs; subsidies; and positive externalities. These comparisons should not be extrapolated to any project in any location. They are only valid for "average" U.S. locations where it is feasible to build any of these plants. LCOE is a high-level policy discussion tool. Developers do not use LCOE for investment decisions, and it is not recommended for the market-IRP. CCS = carbon capture and sequestration; NGCC = natural gas combined cycle; PV = photovoltaic.

Figure 13 duplicates figure 56 of Wiser and Bolinger (2018) to demonstrate the range of aggregate wind system-integration cost estimates for various U.S. systems. The chart captures cost estimates from about 30 studies. The definitions of system-integration costs and methodologies are not identical across the studies, but most studies typically include costs associated with balancing and backup reserves as system-integration costs. **Importantly, they do not include costs of incremental transmission or curtailment.** Overall, costs tend to increase with penetration levels and can be as low as $1/MWh or as high as $19/MWh. Generally speaking, they are lower in larger balancing areas for the same level of penetration, but there are many other system characteristics that play a role (e.g., shape of load profile and mix of generation technologies).

Balancing and backup costs have received the most attention in the industry because they represent immediate operational, reliability, and market changes that need to be addressed. Some studies (e.g., NREL, 2011) have used a version of the following working definition: Integration costs include those incremental costs incurred in the operational time frames that can be attributed to the variability and uncertainty introduced by generation.[33] Some of these issues are discussed in Part I, "Electricity Grid and Market: A Precise Balancing Act." System operators developed new procedures, developed new ancillary services, or otherwise compensated market participants providing balancing and other services. Regulators approved these new schemes in addition to mandating or approving expansion of T&D infrastructure to accommodate renewables, with their costs passed on to the customer bills.

Other economic costs caused by penetration of larger amounts of subsidized, low-dispatch-cost, intermittent, and variable resources are becoming more visible. For the purposes of augmenting the LCOE, I follow the mathematical definition of Ueckerdt and others (2013), who

33. Calculating integration costs using this working definition typically involves running chronological production simulations for an extended period of time, typically for one to multiple years.

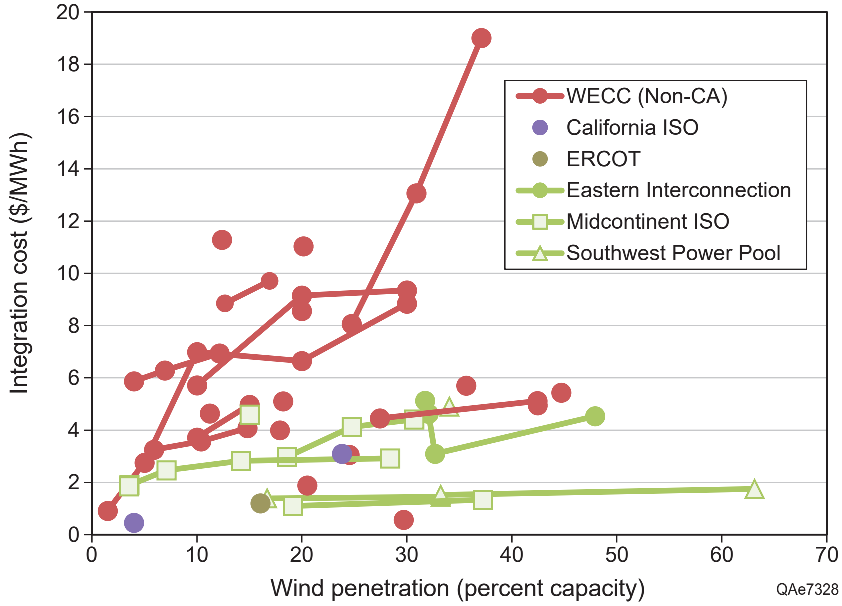

Figure 13. Wind integration costs at various penetration levels for various U.S. systems. Source: Wiser and Bolinger (2018), figure 56.

use their estimates to calculate a "system LCOE" with the following five main categories of integration costs:[34]

- **Balancing costs** are associated with additional reserve capacity with faster ramping capability that the system operator needs for real-time balancing to accommodate uncertain variability of wind and solar.
- **Grid costs** represent new T&D investment to accommodate remote renewable resources and the cost of managing increased congestion caused by the addition of renewables.
- **Adequacy, or backup, costs** are the costs of dispatchable, conventional plants or storage that have to be available to compensate for the intermittency of wind and solar.
- **"Full-load hour reduction" costs** capture the stranded costs incurred by existing generators as a result of subsidized renewables reducing their revenues because they lower generation from mostly intermediate and baseload plants. At higher penetration, renewables also reduce prices and revenues for other plants, including their own.
- **"Overproduction" costs** refer to curtailed wind and solar because their generation exceeds load. This curtailment can be enhanced spatially if resources are located behind transmission constraints.

Ueckerdt and others (2013) call the first three cost categories "standard" integration costs but enhance the analysis by also considering "economic costs of variability." They generalize adequacy costs (calling them "backup" costs) by adding what they call "full-load hour reduction" and "overproduction" costs. The new aggregate is called "profile costs" in reference to intermittent generation profiles of wind and solar. As Ueckerdt and others (2013, p. 65) put it, renewables "contribute energy while hardly reducing the need for total generation capacity in the power. Thus, the average utilization of dispatchable power plants is reduced, which leads to inefficient redundancy in the system." They illustrate these costs by the shift from load duration to net load duration curve caused by intermittent renewables. Their figure 4 is an idealized version of the load and net load curve comparison of figure 2 in Part I, which is based on actual ERCOT data.

Essentially, the two new cost items are negative externalities incurred by some market participants and/or

34. Other costs that do not neatly fit into these five categories may be included, but cost estimates are limited and contentious. For instance, increasing cycling by thermal units would reduce overall efficiency, cause additional wear and tear on equipment, and increase emissions. There are also concerns about the inability of wind to provide system inertia, which might be captured in balancing costs in some studies. Neither cost appears to be significant according to Heptonstall and others (2017).

society in general. The cost of these externalities has not been internalized in system operations, but some market design and other changes are under discussion to address this issue, as covered in Part I under "Resource Adequacy." No doubt that cheap natural gas from the shale revolution played a role in undermining nonsubsidized generators' commerciality. But the impact of lower natural gas prices was magnified by the deficiencies in market designs since their early days and the increasing penetration of out-of-market resources. Supporting renewables was, at least partially, caused by another market (or rather policy) failure, i.e., the absence of market prices that reflected the cost of environmental externalities.

Regardless of what confluence of factors brought the industry to its current disarray, we must better understand the overall costs to compare them with benefits of the energy transition. Many argue for significantly larger investments in this transition, within a faster time frame than in the past (e.g., ACORE, 2018). In the following sections, I provide a brief summary of cost estimates for each of the five categories of system-integration costs. Many references are from other surveys, such as Hirth and others (2015) and Heptonstall and others (2017), since I do not intend this as a critical review of assumptions or methodologies in various studies. The goal is to obtain a range for the total system-integration costs to augment the LCOE metric and highlight cost importance for policy discussions.

Balancing Costs

As discussed in "Electricity Grid and Market: A Precise Balancing Act" in Part I, intermittency and variability of wind and solar cause several distortions in power systems and markets, such as increasing ramping needs (larger net load ramps), having low inertia, and changing real-time needs to supply the load because of forecasting errors. For the most part, system operators have been able to manage these renewables adoption issues using new or modified ancillary services that are mostly priced in the market. Some generators helping to balance the system are compensated via out-of-market compensation, which FERC and system operators have tried to internalize via market design changes.

There have been significant improvements in day-ahead or hour-ahead forecasts of renewable generation because of the increasing amount of historical data and enhancements in forecasting techniques. However, the ERCOT and MISO (2018) examples covered in Part I demonstrate that, despite improvements in forecasting, errors that can amount to thousands of megawatts still exist and will increase at higher penetration levels. Geographic diversity of wind and solar reduces system-wide intermittency but requires additional investment in long-distance transmission lines to connect remote wind or solar farms with sufficiently different availability throughout the day. Cost causality indicates that these new transmission investments are system costs that can be assigned to renewables that would not have been built or dispatched fully in their absence (see the next section, "Grid Costs").

Variability can be a bigger challenge than intermittency for real-time operations. Variability of wind and solar generation can be predictable in terms of cycles throughout a day and across seasons, but meteorological conditions (e.g., clouds, storms) as well as technical difficulties (e.g., equipment malfunction) can cause unpredictable variability in very short time frames. This uncertainty can be more challenging and costlier than intermittency to accommodate in the grid.

Early literature on system-integration costs focused on balancing costs, making it probably the most extensively studied among all costs of system integration. Overall, balancing costs are found to be relatively small when the renewables penetration level is low (e.g., less than 5 percent of total annual generation). Costs can become more significant at higher penetration levels but are still less than $5/MWh in most regions (table 3). These regional differences often reflect the existing generation mix and load profile of the system analyzed, but methodologies used to estimate these costs also can influence the cost estimates.

Grid Costs

Often new transmission investment is necessary to accommodate wind and solar from best locations far away from load centers and the main grid. Weiss and others (2019) estimate that $3–$6 billion incremental transmission investment between 2018 and 2030, and $6–$10 billion between 2031 and 2050, will be needed for renewable integration, depending on the electrification scenario.

If renewables enhance grid congestion or cause frequency fluctuations, grid management costs might increase, as well. Slow load growth in some regions,

Table 3. Sample studies on balancing costs

Reference	Method	Technology	Penetration level	$/MWh
NEA (2018)	Literature survey	Wind	10%	$2.00
		Wind	30%	$6.00
		Utility PV	10%	$0.50
		Utility PV	30%	$1.00
Wu and others (2015)	Production-cost and dispatch simulation	Utility PV	17%	$1.00 to $4.40
Baker and others (2013)	Review of studies	Utility PV	10%	$5.00
			20%	$20.00
Mills and others (2013)	Production-cost and dispatch simulation	Utility PV	18% of peak load	$1.88
			32.5% of peak load	$3.77
Nieuwenhout and Brand (2011)	APX–ENDEX market data	Wind	4%	$0.66
NREL (2011)	Production-simulation model	Wind—onshore	20%	$5.13
		Wind—offshore	20%	$3.10
		Wind—on- and offshore	30%	$4.54
Meibom and others (2009)	Custom model for Nordic wind integration	Wind	20%	$3.00 in Germany $2.20 in Denmark

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Note: Penetration level as share of total annual generation unless otherwise noted. PV = photovoltaic.

sometimes exacerbated by expansion of DER such as rooftop solar, could have unintended consequences in terms of overall demand–supply balance (e.g., overexpansion of central generation and/or transmission capacity). A challenge is that DER expansion is somewhat invisible to system operators and other market participants because these facilities are at a customer site (known as behind-the-meter) and do not need to follow grid procedures such as interconnection assessment. Although each DER facility is very small relative to the size of the generation portfolio across the grid, DER capacity can reach significant levels in aggregate.

In many systems, costs of new transmission lines are uplifted to the system and reflected on customer bills as additional T&D charges. This phenomenon partially explains why retail costs per unit of electricity have been increasing despite falling wholesale electricity prices (fig. 14). The post-2008 divergence between average wholesale electricity price and average retail prices paid by different customer classes is striking, especially for residential and commercial customers.[35] Retail prices include T&D costs and, in some regions, retail provider charges and/or renewables charges in addition to energy costs (i.e., the wholesale price of electricity). Although retail prices were rising throughout the 2000s, the gap between retail and wholesale prices was mostly stable. In fact, industrial users could mostly get electricity service at the wholesale price. Since 2009, the gap started to increase, especially for residential and commercial customers.

Among the reasons for this divergence are increases in fixed charges for new T&D infrastructure (e.g., new transmission lines, distribution-system upgrades such as smart meters) and increased costs of grid management. Since 2001, T&D capital and operating expenses have significantly increased relative to changes in retail and wholesale prices over the same time period (fig. 15). Drivers of T&D investment include the following: replacement or upgrading of the aging infrastructure, enhancement of system resiliency, compliance with evolving grid reliability and security standards, and integration of utility-scale and distributed renewables (e.g., EIA, 2018d).

35. The retail prices are lower-48-states averages that include both restructured markets and regulated regions; the average wholesale price reflects eight competitive markets based on financial contracts traded at the Intercontinental Exchange. Average prices followed similar patterns in regulated regions, too. The average wholesale price follows the price of natural gas, which was high and volatile throughout the 2000s. With the collapse of natural gas price, the wholesale electricity price also fell. Low-cost renewables further suppressed prices where they increased their market share.

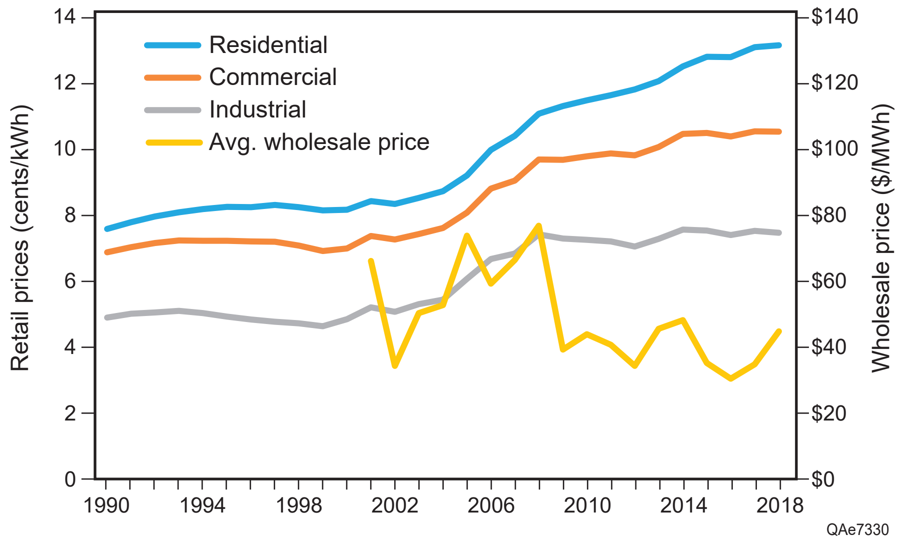

Figure 14. U.S. average retail electricity prices (cents/kWh) and wholesale electricity price ($/MWh). Lower-48-states retail prices are from EIA Form-861 annual survey data, available at https://www.eia.gov/electricity/data.php#sales. Data from 2018 are calculated from monthly data through November 2018 for all 50 states to match the historical relationship with annual data. Average wholesale price is the average daily price of eight contracts traded at the Intercontinental Exchange (ERCOT North 345KV Peak, Indiana Hub RT Peak, Mid C Peak, Nepool MH DA LMP Peak, NP15 EZ Gen DA LMP Peak, Palo Verde Peak, PJM WH Real Time Peak, SP15 EZ Gen DA LMP Peak) and reported by the EIA (https://www.eia.gov/electricity/wholesale/).

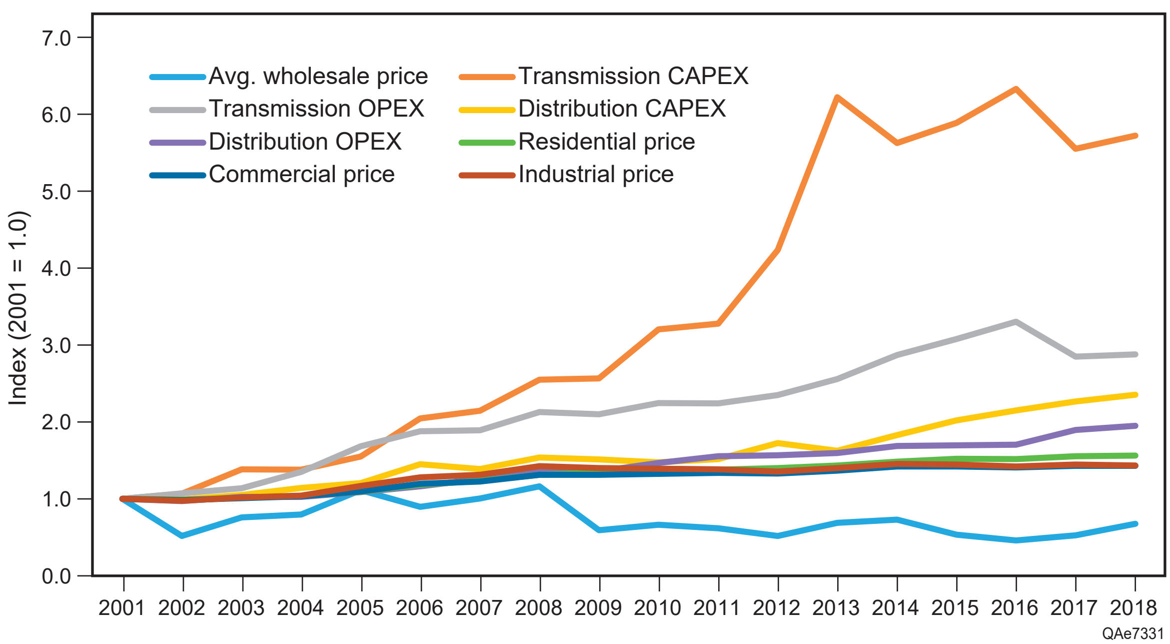

Figure 15. Index of retail prices, wholesale price, and transmission and distribution (T&D) capital and operation expenses (2001 = 1.0). Retail and average wholesale prices are the same as those depicted in figure 14. Capital and operating costs (CAPEX and OPEX) for T&D segments are based on data reported to FERC by utilities in Form 1 (same as data used in EIA [2018d]) but expanded to include estimated investment by utilities not reporting to FERC via Form 1. Years 2017 and 2018 are projected.

TRANSMISSION CONSIDERATIONS

The American Society of Civil Engineers (2017) rates the U.S. energy infrastructure as D+ and recommends upgrading the aging and congested power systems not only to improve their reliability and resiliency but also to accommodate remote renewables. Industry surveys confirm these concerns. For example, Black & Veatch (2018), consistent with their last five annual surveys, report aging infrastructure among the top concerns of utilities in addition to grid reliability, cybersecurity, long-term investment, and economic regulation. EIA (2018a) suggests that high-voltage direct current lines could be cost-effective solutions to connect regions with high-quality renewable resources with load centers.

Not everyone agrees with the use of long-distance transmission to integrate more renewables. For example, the Clean Coalition, which promotes wholesale distributed generation, argues against long-distance transmission investment in the Western Electric Coordination Council (WECC) region (Karpa, 2018). Most of these lines are designed to increase California's ability to import electricity generated by large-scale renewables facilities from diverse regions such as wind farms in Idaho and solar farms in Nevada and Arizona. The "exploding costs of transmission" are seen as eroding the benefits of low-dispatch-cost renewables.

The socialized cost of transmission undermines the principle of cost causation and distorts price signals to both consumers and investors in new resources. Regulated rates give an incentive for regulated T&D utilities to support such transmission expansion. The "utility death spiral" is seen as a real threat by most utilities (Black & Veatch, 2018), especially those facing more DER and community power developments, often supported by state policies such as net energy metering and DER mandates. Investing in long-distance transmission assets could help utility economics.

It can be difficult to garner support for cross-jurisdictional transmission lines. One of the projects studied in EIA (2018a), Clean Line Energy, lost the support of the U.S. DOE in early 2018 as a result of opposition from states along its path. Such challenges are likely to increase with the visibility of larger projects and raise questions about the feasibility of clean-energy-portfolio visions such as the one proposed in Dyson and others (2018).

Increases in distributed resources such as rooftop solar can necessitate distribution circuit upgrades depending on the circuit (e.g., hosting capacity). Jothibasu and others (2016) conclude that significant rooftop PV generation (15 percent to almost 100 percent) can be added with little or no cost, depending on the circuit. The authors suggest that, when necessary, increased inverter costs can reach $1,000 per unit of inverter and may need to be financed by the utility, whose other alternatives such as "including line regulators to mitigate the over-voltage concern would require a huge investment." The authors also conclude that "including energy storage is unjustifiable for the sole purpose of increasing PV penetration."

A related issue is the impact of NEM, a policy used by many jurisdictions to promote DER, in particular rooftop solar. MIT (2015) recommended the elimination of NEM, which shifted costs from those customers with rooftop solar who could sell their excess solar back to the grid at retail rather than wholesale price to those without solar. Craxton and Sweeney (2017) confirm the cost shifting and conclude that the costs of California's NEM policy outweighs the benefits, especially for certain customers.

Fitch Ratings (2016) identified residential PV and NEM as potential long-term threats to utilities' creditworthiness. As long as DER penetration is limited and regulators allow adjustments to customer tariffs, utilities should not face a serious credit threat, but other issues—such as the equity of tariffs from a ratemaking perspective and potential for larger customer defection—exist. In response to complaints from utilities, customer groups, and other generators, many jurisdictions modified or backtracked on their NEM policies, but the conflicts around DER adoption continue. For example, members of the Tri-State Generation and Transmission Association, a co-op, are in disagreement over the future energy mix and its cost, and over the future utility model. Some members pursue renewables and DER while others are concerned about the cost of that transition. See Trabish (2019) for detailed coverage of these issues.

Transmission grids operate on the principles of open access. Any new transmission line that connects to the rest of the grid is available to any generator without discrimination.[36] This open access complicates the task of

36. In fact, per-unit transmission cost will be lowest if capacity utilization across hours can be maximized, which is not possible with intermittent renewables. Facilities near a transmission connection have nearly identical hourly generation profiles. Transmission capacity that is built to accommodate their maximum wind output will be idle during hours when wind generation falls.

Table 4: Sample studies on grid costs

Reference	Method	Technology	Penetration level	$/MWh
NEA (2018)	Literature survey	Wind	10%	$8
		Wind	30%	$12
		Utility PV	10%	$13
		Utility PV	30%	$17
Griffiths and others (2018)	CREZ capital cost allocation in ERCOT	Wind	10%	$15
Heptonstall and others (2017)	Literature survey	Wind and solar PV	10%	$6.5
			30%	$22
DENA (2010)	$1.1 billion annual in Germany	Wind and solar PV	39%	$11
NREL (2012)	Modeling of grid costs in U.S.	All renewables with 50% from wind and solar PV	80%	$6
Holttinen and others (2011)	Grid capital cost allocation	Wind	10%	$2.2
			40%	$7.7

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Note: Penetration level as share of total annual generation. CREZ = competitive renewable energy zone; PV = photovoltaic.

discerning costs and pricing for transmission capacity that is mainly attributed to renewable energy generation, but there are some clear cases such as the CREZ lines in Texas, the WECC–CAISO lines questioned by Karpa (2018), or three major north-to-south lines under consideration in Germany. For example, Gahran (2016) reports that Germany expected to invest €18 billion by the early 2020s in transmission and other grid infrastructure to facilitate integration of renewables. Research suggests that this ex-post transmission investment is inefficient. For example, Wagner (2019) finds that subsidized wind developers do not pick locations optimally from the system perspective. **Such findings argue for an improved IRP approach to co-optimize generation and T&D projects.**

It is possible to expand the equivalent-firm-power contract proposed by Helm (2017) to address adequacy costs (see next section) to include the cost of transmission investment targeted for a specific resource. Similarly, Wagner (2019) suggests a location-dependent network charge on wind producers to internalize grid costs. In fact, all generation resources must pay for the incremental T&D costs they cause. Karpa (2018) argues that wholesale distributed generation (or DER) avoids much of the transmission costs and, thus, is a lower-cost alternative for increasing the share of clean energy. Burger and others (2019) demonstrate, however, that the value of DER is not always larger than its incremental costs on the system and that there could be an opportunity cost if "small-scale DERs are deployed in lieu of more cost-effective, larger-scale installations of the same resource." In late 2018, generators petitioned PUCT to modify the socialization of transmission costs in the ERCOT market, which allowed for the CREZ lines. In other systems (e.g., MISO), the responsibility of paying the cost of any new T&D investment lies with the generation developer and acts as a reality check in terms of cost competitiveness and commerciality.

Grid costs are highly region-specific given the differences in existing generation portfolios, load profiles, system operation procedures, market processes, and regulatory rules. The literature reviewed for this report often does not distinguish between wind and solar PV or between utility-scale and residential PV. Assumptions and methodologies differ. As such, there is a wide range of cost estimates (table 4).

Adequacy Costs

Adequacy, or backup, costs occur when dispatchable resources such as conventional thermal generation plants are needed to fill the gap when generation from intermittent resources falls below load.[37] Along with a possible increase in operational costs of dispatchable plants that

37. As discussed before, another option, battery storage, will provide little backup capacity with duration limitations despite recent capacity expansion.

might cycle more and ramp faster, there is also a long-term cost issue of compensating conventional capacity that cannot be retired because wind and/or solar have low capacity credits due to their low intermittency and noncoincidence with traditional load profiles, especially during peak periods.

Heptonstall and others (2017) define *capacity credit* as "a measure of how much conventional plant can be replaced by variable renewable generation whilst maintaining overall reliability at peak demand." This concept is the same as the "peak average capacity contribution" factor used by ERCOT when forecasting reserve margin. ERCOT assigns 14 percent to West Texas wind, 58 percent to coastal wind, and 77 percent to solar. Some systems use the term *effective load carrying capability* as ERCOT did. Note that thermal plants have no capacity credit because there is no technological reason for not counting on the dispatchable capacity of these plants during peak hours. The Heptonstall and others (2017) survey concludes that, at 25 to 30 percent renewables penetration, backup costs range between \$5.2 and \$9.1/MWh, with a maximum of \$19.5/MWh at 50 percent penetration. These estimates are based primarily on wind-integration studies. Ueckerdt and others (2013) estimate backup costs in Germany in the range of \$8–\$9/MWh for wind and \$6–\$7/MWh for solar. These estimates remain stable at penetration levels higher than 2 to 3 percent.

Factors that impact these estimates include diurnal and seasonal profiles of generation, geographic distribution of wind and solar farms, peak demand periods, and the cost of building a new generation asset to balance the system. In most systems, existing thermal plants have been sufficient to provide the backup service, keeping backup costs low at low levels of renewables penetration. If a new plant is needed, the plant type chosen for the analysis matters. The cost of new entry in the United States is often calculated on the basis of an NGCT because it is the cheapest plant to build and can ramp up fast. But some studies assume that more-expensive NGCC plants will be built as backup, which is reasonable since NGCC plants, and even coal plants, have been used for accommodating renewables. The costs to these plants can be particularly significant if they lose market share during high-priced peak periods.

Following the cost-causation principle, Helm (2017, p. viii) recommends an equivalent-firm-power capacity auction while phasing out FiTs and low-carbon contracts for differences: "The costs of intermittency will then rest with those who cause them, and there will be a major incentive for the intermittent generators to contract with and invest in the demand side, storage and back-up plants." These contract costs would render adequacy costs more transparent and internalize them within the LCOE of intermittent resources. Such LCOEs are more comparable to LCOEs of dispatchable resources.

Full-Load-Hour Reduction Costs

The issue of reduced generation is at the center of the missing money and resource adequacy discussions in organized markets, as described at some length in Part I. In Ueckerdt and others (2013), *full-load-hour* (FLH) *reduction costs* refer to costs associated with reduced utilization of dispatchable thermal units, often including intermediate and baseload plants, that are cycled down to accommodate intermittent and variable renewable generation. These displacements increase as more renewables are added. Intermittent renewables are dispatched first when available, subject to transmission constraints. Dispatch priority is often mandated in state renewable programs, but note that, once built, wind and solar have low operating costs and that they would be dispatched first as part of economic dispatch. However, the amount of wind and solar would not have been this high and price suppression effects not this large without subsidies and mandates.

Price suppression can be worsened via negative bidding, which occurs because of transmission constraints and overgeneration relative to demand at any given point in time. Under such conditions, wind generators have an incentive to bid negative in order to get dispatched and collect their federal PTCs. As such, negative prices typically have a floor roughly equivalent to the sum of the values of PTCs and RECs (where an RPS market exists). Solar plants typically receive ITCs rather than PTCs. Some also receive RECs, which can be significantly higher in markets with separate solar RPS targets.

The ERCOT market is host to more than 20 GW of wind capacity and experienced negative bidding, as well as low prices thanks to the low dispatch cost of wind. Tsai and Eryilmaz (2018, p. 21) find that in ERCOT, "for every additional 1000 MW of wind generation in a Real-Time 15-minute Settlement Interval, nodal

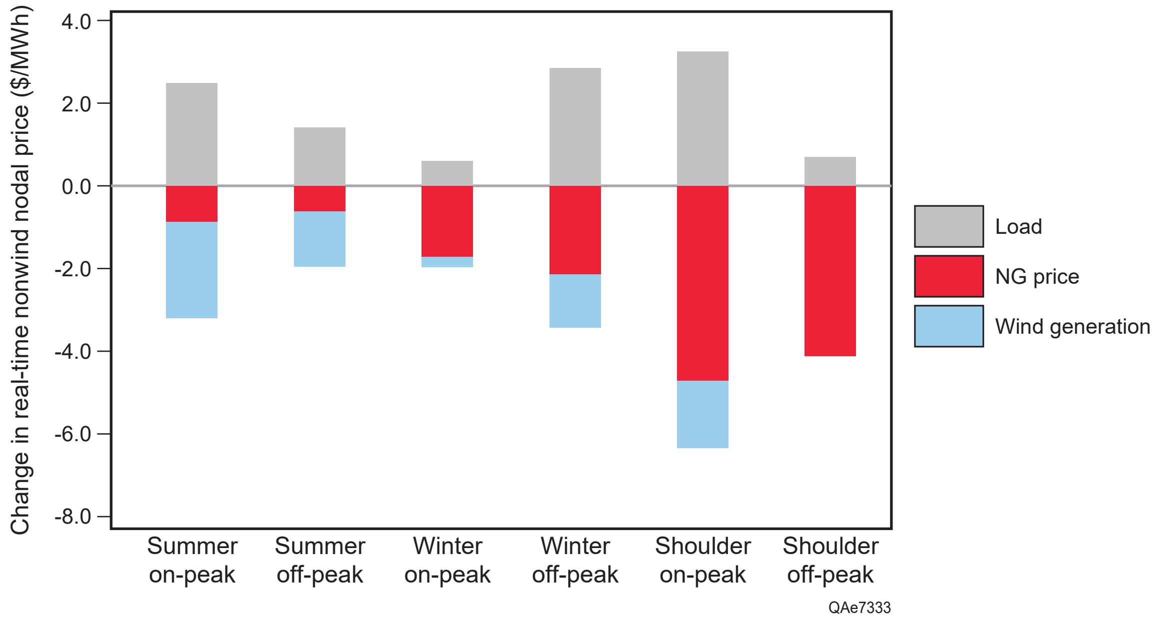

Figure 16. Changes in real-time nonwind nodal prices ($/MWh) in ERCOT, 2015–16 (NG = natural gas). Based on analysis of Tsai and Eryilmaz (2018).

prices at nonwind resources would be suppressed by $1.45/MWh to $4.45/MWh, with considerable heterogeneity across time and space." Figure 16 depicts change in the estimated impacts of load, natural gas price, and wind generation from 2015 to 2016 on prices in nodes where wind does not determine the price. The natural gas price has the largest negative impact in most periods, but the increased wind generation also lowers the price of electricity across the ERCOT system. The negative impact of wind is highest during on-peak hours of summer and shoulder months. Wind capacity in ERCOT continues to increase. At times, wind generation accounts for more than half of instantaneous demand.

The negative prices by renewables plants can be temporary as system operators invest in new transmission capacity and other grid upgrades, as well as adjust market designs. The phasing out of federal PTCs by 2019 also will reduce negative bidding. But the low dispatch cost of renewables will continue to put downward pressure on wholesale electricity prices, which have become a concern for all generators, including operators of wind and solar farms. For example, in their modeling of renewable penetration in CAISO, ERCOT, Southwest Power Pool, and NYISO, Seel and others (2018) report an average reduction in energy price between $0.21 and $0.87/MWh for each additional percentage of renewable penetration, which is reported to be "within the range of previous studies." The authors observe that these lower prices will reduce the profitability of inflexible generators such as nuclear, solar, and wind. These observations are consistent with Sivaram and Kann (2016), who demonstrated the declining value of solar as more solar generation penetrates the power system.

Lower generation and lower prices lead to lower revenues to existing plants (fig. 17). Lost revenues by generators built under the expectation of a competitive market is a negative externality that is conceptually the same as stranded cost recovery, which was granted to regulated utilities when their markets were opened to competition. In those days, regulated utilities argued that they made investments under the regulatory compact. Opening electric power markets to competition posed a threat to their cost recovery at allowed returns. Similarly, merchant generators made investments under the competitive-market construct, but subsidized renewables are imposed on competitive markets by government policies. Many state regulators, governments, and electric system operators have been developing other policies to save other plants, which raises uncertainty for not only new investments but also operating plants. These are some of the legitimate arguments used by plaintiffs in the resource adequacy cases discussed in Part I. The FLH reduction of Ueckerdt and others (2013) offers a way to capture these stranded costs in the LCOE calculation.

Overproduction Costs

According to Ueckerdt and others (2013), overproduction costs occur when wind or solar generate more than demand at any point in time. Increasing penetration of wind or solar or both has already caused this phenomenon in several markets, such as Germany and California. System operators have to curtail excess generation. Given the congestion across the transmission grid, this phenomenon can be localized even if the systemwide net load curve does not go negative. In other words, there was too much investment in renewable capacity relative to load profile of the system. This capital inefficiency can be represented in the LCOE by a proportionate increase in capital cost. Alternatively, a lower CF can be used since curtailment would reduce the effective CF of wind and solar. Either way, the LCOE would be higher.

California's duck curve is the best-known example of overproduction of renewable generation. Figure 18 depicts the CAISO analysis from the early 2010s of how solar generation in midday can reduce net load on a typical sunny spring day (March 31 in this case) as low load would coincide with maximum solar output. Note that the minimum net load is still positive, which means that this example is not as extreme as the depiction of overproduction in Ueckerdt and others (2013), but it exposes the trend. In fact, actual net load and 3-hr ramps in California

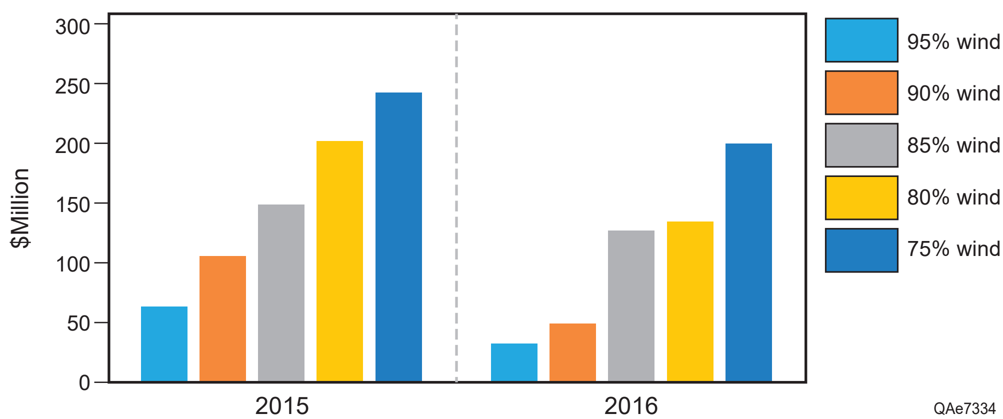

Figure 17. Gas-fired plant revenue changes in ERCOT under hypothetical wind-constraint scenarios (percent of actual). Based on data presented in Tsai and Gülen (2017c).

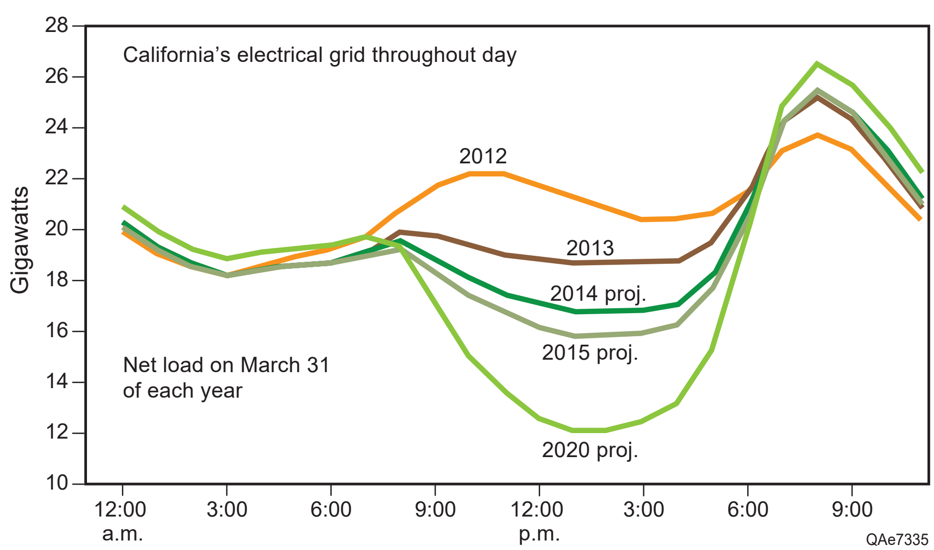

Figure 18. Solar overproduction in California. Source: California Independent System Operator (CAISO).

are approximately 4 years ahead of the ISO original estimate: net load fell below 9 GW, and the ramp from 4 p.m. to 7 p.m. surpassed 13 GW on several days in 2017 and 2018. Importantly, the duck curve has been increasing the frequency of negative prices, which are often bid by generation units with higher shutdown and start-up costs.

According to Energy and Environmental Economics (2014), overproduction is the most significant integration challenge facing California as the state pursues more than 30 percent penetration. Gas-fired generation capacity is discouraged in California and has been declining, although some utilities and the CPUC are keeping some units alive after realizing their importance for reliability. Longer-term solutions include curtailing production from solar PV during midday, improving integration with neighboring grids to export excess Californian solar generation, adding battery storage, and increasing advanced demand response. But Energy and Environmental Economics (2014, p. 18) acknowledges that "we are not aware of any detailed studies of the technical potential for pumped storage or upwardly-flexible loads in California. Battery technologies have not been fully demonstrated as commercial systems in the types of applications or at the scale required to address the integration issues identified in this study. Regional coordination is promising but has progressed slowly over the past decade. There are likely to be significant challenges to implementing any of these solutions." As discussed earlier in "Grid Costs," some are concerned about the high costs of long-distance transmission lines to connect the CAISO system to other systems across the WECC region.

The duck-curve example illustrates why adequacy, FLH reduction, and overproduction costs are grouped as profile, or utilization, costs. Hirth and others (2015) offer some profile cost estimates based on a literature survey (their table 3). There is a wide range of estimates, depending on the system and penetration level studied and on the methodology used. Nevertheless, above 5 percent share of generation, profile costs of wind start at about \$5/MWh and can be as high as \$45/MWh at 20 percent penetration. Solar penetration may actually lower system costs below 10 percent penetration, after which profile costs can increase from about \$10/MWh to \$45–\$50/MWh at 30 percent penetration. Based on a literature survey, the NEA (2018) reports profile costs of \$5–\$9/MWh for wind and \$13–\$26/MWh for utility-scale PV, at 10 and 30 percent share of generation, respectively.

System Levelized Cost of Electricity

Ueckerdt and others (2013) demonstrate that, in the short term, total system LCOE increases as penetration

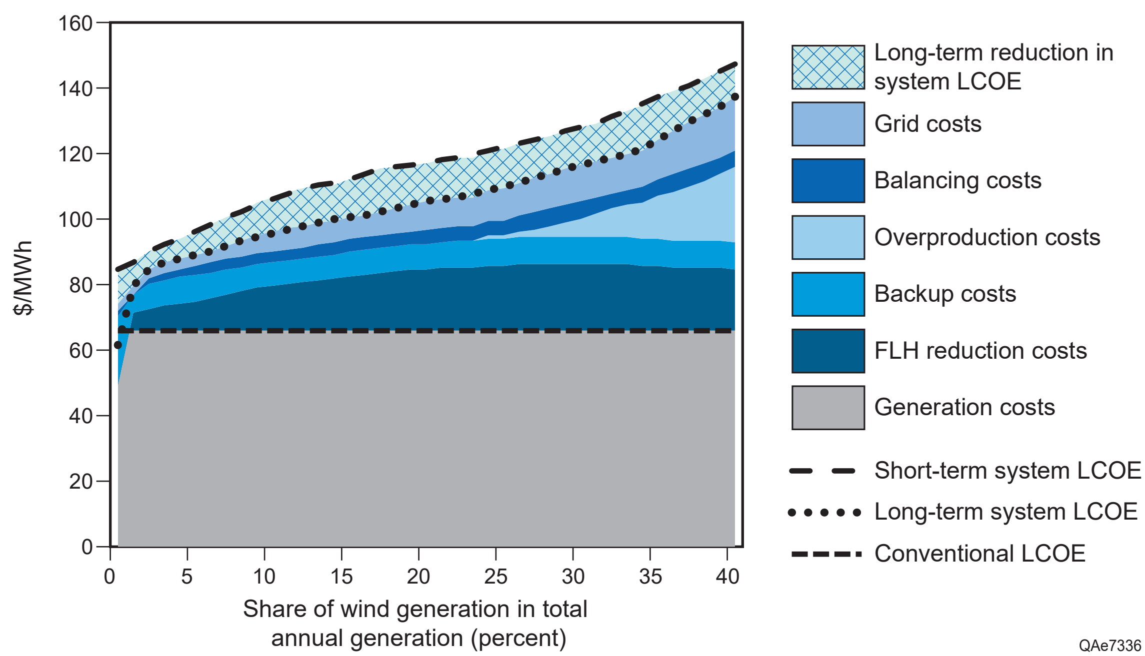

Figure 19. Wind-integration costs in a typical thermal system in Europe at various penetration levels. Adapted from Ueckerdt and others (2013). Blue-shaded series represent various categories of system-integration costs. FLH = full load hour.

level of renewables gets higher. That is, if too much wind and solar capacity are added too quickly, costs will be higher. System-integration costs will persist but decline over time as systems adapt. For example, wind-integration costs in figure 19 (blue-shaded categories) depict a system in Europe that is dominated by thermal generators (gas, coal, and/or nuclear). Different systems will experience these costs at different levels depending on their generation mix, load profiles, grid connectivity, and the pace of renewable capacity additions. There may be other factors, some peculiar to each region. Note that short-term system-integration costs can be as high as conventional LCOE (gray generation costs at the bottom of fig. 19) at about 30 percent penetration, after which overproduction costs increase much faster, while other system-integration costs stabilize or start to decline. In the long term, system LCOE is expected to be lower as system operators adapt to managing variable resources, as the variability is naturally balanced via geographic distribution and enhanced transmission grid, and/or as stranded assets are fully amortized or retired. This reduction from short-term system LCOE to long-term system LCOE is marked by the shaded area between the dashed line and the dotted line at the top of figure 19.

FLH reduction costs appear before overproduction costs because renewables start displacing existing generators at low levels of penetration. FLH reduction costs gradually increase and stabilize once the penetration level reaches about 20 percent for wind (15 percent for solar, not shown in fig. 19). Under high penetration levels (about 25 percent for wind and 15 percent for solar), overproduction costs begin to show up and keep increasing, rendering an overall upward trend of system-integration costs.

In figure 20, I have added integration costs to the LCOE with emission externalities that appeared in figure 12. This is now a more accurate metric to assess

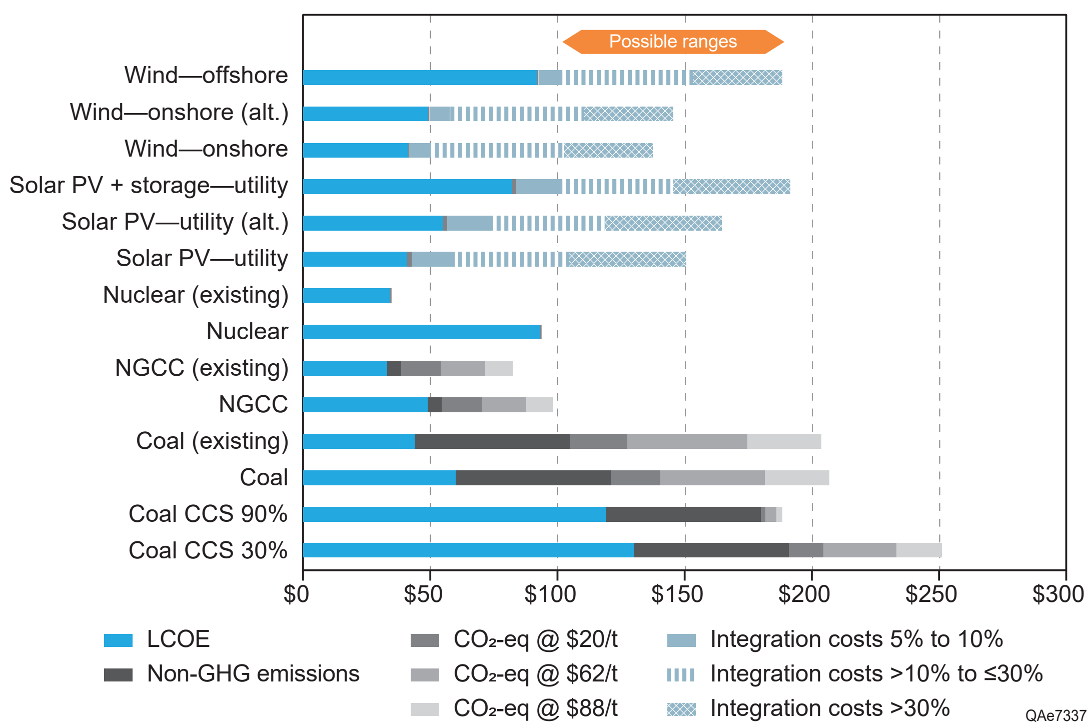

Figure 20. Representative U.S. LCOE with air emissions and system-integration costs ($/MWh). Excludes negative externalities associated with water, land, and ecological impacts; positive externalities; and subsidies. System-integration costs are negligible below 5 percent for wind and 10 percent for solar. Beyond these levels, integration costs (patterned light-blue bars) represent possible ranges from the literature. The specific value for any system depends on existing generation mix, load growth and profiles, grid topography, pace and mix of renewable additions, and other power system elements. The number of estimates for beyond 30 percent penetration is limited. Base LCOE comparisons should not be extrapolated to any project in any location. They are only valid for "average" U.S. locations where it is feasible to build any of these plants. The LCOE is a high-level policy-discussion tool. Developers do not use LCOE for investment decisions, and it is not recommended for the market-IRP. CCS = carbon capture and sequestration; CO_2-eq = CO_2 equivalents; GHG = greenhouse gas; NGCC = natural gas combined cycle.

relative social costs of different generation options. It is important to note, however, that the system-integration costs beyond the base penetration levels (roughly 5 and 10 percent share of annual generation for wind and solar, respectively; solid light blue bars in fig. 20) are meant to represent possible ranges (patterned light-blue bars) to reflect the inherent uncertainty and variability of these estimates. Depending on the characteristics of the grid in which they are located, the same level of penetration of the same renewable technology may lead to higher or lower system-integration costs within the range represented. The estimates are limited for higher penetration levels, especially beyond 30 percent.

Below 5 percent for wind and 10 percent for solar, system-integration costs are often negligible and sometimes negative. This effect could reduce the system LCOE as depicted in the case of wind in Europe (fig. 19) up to about 2 percent. The impact may be larger for solar. As discussed before, several studies report that, at low penetration levels (typically less than 5–10 percent), utility-scale PV can reduce overall system costs because solar generation is mostly coincident with peak load periods. Shaving peaks lowers system price. However, as the share of utility-scale PV generation increases, overproduction and FLH reduction costs surpass the savings associated with lower prices.

The competitiveness of existing nuclear increases once system-integration costs are added. In the absence of proper market fixes, ZECs or other subsidies to keep some nuclear plants alive appear more justified, especially once renewable penetration surpasses about 5 percent of generation. Similarly, system-integration costs would necessitate a higher SCC than the previous comparison (fig. 19) for competitiveness against NGCC plants, especially existing plants. The higher the system-integration costs, the higher the SCC would need to be. Alternatively, even at a higher natural gas price, NGCC plants can remain competitive. As always, there are regional differences. Best wind and solar regions might have a naked LCOE that is lower than the ones presented here. If those regions also experience low system-integration costs, the SCC does not need to be that high. In contrast, even in the best wind and solar locations (i.e., those with highest CFs), higher system-integration costs undermine their competitiveness and overall value to the system. Given the ranges associated with system-integration costs, it is not possible to draw additional general conclusions.

Subsidies

Unfortunately, subsidies are ubiquitous across all energy value chains: oil, natural gas, coal, nuclear, and renewables. There are also plenty of subsidies for energy consumers, not to mention subsidies across other segments of the economy (e.g., agricultural), that sometimes impact energy systems. The willingness of governments to offer such subsidies certainly feeds rent-seeking behavior; encourages inefficiency in capital expenditures, production, and consumption of subsidized goods or services; and undermines competitive markets. This environment makes it difficult to compare societal costs across different energy technologies. Subsidy policies differ across jurisdictions and change over time—not necessarily to converge to best practices. Some are offered in the form of tax credits, which can be for production, investment, or certain attributes such as low emissions, or for being a certain technology with some perceived benefits.

Not all fuels or technologies are used for the same purposes. For example, wind and solar can be used for power generation but, unlike hydrocarbons, not in the petrochemical or other manufacturing sectors as feedstock. These differences in the collection of end uses can influence how support policies are shaped and their direct impact. Many subsidies have global origins and/or implications, such as consumer subsidies provided by many governments on diesel, kerosene, or other petroleum products and Chinese subsidies for the manufacturing of solar PV panels, windmills, and batteries.

With these complex realities in mind, I add per-megawatt-hour value of federal subsidies in the form of direct funding and tax expenditures provided to the energy sector based on the estimates of Griffiths and others (2017). Wind and solar have been receiving significantly larger subsidies on a per-megawatt-hour basis, although total dollars received by renewables and conventional fuels or technologies have been roughly the same in the 2010s (see Part I for details).

Subsidies are often justified to level the playing field because of a market failure, i.e., not pricing the cost of externalities. Griffiths and others (2017) do not consider the noninternalized cost of externalities as a subsidy, but the augmented LCOEs that include the cost of air-emission externalities explicitly help with the comparison of overall social costs of generation technologies rather than conflating the subsidy accounting (fig. 21).

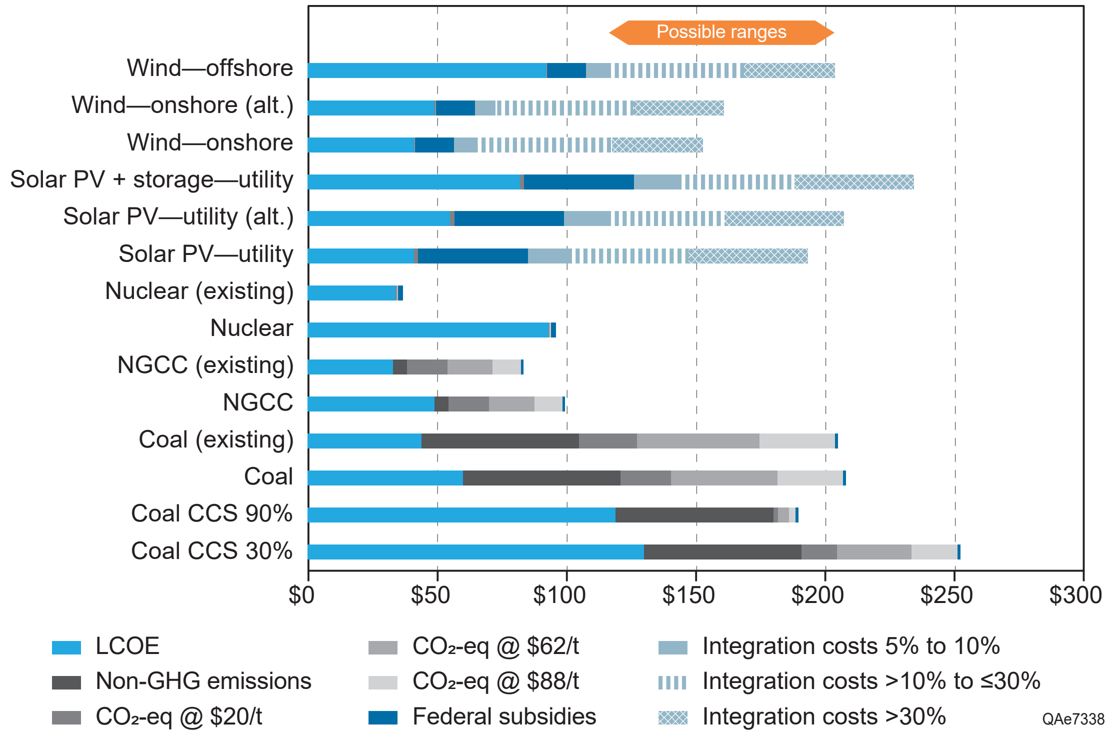

Figure 21. Representative U.S. LCOE with air emissions, system-integration costs, and federal direct and tax subsidies ($/MWh). Excludes negative externalities associated with water, land, and ecological impacts; positive externalities; nonfederal subsidies; and federal subsidies other than direct and tax expenditures. These comparisons should not be extrapolated to any project in any location. Base LCOEs are only valid for "average" U.S. locations where it is feasible to build any of these plants. State-level subsidies differ. The LCOE is a high-level policy-discussion tool. Developers do not use LCOE for investment decisions. It is not recommended for the market-IRP. (For abbreviations, see fig. 20.)

Adding subsidies to the augmented LCOE significantly reduces the competitiveness of renewables, even without system-integration costs. Existing nuclear plants, even with ZECs and other state subsidies, are the cheapest options from a social cost perspective. An average onshore wind facility is now more attractive than utility-scale solar and can beat an existing NGCC at a carbon penalty of slightly over $20/t (excluding system-integration costs). With the alternative CF, onshore wind can compete as long as carbon emissions are priced at about $35/t. At higher penetration rates, system-integration costs would require a higher GHG emissions tax to maintain social-cost competitiveness of onshore wind.

To the extent solar PV costs continue to decline as a result of technological improvements and—perhaps at this time more importantly—economics of scale, per-megawatt-hour subsidies and the average LCOE will be lower (e.g., owing to improved CF). This is probably already the case in places like Arizona and West Texas that have high-quality solar resources. In fact, some of those projects probably do not need subsidies to be competitive. By the same token, low-quality solar regions will remain disadvantaged. The disadvantage of lower average CF is nearly $15/MWh, as seen in the alternative case.

Note that state and local subsidies are not included. These differ significantly across jurisdictions and could not be adapted to a U.S.-level representation. Ready estimates on all jurisdictions are not available, but this is an important area of future research. Griffiths and others (2018) compare state subsidies in Texas and California (subsidies offered by municipal or other local governments are excluded). The authors calculate that in Texas, which has limited subsidies for energy, per-megawatt-hour subsidies are $1.25/MWh for natural gas and $17/MWh for wind because of CREZ lines, without which wind subsidies would be less than $2/MWh. In California, which has been pursuing the most aggressive policies toward increasing the share of renewables as quickly as possible, subsidies to solar declined from $606 to $96/MWh since 2010, while subsidies to wind declined from $56 to

$40/MWh over the same period. It is important to note that subsidies in California are probably even higher; these numbers reflect the programs for which the authors could find relatively clear-cut information to tabulate. Other states are most likely to have estimates between these two extremes, based on their RPS program targets and other programs such as the recent ZEC markets, which increase the cost of existing nuclear plants.

Levelized Cost of Electricity as a Policy Tool

Although these enhanced LCOE estimates offer a more holistic metric for comparing different generation resources, they still fall short in some respects. For example, owing to lack of data or consensus, externalities other than those associated with air emissions are ignored. Regional variations in air emissions are not considered either, but these are probably small. Also, system-integration costs from the literature cover a wide range as a result of different methodologies and assumptions and, perhaps most importantly, different characteristics of the individual system studied (e.g., generation mix, grid configuration, load profiles, and growth patterns). All of these caveats, however, make the case for conducting regional analyses rather than using generic LCOE estimates.

All of these caveats make the case for conducting regional analyses rather than using generic LCOE estimates.

Wiser and others (2017) surveyed the literature on retail electricity rate impacts of renewables, with instructive preliminary conclusions indicating that state RPS policies have generally increased rates, sometimes significantly—but not everywhere. Depending on the quality of wind and/or solar resources, and on the design and target of the programs, rates can decrease. However, incentives such as federal tax credits "reduce retail electricity rates by making [renewable energy] purchases less expensive" (Wiser and others, 2017, p. 30). As argued in Part I, both federal and other incentives reduce the cost of capital by inducing utilities to sign long-term PPAs at prices that reflect these subsidies. This is another reason why federal subsidies should be included in a social-cost LCOE as a separate item.

Wiser and others (2017) also observe that NEM can increase retail rates, especially at higher penetration levels. But rates remain stable or even decline in some locations, depending on the rate design and value of solar. Incentive programs with retail rate surcharges directly increase the cost of electricity to customers. The analysis and literature surveyed in Wiser and others (2017) do not consider other environmental and economic impacts, either positive or negative, such as "claimed benefits of [renewable energy]: human health, water usage, energy price risk, GHGs…the claimed environmental impacts of [renewable energy] on wildlife or local communities, or claimed positive or negative impacts on employment and economic development" (p. 30). Nor does the literature always consider "the relative balance between the full cost of delivering renewable energy and the value of that energy in terms of its ability to offset the cost of other generation sources." Adding the cost of externalities and system-integration costs to LCOE gets us closer to a more accurate social-cost comparison, but it is still incomplete.

In summary, social-cost accounting of generation technologies needs to improve to include not only all negative environmental externalities but also other costs borne by society as ratepayers, taxpayers, and/or shareholders. The augmented LCOE is one way to conduct such an analysis but not the only, or the best, one from an industry-expert perspective. Nevertheless, it has the advantage of being familiar to the media and, thus, the larger population. It is probably a good place to start educating wider audiences about the other dimensions of electricity cost.

Epilogue

Competitive electricity markets were never allowed to reach their potential. The legacy of a public service provided by integrated utilities in monopolistic territories regulated by state and federal agencies was prevalent during restructuring processes. A large infrastructure built since the early 1900s is based on the regulated utility model, large central generation plants, and the transmission and distribution (T&D) network.

All of these preexisting conditions influenced restructuring policies and dictated certain elements of the newly created markets. Part of this influence was justified based on the physics of electricity and engineering of the infrastructure that delivers it to us every (or most every) moment of every day. Another part was driven by cultural and sociopolitical considerations. For example, price caps and lack of demand-side participation were not technical requirements but rather political choices that curtailed the market's ability to send the right price signals to both developers of power plants and consumers.

The maintenance, upgrade, and expansion of the T&D grid, the nervous system of the electricity industry, used to be a part of the utility integrated resource plans but has become detached from the optimization of overall system costs. Sometimes the cheapest option to balance electricity demand and supply is T&D investment. But, with restructuring, investment in T&D started responding to market and policy developments with a delay rather than being part of an optimization problem. Today, much of the T&D infrastructure around the country is aging and heavily congested, although annual investment has been increasing in recent years. Without a reliable grid, the frequency and duration of power outages increases, with the attendant negative economic impacts. The 2003 U.S. Northeast blackout is extreme in its geographical extent and duration, but customers around the country experience outages regularly. Such outages are probably becoming less tolerable as the constant supply of high-quality electricity is becoming more critical to sustain an increasingly connected Internet of Things economy. This concern is a key driver of some consumers seeking their own generation, or even grid independence.

Not pricing the cost of externalities in the market also turned out to be a shortsighted policy failure. Environmental regulations since the 1970s have addressed some of the air and water pollution problems. Most recently, the targeting of mercury emissions induced investment in new environmental controls, which also reduced other emissions. Some plants retired because their owners did not want to invest in such controls in aging plants in an environment of low electricity prices. Such regulations are typically less effective than a Pigouvian tax, or a matching cap-and-trade market, which yielded significant reductions in SO_2 and NO_X emissions. Continuing environmental concerns, especially regarding climate change, have been inducing federal, state, and local incentives to available technologies and resources instead of an economy-wide GHG emissions tax, which remains politically infeasible. In many cases, though, local economic development also has been an important driver in deciding which technologies qualify as clean and in garnering sufficient bipartisan support to enact incentive legislations. Unfortunately, local economies did not always benefit as much as expected.

With consumers not seeing the true cost of electricity in real time, uncoordinated policies at various government levels have led to investment in generation and T&D networks that was beyond the needs of the demand growth, inefficient from a capital allocation and return perspective (in terms of both financial and environmental benefits), in the wrong places for the grid's reliability needs, or in existing technologies that did not fit a future vision of 100 percent clean energy. For example, in locations with high-quality wind and solar resources with low system-integration costs, subsidies are not necessary for onshore wind and utility-scale solar to be competitive with alternatives. On the other hand, the low capacity credit of renewables in many locations they are incented adds to system costs. When new transmission is built to connect remote renewable resources, customer bills reflect these costs, although they are not visible in wholesale markets.

The addition of intermittent resources, either in large-scale but remote facilities or in small-scale distributed systems, further complicates the balancing of the grid in real time. Distributed resources sometimes cost more than the value they bring to the power system. This environment also triggers a domino effect of subsidies to other resources. To be clear, although system operators had to adjust to intermittency and variability of renewables, the fundamental challenge is one not of technology but of economics. The benefits of renewables such as reduced emissions and fuel savings must be compared to these costs as part of a more holistic social-cost accounting.

Interestingly, after resisting consumer participation for years, even in restructured markets, some form of dynamic or time-of-use pricing and demand response is gaining support, particularly among the promoters of distributed resources such as rooftop solar and battery storage. The technology landscape, with smart meters and Internet of Things, is now more visible and, in fact, actively promoted within the electric power industry. Also, younger generations seem more comfortable with this high-connectivity world. Many envision microgrids rendering the traditional T&D infrastructure obsolete.

Policy-driven abandonment of infrastructure before the end of its commercial life would lead to stranded costs for ratepayers and shareholders.

However, after the expansion of smart metering across the nation with DOE funding and regulatory rate approvals, some regulators seem more cautious today before approving new investments in advanced metering or similar demand-side infrastructure. Also, having a smart meter does not guarantee that a customer will see dynamic prices. Even in ERCOT, with retail choice, retail electricity providers have struggled to find value in time-of-use products for residential customers despite smart meters being ubiquitous. Further market or regulatory reforms are needed to induce more demand-side participation.

In the meantime, utilities around the country have spent more than $120 billion in transmission and $140 billion in distribution systems since 2010. These costs are approved by regulators and will be reflected in customer bills for years to come. Utilities continue to invest tens of billions of dollars in T&D, driven primarily by the need to modernize the grid, improve reliability, and integrate more renewables. But the desire to avoid the possible negative consequences of the 2017 tax reform and the risk of FERC reducing the return-on-equity incentives also may have started to play a role. The T&D grid of the past is here to stay, along with the utilities that build the system and manage it.

This expanding and rejuvenating grid supports not only a rapidly growing amount of wind and solar but also about 950 GW of conventional generation capacity —about 87 percent of total installed capacity as of the end of 2018, including 99 GW of nuclear, 103 GW of mostly large hydro, 245 GW of coal, and 468 GW of gas plants. Nearly 70 GW of coal capacity has been taken out of service since 2010. More coal plants will retire in the near future because of advanced age, high environmental impact, declining competitiveness, or a combination. Sixty-year operating licenses of about 24 GW of nuclear capacity will expire by 2030. Some of these, as well as other nuclear plants, may retire earlier owing to poor economics unless saved by market reforms or, more likely, state subsidies.

In contrast, two-thirds of the gas fleet was built after 2000, and more plants are under construction or pursuing permits. The fleet is getting younger and more efficient as new builds, mostly combined-cycle facilities, replace older steam turbines. A rough estimate of investment in new gas plants since 2010 is $80 billion. The young natural-gas fleet has been and will be the main replacement for the retiring baseload coal and nuclear facilities for the next 10–15 years, especially if those retirements happen sooner rather than later. Increasing the utilization of existing plants will be sufficient to replace these retirements. Combined-cycle natural-gas plants are dispatchable, highly efficient, and, in most cases, built near existing transmission infrastructure.

Several hundred billion dollars invested in traditional generation and T&D infrastructure since 2010 represent an economic life of at least 20 years but a much longer operational life. Policy-driven abandonment of infrastructure before the end of its commercial life would lead to stranded costs for ratepayers and shareholders. Closing facilities before the end of their physical life (i.e., while they still have market value) would represent an opportunity cost. Regardless of what one calls them, these are societal costs. If they are incurred, benefits of replacing them with alternative technologies should be greater.

A truly competitive market could have already led us to the microgrid vision, if that were the practical solution to meeting our needs. More likely, we would have ended up with something different but better in terms of being clean, reliable, and cost-effective. Price signals that reflected the net cost of the externalities would have induced consumers to adjust behavior and demand higher efficiency, conservation, and innovation (e.g., creating next-generation technologies that are more efficient and durable with less waste along their supply chains), as well as more-efficient investments.

Trusting the proper price signals is the economic principle that underlines the renewed proposals for a GHG emissions tax. As the "Economists' Statement" from the Climate Leadership Council puts it, an economy-wide GHG emissions tax "will send a powerful price signal that harnesses the invisible hand of the marketplace to steer economic actors towards a low-carbon future." Many promising ideas from the technology R&D space across all energy value chains could have been unleashed over the years in response to market price signals. Many failed, some succeeded. Many failures were due to lack of sufficient funding. Government funding for specific R&D is as fickle as political and macroeconomic cycles. Private funding is difficult to sustain in the absence of the profit motive. Pricing the externality in the market creates the incentive to innovate, which supports R&D targeting a fix for the externality and induces consumers to adjust their behavior to avoid the externality. In contrast, subsidizing installment of existing technology does not support fundamental R&D and innovation and does not nudge consumer response. As discussed in Part I, support programs often are found to be more expensive than market-based alternatives.

But was (is) it realistic to expect that such a market for electricity can be created and sustained? Creating and sustaining a competitive market requires confidence in economic theory that many in the public as well as the policymaking community have consistently lacked—to be fair, sometimes for good reason. Market designs have been complex and inconsistent, markets have been manipulated, and externalities have been ignored. But, as argued before, many of these occurrences are failures of policy and not market failures, as conveniently assumed by many; markets are creations of policy.

Electricity has always been a political commodity. Policies change along with political winds. With the tangled economic and environmental objectives surrounding the electricity industry, the policy environment has been particularly dynamic. Political cycles are significantly shorter than the time it would take for a market to yield results that meet the objectives, assuming that the objectives stayed the same. The financial sector's short-term return expectations are not easy to meet by long-lead, capital-intensive industries that have defined not only the electricity sector but also the energy industry at large. Sectors or technologies that promise rapid growth and, thus, high returns—such as shale gas, oil and gas midstream, solar PV, battery storage, and other "bright and shiny technology" (as CPUC President Picker put it)—attract capital more easily, especially if they are incented. This environment creates a feedback loop that encourages rent-seeking via policy but also creates a lot of uncertainty because the stability of policies or regulations over time is not trusted.

The Future of Electricity

A modern economy runs on reliable and affordable electricity. The public also wants a cleaner environment. Throughout this report I have discussed the principles of a competitive market that could deliver communities clean, reliable, and affordable electricity. These principles include dynamic pricing without price caps, exposure of consumers to these prices (with necessary exceptions for vulnerable segments of the consumer population), pricing of externalities, and elimination of out-of-market incentives to specific technologies. But fixing the current organized markets according to these principles does not seem to be politically feasible, at least not any time soon. Ad hoc resource planning is the de facto outcome of the current environment in which subsidies, mandates, regulated investments, and administrative fixes to make it all fit increasingly determine the mix of generation—without the benefit of informed and integrated planning that considers all resources, including generation, T&D, and demand side.

Since the 1990s, many jurisdictions restructured their electricity industries, hoping that competition would reduce the inherent inefficiencies of the regulated monopoly model. We should avoid the same inefficiencies if we are to rely more on planning. At the same time, many jurisdictions never restructured their electricity industries. In those regions, integrated utilities have continued to plan generation and T&D subject to state policy and regulatory directives. In some of these regions, electricity prices have been as low as or lower than those in some restructured markets, mainly because wholesale competition is not the only determinant of retail electricity prices. Some regions also invested in more renewables, often via competitive bids by third-party developers. These two worlds are not neatly separated; transmission grids connect many states that are part of organized markets with those that are not. Differences in state and federal policies have been creating many tensions between federal agencies (especially FERC) and states, as well as among states. Lessons can be learned from both restructured markets and those that have maintained the traditional model, as well as from the seams issues around which they have co-existed, albeit uneasily.

Nothing is free, government and financial resources are limited, and time frames matter.

First, however, society's objectives must be identified and reconciled in a politically sustainable form because some objectives conflict with each other while others can be complementary. Various stakeholders assess different objectives in often distinctly different ways. Preferences of consumers change not only over time but across customer classes (e.g., residential versus industrial, low income versus higher income) as well as professional and cultural background. Perhaps most challenging—but necessary—is reconciling differences across jurisdictions. The flow of electrons across wires does not care about state boundaries. Renewables goals cannot be achieved cost-effectively without harnessing best resources via long-distance transmission lines that cross multiple states. Global problems such as climate change that do not recognize international or industrial boundaries cannot be solved via parochial policies, especially if they do not target the objective but rather support preferred available technologies only in the electricity sector, which accounts for about 30 percent of GHG emissions in the United States.

In the effort of reconciliation, objectives must be ranked via transparent benefit–cost analysis. Some kind of practical optimization is necessary to achieve as many of the objectives as possible at least cost, subject to budget and technical constraints. For example, targeting local environmental externalities is easier for local communities to support and will also yield side benefits. Coal plants that closed because of mercury regulations during the early 2010s also reduced SO_2, PM, NO_X, and GHG emissions.

Nothing is free, government and financial resources are limited, and time frames matter. Kaplan (2019) points to historically high levels of government and corporate debt as a risk factor for the U.S. economy. The next recession may be more severe than the Great Recession of 2008–2009, and quantitative easing and low interest rates may not work as efficiently. The federal budget deficit has declined from its historic peak in 2009 but remains higher than throughout most of the post-WWII era in terms of percentage of GDP. Fiscal stimulus not only is less likely but also would be irresponsible given the high government debt, federal budget deficit, and size of unfunded entitlements. The energy sector, which attracted large sums of capital in an era of low interest rates and a recovering economy, cannot sustain recent growth performance in the future, especially those segments that are more dependent on incentives. States have been driving most energy transition policies, but many states have been facing fiscal deficits, which present another challenge for sustaining direct support to preferred technologies.

This macroeconomic environment is germane to energy sector policies and their chance of success. The private sector and consumers should be incented to carry the energy transition forward. Being clear about trade-offs, associated opportunity costs, and complementarities among the energy–environment–economy objectives would allow for rational investment decisions by the private sector across the electric power value chain. Consumers must be a fundamental part of this calculus so that they can make choices while being well-informed about costs and benefits of their preferences. Consumer choice is a popular goal nowadays, but true and widespread choice is only possible when consumers make decisions in response to price signals that reflect the societal objectives and technical cost of meeting them. Equally important is the influence of knowledgeable consumers on policymaking. No doubt, equity adjustments across income groups will be necessary, but consumer protection has always been a part of regulation.

Moving forward on this path requires the strengthening of the policy and regulatory infrastructure. Policymakers and regulators must be provided with the institutional capacity to develop policies and adjust them as necessary, develop innovative regulations and implement them, and monitor industry players to approximate market efficiency and ensure consumer protection. These institutions must be able to afford the necessary number of highly qualified staff members of various disciplines, state-of-the-art modeling tools, and databases to maintain their independence and conduct relevant analyses such as diligence on resource plans.

The many choices—not only in generation technologies but also in T&D and demand-side spaces—each come with different considerations (some negative, some positive, depending on the objective). All of these choices can be utilized, in various combinations, to meet electricity and environmental needs of society. The physical characteristics of the power system also will influence the blend of these options that leads to the least-cost solution. An illustration of this complexity is offered in table 5. The lists of electric power options and dimensions are not intended to be complete, but they capture almost everything that has been a topic of discussion in recent years. Similarly, considerations are meant to highlight some of the main arguments. Different technologies offer value to the grid or to meeting certain objectives at varying degrees. In other words, there are no silver bullets that would make everyone happy while keeping the lights on: thus the need for prioritization of objectives and optimization based on transparent benefit–cost analyses. I am

Table 5. Electric power options, objectives, and considerations

Electric power options	Dimensions	Considerations
Biomass **Coal** (bituminous, subbituminous, lignite, IGCC, CCS) **Demand response** (smart meters, dynamic pricing) **Distribution** **Energy efficiency** **Geothermal** **Hydro** **Municipal solid waste** **Natural gas** (combined cycle, combustion turbine, combined heat and power, microturbine) **Nuclear** (conventional, small modular reactor) **Solar** (utility-scale PV, rooftop PV, concentrated solar thermal) **Storage** (onsite fuel, pumped hydro, batteries, compressed air, flywheels, thermal) **Transmission** (AC, DC, voltage) **Wind** (onshore, offshore)	Conversion efficiency	Fuel-to-electricity conversion efficiency (i.e., heat rate) matters for thermal-generator-operating costs since fuel is not free and prices can be volatile.
	Cost (capital)	Overnight capital cost ($/W) is variable contingent upon location, supply chains, and myriad other factors.
	Cost (O&M)	Operating expense, including fixed and variable operating and maintenance expenses, fuel costs, start-up costs, and any other costs that can be incurred to comply with system-operator instructions.
	Dispatchability	Ability to ramp generation unit up and down at any time per system-operator instructions. Wind and solar are not dispatchable in the same way as thermal plants.
	Emissions (global GHG)	CO_2, CH_4, N_2O, etc. In addition to generation, emissions along supply chains of fuels (coal, gas, uranium) and minerals used in wind, solar, and batteries to be considered.
	Emissions (local)	Mercury, SO_2, VOCs, NO_X, PM. Some emissions have regional impact (e.g., acid rain). Closure of emitting facilities such as coal-fired plants will also reduce GHG.
	Land use	Land-use footprint and impact on land resources and species. Land use associated with drilling and mining for fuels (coal, gas, uranium) and minerals used in wind, solar, and batteries to be considered.
	Reliability	Contribution to grid reliability (e.g., reserve margin, frequency response). With energy transition, reliability metrics need a rethink.
	Resource adequacy	Ability to serve peak load. Wind and solar cannot be counted on to be available during peak demand. They have low capacity credit. System needs sufficient thermal capacity, storage, and/or demand response to meet peak demand.
	Safety	Risk of accidents and potential damage of accidents.
	Scale	Technical economies of scale are important for traditional, centrally dispatched systems. Distributed systems (e.g., microgrids), demand response, and energy efficiency can undermine significance of scale.
	Security (resilience)	Availability of fuel or technology during extreme conditions; robustness against cyber or physical attacks.
	Solid waste	Coal ash, nuclear waste, waste from mining of coal, uranium, lithium, cobalt, and other minerals used in wind, solar, and batteries; recycling.
	Water use	Cooling and other water needs, and impact on water resources. Use along supply chain can be different for different technologies.

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Note: Both electric power options and dimensions are listed in alphabetical order. Lists are not exhaustive or exclusive. Descriptions are generic, not definitive. CCS = carbon capture and sequestration; GHG = greenhouse gas; IGCC = integrated gasification combined cycle; O&M = operations and maintenance; PM = particulate matter; PV = photovoltaic; VOC = volatile organic compounds.

not arguing for a supercomputer model that will give the optimal answer—that's a fool's errand and ignores human nature, one of the most important dimensions when discussing energy issues. There are already many good models on different aspects of energy systems, which can be used more transparently and in a complementary fashion. I am suggesting these tools to enhance our understanding of the problem space so that flexible policies can be developed, implemented, and adjusted when necessary.

As outlined at the end of Part I in more detail, the job of regulator should be more consistent with traditional practices and more predictable in a market-IRP world. Utilities are incented to pursue competitive provision of as many of the services across the electric power value chain as possible. Unbundling is still an excellent idea. The merchant generation segment is mature and has been providing most of the new capacity in conventional and renewable plants for years. There are also many companies that can deliver demand-side technologies and services. The cost-of-service regulation should be replaced with a method to align utility compensation with efficiency and improved customer service instead of building assets for the rate base.

Will this route to a market-IRP be any easier than fixing competitive markets? At this time of political impasse, either option seems equally utopian. Any effort to convince various stakeholders of the superiority of either option is quixotic. Nevertheless, we must continue to argue for the benefits that society can harness from competitive provision of services along the electric power value chain. Otherwise, society will continue to incur unnecessary costs while achieving fewer objectives at a slower pace, in a combative environment where every interest group defends its turf.

My goal has been to expose as many electric power issues and societal costs caused by industry trends of the last 10-plus years as possible and to do so as cohesively as possible. The issues are well-known individually, at least among industry participants and close observers, but hopefully I have conveyed that the sum is greater than its parts. That is, there is value in looking at the objectives, potential solutions, their costs and benefits, and constraints holistically with a fresh eye. An improved IRP can be the platform to deliver this value and avoid the excess costs of the current energy environment. I offer an augmented LCOE not as a finalized tool but as a way to recognize the trade-offs and raise a caution flag against the use of simplistic LCOE estimates in policy discussions. Despite its shortcomings as a professional metric, policy dialogue can leverage LCOE's familiarity to the media and, thus, the public at large.

Getting to common ground requires input from professionals—especially those with long experience in the power sector—in engineering disciplines, energy economics, environmental science and economics, financial economics, law, political science, macroeconomics, and, not least, behavioral science. The interdisciplinary work necessary to develop a market-IRP and complete the augmented LCOE or replace it with better metrics should start without delay.

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