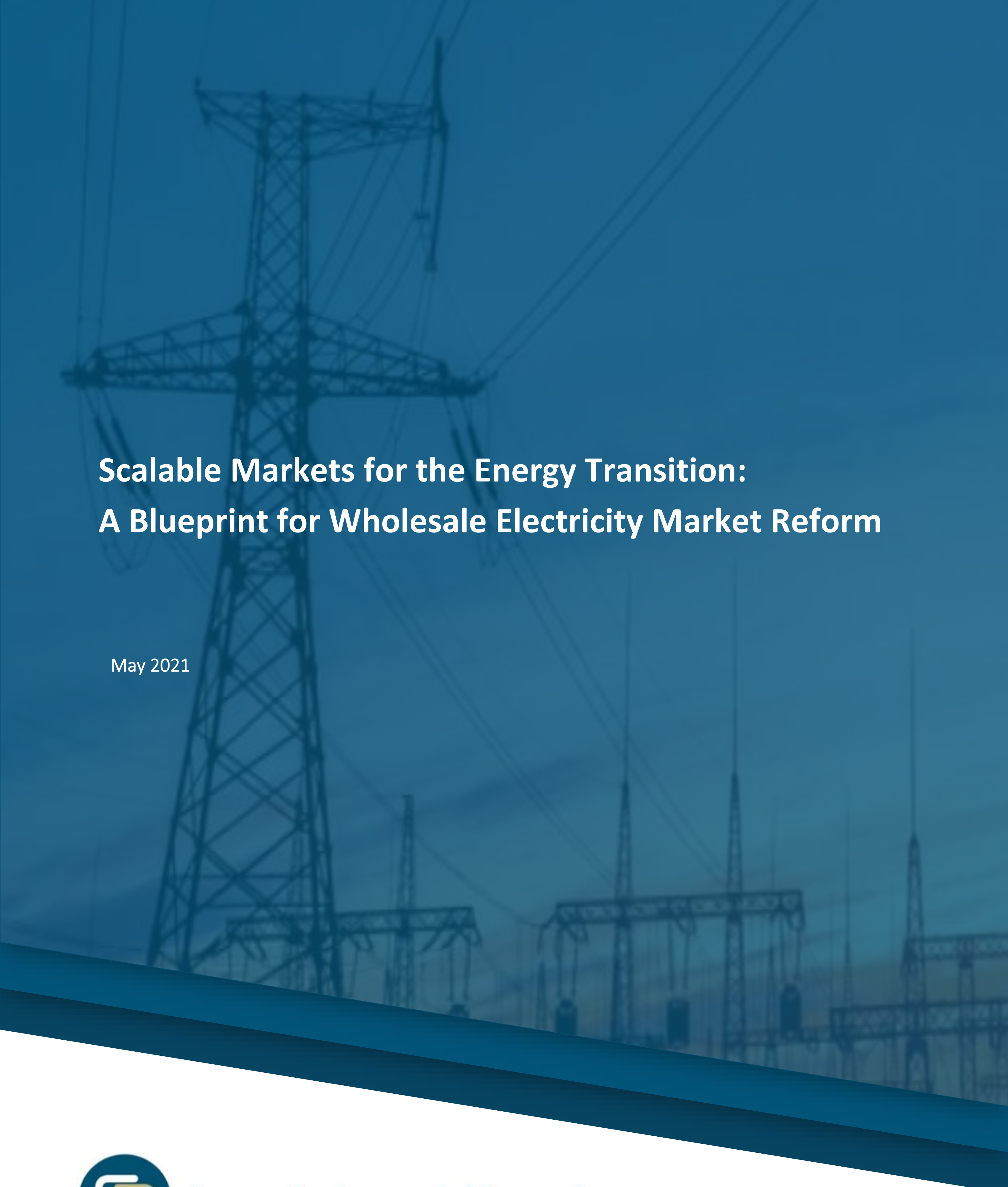

Scalable Markets for the Energy Transition: A Blueprint for Wholesale Electricity Market Reform

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Energy+Environmental Economics

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1 Executive Summary

As the U.S. ramps up efforts to confront climate change by steeply reducing carbon emissions, clean electricity is increasingly seen as the linchpin to achieving economywide goals. Low- or zero-carbon forms of electricity will be needed in unprecedented quantities to reduce carbon emissions in the electricity sector while meeting large increases in electricity demand due to electrification of end uses in other sectors.[1] These resources will reshape the dynamics of the electric grid as the power produced today by on-demand combustion of fossil fuels is replaced by a combination of variable renewables, energy storage resources for balancing, and direct use of low- or zero-carbon fuels.

The enormity of this infrastructure transformation and the profound changes in how the grid will operate have led to legitimate questions about whether existing electricity market institutions will be sufficient to spur the necessary levels of capital investment. In this report, we review existing wholesale electricity market designs and many of the proposals to reimagine them, drawing on technical analyses of deeply decarbonized power systems performed by E3 and others and on E3's experience consulting with a broad spectrum of energy industry market participants and stakeholders. Our goal with this report is to identify practical reforms that can facilitate the rapid transition to clean energy resources needed to achieve deep decarbonization and combat global climate change.

Our review of technical studies of decarbonized grids and existing and proposed market designs leads to several general observations about deeply decarbonized power systems that shape our recommendations for reform of wholesale electricity markets. First, we observe that **the physical needs of a low-carbon grid will remain largely the same as today.** An electricity system operator will continue to need capacity, energy, and grid services – albeit in different quantities and at different times than historically – to ensure that customers' electricity needs can be met efficiently and reliably. Second, however, we expect that **the physical capabilities of the resources that serve those needs will change – dramatically.** Renewables, storage, and other potential low-carbon resources offer significantly different technical capabilities than the traditional portfolios of resources that have been managed by utilities and grid operators in the past. Third, we note that the **"clean" attribute of clean energy serves a societal need, not a grid need.** A reliable power system needs energy, capacity, and grid services and is indifferent to whether the resource that provides those services emits carbon. Rather, the societal goal to rapidly scale up clean energy stems from a desire to avoid the widespread and potentially calamitous impacts of a warming climate.

[1] E3, "Deep Decarbonization Pathways in a High Renewables Future," https://efiling.energy.ca.gov/GetDocument.aspx?tn=223785; Princeton, "Net-Zero America," https://www.princeton.edu/news/2020/12/15/big-affordable-effort-needed-america-reach-net-zero-emissions-2050-princeton-study

Fourth, we observe that **wholesale electricity markets have played an important role in facilitating carbon reductions to date**. They have done this by: (1) leveraging the benefits of scale and diversity across broad geographic areas to facilitate the integration of large amounts of wind and solar generation; (2) reducing carbon emissions through more efficient generator dispatch; and (3) hastening the retirement of older, less efficient and more polluting resources by exposing them to the forces of competition. Finally, we note the **success that existing institutions have had in financing capital-intensive clean energy projects** and dramatically accelerating the pace of clean energy adoption even in the absence of strong federal carbon policy. To be sure, federal policies such as the Public Utility Regulatory Policies Act (PURPA) and investment or production tax credits for renewable energy technologies have played a key supporting role in enabling clean energy adoption to date. But this success indicates that wholesale electricity markets have not been a significant barrier and, in fact, have been key facilitators of clean energy development in the U.S.

From these observations, which we expand upon in this report, we develop a number of recommendations for the reform of wholesale electricity markets to ensure they can procure the capabilities needed for very low-carbon power systems and to operate such systems reliably. We summarize our recommendations generally as follows:

1. **The general structure of existing organized electricity markets in the United States – with separate but related markets for procuring capacity, energy, and ancillary services – should be preserved.** These markets properly identify and efficiently procure the capabilities needed to ensure efficient and reliable operation of modern power systems. While we identify needed reforms for each of these mechanisms, the general structure is sound and does not require a major overhaul.

2. **Reforms are needed to existing Independent System Operator (ISO)/Regional Transmission Organization (RTO) markets to promote efficiency in light of the different capabilities of new resources.** Reforms to these market structures should focus on two general types of improvements: (1) development of more sophisticated methods to dynamically determine system needs based on changing grid conditions; and (2) steps to ensure that all resources including renewables, energy storage and flexible demand can fully participate in markets to the extent allowed by their physical capabilities. We offer a series of specific recommendations to improve the functioning of existing markets along these lines.

3. **Capacity markets should continue to focus on capacity.** Reliable electric power supply is critically important for life safety and the functioning of a modern economy, as recent events in Texas and California have reminded us. Ensuring resource adequacy is a key function of electricity markets. Capacity markets do not directly cause carbon emissions; emissions occur only when the resources are dispatched to provide energy and grid services. Accordingly, clean energy policy should focus on reducing the need for carbon-emitting plants to *operate* while continuing to facilitate the investment needed for resource adequacy. Our recommendations here are aimed at accurately quantifying the contribution of dispatch-limited resources toward meeting capacity needs and ensuring that firm resources are backed by adequate stored or firm energy supplies so they can operate when called upon.

4. **Compensation of the clean attribute – which fulfills a societal need – should occur in a context that is removed from grid operations.** Under a national carbon policy, the price would be determined

either by policymakers (in the case of a tax) or through an economy-wide cap-and-trade, not by electric grid operators. This leaves grid operators to continue to do what they do best – manage the flow of electricity on the grid to serve customer needs – while valuation of non-grid-related attributes occurs in a separate venue. In the absence of a national carbon price, several proposals have been put forth to incorporate the procurement of clean energy attributes into organized capacity markets. We believe these proposals are misguided for several reasons: (1) they are highly complex, in some cases perhaps unworkably so; (2) they may be counterproductive by creating carbon leakage or inhibiting bilateral procurement of clean energy that has proved successful thus far; (3) they are unlikely to resolve and may exacerbate the jurisdictional tension that exists today between states with clean energy targets and a federal government without them; and (4) most importantly, they are unnecessary. Instead, we propose in this report an enhanced bilateral market mechanism that prioritizes implementation flexibility, allowing individual states, private citizens, and corporations to preserve autonomy in the specific mechanisms they choose to procure clean energy.

In order to achieve deep carbon reductions at the lowest possible cost, electricity markets must be accompanied by a scalable market mechanism to signal the value that society places on such reductions. This value is not a function of U.S. electricity markets – climate change is a global challenge that spans all nations and economic sectors. While the literature is nearly unanimous in its conclusion that a price on carbon would yield the most efficient carbon abatement[2], the political will to enact an economywide carbon tax or cap-and-trade program at the national scale has proved elusive. Instead, state and local policymakers, private citizens, and corporations have taken matters into their own hands through electricity-only measures such as Renewables Portfolio Standards (RPS) and voluntary clean energy procurement. Our recommendation for a scalable market mechanism recognizes that this "bottom-up" policy context is likely to continue to be the dominant paradigm for years to come in the United States.

Instead of a highly complex, centrally cleared, multi-attribute forward market, we recommend a deceptively simple change to the existing policy framework: voluntary, multilateral adoption of a uniform definition of clean energy for the purpose of rapidly scaling up low-carbon electricity supplies throughout the U.S. The challenge with today's mix of bottom-up clean energy policies is not that they are ineffective at providing investment signals; on the contrary, they have facilitated the development of over 100 gigawatts (GW) of renewable energy in the last 10 years. Rather, it is that they do not, collectively, achieve least-cost carbon reductions. Today's smorgasbord of state and local clean energy policies includes measures focused on local solar, offshore wind, biomass, waste-to-energy, and other mechanisms with a wide range of effectiveness in terms of cost per ton of carbon reductions. This approach will become increasingly costly as carbon reduction targets become more ambitious.

Our proposal for a Bilateral Clean Energy Market (BCEM) mechanism addresses shortcomings in the scalability of today's policy designs that limit their ability to efficiently reduce carbon emissions and incentivize the clean energy transition. BCEM price formation would reflect the "missing money" needed

[2] We note that there is also a significant body of literature that emphasizes the need for complementary policies to support infrastructure transformation. We do not suggest that a carbon price alone would be sufficient to achieve societal carbon goals; however, we believe that a long-term, stable signal for the value of carbon reductions must be the centerpiece of a comprehensive carbon policy.

to incentivize clean energy resources; i.e., the net cost of clean energy after energy, ancillary services, and capacity market value. The BCEM would have the following characteristics:

+ A uniform definition of the clean energy attribute of energy resources, referred to here as an "Energy Transition Credit" (ETC), for the purpose of rapidly scaling up low-carbon electricity supplies to reduce electricity sector carbon emissions. A major challenge with scaling existing state-jurisdictional clean energy programs is the set of unique, non-standard definitions associated with these programs. While states may have additional policy goals for investing in clean energy resources (such as local air quality, local economic development, market transformation, etc.) and may even define additional attributes to reflect these goals, climate change is a global problem. Harmonizing the definition of the clean attribute could unlock efficiencies by allowing the market to develop clean energy resources in places with the highest resource quality and the lowest cost of grid integration. Unbundling of a universally defined clean energy attribute from other attributes would encourage market efficiency and liquidity, provide a long-term, consistent price signal for investment in clean energy resources, and improve the affordability and thus the political viability of deep carbon reductions.
+ A single centralized attribute tracking system similar to those in place today to track the creation, trading and ultimate retirement of the clean energy attribute. The ETC would serve as a common currency, tradable across all participating jurisdictions. In the BCEM's simplest form, this tracking system would provide all the governance that the BCEM needs; the use of ETCs by individual load-serving entities for compliance would be governed directly by state and local jurisdictions that choose to participate. Tracking of any additional (i.e., non-carbon) attributes of clean energy could continue as today.
+ Partial credit for lower-emitting resources. Today, the average carbon intensity of electricity supply varies widely across regional electricity markets. This difference is expected to narrow over time as coal generation is retired and all regions move toward a mix of renewables, nuclear, and gas generation. This transition can be hastened by providing temporary, partial credit for lower-emitting resources to incentive their dispatch ahead of higher-emitting resources. There are many ways that partial credit could be administered: it could be defined uniformly for all participating jurisdictions relative to a pre-determined baseline; alternatively, it could be determined individually for each participating jurisdiction based on the characteristics of their individual electricity systems to ensure that credits are only earned by displacing higher-emitting resources. We discuss some of the pros and cons of the various options in Appendix B of this report.

Together, these elements establish the foundation for a scalable, flexible framework to encourage investment in the clean energy resources needed to rapidly decarbonize the power system. By aligning market incentives more directly with carbon emissions, the BCEM improves the efficiency of today's clean energy policies and enables better long-term compatibility with the economywide carbon accounting needed to meet long-term climate goals.

2 Introduction

As the U.S. ramps up efforts to confront climate change, it must steeply reduce carbon emissions from all sectors of the economy. Decarbonization of the electric power sector will require a continued transition to low- or zero-carbon sources of electricity; i.e., "clean" energy. Electric power will also be foundational to reducing carbon from vehicles, buildings, and other parts of the economy by replacing direct combustion of fossil fuels with electricity.[3] Together, the transition to clean electricity and the growth of power demand from electrification will require unprecedented quantities of low- or zero-carbon power. This growth of clean energy supply will be a linchpin to achieving economywide carbon goals.

Clean energy resources differ from conventional resources in important ways. Wind and solar power, the largest potential sources of clean energy available today, are variable and uncertain, creating a need for integration services to ensure reliable system operations as significant quantities of these resources are added. Clean energy resources also tend to have a somewhat different cost structure from conventional resources, with higher upfront capital costs and low to zero variable operating costs. This means that facilitating access to low-cost, long-term financing for these resources will be an important goal of clean energy policy and electricity market design. Finally, clean energy resources interact with each other in complex ways, and diverse portfolios of resources are more likely to be able to reduce carbon emissions at low cost than portfolios consisting mostly of a single resource type.

Because these key characteristics of clean electricity resources are different from conventional resources, questions have naturally arisen about whether wholesale electricity markets, which were largely designed during an era when thermal generation was predominant, are able to facilitate the scale-up of clean resources. A number of market reforms have been proposed, principally in the area of capacity remuneration where existing market structures are viewed as either biased against clean energy resources or else incapable of procuring the right mix of capabilities to ensure seamless integration of clean resources. In this report, we review existing wholesale electricity market designs and many of the proposals to reimagine them, drawing on technical analyses of deeply decarbonized power systems performed by E3 and others and on E3's experience consulting with a broad spectrum of energy industry market participants and stakeholders. Our goal with this report is to identify practical reforms that can facilitate the rapid transition to clean energy resources needed to achieve deep decarbonization and combat global climate change.

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[3] E3, "Deep Decarbonization Pathways in a High Renewables Future," https://efiling.energy.ca.gov/GetDocument.aspx?tn=223785; Princeton, "Net-Zero America," https://www.princeton.edu/news/2020/12/15/big-affordable-effort-needed-america-reach-net-zero-emissions-2050-princeton-study

Based on our review, we conclude that the general structure of existing organized electricity markets in the United States – with separate but related markets for procuring capacity, energy, and ancillary services – should be preserved. Wholesale electricity markets have played an important role in facilitating carbon reductions to date by: (1) leveraging the benefits of scale and diversity across broad geographic areas to facilitate the integration of large amounts of wind and solar generation; (2) reducing carbon emissions through more efficient generator dispatch; and (3) hastening the retirement of less efficient and more polluting resources by exposing them to the forces of competition.

We recommend improvements to existing wholesale market designs and operating practices to (1) facilitate optimal utilization of the flexible dispatch capability of both conventional and inverter-based resources such as wind, solar and battery storage, and (2) ensure resource adequacy by accurately characterizing the contribution of both dispatch-limited and "firm" resources. These recommendations reflect technical and economic factors that are equally applicable to ISO/RTO markets and to vertically integrated utilities that operate outside such markets, though the specific implementation needs will depend upon market context.

In order to achieve deep carbon reductions at the lowest possible cost, these technical improvements to electricity markets must be accompanied by a scalable market mechanism to signal the value that society places on such reductions. This value is not a function of U.S. electricity markets – climate change is a global challenge that spans all nations and economic sectors. The literature is nearly unanimous in its conclusion that a price on carbon would yield the most efficient carbon abatement; however, the political will to enact an economywide carbon tax or cap-and-trade program at the national scale has proved elusive. Instead, state and local policymakers, private citizens, and corporations have taken matters into their own hands through electricity-only measures such as RPS and voluntary clean energy procurement. Our recommendation for a scalable market mechanism recognizes that this "bottom-up" policy context is likely to continue to be the dominant paradigm for years to come in the United States.

A variety of proposals have been put forth to integrate clean energy procurement into the functions of wholesale electricity market operators, largely by expanding the role of forward capacity markets to include additional attributes such as clean energy and "flexibility". These proposals would substantially complicate the job of market operators and expand their role in the implementation of clean energy policy, nesting clean energy policy within the confines of electricity markets rather than the other way around. They do little to alleviate existing tension between state and local governments with ambitious clean energy goals and a federal government without them. They may even be counterproductive by interfering with existing mechanisms that have proved successful at financing clean energy development. Most importantly, we believe they are unnecessary to achieve much higher penetrations of clean energy resources.

Instead of a highly complex, centrally-cleared, multi-attribute forward market, we recommend a deceptively simple change to the existing policy framework: bilateral or multilateral adoption of a uniform definition of clean energy for the purpose of meeting state, local and voluntary private clean energy goals. The challenge with today's mix of bottom-up clean energy policies is not that they are ineffective at providing investment signals; on the contrary, they have facilitated the development of over 100 GW of renewable energy in the last 10 years. Rather, it is that they do not, collectively, achieve least-cost carbon reductions. Today's smorgasbord of state and local clean energy policies includes measures focused on local solar, offshore wind, biomass, waste-to-energy, and other mechanisms with a wide range of effectiveness in terms of cost per ton of carbon reductions. This approach will become increasingly costly as carbon reduction targets become more ambitious.

Carbon pricing is a logical, economically efficient approach to ensuring carbon reductions when implemented at the national scale. However, there are significant practical issues with implementing carbon pricing on a state-by-state basis. Chief among these is the potential for "leakage", wherein carbon-intensive activities such as electricity generation migrate across political boundaries to jurisdictions with less stringent standards. As a result, state-led carbon pricing programs, where they exist, have not been the principal driver of carbon reductions that have occurred to date.[4] A federal carbon pricing system would significantly ameliorate these disadvantages but remains a difficult proposition politically. In the absence of an economywide federal carbon price, a mechanism is needed to enhance the effectiveness of state-driven policy actions at reducing carbon emissions.

A BCEM would address the shortcomings of today's clean energy policies by facilitating efficient trading of credits for clean electricity across multiple participating jurisdictions. As we show in this report, a well-designed BCEM can mimic the behavior of a nationwide carbon price in achieving the least-cost carbon abatement measures, at least within the electricity sector. A broadly adopted BCEM could, like a carbon price, enable geographic regions with lower-cost abatement potential to reduce emissions more quickly, while regions where abatement is difficult or expensive can transition more slowly. By agreeing to a uniform definition of clean energy, states and local jurisdictions can opt in to a multilateral framework aimed at achieving a rapid scale-up of clean energy and deep reductions in carbon emissions. Best of all, a BCEM requires no new complicated governance structure; it requires only a common definition of clean energy and a record-keeping entity to track the creation, trading and retirement of clean energy attributes like those that exist today to track Renewable Energy Certificates (RECs).

Federal legislation remains the best way to achieve the scale necessary for efficient nationwide carbon reductions, and federal legislation would likely simplify the design process for a BCEM by shifting it from a multilateral negotiation among interested state, local and private actors to a regulatory process carried out by the Environmental Protection Agency or the Federal Energy Regulatory Commission. Still, a bottom-up BCEM can lay the groundwork for an eventual shift to a federal policymaking locus and would blend seamlessly with an increasingly stringent federal carbon price resulting in efficient carbon reductions at any given point in time. As noted above, a BCEM would work within today's bottom-up policy construct, offering a way to achieve scale and efficiency even in the absence of strong federal policy.

This report proceeds as follows. Section 3 summarizes our overall recommendations for wholesale electricity market design, consisting of key improvements to existing wholesale electricity market structures and the creation of a BCEM. Section 4 summarizes the key features and benefits of a BCEM and describes how the BCEM would interact with the eventual implementation of a federal carbon price. Appendix sections provide additional detail regarding our recommendations for technical reforms to wholesale electric energy, ancillary services, and capacity markets and a more detailed example regarding BCEM baseline definition and tracking.

[4] Cullenward and Victor, "Making Climate Policy Work," December 2020, SBN: 978-1-509-54180-5.

3 Market Design Fundamentals under a Changing Grid

3.1 Current Wholesale Power Market Design

At the advent of deregulation in the 1990s, wholesale electricity markets were designed to procure services traditionally provided by vertically-integrated utilities. Although variations exist across markets, most organized market designs include the following three primary products, consistent with the fundamental requirements of the electricity grid:

+ **Energy:** Market to procure energy on a real-time basis to meet changing demand;
+ **Ancillary Services:** Market to procure sufficient real-time standby capacity to meet expected and unexpected fluctuations in demand and supply; and
+ **Capacity:** Forward market to procure sufficient investments in resources to ensure the reliable provision of energy across a broad range of system conditions[5].

This basic market design has been in place for more than twenty years and has provided the foundation for the procurement and delivery of energy supplies for electricity consumers in large portions of the United States.[6] These organized markets are vital to ensuring competitive electricity supplies in jurisdictions with restructured retail markets. However, their benefits have been recognized in jurisdictions that continue to have regulated, vertically integrated utilities, and, in reality, nearly all organized markets in the U.S. serve a mix of competitive and vertically integrated retail suppliers.

Because the fundamentals of these three markets (including their interdependence) are key to understanding their robustness to anticipated future changes in the resource mix, we briefly describe these markets and the fundamentals of price formation. We conclude that, with a few key improvements, this framework continues to be well-suited to meet the needs of a nearly zero-carbon grid.

3.1.1 Energy

Energy markets procure the production of energy through security-constrained, bid-based auctions to select the least-cost dispatch of generating plants on an hour-by-hour basis.[7] Markets clear at the marginal cost of energy supply at each location. Generators maximize profits by placing bids equal to their short-run marginal cost of generation, which, in most cases, constitutes fuel, variable operations and maintenance, and emissions (if applicable).

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[5] Capacity markets or compensation mechanisms take several unique forms, with differing levels of state and/or ISO oversight. One notable U.S. exception to forward procurement of capacity is the Electric Reliability Council of Texas (ERCOT), which has an energy and ancillary services market with an administratively determined capacity remuneration mechanism tied to real-time market conditions that results in hourly market prices that are much higher than in other markets. Long-term bilateral contracts and hedges against these energy prices are widely used in ERCOT to finance the development of new energy generation resources.

[6] Tierney, Susan F., *Wholesale Power Market Design in a Future Low-Carbon Electric System: A Proposal for Consideration*, November 28, 2020, https://media.rff.org/documents/tierney-white-paper-on-wholesale-market-design-12-15-2020-final-to-wri-rff.pdf

[7] Joskow, Paul L. *Challenges for wholesale electricity markets with intermittent generation at scale: the US experience*. Oxford Review of Economic Policy, Volume 35, Number 2, 2019, pp. 291-331.

Under this market design, generators with a short-run marginal cost less than the clearing price earn margins that contribute toward the recovery of their fixed costs. Resources with lower short-run marginal costs (like nuclear and renewables) earn higher margins in the energy market, while resources with higher short-run marginal costs (like natural gas peaker plants) earn lower margins due to their higher cost and lower frequency of clearing the market.

3.1.2 Ancillary Services

In addition to energy, daily markets require a number of additional grid services to address fluctuating system conditions and the potential for contingencies. There are multiple types of these ancillary services, including frequency regulation and fast frequency response (which respond to changing grid conditions in real time), contingency reserves (spinning and non-spinning reserves, which stand ready to ramp up after the loss of a large generator or transmission line), black start, voltage control and others. Resources that provide ancillary services have a reduced ability to participate in the energy market since they must reserve capacity to maintain the ability to quickly ramp up, which results in foregone energy market margins. Because of this interaction, generators maximize their profits by placing bids equal to their opportunity cost – the amount they expect the standby capacity could have otherwise earned in the energy market. Plants that provide ancillary services typically have either (1) high short-run marginal costs and thus low energy market opportunity (such as gas generators), or (2) have excess capacity that can be utilized only for short periods of time (such as hydroelectric generators). All resources must be sufficiently flexible to meet the technical requirements for the products offered (e.g., spinning reserves must be capable of ramping up within 10 minutes).

In most markets, the energy and ancillary service auctions are cleared simultaneously, allowing for co-optimization to ensure that the combined cost of providing these services is minimized.

3.1.3 Capacity

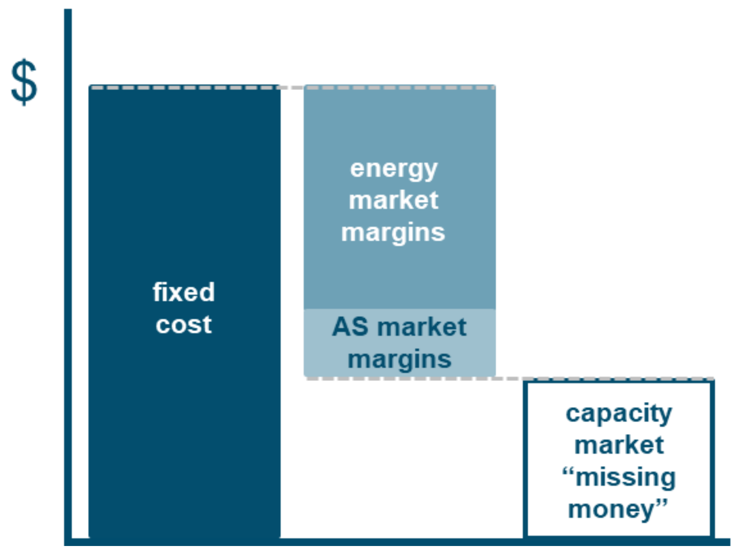
Electricity systems require sufficient capacity to ensure reliable energy supplies across a wide range of system conditions, including very high loads or significant generator outages. Capacity requirements are often structured to cover peak load plus a planning reserve margin (e.g., 15%). In an energy-only market, there is no guarantee that sufficient capacity will enter the market to meet these requirements because many resources with high short-run marginal costs do not earn sufficient margins in the energy market to cover their fixed costs. Bilateral forward contracting can enable buyers to hedge real-time energy market risks, while providing some revenue assurance to suppliers; however, they may still be insufficient to induce market entry, particularly if energy prices are capped or the potential for extreme market volatility is not widely understood.

To incentivize the construction of sufficient capacity, most markets include some form of capacity compensation mechanism, where generating plants can seek to recover the difference between their fixed costs and their expected energy and ancillary service market margins, often referred to as "missing money."[8] Generators maximize their profits by placing bids equal to their go-forward fixed cost of operation less their expected margins in the energy and ancillary service markets. For a plant that has not yet entered the market, its go-forward fixed costs include construction and financing costs. Resource types with low short-run marginal costs that expect to earn significant energy market margins may have little or no missing money and may bid zero in the capacity market auction to ensure that they receive a capacity payment at the market-clearing price.

3.1.4 Interactions Between Markets

Generator bids and price formation for each of the three energy market products (energy, ancillary services, and capacity) are interdependent. As previously noted, ancillary service bids are a function of expected energy market margins, and the system operator clears these markets simultaneously through co-optimization to minimize total costs of operation. Additionally, the capacity market clearing price is directly a function of anticipated dynamics in energy and ancillary service markets. To the extent that energy prices rise or fall, capacity prices can be expected to move inversely. This phenomenon is supported both theoretically and empirically. An illustration of this phenomenon is provided below.

Figure 1: Conceptual Illustration of the "Missing Money" Problem as Applied to Capacity Resources



There is, therefore, an inverse relationship between capacity and energy market prices. If energy market prices (and margins) are low, plants may have to bid-higher capacity prices to ensure that they recover their fixed costs. Conversely, if energy prices (and margins) are high, capacity prices would tend to be lower.

[8] The term "missing money" is attributed to Roy Shanker. For example, see Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003

3.2 A Changing Grid

The electricity system is changing rapidly and significantly due to both policy and economic factors. At the same time, as the cost of renewable energy and energy storage has declined significantly, many states, utilities, and cities have set aggressive electricity sector decarbonization targets that will require the expansive buildouts of zero-carbon resources. The nature of renewable and storage resources is substantially different along several key dimensions from the traditional dispatchable resources (coal, nuclear, natural gas) that dominated the grid for more than a century, as described below:

- **Operating Costs:** The short-run marginal cost of generation of traditional resources – which has historically shaped the dynamics of wholesale energy markets – reflects the cost of fuel and variable operations and maintenance costs. Many clean energy resources have negligible or zero marginal costs.
- **Bidding Behavior:** In a perfectly competitive market, resources competing in the energy market submit bids equal to their marginal cost of generation. This may change in multiple ways. Renewable resources may have incentives to bid into the market at negative prices if energy production is required to realize revenue from a production tax credit or the sale of a clean energy attribute. And while the marginal cost of generation from an energy storage resource may be zero, its bidding behavior will be dictated by its perceived opportunity costs, as its limited state of charge means that dispatching at any one point in time means forgoing potential revenue at a later point.[9]
- **Capacity Characteristics:** Traditional resources subject to economic dispatch are "firm", meaning the system operator can dispatch these resources when needed for as long as needed in order to meet system needs.[10] In contrast, renewable resources generate energy only when the resource is available, e.g., when the wind is blowing, or the sun is shining. Energy storage can discharge when instructed by the system operator but only for limited durations until the stored energy is depleted. Demand response resources similarly can be called a limited number of times for a specified maximum duration. Saturation of power systems with renewable resources can change the hours in which the system is most constrained; this was visible during the August 2020 blackout events in California, which occurred not during the highest load hours in the afternoon but after sundown when solar generation was no longer available.
- **Resource Interactivity:** Traditional dispatchable resources are capable of providing both energy and capacity, irrespective of what other resources are on the system. Because they cannot always be dispatched when needed, renewable and storage resources must be optimized as part of a portfolio of resources that, when combined, can meet the system's needs. The most obvious example is that of solar and battery storage, where a portion of the solar output is used to charge a battery that can continue to generate after sundown, but there are also important interactions

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[9] This dynamic already exists in some energy markets today. The Mid-Columbia (Mid C) bilateral wholesale market is heavily influenced by opportunity costs of hydroelectric generation with significant reservoir storage due to its dominance in the Pacific Northwest's electricity supply.

[10] The capacity value credited to firm resources typically accounts for expectations of unplanned outages. This reduction in capacity value for either anticipated availability or realized performance of less than 100% is used to ensure capacity payments reflect value contributed to the grid.

among other these and other dispatch-limited resources such as wind, hydro, and demand response.

- **Flexibility Requirements:** Grid operators must ensure that the electricity system has not only sufficient capacity to meet energy needs at all times, but also sufficient flexibility to continually balance supply and demand. Historically, production flexibility was needed primarily to meet variable and uncertain demand. Today's system of day-ahead energy and ancillary service procurement, along with the potential for adjustments in resource commitment during the operating day, was designed to ensure this need was met. However, the production from wind and solar generation is also variable and uncertain, increasing overall system variability and adding to flexibility needs. For example, a key challenge in solar-heavy markets has been to ensure reliable operations during sunrise and sunset when large amounts of solar generation quickly come online/offline, requiring countervailing downward and upward ramping responses from conventional resources.

- **Load Interactivity:** Renewable and energy storage resources are increasingly located on the electricity consumer's premises. Advances in technology and manufacturing scale have made it possible for consumers to procure on-site resources at a cost that is competitive with electric utility retail rates, if not yet wholesale with prices. Distributed control technology is also expected to play an increasingly prominent role in helping customers to shape their load in ways that reduce their electric bills while also potentially providing benefits to the system. This raises both jurisdictional challenges – retail markets are regulated by states, while wholesale markets are regulated by the federal government – and technical challenges. Rooftop solar, in many cases, is not directly metered or observable by wholesale market operators, who therefore may not have an accurate view of the potential for cloud cover to result in significant increases in metered load due to reduced onsite production.

A summary of these key dimensions of grid evolution is presented in the table below.

Figure 2: Summary of Key Differences between the Characteristics of Traditional and Future Electric Power Systems

Category	Traditional Grid	Future Grid
Capital Costs	A range of capital costs from low (gas peakers) to high (nuclear)	Relatively high capital costs as a proportion of total lifetime costs
Operating Costs	High variable costs as a proportion of total lifetime costs	Low variable costs as a proportion of total lifetime costs
Bidding Behavior	Set by short-run marginal cost	Impacted by policy and shaped by opportunity cost
Capacity Characteristics	Firm and dispatchable; capacity contributions are independent and additive	Intermittent and dispatch-limited; capacity contributions are interrelated and dependent upon other resources on the grid
Nature of Reliability Constraints	Capacity limited: capacity sufficiency generally ensures energy sufficiency	Capacity and/or energy limited: capacity sufficiency may not ensure energy sufficiency
Flexibility Requirements	Low to moderate, subject to load uncertainty and generator contingencies	High, subject to load variability/uncertainty, generator contingencies, and generator variability/uncertainty due to weather

Category	Traditional Grid	Future Grid
Load Interactivity	Low: grid operators largely serve passive loads	High: loads participate in retail and wholesale markets through self-generation, customer-sited battery storage, or load flexibility

These key differences will cause fundamental changes in the dynamics observed in wholesale markets during the transition to cleaner energy sources. In anticipation of these changes – which have already emerged to a limited extent in some markets today – many have raised questions of whether the current market designs (energy, ancillary services, capacity) that were developed in a previous era are suitable for a future decarbonized grid. Some critiques that have been raised of today's market design include:

+ An abundance of zero-marginal cost generation (wind, solar) will suppress energy prices in the energy market (and thus energy margins) during many hours, and therefore the ability of both clean resources and conventional capacity resources to recover their fixed costs.[11, 12] Energy prices may increase during other hours, but likely not enough to avoid significant reductions in energy margins in the absence of strong policy support such as carbon pricing. For clean resources, this issue is compounded by their relatively higher capital costs.
+ The interactivity between resources (e.g., renewables and storage) can make it difficult to structure markets to procure portfolios of resources that can efficiently meet energy and capacity needs.[13]
+ Renewable and storage resources require significant capital investments (with low to zero operating costs), and the lack of long-term revenue certainty increases the risk and cost of financing these upfront investments.[14]
+ Existing capacity market constructs are perceived as biased against clean energy resources because they favor resources with low capital costs and do not consider the characteristics a low-carbon grid will need such as low-carbon energy production and flexibility.[15] Existing capacity markets are even described as delaying the transition to lower-carbon resources by unnecessarily prolonging the life of emitting resources.[16]

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[11] Tierney *op. cit.*

[12] Gimon, Eric, *Let's Get Organized! Long-Term Market Design for a High Penetration Grid*, December 2020, Energy Innovation, https://files.wri.org/s3fs-public/gimon-lets-get-organized-long-term-market-design-for-a-high-penetration-grid.pdf?X4nQ7AI.bUNpEsP9KlGgk5ttAD2MiUeU

[13] Corneli, Steven, A Prism-Based Configuration Market For Rapid, Low Cost and Reliable Electric Sector Decarbonization, 2020, World Resources Institute, https://files.wri.org/s3fs-public/corneli-prism-markets-for-rapid_decarbonization-final_word_version.pdf?F4wH_vPKbMICE8gYyD90jcQ.X9mOD6.2

[14] Pierpoint, Brendan, *A Market Mechanism for Long-Term Energy Contracts to Support Electricity System Decarbonization*, December 2020, World Resources Institute, https://files.wri.org/s3fs-public/pierpont-long-term-electricity-markets-paper-dec-2020-final.pdf?U8IBZGrr1KZiATJKt4kJ2ascL0xKkdHs

[15] Dennis, Jeff, "Reforming capacity markets to meet clean energy goals and support the grid of the future," Utility Dive, March 22, 2021, https://www.utilitydive.com/news/reforming-capacity-markets-to-meet-clean-energy-goals-and-support-the-grid/597069/

[16] Sierra Club, https://gridprogress.files.wordpress.com/2019/11/too-much-of-the-wrong-thing-the-need-for-capacity-market-replacement-or-reform.pdf

- **The increased flexibility requirements in a high renewable grid** may exceed the capability of the grid to provide this service in the absence of a specific forward market product for flexibility.[17]

3.3 Alternative Market Design Proposals

3.3.1 Description of Market Design Proposals

To address potential shortcomings that have been raised of current market designs to a changing grid, various proposals have been put forward to modify or overhaul existing market designs. Broadly, proposals that seek to overhaul existing designs can be grouped into four categories: (1) centralized forward procurement of clean energy attributes; (2) centralized forward procurement of multiple attributes including clean energy, capacity, and flexibility; (3) energy-only markets with long-term contracting, and (4) ISO-run carbon pricing. Each category is described below:

- **Centralized Forward Clean Energy Procurement:** In this market design, the market operator would procure clean energy through a centralized auction, similar to how other grid services (energy, capacity, ancillary services) are procured. Loads would specify clean energy requirements – either to meet policy requirements or to voluntarily exceed it – and clean resources would bid a $/megawatt-hour (MWh) price to collect any missing money between the cost of the clean resources and expected revenues in the traditional energy, capacity, and ancillary services markets. The Brattle Group's Forward Clean Energy Market (FCEM) is an example of this type of design.[18]
- **Centralized Multi-Attribute Procurement:** Under this type of design, the market operator would run a forward auction to procure multiple products, including potentially capacity, clean energy attributes, specified energy delivery quantities, and flexibility attributes. A more holistic evaluation of resources by the single central procurement agency would enable the entity to optimize the generation mix while accounting for interactions and synergies between resources (e.g., solar and storage). Resources would bid their costs and attributes into the long-term auction and would be required to perform to this standard in order to receive full compensation. An optimization model would solve for the lowest overall system cost while procuring sufficient capacities of each specified attribute. Examples of this type of market design include the "configuration market" proposed by Corneli[19] and the Integrated Clean Capacity Market proposed by Brattle[20].
- **Energy-Only Market with Long-Term Contracting:** In this market design, load-serving entities (LSEs) would be responsible for forward procurement of hourly energy requirements through bilateral contracts with supply. Contracts with specific low-carbon resources would ensure that LSEs are

[17] Mays, Jacob, "Missing Incentives for Flexibility in Wholesale Electricity Markets," Energy Policy 149, 112010 (2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3623962

[18] https://www.brattle.com/news-and-knowledge/publications/forward-clean-energy-markets-a-new-solution-to-state-rto-conflicts

[19] Corneli, *op. cit.*

[20] Spees, Kathleen, The Brattle Group, The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition, October 1, 2020, https://www.brattle.com/news-and-knowledge/publications/the-integrated-clean-capacity-market-a-design-option-for-new-englands-grid-transition

compliant with all clean energy requirements. This market design would be similar to the energy-only market designs that exist today, where capacity is not identified as an independent attribute but rather is incorporated into forward contracts for energy delivery. Examples of this market design have been proposed by Gimon[21] and Pierpont.[22] Gramlich and Hogan[23] propose to retain today's centralized spot markets, supplemented with "active decentralized forward procurement" of capacity and clean energy.

+ ISO-Run Carbon Pricing: ISO-New England and the New York ISO[24] have both advocated carbon pricing across their footprints as a means to send a long-term price signal to incentivize clean energy development. ISO-NE has called for "net" carbon pricing[25] in which generators would pay administratively determined carbon prices to the ISO in proportion to their carbon intensity, which the ISO would then rebate to wholesale electric customers according to an agreed-upon formula (such as load-weighted share, in proportion to state policy goals, or through more complicated formulas). The NYISO sponsored an Analysis Group report that provides a detailed roadmap for the implementation of a carbon price in New York.[26]

Each of these designs aims to address the changing needs of the grid through a holistic solution; i.e., simultaneous forward procurement of multiple power system attributes.

3.3.2 Critique of Alternative Proposals

Each of these proposals responds thoughtfully to the challenges facing the electricity industry, and many of the ideas have significant merit and may form elements of evolving policy solutions. However, there is no perfect policy solution available absent comprehensive federal action, and each of the ideas described above has significant drawbacks or limitations. We discuss some of these in this section. Rather than critiquing each proposal individually, we draw out and discuss common themes from all the proposals.

+ Geographically-limited market designs cannot easily be linked to other markets. A central procurement process in a single market or jurisdiction could be successful at locking in prices and quantities under long-term contract for the various services procured: energy, capacity, flexibility, and clean energy attributes. However, the results would necessarily be specific to the power system for which the auction was conducted. The clean energy attribute prices would not represent a broader, societal value of clean energy; rather, they would represent the net cost of procuring clean energy at that specific time on that specific power system. This introduces

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[21] Gimon, *op. cit.*

[22] Pierpont, *op. cit.*

[23] Gramlich, Rob and Michael Hogan, *Wholesale Electricity Market Design for Rapid Decarbonization: A Decentralized Markets Approach*, June 2019, https://gridprogress.files.wordpress.com/2019/06/wholesale-electricity-market-design-for-rapid-decarbonization-a-decentralized-markets-approach.pdf

[24] https://www.nyiso.com/carbonpricing

[25] https://www.iso-ne.com/static-assets/documents/2020/09/carbon_pricing_technical_conf_comments_opening_statements.pdf

[26] Tierney, Susan F. and Paul H. Hubbard, Analysis Group, *Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets*, October 3, 2019, https://www.nyiso.com/documents/20142/2244202/Analysis-Group-NYISO-Carbon-Pricing-Report.pdf/81ba0cb4-fb8e-ec86-9590-cd8894815231?t=1570098837163

challenges to linking these markets to those conducted for other power systems, in which a different set of loads, resources, fuel price assumptions, etc. were used. More broadly, central procurement fixes the clean energy attribute within the context of a specific power system, rather than placing the power systems within the context of a societal value of clean energy.

+ **Multi-attribute auctions are highly complex.** Simultaneous, centralized procurement of multiple attributes such as energy, capacity, clean energy attributes, and flexibility would be highly, perhaps unworkably, complex. It would require computer optimization algorithms that simultaneously value multiple attributes across a long-time horizon over which there is significant uncertainty. Valuing resources with disparate dispatch patterns and operational characteristics would require detailed energy and ancillary service market simulations. Accurate valuation would also require simulating future grid conditions based on forecasts of market penetration for each of many different technologies.

  Further, accurately parsing out the central solution to determine accurate pricing by time period for individual characteristics such as capacity, clean energy and flexibility within a complex, long-term, multi-attribute optimization may not be straightforward. By contrast, today's capacity markets are relatively simple in concept: market participants bid their net cost into a central auction that procures a single, uniform product for a fixed term.

  Because it procures only two products simultaneously (capacity and clean energy), the Integrated Clean Capacity Market (ICCM) concept is conceptually simpler and may not suffer from the same challenges as more complex versions. However, it still mixes together two attributes that are only tangentially related: the most economic capacity resources today (existing combustion turbines) will not provide clean energy until a scalable clean fuel is available, while the most economic clean energy resources (solar and wind) provide very little capacity in many markets. Energy storage may be deemed to qualify as "clean" for the purpose of an ICCM, but, in reality, its impact on system emissions is complex and will depend on future real-time market conditions that determine the resources available for charging, and it will only be truly emissions free if it is charged from zero-carbon energy. We see no fundamental technical advantages to linking these two products in this manner.

+ **Mandatory, centralized auctions may lead to loss of autonomy and shift risk to captive ratepayers.** In today's markets, individual market participants develop their views on key input parameters such as fuel prices, the cost trajectories of various technologies, the nature and extent of future arbitrage opportunities, and others. Individual market participants also have different tolerances for various sources of risk, such as variations in annual wind or solar production, production curtailment, merchant exposure to fuel price risk and market volatility, contract term, and many others. Centralized procurement would require centralized determination of a common set of input assumptions and parameters for use in the procurement algorithm. A significant concern with this concept is that it represents a step backward from competitive trade among multiple buyers and sellers with differing preferences, as in today's deregulated markets. The cost of the long-term contracts would necessarily be allocated to load through a cost allocation process that resembles cost-of-service regulation. As a result, loads would bear the risk that technologies under contract become uneconomic relative to emerging technologies.

+ **Mandatory markets risk disrupting existing procurement models.** A mandatory, centralized forward auction would require the standardization of all attributes to be valued in the auction, including contract duration, performance guarantees and other terms and conditions in addition to the clean energy attribute. This runs the risk of stifling voluntary procurement by corporate entities, which purchase clean energy to meet a variety of self-determined climate targets. If clean energy supply and demand must be cleared through a centralized auction instead of today's highly flexible options for bilateral contracting, voluntary market participants may reduce their procurement due to the perceived inflexibility and risks associated with centralized auction design. For example, a corporate off-taker may value attributes of a resource such as technology type or coincidence with hourly load that are not captured in a centralized auction for clean attributes. A major shift towards centralized clearing of clean attribute supply and demand could jeopardize ongoing procurement activity in the increasingly large voluntary markets, which are expected to drive 55-85 GW of solar and wind capacity additions by 2030.[27]
+ **Federal Energy Regulatory Commission (FERC)-jurisdictional markets may not resolve jurisdictional tension.** Today, clean energy markets are defined and regulated by state and local governments or by voluntary actions from individuals and corporations. Complex, centralized forward procurement mechanisms would bring many aspects of clean energy procurement that have traditionally been the purview of states under the jurisdiction of the market operators and the FERC. This could be compatible with today's environment of state-driven procurement as long as multiple states can agree on the specifications of a centrally-cleared attribute market. Otherwise, this may not resolve the jurisdictional tension that exists today and risks exacerbating it.
+ **Forward energy contracting may not be sufficient to assure resource adequacy.** Some proposals put forward long-term contracting for energy alone as a substitute for a centralized capacity construct. These proposals may be motivated by a concern that today's capacity markets are inconsistent with the scale-up of clean energy or are contributing to the retention of existing emitting resources. This concern is misplaced, as we discuss in this report, because capacity products do not themselves result in adverse environmental outcomes – emissions only occur when the resources are dispatched in real-time markets. Moreover, we believe that administrative capacity constructs have several significant advantages over mandatory bilateral forward energy contracting:
    - Only centrally administered requirements can fully and accurately assess load diversity across the market footprint in determining physical resource need. Many individual loads are highly variable, either requiring significant over-procurement of forward energy to ensure full hedging, or else leaving a portion of energy demand unhedged. These variations

[27] Kobus, James, Ali Nasrallah and Jim Guidera, *The Role of Corporate Renewable Power Purchase Agreements in Supporting US Wind and Solar Deployment*, March 2021, https://www.energypolicy.columbia.edu/research/report/role-corporate-renewable-power-purchase-agreements-supporting-us-wind-and-solar-deployment

are proportionately much smaller when evaluated at the aggregated system level. Even if individual market participants know their own load with certainty, they cannot know the extent to which their high-load periods coincide with those of other market participants.

- Similarly, only a central administrator can accurately capture diversity among resources (e.g., solar and storage), as described elsewhere in this report, in contributing to capacity needs. This will be an increasingly important factor in determining overall system need as the share of these resources grows.
- Capacity-only constructs, as currently configured, do not require an administratively determined strike price or energy quantity. Capacity resources are required to be available whenever needed for as long as needed and are harshly penalized if they do not perform. The strike price is determined in real time by the energy market software based on prevailing market conditions. Where administrative elements are utilized, they are related to the value of lost load in determining the quantity of capacity to be forward procured. Thus, this construct focuses the administrative action on the true externality – capacity adequacy to avoid loss of load – while leaving financial energy risk hedging in the hands of individual market participants.

+ **Sub-regional carbon pricing may be ineffective due to leakage.** As discussed above, there are significant practical issues with implementing carbon pricing on a state-by-state basis, particularly the potential for "leakage," wherein carbon-intensive activities such as electricity generation migrate across political boundaries to jurisdictions with less stringent standards. Prior modeling by E3 of the PJM Interconnection (PJM) region found that imposition of a carbon price in a portion of the PJM footprint led to both higher costs and higher emissions due to reduced generation at gas plants in states with a carbon price and increased generation at coal plants in states without a carbon price[28]. Administrative remedies such as border adjustments have been proposed; however, these are complex. While leakage is significantly mitigated if the carbon price could be applied across an entire market, this raises thorny jurisdictional issues if not all states in the market footprint have the same carbon policy goals.

We believe that our proposal for a Bilateral Clean Energy Market that complements existing energy, capacity, and ancillary service markets avoids most of these challenges. We note that while auctions or other central centralized procurement mechanisms may suffer from challenges related to complexity and central determination of key input parameters, there may be markets where voluntary or state-run auction mechanisms are desired to drive long-term contracting, where it may not naturally occur. For example, in deregulated retail markets, retail energy providers have uncertain future loads and no guarantee of cost recovery, which reduces their incentives and ability to sign long-term bilateral contracts. In such markets, a purely *voluntary* auction mechanism may help facilitate clean energy procurement while maintaining flexibility for procurement via alternative channels, such as sourcing of clean energy from other markets, where it is more cost-effective. The key distinction is that individual market participants retain the

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[28] E3, *Least Cost Carbon Reduction Policies in PJM*, 2020, https://www.ethree.com/wp-content/uploads/2020/10/E3-Least_Cost_Carbon_Reduction_Policies_in_PJM-1.pdf

autonomy to define the product they wish to procure and the means they wish to use for procurement. Additionally, these jurisdictions would benefit if the attributes procured in the auction could also be traded in a national BCEM.

3.4 Robustness of Existing Market Designs to a Changing Grid

Despite the changing nature of the on the grid, as described in Section 3.2, a close examination of existing market designs finds that a significant redesign is not needed, provided a few targeted but important changes are implemented. This section describes the results of this examination and presents recommendations for these key improvements.

Our review of technical studies of decarbonized grids and existing and proposed market designs leads to several general observations about the grid that shape our recommendations for the reform of the wholesale electricity markets. First, we observe that **the physical needs of a low-carbon grid will remain largely the same as today.** An electricity system operator will continue to need capacity, energy, and grid services – albeit in different quantities and at different times than historically – to ensure that customers' electricity needs can be met reliably. Second, however, we expect that **the physical capabilities of the resources that serve those needs will change – dramatically.** Renewables, storage, and other potential low-carbon resources offer significantly different technical capabilities than the traditional portfolios of resources that have been managed by utilities and grid operators in the past. Third, we note that the **"clean" attribute of clean energy serves a societal need, not a grid need.** A reliable power system needs energy, capacity, and grid services and is indifferent to whether the resource that provides those services emits carbon. Rather, the societal goal to rapidly scale up clean energy stems from a desire to avoid the widespread and potentially calamitous impacts of a warming climate.

Fourth, we observe that **wholesale electricity markets have played an important role in facilitating carbon reductions to date**. They do this by: (1) leveraging the benefits of scale and diversity across large geographic areas to facilitate the integration of large amounts of wind and solar generation; (2) reducing carbon emissions through more efficient generator dispatch; and (3) hastening the retirement of less efficient and more polluting resources by exposing them to the forces of competition. Finally, we note the **success that existing institutions have had in financing capital-intensive clean energy projects** and dramatically accelerating the pace of clean energy adoption, even in the absence of strong federal carbon policy. To be sure, federal policies such as PURPA and investment or production tax credits for renewable energy technologies have played a key supporting role in enabling clean energy adoption to date. But this success indicates that wholesale electricity markets have not been a significant barrier; in fact, they have been key facilitators of clean energy development in the U.S.

From these observations, we develop a number of recommendations for the reform of wholesale electricity markets to ensure they can procure the capabilities needed for very low-carbon power systems and to operate such systems reliably. We summarize our recommendations generally as follows:

1. **The general structure of existing organized electricity markets in the United States – with separate but related markets for procuring capacity, energy, and ancillary services – should be preserved.** These markets properly identify and efficiently procure the capabilities needed to

ensure efficient and reliable operation of modern power systems. While we identify needed reforms for each of these mechanisms, the general structure is sound and does not require a major overhaul.

2. **Reforms are needed to existing ISO/RTO markets to promote efficiency in light of the different capabilities of new resources.** Reforms to these market structures should focus on two general types of improvements: (1) development of more sophisticated methods to dynamically determine system needs based on changing grid conditions; and (2) steps to ensure that all resources including renewables, energy storage and flexible demand can fully participate in markets to the extent allowed by their physical capabilities. We offer a series of specific recommendations to improve the functioning of existing markets along these lines.

3. **Capacity markets should continue to focus on capacity.** Reliable electricity supplies are critically important for life safety and the functioning of a modern economy, as recent events in Texas and California have reminded us, and ensuring resource adequacy is a key function of electricity markets. Capacity markets do not directly cause carbon emissions; emissions occur only when the resources are dispatched to provide energy and grid services. Accordingly, clean energy policy should focus on reducing the need for carbon-emitting plants to *operate* while continuing to facilitate the investment needed for resource adequacy. Our recommendations here are aimed at accurately quantifying the contribution of dispatch-limited resources toward meeting capacity needs and ensuring that firm resources are backed by adequate stored or firm energy supplies so they can operate when called upon.

4. **Compensation of the clean attribute – which fulfills a societal need – should occur in a context that is removed from grid operations.** Under a national carbon policy, the price would be determined either by policymakers (in the case of a tax) or through an economy-wide cap-and-trade, not by electric grid operators. This leaves grid operators to continue to do what they do best – manage the flow of electricity on the grid to serve customer needs – while valuation of non-grid-related attributes occurs in a separate venue. In the absence of a national carbon price, several proposals have been put forth to incorporate the procurement of clean energy attributes into organized capacity markets. We believe these proposals are misguided for several reasons: (1) they are highly complex, in some cases perhaps unworkably so; (2) they may be counterproductive by creating carbon leakage or inhibiting bilateral procurement of clean energy that has proved successful thus far; (3) they are unlikely to resolve and may exacerbate the jurisdictional tension that exists today between states with clean energy targets and a federal government without them; and (4) most importantly, they are unnecessary. Instead, we propose in this report an enhanced bilateral market mechanism that prioritizes implementation flexibility, allowing individual states, private citizens, and corporations to preserve autonomy in the specific mechanisms they choose to procure clean energy.

We expand on these conclusions in this section and provide additional detail in Appendix A.

3.4.1 Energy and Ancillary Services Markets

A low-carbon grid will continue to need adequate energy supplies that are dispatched and balanced on a daily and hourly basis to meet fluctuating energy demand. Existing energy market bid-based auctions are efficient at dispatching electricity systems in a way that minimizes total short-run cost. While the proportion of zero-marginal cost resources bidding into these markets will increase over time, daily and real-time optimized dispatch will continue to be a critical function of market operators. Critiques of market designs have largely agreed that these markets are needed.

However, it is prudent to continually reevaluate the specific optimization mechanisms to ensure they continue to produce efficient dispatch outcomes. In particular, some critiques have focused on potentially missing signals for ramping and grid flexibility. We offer the following five recommended reforms to these markets to ensure that they continue to dispatch available resources efficiently among increasing grid flexibility needs.

1. **Evaluate operating reserve needs dynamically.** Ancillary service procurement requirements today are largely static and based on crude estimates of potential net load variability. However, as the proportion of variable generation on the system increases, and as carbon emission regulations become more stringent, developing more sophisticated methods of calculating the necessary reserves will allow the system to operate more efficiently by reducing the amount of thermal generation held online to provide reserves, while maintaining or improving reliability.

2. **Unlock full flexibility of wind, solar, and other inverter-based resources.** While wind and solar generation is a cause of increased system flexibility needs, these resources can themselves be operated very flexibly. Increased integration of these resources into wholesale market dispatch will provide opportunities to optimize their operation to maximize system efficiency.

3. **Separate upward and downward reserve products.** Some, but not all, markets procure regulation as a single product, in which a generator commits to being available for either upward or downward dispatch at a symmetric price and volume. As renewable share and reserve needs grow, potentially incorporating new flexibility reserve products, distinguishing between upward and downward reserve products will enable more efficient dispatch of both renewable and conventional generators.

4. **Fully optimize energy storage during market operations.** Energy storage is one of the most flexible resources available on a power system. It can charge or discharge, shift energy to different time periods, and, as discussed above, provide a variety of grid services. Market software must also evolve to capture the maximum value from these resources, accounting for all relevant drivers of storage variable costs.

5. **Incorporate price-responsive demand in energy markets**. In most energy markets today, there is very little demand that is price responsive, meaning that while the supply curve might take on a familiar, upward-sloping shape, the demand curve is essentially vertical. "Bending the demand curve" by allowing loads to participate in wholesale markets offers multiple benefits to the electricity system as a whole. A deeply decarbonized electricity system that relies heavily on

variable resources whose capabilities are driven by the weather will alternate between periods of abundant supply and periods of relative scarcity. End uses like electric vehicle charging and water heating are good candidates to shift electricity demand from the latter period to the former, serving as a form of virtual storage to facilitate the integration of renewable resources. This will require variable pricing mechanisms that signal to consumers when to reduce energy demand and when to increase it.

Additional technical detail on each of these recommendations is provided in Appendix A.

3.4.2 Capacity Markets

Forward capacity markets or procurement requirements are a feature of organized energy markets everywhere in the U.S. except in ERCOT.[29] The function of these markets has been to ensure that sufficient capacity is procured on a forward basis to meet acceptable standards for resource adequacy, generally defined as loss-of-load expectation of no more than one day in 10 years. These markets are an important source of revenue for generators, particularly in Northeastern markets where most generation is owned by independent power producers (IPPs). However, many of the generators that clear these markets are fueled by natural gas or coal, and the organized capacity markets have been criticized for extending the lifetime of these resources.[30]

Other critiques have suggested that capacity markets should be reformed to do more than just procure capacity (e.g., that they should also procure flexibility[31]), or that low-carbon sources of capacity should be prioritized. Our review of scalable market structures concludes that these critiques are misplaced. While flexibility and clean energy are both important to a well-functioning, reliable power system that also meets clean energy goals, other venues are better suited for procuring these attributes. Meanwhile, resource adequacy remains critical for a modern economy, meaning that capacity constructs continue to have an important job to do.

At the same time, capacity markets must also evolve to reflect the increasingly complex and interactive nature of energy resources. We offer four recommendations for capacity market reform to enhance their ability to ensure resource adequacy:

1. **Keep the capacity markets focused on capacity.** A number of suggestions have been made for expanding capacity markets to procure flexibility or clean energy. These suggestions are unnecessary and perhaps counterproductive to ensuring efficient, scalable markets for clean energy. Research suggests that the fast response times and accurate dispatch of inverter-based resources like solar photovoltaics (PV) and wind power, plus the expectations for a large economic buildout of battery storage in response to energy and capacity market price signals, will provide

[29] In CAISO, there is no formal ISO-run capacity market, but the CPUC's RA program serves an equivalent purpose.

[30] Roberts, Casey, Sierra Club, "PJM's Costly Capacity Cushion", March 16, 2020, https://www.sierraclub.org/articles/2020/03/pjm-excess-capacity-cost

[31] Tierney, *op cit.*

more than enough flexibility to meet real-time system needs without additional forward capacity market products.[32]

2. **Use effective load carrying capability (ELCC) for accurate capacity accreditation.** The higher the penetration of non-firm resources such as wind and solar, the more important it will be for market operators to use robust methods to evaluate the contribution these resources can make toward capacity needs. Stemming from the Loss-of-Load Probability (LOLP) modeling that system operators have used for decades to ensure adequate capacity, ELCC is increasingly preferred as the best method of measuring the capacity contribution of non-firm resources because of its robust consideration of the widest possible range of weather and resource outage conditions as well as its ability to translate all resources into a common currency. Using the ELCC approach ensures that dispatch-limited resources are compensated appropriately for their contributions toward meeting capacity needs, reducing the "missing money" that they must recover through clean energy attribute markets. ELCC can be used for accurate accreditation of conventional resources as well; however, for most power systems, an unforced capacity (UCAP) approach yields nearly identical results to ELCC with significantly less complexity.

3. **Ensure that "firm" resources are truly firm.** Most conventional resources are considered firm, meaning they can be turned on when needed and operated for as long as needed to ensure reliability. However, these resources are not truly firm if lack of fuel prevents them from operating when called upon. Capacity market accreditation practices must evolve to address the question of energy availability. This could be assured through firm natural gas transportation contracts or onsite fuel storage. More generally, market operators should reexamine current practices related to generator certification and performance requirements, as well as central assumptions about peak load forecasts, in light of the increasing evidence that a changing climate is resulting in more frequent and severe extreme weather events.[33] The question of standards for weatherization, for example, has been debated vigorously since the ERCOT events of February 2021.

4. **Account for price-responsive demand when assessing system needs.** The principal role of a forward capacity market is to procure sufficient capacity to enable supply and demand to match in real-time under all but the most exceptional conditions. The inherent challenge is that capacity procurement decisions must be made on a forward basis, as much as three years ahead, when the precise level of demand is highly uncertain. If a significant portion of demand were able to respond to prices and reduce consumption during high-priced hours, the quantity of capacity that would need to be procured on a forward basis could be reduced substantially.

Additional detail on each of these recommendations is included in Appendix A.

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[32] Loutan, et al., *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*, https://www.nrel.gov/docs/fy17osti/67799.pdf ; E3, *Investigating the Economic Value of Flexible Solar Power Plant Operation*, https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

[33] For example, ISO-NE and PJM have reformed markets rules to incentivize capacity performance and ensure seasonal reliability constraints can be met in the wake of 2013-14 winter outages and fuel shortages.

3.4.3 Environmental Attribute Markets

As the U.S. increases its focus on mitigating climate change by reducing carbon emissions, there is a growing need for consistent carbon accounting and clear incentives to drive the energy transition. A large and growing number of studies have demonstrated that deep greenhouse gas (GHG) reductions in all sectors of the economy are needed in order to achieve deep economywide reduction targets on the order of 80% or more below 1990 levels by 2050.[34]

While achieving these goals is likely to require coordinated policy changes across all levels of government, there is nearly universal agreement that a price on carbon would result in the most efficient carbon abatement. A price on carbon signals the value that society places on averting the damage caused by climate change. It enables the market to seek out the least-cost emissions reductions at any given point in time, whether they come from solar energy, electric vehicles, or building shell retrofits. A national or even a global price on carbon could enable geographic regions with more low-cost abatement potential to reduce emissions more quickly, while regions where abatement is difficult or expensive can transition more slowly. The more aggressive the carbon goal is, the more important it will be for policymakers to invoke the power of market discipline to keep costs from escalating unnecessarily.

However, a federal carbon price may prove difficult to legislate in today's polarized political environment. And state-driven carbon pricing programs to date have significant drawbacks: (1) the lack of political will to impose financial pain on carbon emitters; (2) frequent carve-outs for important industries and large employers due to fear of job migration; and (3) the potential for carbon leakage, where carbon pricing results in migration of carbon-intensive activities between jurisdictions without a concomitant reduction in global carbon emissions.[35] This latter phenomenon is perhaps most directly observed in the electricity industry, where studies have indicated that carbon pricing in one jurisdiction can result in both higher costs and higher carbon emissions by shifting electricity generation from gas generation in jurisdictions with carbon pricing to coal generation in jurisdictions without.[36] These challenges have resulted in jurisdictions with carbon pricing enacting more traditional command-and-control policies in addition to carbon pricing; in California, these so-called "complementary policies" are estimated to account for 80% of emissions reductions through 2020.[37]

In the electricity sector in particular, states have favored production quotas—principally in the form of Renewables Portfolio Standards—as the preferred means for achieving clean energy goals. These policies are simple, intuitive, and offer a politically appetizing "carrot" for clean energy (as opposed to the "stick" of carbon pricing). They also align better with the limits of state jurisdiction; RPS statutes place the compliance burden on state-regulated utilities and load-serving entities, incentivizing clean energy development through regulation of these entities' procurement activities rather than directly regulating carbon dioxide emissions from power plants whose output may flow across state lines.

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[34] E3, "Deep Decarbonization Pathways in a High Renewables Future," Princeton, "Net-Zero America."

[35] Cullenward and Victor, *op. cit.*

[36] E3, Least Cost Carbon Reduction Policies in PJM, *op. cit.*

[37] E3, "Achieving Carbon Neutrality in California," 2020, https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf

The good news is that these policies, if designed well, can mimic the best aspects of a carbon price by facilitating competition and providing tangible price signals to incentivize investment.[38] For a solar developer seeking to finance new projects, the ability to generate RECs trading at $20/MWh is a fungible source of value. The advent of state RPS programs and corporate clean energy goals has created a diverse marketplace for compliance instruments like RECs alongside organized markets for traditional power commodity products like energy and capacity.

While these policies have been successful in creating markets for various types of clean energy, there are two major shortcomings in how they have been implemented to date that limit their long-term scalability.

+ Firstly and most importantly, there is no standardized definition and price signal for clean energy that can enable efficiencies across jurisdictions. With regard to RPS policies, each state has its own unique definition of qualifying renewable resources. Some states have created multiple RPS resource categories, such as California's three RPS "buckets"[39]. Some states have additionally created "Zero Energy Credit" (ZEC) programs to provide financial support for existing nuclear facilities. ZECs and RECs are generally not interchangeable. There are many other examples. While this multiplicity of resource definitions may serve specific state policy goals, they are, collectively, a significant hindrance to efficient carbon reductions.
+ Secondly, as presently implemented, clean energy standards do not provide incentives for more frequent dispatch of lower-emitting resources over higher-emitting ones. If clean energy standards are the primary policy for carbon reductions, they may result in a missed opportunity to reduce near-term emissions via fuels switching and hasten the retirement of more carbon-intensive resources. For example, a credit for zero-carbon energy does nothing to price the substantial difference in carbon emissions between an inefficient coal plant and an efficient combined cycle gas plant. However, this drawback is more of a temporary phenomenon since the marginal emitting resource for all markets will trend toward natural gas as the nation's aging coal fleet is retired.[40]

Addressing these shortcomings in our current energy market design is critical to achieving an affordable and equitable energy transition that scales to meet long-term policy objectives.

The prior sections provide recommendations for how existing market designs can be modified to accommodate a changing resource portfolio to continue delivering the same key services needed for reliable, efficient electricity markets (energy, capacity, and ancillary services). However, the proposed changes do not address the key question animating policy discussions today: How, if at all, should electricity markets be modified to provide financial support for clean energy investments? In other words, the market reforms identified up to this point may still leave the problem of "missing money" for clean energy resources, illustrated in the chart below.

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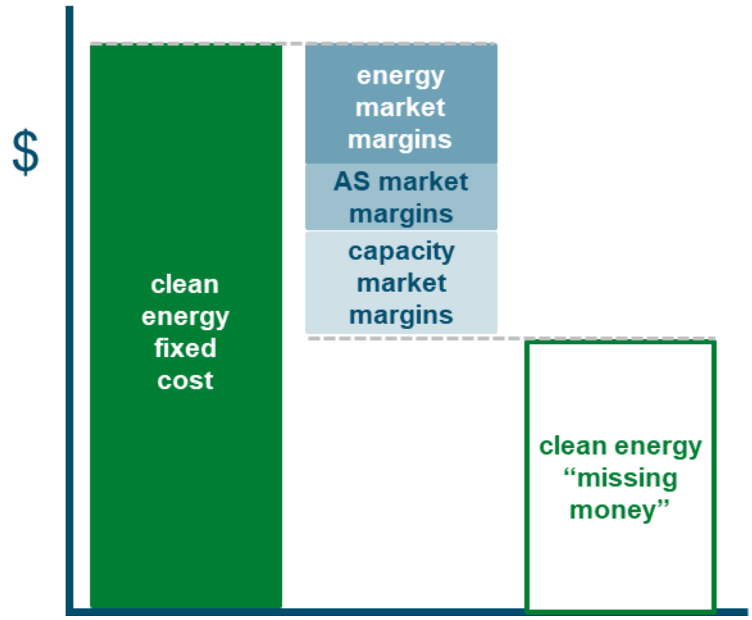
[38] E3, Least Cost Carbon Reduction Policies in PJM, *op. cit.*

[39] https://www.cpuc.ca.gov/General.aspx?id=6442463711#:~:text=Category%203%3A%20RECs%20that%20do,RECs%20themselves%2C%20not%20the%20energy

[40] Assuming gas prices remain near today's historically low levels, we expect a combination of economics and environmental regulations to drive a majority of the U.S. coal fleet offline over the next decade. This will leave gas generation as the marginal source of emissions across nearly all U.S. markets.

Figure 3: *Conceptual illustration of the "missing money" problem as applied to clean energy resources*



There are many options to recognize and compensate for the clean attribute of energy resources. As discussed above, classical economics has focused on carbon pricing schemes that, in theory, would provide efficient signals to invest in new resources and reduce emissions from existing ones. However, if a carbon price is not politically feasible, a BCEM may be a good substitute.

The BCEM would have the following characteristics:

+ A uniform definition of the clean energy attribute of energy resources, referred to here as an "Energy Transition Credit" (ETC) that would be awarded per MWh of low- or zero-carbon generation. A major challenge with scaling existing state-jurisdictional clean energy programs is the set of unique, non-standard definitions associated with these programs. While states may have additional policy goals for investing in clean energy resources (such as local air quality, local economic development, market transformation, etc.) and may even define additional attributes to reflect these goals, climate change is a global problem. Carbon emissions in California have the same impact on the climate as carbon emissions in Maine. Harmonizing the definition of the clean attribute could unlock efficiencies by allowing the market to develop clean energy resources in places with the highest resource quality and the smoothest grid integration. Unbundling of the low-carbon attribute from other attributes of clean energy would maximize market efficiency and liquidity, providing a long-term consistent price signal for investment in clean energy resources.
+ A single centralized attribute tracking system similar to those in place today to track creation, trading, and ultimate retirement of the carbon attribute. The ETC would serve as a common currency, tradable across all participating jurisdictions. In its simplest form, this tracking system would provide all the governance that the BCEM needs; the use of ETCs by individual load-serving entities (LSEs) would be governed directly by state and local jurisdictions. Tracking of non-carbon attributes of clean energy could continue as today.

+ Partial credit for lower-emitting resources. Today, the average carbon intensity of electricity supply varies widely across regional electricity markets. This difference is expected to narrow over time as coal generation is retired and all regions move rapidly toward a mix of renewables, nuclear and gas generation. This transition can be hastened by providing temporary, partial credit for less-emitting resources. There are many ways that partial credit could be administered: it could be defined uniformly for all participating jurisdictions relative to a pre-determined baseline; alternatively, it could be determined individually for each participating jurisdiction based on the characteristics of their individual electricity systems. The next section discusses some of the pros and cons of the various options.

The Energy Transition Credit would integrate seamlessly into existing electricity market designs due to the interactions in price formation with other energy market products. Because the price of the clean attribute is a function of the missing money of the fixed cost of clean energy relative to energy, ancillary service, and capacity market margins, the price will dynamically adjust as these other markets evolve. To the extent that an abundance of zero marginal cost generation suppresses the energy margins of all resources, the value of an ETC will necessarily increase in order to ensure sufficient and efficient clean energy procurement. This saturation effect would occur at different times in different markets; markets with high-quality renewable resources and lower-cost grid integration would likely saturate first. The cost of creating an ETC would rise in these markets, causing suppliers to look to other markets for their next investments. In this way, the BCEM would mimic the functioning of a national carbon price.

The following sections provide additional detail about the nature and characteristics of the BCEM and the ETCs it would create, and how the BCEM would enable a transition towards deeper, longer-term decarbonization.

4 BCEM Design and Implementation

As discussed in Section 3, the BCEM would provide the "missing money" needed to incentivize the adoption of clean energy required to reduce carbon emissions in an efficient manner. In Section 4, we describe the key features of a BCEM design and implementation considerations that will shape its ability to scale and drive new investments.

4.1 Key Features of a BCEM

4.1.1 BCEM Independence from Existing Power Markets

A BCEM designed to incentivize clean energy attributes would function independently of other wholesale power attributes, such as energy and capacity, which would be valued in their respective markets. BCEM price formation would reflect the "missing money" needed to incentivize clean energy resources; i.e., the net cost of clean energy after energy, AS, and capacity market value.

Demand for clean energy will increase over time due to both increasing overall demand for energy and increasing targets for the percent of energy from clean sources. Under equilibrium conditions – that is, in the absence of any temporary ETC oversupply or undersupply that causes price excursions – clearing prices for clean energy will reflect the cost of new entry or life extensions of existing resources. The resources that offer the lowest expected net cost for clean energy over their life will be the most competitive sources of supply, taking into consideration both any capital costs associated with the resources and differences in the value of energy, ancillary services, and capacity they provide.

Procurement of clean energy has generally functioned well under today's paradigm of bilateral contracting and would continue to do so under a BCEM. While most clean energy resources are characterized by large upfront capital costs and long asset lives, this has not limited the development of new clean energy projects today. Instead, providers of capital have used a variety of mechanisms to facilitate low-cost financing of clean energy. Long-term bilateral power purchase agreements (PPAs) and financial hedges have proven sufficient to incentivize multi-billion-dollar outlays for new solar, wind, geothermal, and battery storage projects. States like California have generally met or exceeded their RPS targets via bilateral procurement of diverse resources without the need for a centralized market.

Today's buyers of clean energy range from state agencies to utilities to corporate buyers. Any market for clean energy must recognize the diverse types of demand with different offtake needs, which are best served by flexible bilateral contracting. In a BCEM, there is no need for an ISO role in defining or certifying the attribute or facilitating the trade of certificates.

A BCEM that complements and operates outside of energy, capacity, and ancillary service markets obviates the need for a complicated, ISO-operated, multi-attribute forward market such as those discussed above in Section 3.3. The BCEM provides the revenue stream needed for clean energy procurement, while the ISOs can continue to focus on efficient daily operations through locational marginal pricing (LMP)-based markets, supplemented with forward capacity auctions to ensure resource adequacy.

4.1.2 Standardized Definition for Clean Energy Attribute

The BCEM builds off today's most successful policy mechanisms for incentivizing clean energy and provides the opportunity to enhance them for greater future efficiency and scalability. While today's policies have driven investment in a variety of clean energy resources, the BCEM would help identify which resources offer the most "bang for the buck" in terms of carbon reductions. The BCEM would incentivize investment in the most cost-effective resources by pooling supply and demand, creating a deep liquid market for clean energy, and facilitating flexible procurement that recognizes the diversity of clean energy buyers, clean energy resources, and their associated financing needs.

Clean energy is compensated through many different policies and market mechanisms today, including:

- Research and development (R&D) grants and federal research spending focused on innovation;
- Federal tax incentives, such as the Investment Tax Credit (ITC), Production Tax Credit (PTC), and eligibility for accelerated depreciation;
- Federal loan guarantees for large nuclear power project investments;
- Higher energy market prices driven by carbon costs imposed on fossil-fueled generators;
- State policy mandates, such as REC and zero-emissions credits (ZEC) programs and offshore wind carve-outs;
- State incentive programs for selected technologies (e.g., California's Self Generation Incentive Program and New York's NY-Sun program)
- State retail energy tariffs that allow cross-subsidization of selected resources, such as rooftop solar;
- State tax exemptions for various forms of energy investments;
- Voluntary market premiums paid by consumers for RECs, carbon offsets, or other green attributes; and
- Standardized tariffs administered by utilities according to the PURPA.

Each of these policies employs a different approach to incentivize investment in clean energy resources. In most cases, policymakers prescribe the size of the incentive. For example, the value of the PTC is administratively set by federal legislation. In other cases, policy mandates require compliance at any cost up to an administrative cap.[41] Perhaps the most diverse and impactful clean energy incentives today are state mandates that fall under this latter category. A majority of states now have mandates such as RPS targets that require that specific types of energy be generated at a premium cost determined by the market.

Under state mandates, energy providers pay significantly different amounts for different types of clean energy. For instance:

- Solar REC (SREC) programs pay between \$20 and \$200+/MWh depending on the state;

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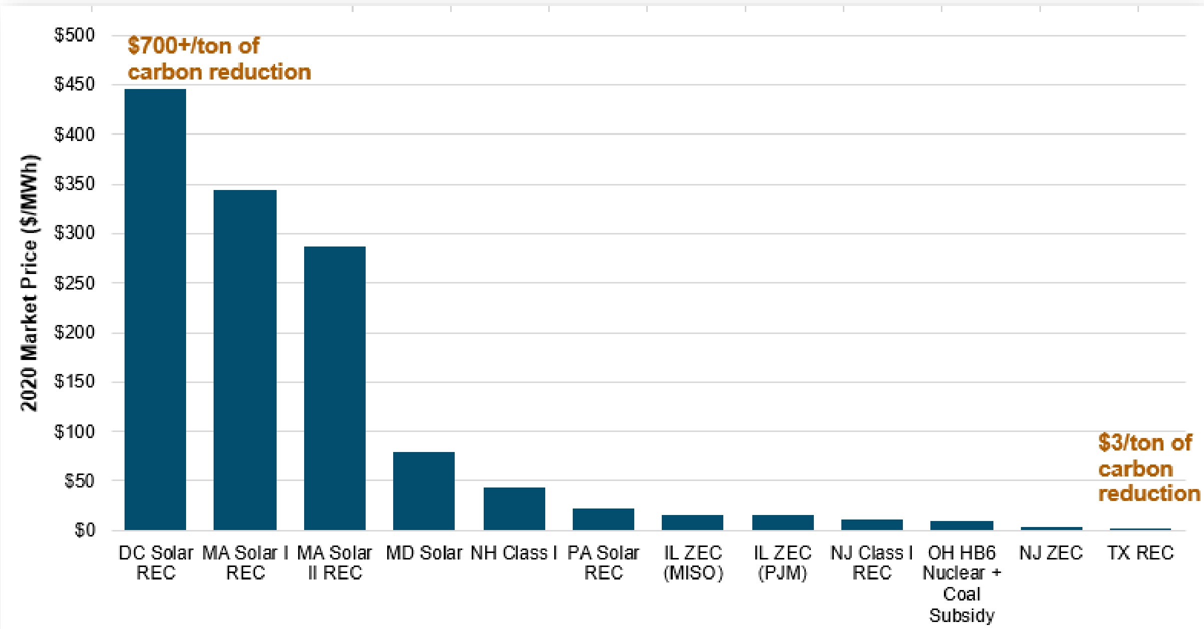
[41] Many state mandates include an alternative compliance payment that effectively serves as a cap on the cost of clean energy.

- Offshore wind RECs (ORECs) have paid \$20 to \$100+/MWh for projects currently under contract covering a mix of bundled and unbundled attributes;
- ZEC programs pay nuclear plants between \$4 and \$20+/MWh depending on the state;
- Generic RECs for renewable energy located anywhere in PJM currently trade around \$10/MWh;
- Power plants receive credits for burning specific fuels, such \$5/MMBtu for biomass in Minnesota (equivalent to \$40+/MWh), \$4/ton for waste coal in Pennsylvania (equivalent to \$3.50/MWh), and varying amounts for other selected fuels. [42]

Collectively, these incentives set a wide range of prices for the same fundamental commodity: one MWh unit of energy.

Figure 4. Current Market Prices per MWh Vary Widely by Market



If each MWh of clean energy offsets a MWh generated from gas, which emits roughly 0.6 tons of CO_2 per MWh, then these clean energy incentives are paying anywhere from \$3 to \$700+ per ton of carbon abatement.

To be clear, there are wider goals for each of these incentives than the generation of a MWh of clean energy. Indeed, state policy mandates have been instrumental in prioritizing strategic industries, whether to incentivize the commercialization of new technologies or to preserve good-paying jobs associated with a transitioning industrial sector. In these cases, state incentives are paying for additional attributes beyond just carbon reductions. Policy goals stated for clean energy initiatives include economic development, market transformation, and local air quality considerations.

[42] Based on E3 analysis of EIA data for fuel consumption and generation at sample plants.

However, to achieve deep levels of carbon reductions and reach the levels of clean energy adoption contemplated in many state policies, such as the "100% clean" goals now in place in several jurisdictions, clean energy incentives must transition from kickstarting new industries to scaling them at cost-competitive economics. After all, a $300/MWh premium for clean energy (nearly 10x the average cost of wholesale power) may be viable when paid for just 1% of all MWhs, but at 10% adoption, this would nearly double the average cost per MWh with minimal carbon benefits.

Standardizing the definition of the clean energy carbon attribute offers clear opportunities for scalability. By allowing all types of clean energy to compete within a single marketplace, policymakers can lay the groundwork for a scalable, low-cost energy transition with a single definition and price for a "clean" MWh. Competition would drive procurement of the most cost-effective forms of clean energy, while states would still have the option to support priority industries through one-off incentives. In effect, unbundling the carbon attribute from other policy objectives would allow for better transparency and price signals to all parties, including those who set state policies.[43]

4.1.3 Credit for Fuel-Switching to Lower-Carbon Resources

Today, every clean MWh has a different impact on carbon emissions, depending on what alternative source of power it displaces. When wind generation is added to the grid, it may offset emissions from a coal plant (approximately 1 ton of carbon per MWh), a gas plant (0.3-0.6 tons/MWh) or, in rare cases, hydropower or other renewables (zero emissions). However, each MWh of wind produces a REC that can be used for RPS compliance regardless of what generation would have been operating in its absence.

This simplistic feature of RPS programs is both a strength and weakness: all MWh that meet programmatic criteria are treated equally, creating a fungible certificate that can be traded to enable LSEs to balance compliance portfolios. It also avoids the need for states to estimate, either before the fact or after, the carbon emissions reductions associated with a given project, some of which would inevitably occur at power plants outside of the state's jurisdiction. We do not propose to deviate from this principle that one MWh of clean energy receives the same credit regardless of its location, with one limited exception, which we discuss in this section.

While the simplicity of RPS programs helps to create market liquidity, we believe that one enhancement to this idea could improve carbon impact: providing temporary, partial credit to less-emitting generation. The principal drawback of simple, clean energy quotas, from a carbon perspective, is that they do not provide incentives for reducing the dispatch of more carbon-intensive resources in favor of less carbon-intensive ones. Providing partial credit to less-emitting resources would remedy this shortfall and enhance the ability of the BCEM to achieve efficient carbon abatement, albeit at the cost of added programmatic complexity.

Modeling by E3 and others of power systems across the U.S. has consistently shown that coal-to-gas fuel switching offers some of the least-cost carbon reductions over the next decade. Coal generation has steadily declined since 2011, due to many factors including low natural gas prices, environmental

[43] For example, if solar RECs trade at $150/MWh today and a generic MWh of clean energy is worth $10/MWh, then the solar attribute is effectively priced at $140/MWh. Crediting resources for clean attributes on a standardized basis and project-specific attributes on a separate basis would allow for more independent accounting and valuation of each respective attribute.

regulation of criteria pollutants, and inferior economics in the face of low-cost renewable energy. However, there is still a major opportunity to reduce carbon emissions through further reductions in coal generation in favor of lower-emission resources. In the absence of a carbon price, a well-designed clean energy credit could incentivize fuel-switching via the same mechanisms used to incentivize zero-emission generation today. For example, all resources with the potential to reduce emissions could be awarded credit on a sliding scale based on their emissions intensity relative to a common baseline. An illustrative example of this is provided in Figure 5.

Figure 5: Carbon Emissions Rates and Attribute Credits for Different Power Plant Technologies

Plant Type	Fuel Carbon Intensity (tons/MMBtu)	Typical Heat Rate (MMBtu/MWh)	Emissions Rate (tons/MWh)	Percent Reduction Relative to Coal	RECs/ZECs Received under Today's Programs	ETCs Received under BCEM
Coal plant	0.10	10	1.00	-	0	0
Gas CT	0.05	10	0.50	50%	0	0.5
Gas combined cycle gas turbines (CCGT)	0.05	7	0.35	65%	0	0.65
Zero-emitting resources (renewables, nuclear)	-	-	0.00	100%	1	1

In markets where coal generation is not prevalent, such as the California Independent System Operator (CAISO) and the Northeast (ISO-NE, NYISO), natural gas is the remaining primary source of carbon emissions. In these markets, emissions-based crediting for lower-emitting resources does not offer significant benefits because opportunities for fuel-switching are more limited. Instead, offering a simpler system of standardized credits to zero-emission resources would be equally effective.

A transition in power supply away from coal will likely obviate the need for partial crediting in the future. For this reason, we see partial crediting of lower-emission resources such as natural gas generation as a potential temporary solution to accelerate the energy transition. Once carbon emissions in a given market are driven primarily by gas, partial crediting could be reduced to zero to reflect a lower baseline emissions rate.[44] Alternatively, the baseline could be set by the most efficient natural gas plant to enable a continued partial credit for resources that are partly supplied by Renewable Natural Gas (RNG) or that have incomplete carbon capture. The table below shows that, despite the different carbon intensities of electricity markets today, gas is likely to become the marginal resource in all markets over the next 10-15 years as coal plants retire. The role of partial crediting for lower-emitting resources like gas would be to

[44] While cleaner fuels such as hydrogen or renewable natural gas offer clear additional emissions benefits, these fuels are not in widespread use today and are not expected to be a major source of carbon reductions in the power generation sector through 2030. Rather, these fuels are expected to play a larger role in solving for the final, most costly MWh to decarbonize via renewable energy and battery storage. In that future scenario, the use of these fuels would be better incentivized via carbon pricing, which can more flexibly incentivize the differences in carbon intensity of future fuel mixes.

accelerate this transition and minimize emissions during the transition period by incentivizing more carbon-efficient dispatch.

While a partial credit for lower-emitting resources would provide a clear incentive for emissions reductions and accelerated coal retirements, it may also prove administratively complex. We note that a variety of other policy mechanisms or market forces could potentially drive comparable outcomes by 2030, such as environmental regulations that reduce coal combustion, pressure on investors to divest from coal, and persistent availability of low-cost gas and renewable energy that outcompetes coal plants on the basis of marginal costs of energy production.

Figure 6. Average and Marginal Emissions Rates by Market[45]

Market	2019 Average Emissions Rate for Fossil Generation (tons/MWh)	2019 Marginal Emissions Rate (tons/MWh)	Projected 2035 Average Fossil Emissions Rate (tons/MWh)[46]
CAISO	0.38	~0.35–0.65	~0.35–0.45
ISO-NE	0.38	~0.35–0.65	~0.35–0.45
NYISO	0.42	~0.35–0.65	~0.35–0.45
ERCOT	0.56	~0.35–1.1	~0.35–0.45
PJM	0.61	~0.35–1.1	~0.35–0.45
MISO	0.75	~0.35–1.1	~0.35–0.45
SPP	0.79	~0.35–1.1	~0.35–0.45

A partial crediting approach requires two key features: (1) a baseline emissions rate; and (2) generator-specific emissions rates. There are numerous ways this could be implemented to improve policy outcomes. More detailed recommendations and an example of a partial crediting approach are provided in Appendix B.

4.1.4 Flexibility in Contracting, Financing, and Trading of Clean Energy

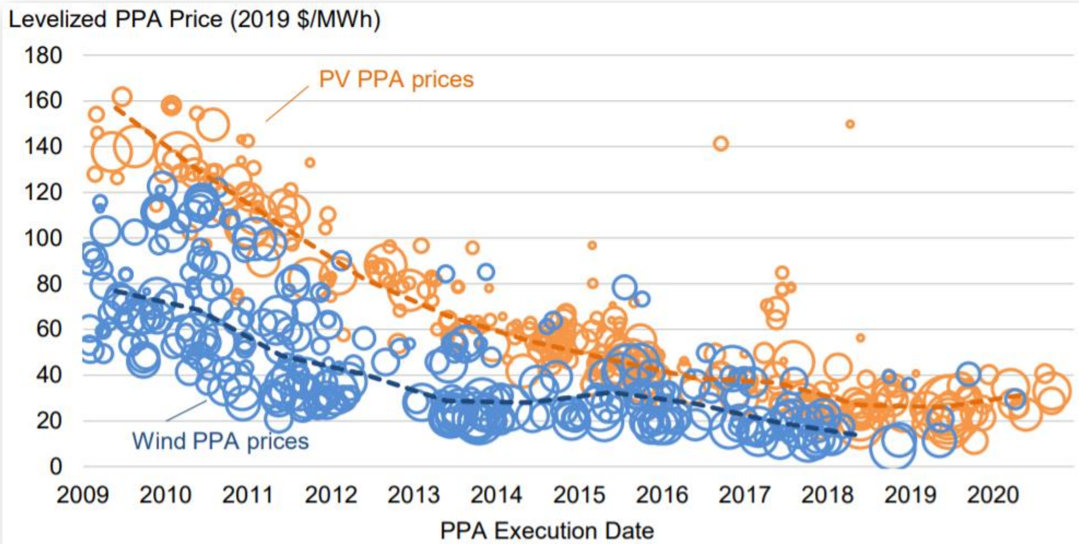
The primary rationale for the variety of clean energy market mechanisms that has been proposed is the need to secure long-term financing for what are generally capital-intensive resources. We agree that project finance is an important component of the clean energy transition. However, it is not clear that a centralized, market-wide auction mechanism is needed to ensure the "bankability" of new projects. Existing, bilateral clean energy markets have financed the development of over 150 GW of new clean energy resources from 2000 to 2020. A majority of this capacity has been project-financed at highly

[45] Source: EPA eGRID data (accessed at https://www.epa.gov/egrid/data-explorer), E3 estimates for 2019 and 2035 based on marginal emissions from gas and coal and average emissions

[46] Assuming all coal plants are retired by 2035.

competitive costs of capital due to the low risk associated with renewable energy projects, which feature predictable development timelines and costs, proven modular technologies with minimal operational risks.

Figure 7. Wind and Solar PPA Prices by Execution Date



Source: Lawrence Berkeley National Laboratory, https://emp.lbl.gov/sites/default/files/webinars/bolinger_webinar_december_8_2020_16x9.pdf

In fact, the current regime of bilateral contracting has been termed a "golden age for power plant procurement" in reference to the highly competitive, all-time low costs for new clean energy from a variety of sources.[47]

Several recent factors have contributed to this trend of highly competitive costs of clean energy under today's bilateral contracting regime:

+ **Increased procurement via competitive all-source request for proposals (RFPs).** Utilities and state agencies typically select their largest investments in clean energy via competitive procurements with deep pools of bidders. Increasingly, utilities are turning to *all-source* RFPs to identify the most cost-competitive sources of power from a wide field of technologies.[48]
+ **Increasing sources of low-cost, tax-efficient financing.** NREL estimates that new renewable energy projects have access to the lowest financing costs of any technology today, cheaper than the costs of capital for new fossil-fueled power plants, as shown in Figure 8.[49] In addition, a growing pool of capital is available to monetize tax credits and maximize the use of low-cost debt in order to

[47] Energy Innovation, "Marking the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," April 2020, https://energyinnovation.org/wp-content/uploads/2020/04/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices.pdf

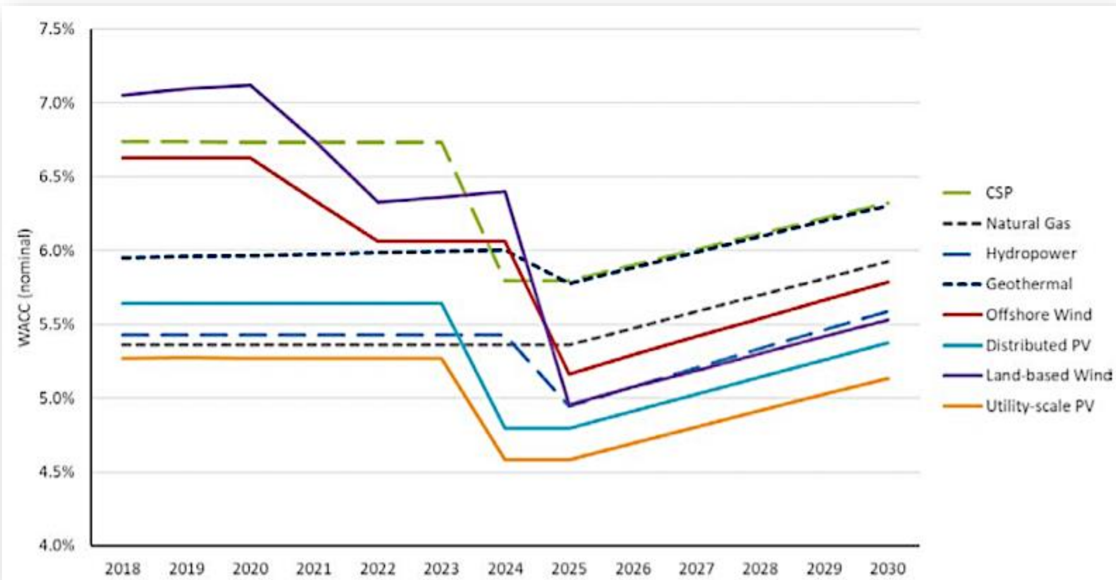
[48] Ibid.

[49] NREL, "Current and Future Costs of Renewable Energy Project Finance Across Technologies," July 2020, https://www.nrel.gov/docs/fy20osti/76881.pdf

minimize overall project costs, with tax-equity investment volume projected to grow from $10 billion in 2017 to around $15-18 billion in 2021.[50]

+ **Increasing numbers of creditworthy off-takers.** Historically, utilities and financial hedge markets have served as the primary creditworthy counterparties to long-term offtake contracts for new clean energy investments. In the past decade, however, corporate buyers have emerged as a growing source of demand for clean energy with the ability to commit to the long-term contracts needed for low-cost project financing. At the same time, new market platforms like LevelTen Energy have emerged to connect buyers and sellers of clean energy and provide price discovery in the increasingly liquid market for long-term PPAs.

Figure 8. *NREL Forecasted Weighted Average Cost of Capital of Different Energy Generation Technologies, 2018-2030*[51]



Source: NREL, "Current and Future Costs of Renewable Energy Project Finance Across Technologies," https://www.nrel.gov/docs/fy20osti/76881.pdf

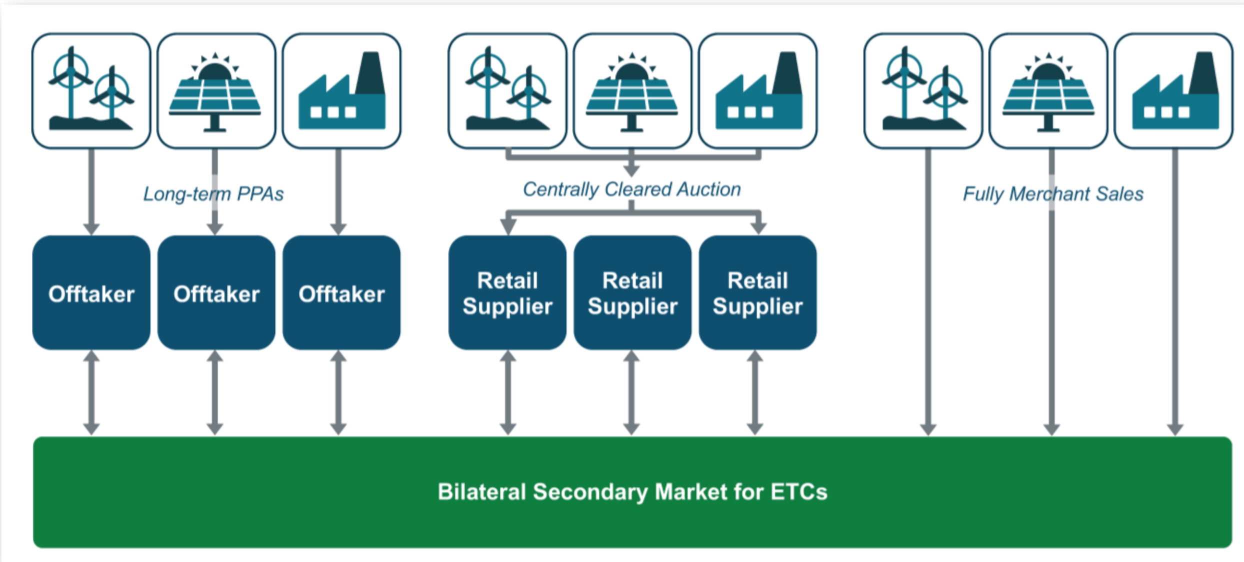
We believe that the key component for securing project finance is a stable, long-term price signal to reflect the value of the clean energy attribute. This value arises from the societal preference for clean energy. In other words, the value of the clean energy credit "currency" derives from the government—or consumer—policy requiring decreasing carbon emissions over time and corresponding increases in carbon-free power. Our proposal for a *bilateral* clean energy market recognizes this source of value, which may differ by party, by providing the necessary price signal for clean energy, while building off the strengths of the renewable energy finance market.

[50] https://www.projectfinance.law/publications/2021/february/cost-of-capital-2021-outlook/

[51] NREL, "Current and Future Costs of Renewable Energy Project Finance Across Technologies," July 2020, https://www.nrel.gov/docs/fy20osti/76881.pdf

While we see value in flexible contracting via all possible channels, our proposed BCEM does not preclude states from sponsoring centralized auctions, which may be useful in states with 100% retail competition or if private capital starts to dry up once the largest and most motivated corporations have procured enough clean energy to meet their electric energy and sustainability-related needs. However, any attributes procured through these auctions should then be tradable in a broader regional or national BCEM to ensure the benefits of a larger, competitive market. The national BCEM price would, in turn, serve as a "price-to-beat" to discipline bids into a state-specific auction. We believe the ability to transact via many mechanisms for a single, standardized clean energy credit will foster the most competitive market while enabling the most innovative, flexible contracting tailored to an increasingly diverse range of technologies and market participants in the clean energy industry.

Figure 9. *Flexibility in ETC Transactions under BCEM*



4.2 BCEM Implementation and Scalability

A fundamental strength of the BCEM concept is its flexibility to be implemented alongside existing policy and market mechanisms and expanded piecemeal over time. However, there are several points of integration with existing policies that have implications for the adoption and scalability of the BCEM. For example, states have already set a variety of independent long-term climate goals with various RPS and CES structures intended to facilitate them. A BCEM is more likely to be adopted if it maintains state independence and autonomy while providing clear benefits to participants over going it alone.

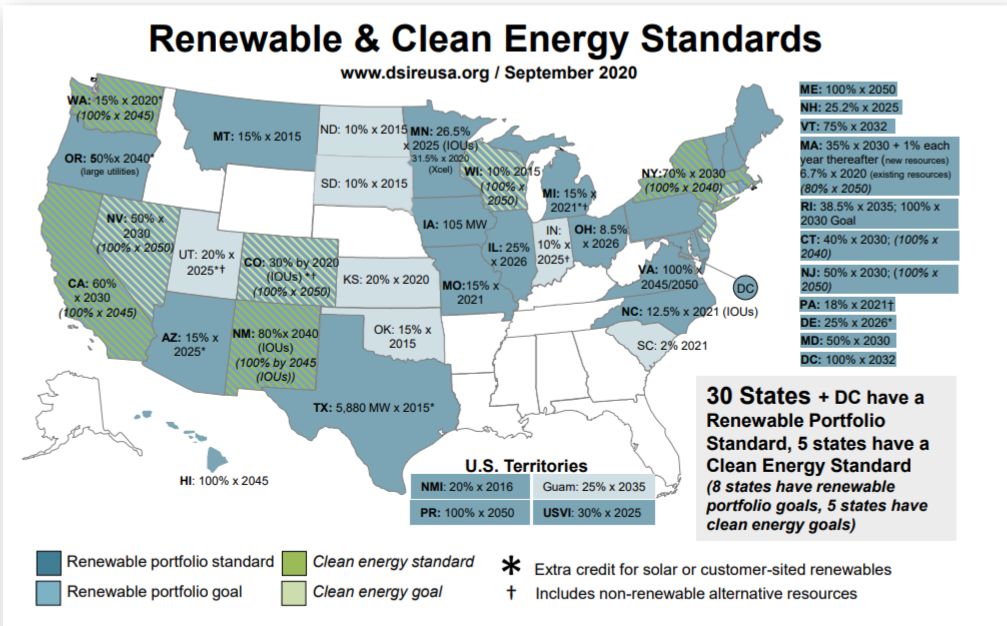
We believe that a deep, standardized BCEM empowers states to amplify their clean energy impact, while maintaining control over their policy goals. A liquid bilateral market for clean energy would continue to put states at the forefront of climate policy while offering several benefits over today's more fragmented policy regime. Under a BCEM, states would maintain their ability to prioritize specific technologies if necessary and accelerate their policy goals while also enabling a more diverse, cost-effective menu of resource options.

The BCEM would also maintain the flexible bilateral contracting environment that has fueled growing corporate procurement of clean energy in the past decade while creating a more standardized framework for measurement and crediting of carbon-free generation.

4.2.1 Integration with Existing State, Utility, and Customer Clean Energy Targets

Over 30 states have RPS and/or CES policy goals that utilize REC markets to facilitate compliance. These policies vary widely in timeline, level of compliance, and qualifying resources.

Figure 10: State Renewable Portfolio Standards and Clean Energy Standards



Source: DSIRE, NC Clean Energy Technology Center, https://s3.amazonaws.com/ncsolarcen-prod/wp-content/uploads/2020/09/RPS-CES-Sept2020.pdf

One clear benefit of a BCEM mechanism is its similar structure to already-established attribute markets and the similar flexibility afforded to states and other clean energy buyers with regards to goal setting. Under a coordinated multi-state BCEM, states could continue to set their own targets for clean energy supply as they do today and could modify these targets, as needed, to meet changing policy goals. As clean energy has rapidly fallen in cost over the past decade, states have set increasingly ambitious climate policies. A BCEM would continue to enable states to raise their targets as they see fit or to back off the accelerator if their policies become cost prohibitive. Likewise, a BCEM enables buyers of clean energy to continue to set goals and procure energy on their own bilateral terms.

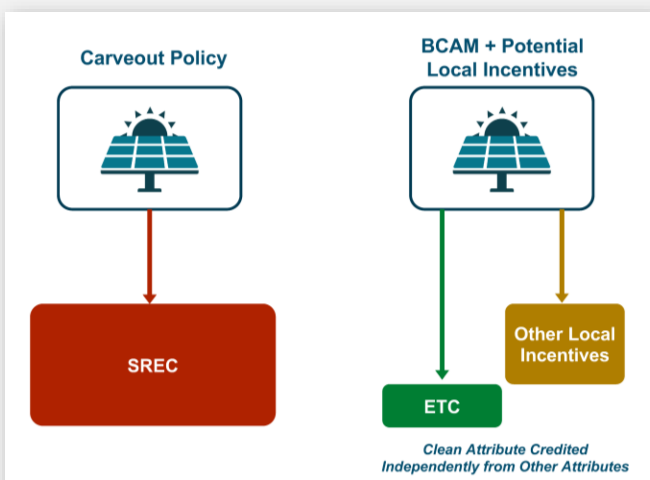
It should be noted that a BCEM would not require 100% participation by all states, or even by a participating state, to provide benefits. Even if only a handful of states participate, the BCEM would still likely provide significant societal value relative to each state going it alone, at a low implementation cost. Further, there is no reason a state would need to use the BCEM for 100% of its clean energy mandates. States could opt to allow BCEM ETCs to account for 20%, 50%, 80%, or 100% of their clean energy mandate. Thus, states would be free to continue to pursue local resource development for a portion of their needs, up the point where this becomes too costly or difficult.

Case Study: State SREC Programs in PJM

Several states have opted to promote the adoption of specific clean technologies via carve-outs within their general RPS targets. New Jersey, Maryland, and Pennsylvania all have solar renewable energy credit (SREC) requirements that are only available to small to medium-size solar projects. While RECs are often fungible across markets within a region or beyond, SRECs generally require that projects be constructed within state lines. They also typically use an administratively determined pricing scheme, largely driven by state commission control and desired program size/budget.

The original intent of carve-out programs was to develop local renewable energy industries, create jobs, and publicly support environmentally friendly technologies which were politically advantageous, as solar is generally very popular with residents. However, cost-effectiveness (i.e., budgetary impact on customer rates) and equity have emerged as growing priorities for solar incentive programs.

New Jersey is currently transitioning its SREC program to a less costly successor program that continues to place a higher value on local economic impact. While this transition program will help address cost concerns, it continues to conflate clean energy attributes with other project attributes. For example, this program features project-specific credit multipliers for desirable characteristics, such as rooftop-mounted systems. This type of inconsistent crediting distorts the ability of policies to drive clean energy outcomes: a MWh of clean energy offers the same carbon reduction value whether generated on a roof or on the ground and should be credited accordingly. To be clear, rooftop solar may offer many tangible benefits, such as reduced land use or deferral in distribution system upgrade costs. However, bundling these benefits with clean energy crediting creates a system that is not scalable to meet long-term carbon-reduction goals. Any additional local benefits are distinct from carbon savings, which are global in impact, and should be unbundled from a BCEM system used to drive large-scale clean energy deployment. Instead, alternative policy mechanisms could be linked more directly to their desired outcome (for example, saved square feet of land or avoided distribution system costs). By tethering carbon-free attributes to other local policy priorities, we limit the scalability of carbon reductions by all other means. A simplified BCEM would remove this constraint.



4.2.1.1 BCEM and State Incentives for Other Resource Attributes

Several state policies have prioritized market support to emerging industries, such as solar and offshore wind, or those facing life-extension decisions, such as nuclear. A BCEM would not prohibit states from continuing to provide support to preferred resources. However, a benefit of the BCEM is that these resource-specific mechanisms may no longer be necessary if the support provided by the price signal stemming from BCEM is sufficient to achieve the state's desired policy objectives.

Altering state policies or removing industry support overnight would be disruptive and risk stranding existing investments in energy infrastructure. Instead, states should focus on unbundling incentives for carbon-free attributes over time and supporting any other desired resource attributes through separate policy mechanisms if necessary. Consistent crediting of clean energy from different sources, such as solar versus offshore wind or nuclear, would allow states to quantify the need for other more focused policy incentives. For example, if nuclear power is cost competitive purely on the basis of its carbon-free value, then states could avoid more controversial nuclear bailouts implemented to achieve various goals. By unbundling carbon-free attributes from other resource attributes for consistent crediting under a BCEM, policymakers could more directly and clearly evaluate projects for their distinct characteristics. This would allow for more informed policymaking and more consistent incentive mechanisms across the energy sector.

4.2.1.2 Voluntary Procurement by Corporate Buyers and Consumers

Over the past decade, companies have taken a more active, independent role in procuring clean energy to meet corporate sustainability goals. Voluntary procurement of clean energy credits above and beyond minimum policy compliance is a key feature of today's market design that must be preserved in the future to facilitate consumer choice.

One central tension in corporate procurement is the desire for impact that is both tangible and cost-effective. This has led to a variety of approaches to procure and claim credit for clean energy purchases for corporate sustainability in power markets, which range from selecting a greener retail tariff to buying unbundled RECs to directly procuring wholesale power from newly developed projects. The lack of a common currency for clean energy attributes has muddied the water with regard to environmental claims.

Corporations rely on a wide range of metrics to substantiate their clean energy achievements. While any claim of "100% clean energy supply" is difficult to prove in the context of complex grid interactions, there is strong interest in the development of more robust mechanisms to do so. For example, Google is piloting a Time-based Energy Attribute Certificate or "T-EAC" system for balancing clean energy supply with its energy demand on an hourly basis.[52] Similarly, other parties have proposed a location-specific hourly emissions rate for quantifying the carbon impact of energy production and consumption.[53]

In our view, while these approaches are interesting and may be right for an entity with the size and motivation to develop or contract for the real-time scheduling capabilities needed to make this work, for most buyers, they add unnecessary complexity and cost. Moreover, they ignore an important fundamental

[52] https://cloud.google.com/blog/topics/sustainability/t-eacs-offer-new-approach-to-certifying-clean-energy

[53] Oates, David Luke and Kathleen Spees, *Locational Marginal Emissions: A Force Multiplier for the Carbon Impact of Clean Energy Programs*, https://resurety.com/uploads/REsurety-Locational-Marginal-Emissions-A-Force-Multiplier-for-the-Carbon-Impact-of-Clean-Energy-Programs.pdf

concept: now and for the foreseeable future, a MWh of carbon-free energy generated anywhere and at any time will offset a MWh of carbon-emitting energy.[54] There is no technical reason why a company should pay $20/MWh for a carbon-free MWh generated at 2 a.m. to match their hourly consumption when there are opportunities to pay $10/MWh for a carbon-free MWh generated at 4 p.m. that has a comparable carbon reduction impact.[55]

This idea may be motivated by a desire to provide procurement mechanisms that scale to 100% clean energy. However, we believe that the 24/7 approach is unlikely to scale because of its cost and complexity. Fundamentally, it reproduces the grid balancing function performed by system operators, but without any of the diversity that comes from matching resources to loads over a broad area. While there are many "premium" products like the T-EAC that may be enticing for some buyers, a commodity product like the BCEM ETC that could be traded on platforms such as the Intercontinental Exchange (ICE) or the Chicago Board of Trade (CBOT) is better able to scale to very high levels with low transaction costs for purchasers.

A standardized and comprehensive clean energy definition under the BCEM would provide a widely accepted and audited standard for company claims regarding the impact of their procurement. Furthermore, a CES linked to carbon intensity would allow corporations to evaluate the carbon savings from greening their power supply versus electrifying a fleet of delivery vehicles on a comparable basis. Defining clean energy credits in a more coordinated and carbon-focused manner would provide better opportunities for companies to set and fulfill their climate goals at least cost.

4.2.2 Scalability of BCEM to Larger Number of Participants

The BCEM concept is modular by nature and could be expanded to include more participants one-by-one on a voluntary basis, similar to other regional market initiatives. There is ample precedent for this type of collaboration at the state level, including the Regional Greenhouse Gas Initiative (RGGI), the Transportation and Climate Initiative (TCI), and the Western Climate Initiative (WCI), each of which was formed by a group of states and/or Canadian provinces. A BCEM could be formed in a similar manner via coordination of multiple states, which need not be regionally adjacent. For example, California and Quebec have operated a linked cap-and-trade program for carbon emissions since 2014. As more participants join the BCEM, the benefits to each would grow due to diversity benefits and economies of scale from a larger market.

The scalability of the BCEM would help states transition from independent clean energy initiatives to more impactful collaborative efforts. States can reach their climate goals at a significantly lower cost by working together and harnessing the most efficient resources to reduce carbon emissions. Under a coordinated BCEM, all participants should see benefits, including better access to low-cost carbon reductions and better ability to mitigate carbon emissions without leakage effects. State policymakers only have jurisdiction to create carbon prices within their state lines, which may lead to higher emissions "leaking" to neighboring states where carbon is not regulated. Leakage is one unanticipated consequence of state-by-state carbon regulation that leads to both higher costs and higher carbon emissions. Incentives for clean energy, on the other hand, are not subject to the same leakage concerns. Every MWh of clean energy today displaces an

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[54] While there will be hours when clean energy is "on the margin" in a given market and more clean energy will not lead to further carbon reductions, during these hours it will also be impossible to deliver incremental clean energy to the grid and generate an ETC.

[55] While the precise carbon impact may vary by system or hour, this variability will decrease in the future once more coal generation has retired.

emitting MWh elsewhere on the grid, which ensures that clean energy mandates lead to incremental emissions reductions. By mandating an increasing amount of clean energy production, states can ensure that their policies are reducing emissions rather than shifting them elsewhere on the grid. If anything, crediting clean energy raises the possibility of *positive* leakage, wherein clean energy in one part of the grid has the secondary effect of displacing higher-emitting generation elsewhere. This outcome is consistent with policy goals—carbon reduction—and becomes less prevalent as a BCEM grows to cover a wider set of markets.

4.2.3 Compatibility with Future Federal Policy

Increased market scale is a necessary foundation for cost-effective carbon reductions and a core benefit of the proposed BCEM approach. A BCEM could be coordinated by any group of states or markets that align on a common definition of clean energy attributes. As more participants join, more benefits would accrue to each.

While scale offers clear benefits via market depth and diversity, coordination may also present challenges at a larger scale in the absence of federal policy as a catalyst. For example, to enable partial crediting based on emissions intensity, BCEM participants would need to align on a common crediting methodology for lower-emitting resources. This may be challenging given the conflicting incentives of different jurisdictions. One potential solution to harness greater market scale and enforce uniform standards is federal action.

The BCEM approach is inherently scalable to the federal level and is consistent with recent policy proposals. In fact, the BCEM offers an ideal mechanism for implementation of a national clean energy standard as contemplated in the Biden administration's American Jobs Plan and in the Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act in the House of Representatives, both of which target 100% clean energy by 2035.[56] The CLEAN Future Act includes 80% by 2030 and 100% by 2035 goals for zero-emission energy supply in the power sector that would measure compliance via tracking of zero-emission electricity credits. Until such legislation is passed, the BCEM would offer a transitional program for states looking to scale their clean energy targets in a coordinated manner while maintaining compatibility with potential future federal policy designs.

4.3 Long-Term Need for a Transition to Carbon-based Accounting

Implementation of a standardized BCEM would rationalize existing clean energy policies and facilitate deeper levels of decarbonized power supply necessary for the clean energy transition. This improved market design would help states scale from the "kick-starter" approach of today's clean energy policies to the deeper adoption of clean energy supply targeted by 2030 in many jurisdictions. However, as targeted levels of zero-carbon energy approach the 80% to 100% levels contemplated beyond 2030 in many jurisdictions, a shift towards more carbon-focused policy will become increasingly important for several reasons. The BCEM design is uniquely suited to enable this transition.

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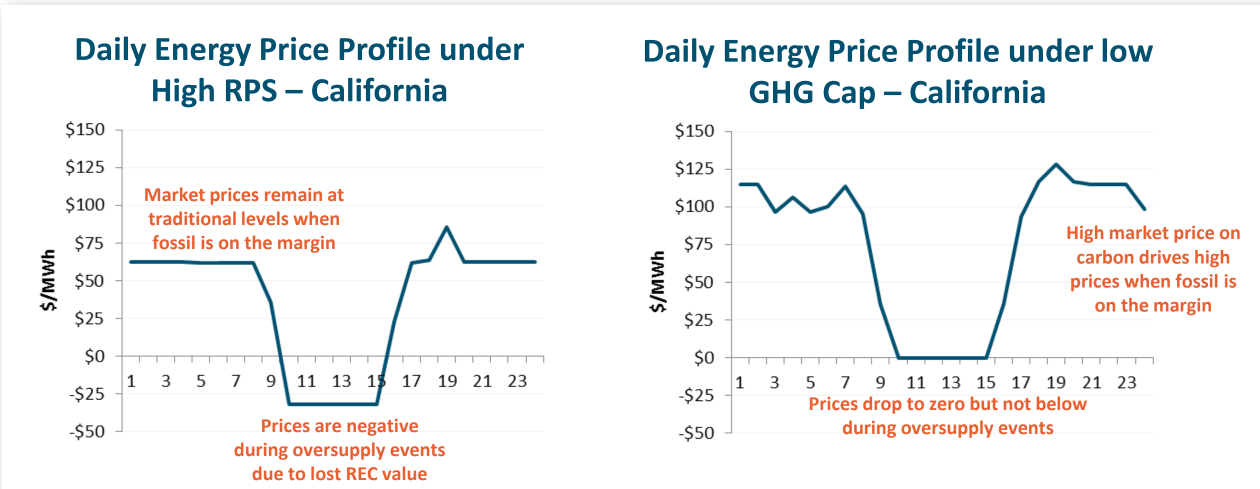
[56] https://energycommerce.house.gov/sites/democrats.energycommerce.house.gov/files/documents/CFA%20Bill%20Text%202021.pdf

4.3.1 Potential for Negative Energy Price Outcomes with BCEM

At high levels of future clean energy adoption, a BCEM that pays for clean energy attributes is prone to one shortcoming: the potential for negative wholesale energy prices. This occurs today in western markets during the springtime, which is a period of relatively low load and high solar and hydropower production. Negative pricing is a rational economic result of markets supplied with low marginal cost clean energy in a specific time interval. Many clean energy sources today have zero marginal cost of generation and can earn a REC for every MWh of energy produced. These resources are thus incentivized to bid in energy markets at the opportunity cost of generating a REC: if a REC is worth $5/MWh, then a solar project may bid -$5/MWh because it will profit at any clearing price above -$5 from its ability to sell the REC. Figure 11 shows the market price patterns during a spring day for a future year in an E3 simulation of the California energy market under an RPS policy (left-hand panel) and a carbon price (right-hand panel).

Figure 11. Energy Market Impacts of Carbon Pricing vs. Clean Energy Credits



Source: E3 market simulations

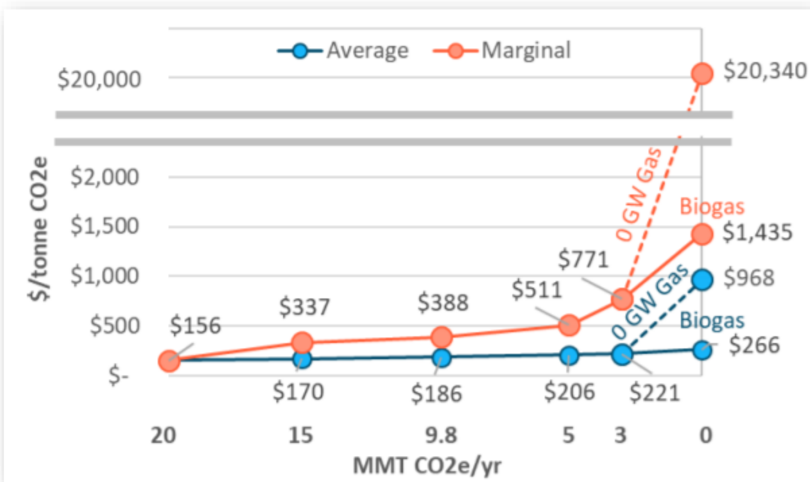
Negative price outcomes are the result of bidding driven by incentive payments outside of wholesale power markets. These outcomes may incentivize undesired demand-side behavior, such as increased load. Negative prices are rare today and offer a price signal for development of new transmission or energy storage that arbitrages away the mismatch in supply and demand. However, in the long term, higher penetrations of "must-take" renewable energy may drive more prevalent negative pricing results. In this future state, markets will benefit from a transition to more direct carbon pricing to incentivize emissions reductions while avoiding undesired energy market outcomes.

4.3.2 Need for Direct Carbon Pricing to Achieve Economywide Objectives

The BCEM mechanism offers a near-term runway for continued clean energy procurement to accelerate the energy transition, but any serious attempt at deep decarbonization to mitigate climate change will require more comprehensive efforts at carbon reduction across all sectors of the economy. E3 studies of economywide decarbonization have consistently concluded that: (1) the power system plays a foundational role in enabling carbon reductions across other parts of the economy, such as buildings and transportation; and (2) decarbonization of the power sector becomes exponentially more costly as emissions targets approach zero.

Direct pricing of carbon offers well-understood efficiencies at the most direct possible price signal for incentivizing emissions reductions. Carbon pricing offers the unique ability to incentivize emissions reductions from both the power sector and other sectors of the economy – such as transportation, buildings, and agriculture – on a level playing field. A common carbon framework across these sectors may be increasingly important in the future as policymakers set more ambitious carbon reduction goals. For example, Figure 12 shows that power sector emissions reductions may become prohibitively costly at deeper levels of decarbonization, in which case other sectors of the economy may offer more cost-effective carbon savings. Moreover, a U.S.-wide carbon pricing program would provide additional opportunities to seek out cost-effective emissions abatement opportunities from anywhere in the country.

Figure 12: Cost of Carbon Abatement in Power Sector in 2050: E3 Study of California



Source: E3, "Long Run Resource Adequacy Under Deep Decarbonization" [57]

[57] E3, *Long Run Resource Adequacy Under Deep Decarbonization*, June 2019, https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf.

4.3.3 Ability to Transition to Future Carbon-Driven Policy

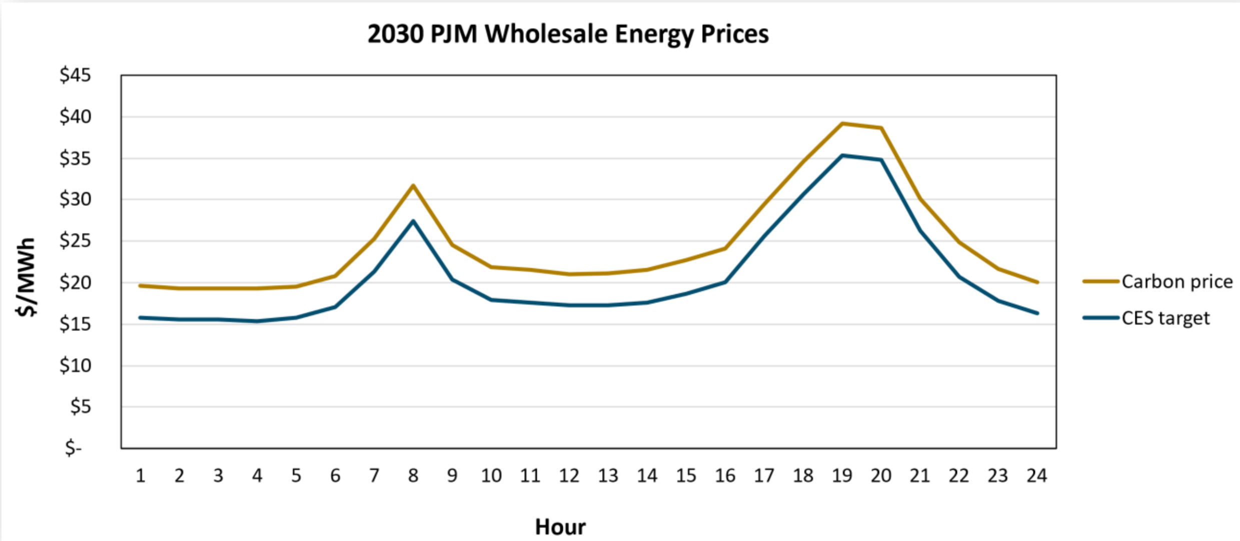
A BCEM that accounts for differences in emissions intensity will provide an ideal platform for future carbon pricing policies needed for economywide decarbonization. In fact, a well-designed BCEM creates nearly identical incentives to a carbon price, which allows for a future transition to carbon pricing without disruptive cost shifts that create new winners and losers.

Clean energy incentives such as ETCs and carbon prices have differing impacts on wholesale energy market price dynamics. A carbon price leads generators to increase their energy market bids by the anticipated cost of carbon they would have to pay to generate a MWh of energy. Thus, a coal generator will have a large carbon bid adder, an inefficient gas combustion turbine will have a higher carbon bid adder than an efficient combined cycle plant (but both much lower than coal), and any non-emitting generator will not have to factor in any carbon bid adder. RECs, on the other hand, have historically driven energy market bids downward because eligible generators are paid out-of-market revenues per MWh of generation and thus reduce their bids by the anticipated value of generating a REC. This dynamic has been seen in CAISO during times of solar curtailment: prices have reflected negative cost bidding and approach the negative REC price. Due to the value of generating a REC, a solar generator would profit so long as the wholesale price exceeds the negative REC price. While there is no current BCEM where credits are granted based on the emissions rate of a resource, we would expect the bidding behavior of eligible generators to mimic what takes place in REC markets: a reduction of bids by the BCEM credit price per MWh.

In the case of ETCs for fuel switching, lower-emitting resources may reduce their energy market bids in a similar manner. Under this construct, a coal generator would not reduce its bid because it would not receive any ETC value, an inefficient gas combustion turbine would reduce its bid by an amount smaller than an efficient combined cycle plant, and any non-emitting resource would reduce its bid by the exact credit price because it would receive full credit.

Effectively, a carbon price drives wholesale energy prices up to reflect the imposed cost of carbon and a BCEM credit would drive wholesale prices down, with the cost difference between the two mechanisms paid outside of the ISO market via BCEM revenues for emissions reductions measures (i.e., clean energy development or fuel switching). These trends can be seen when comparing the following scenarios from E3 modeling of clean energy policies in PJM. The two scenarios highlighted here were designed to achieve nearly the same emissions reductions but with one utilizing a CES policy that gave emissions-based credits for fuel switching to lower-emitting resources, comparable to a BCEM with partial crediting for gas generation, and the other incorporating a carbon price. In both cases, the carbon emissions are reduced by 80% in 2050 from 2005 levels.

Figure 13: Modeled Energy Market Prices on a Sample Day Under Carbon and CES Policy Scenarios



Source: E3, Least-Cost Carbon Reduction Policies in PJM, adapted from Figure 17[58]

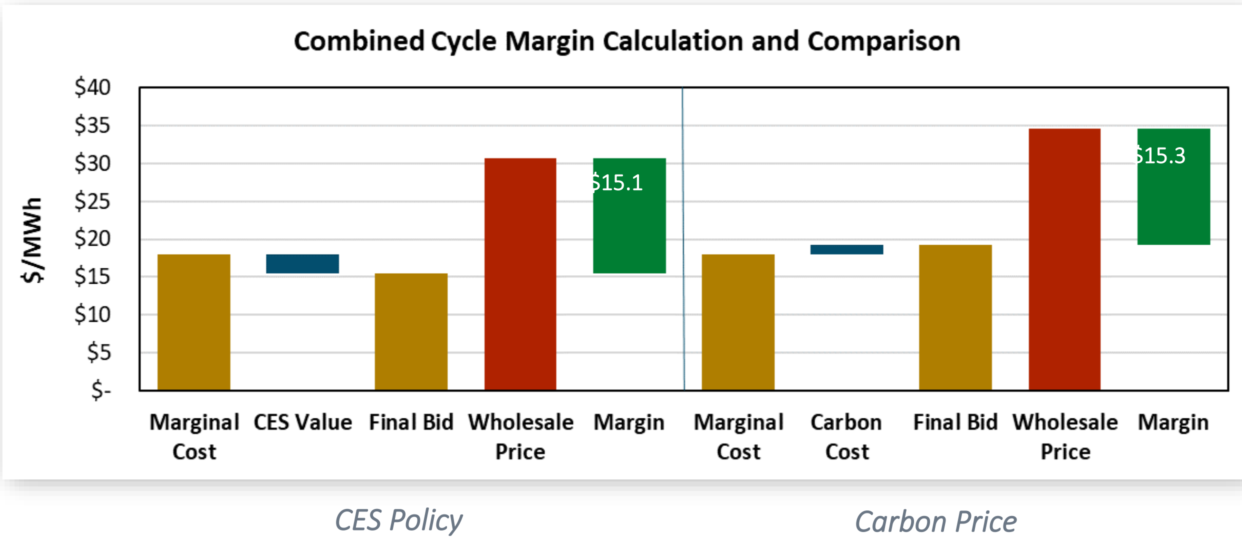
While energy market outcomes differ under each policy approach, these effects on wholesale energy prices do not necessarily change total energy system costs or the power prices paid by ratepayers. In a carbon price construct, higher wholesale energy costs due to generators incorporating carbon prices in their bids will be passed onto ratepayers. In the case of a revenue-neutral carbon tax, the proceeds from carbon prices paid by emitting generators will then be collected and distributed back to ratepayers. In a clean energy standard (CES) construct, lower wholesale energy costs create savings for ratepayers, but the cost of the subsidies going to low- or non-emitting generators is also paid for by ratepayers to recover the cost of utility procurement of clean energy credits. So long as each policy achieves the same level of emissions reductions, the cost of the policy should be nearly the same (not accounting for differences in administrative program costs). Ultimately, the choice of creating a policy that credits generators or penalizes them should be based on ease of implementation, among other factors.

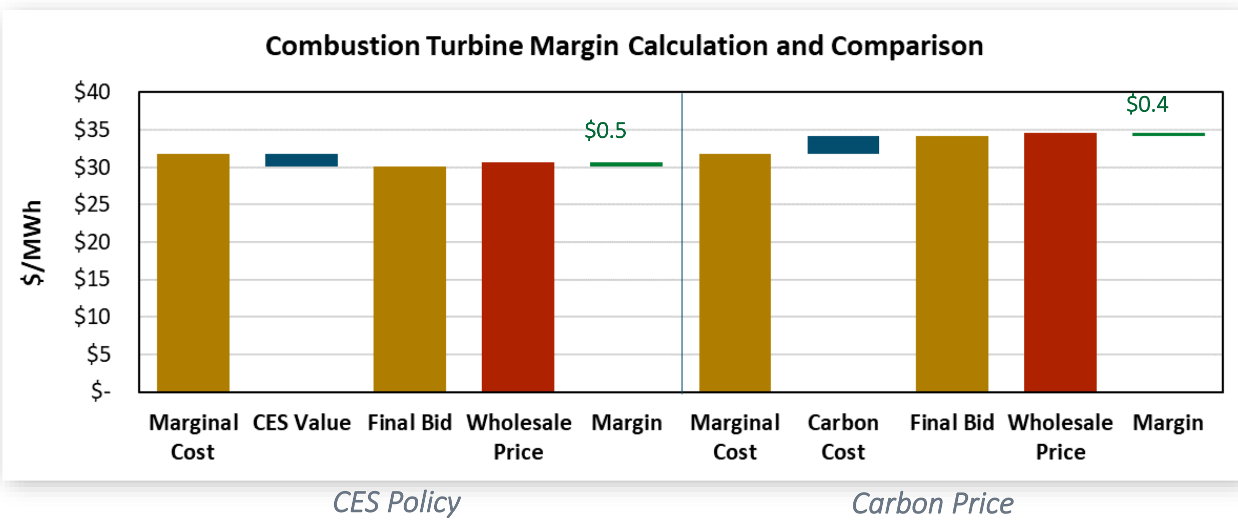
A BCEM is easier to implement and results in similar incentives to carbon policy that will be more difficult to implement, but critical for longer-term policy objectives. Incentives and net profits to power producers are nearly identical under a carbon price or CES that awards partial credit based on emissions intensities, which can be illustrated using a combination of wholesale energy prices, the price of carbon or CES credits, and expected generator bidding behavior under each policy mechanism. The following waterfall figures highlight four types of generators – gas combined cycle, gas combustion turbine, coal, and a renewable generator with a PPA – and the buildup of expected margins under each construct at 6 p.m. on an average day in 2030. Note that the starting point, the marginal cost of energy production for each resource, is the same under both policies. The CES credit value and carbon cost adder change accordingly for each generator based on its emissions rate. Coal receives no CES value as the highest-emitting generator and pays the highest carbon cost. Renewables receive full CES value and have no carbon cost. The gas

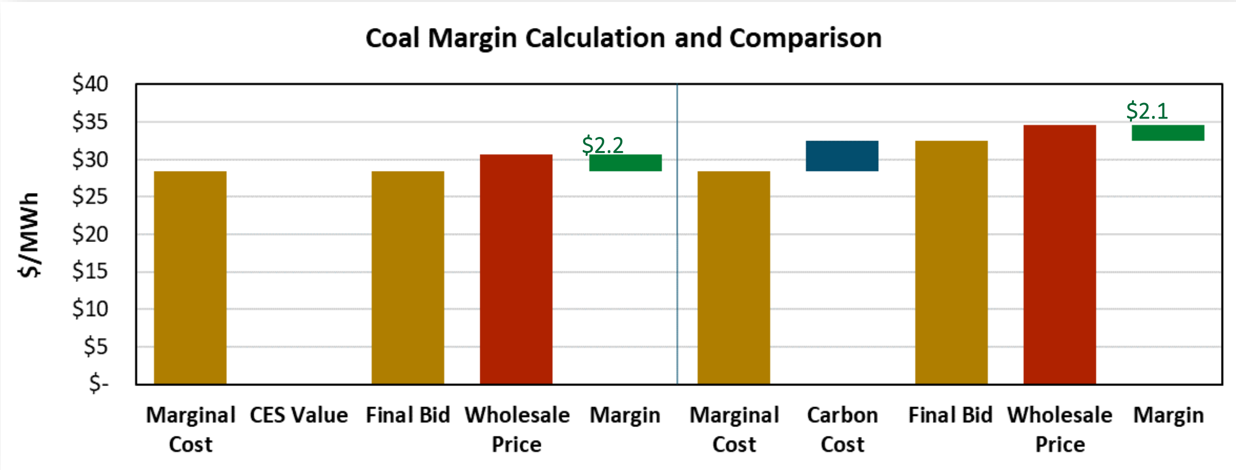
[58] E3, Least Cost Carbon Reduction Policies in PJM, *op. cit.*, p. 37.

generators fall in between. After applying the CES value or carbon price, the final bid is determined. Thereafter, the margin is calculated, taking the difference between the wholesale energy price and the final bid.

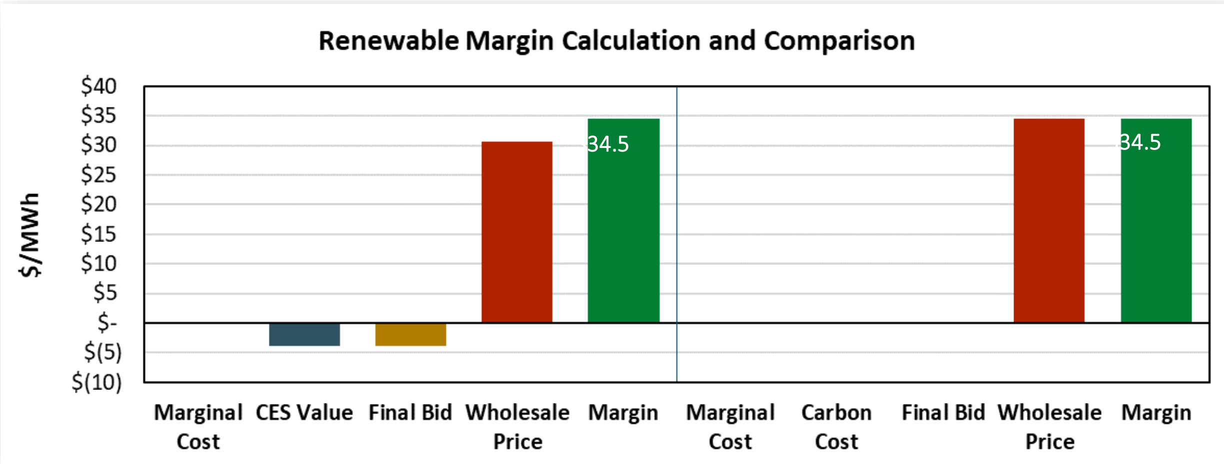
Figure 14: Modeled Hourly Energy Market Margins by Different Generators Under Carbon and CES Policies







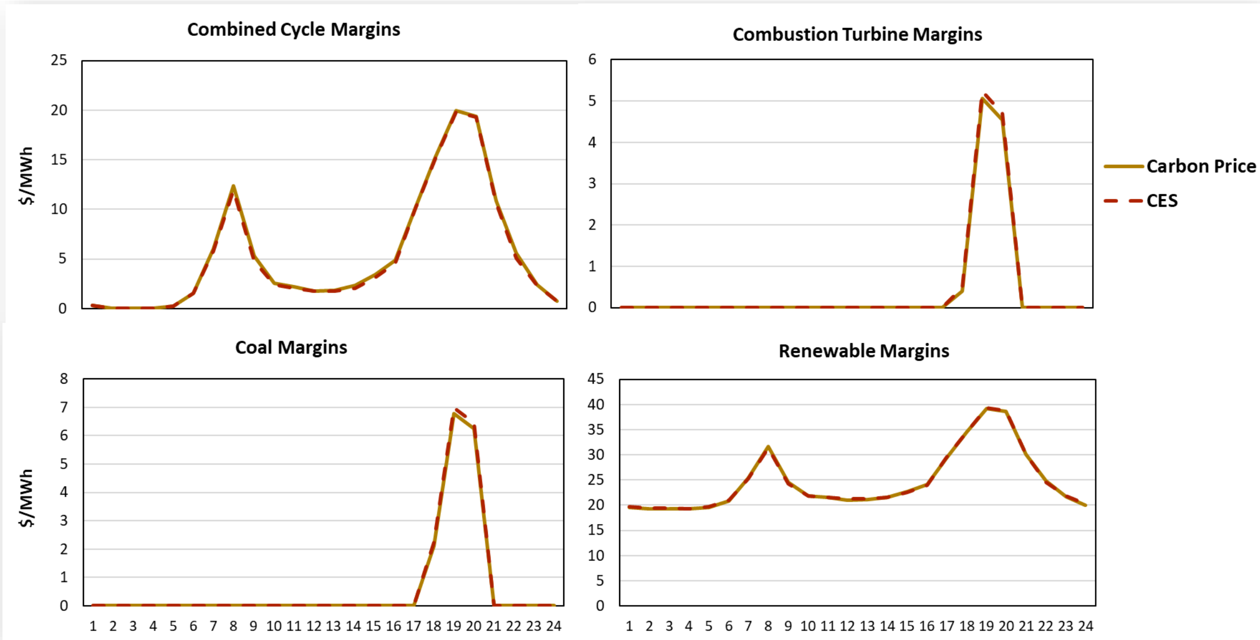
CES Policy *Carbon Price*



CES Policy *Carbon Price*

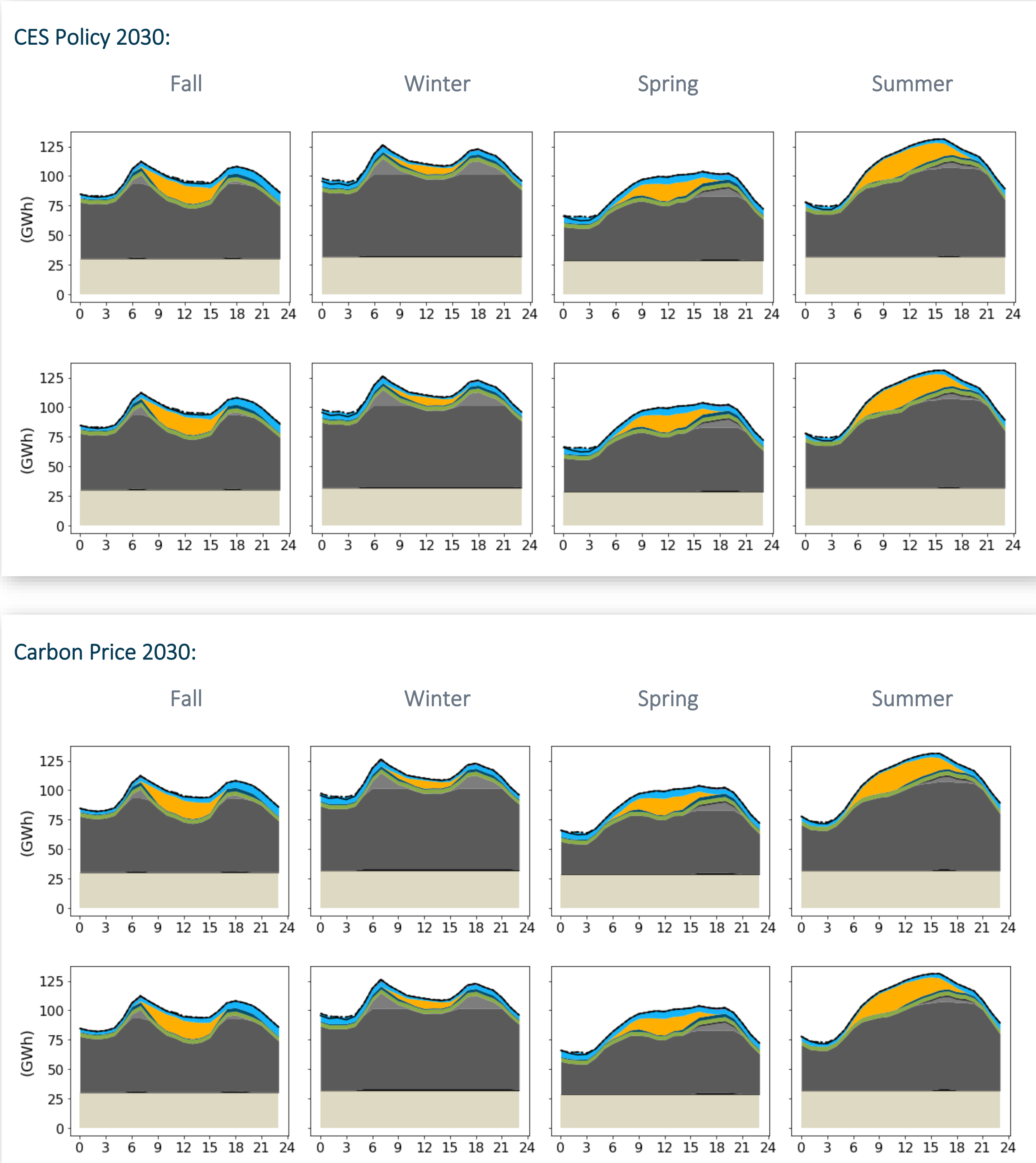
In this single hour, each generator makes nearly the same margin under both policies. The figure below shows that this single hour is not unique – the margins in 2030 align for each generator type across all hours.

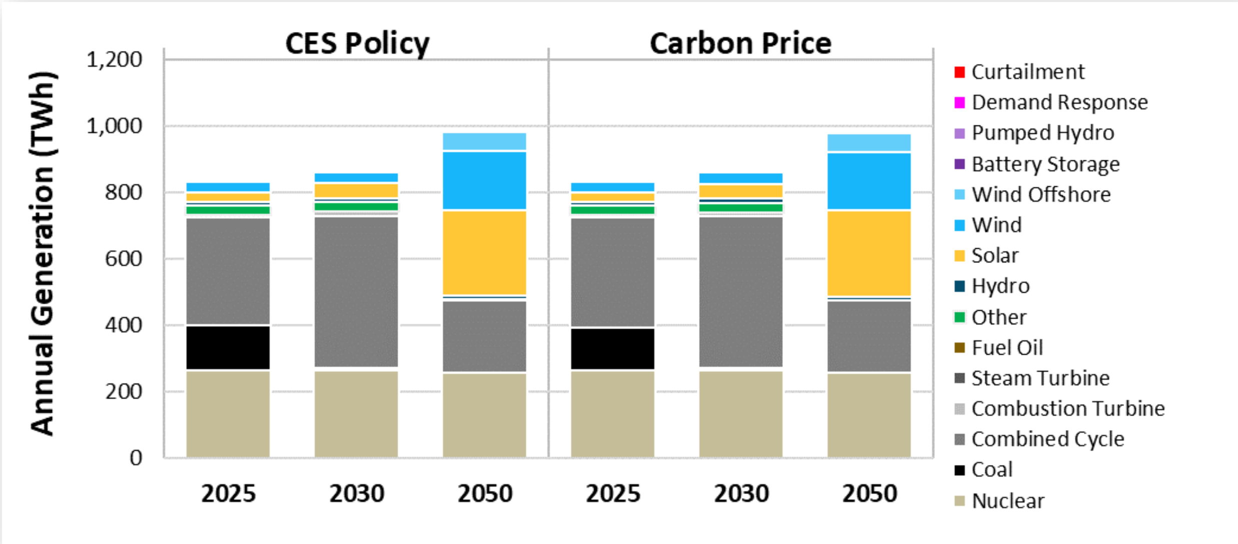
Figure 15: *Modeled Energy Market Margins by Different Generators Under Carbon and CES Policy Scenarios*

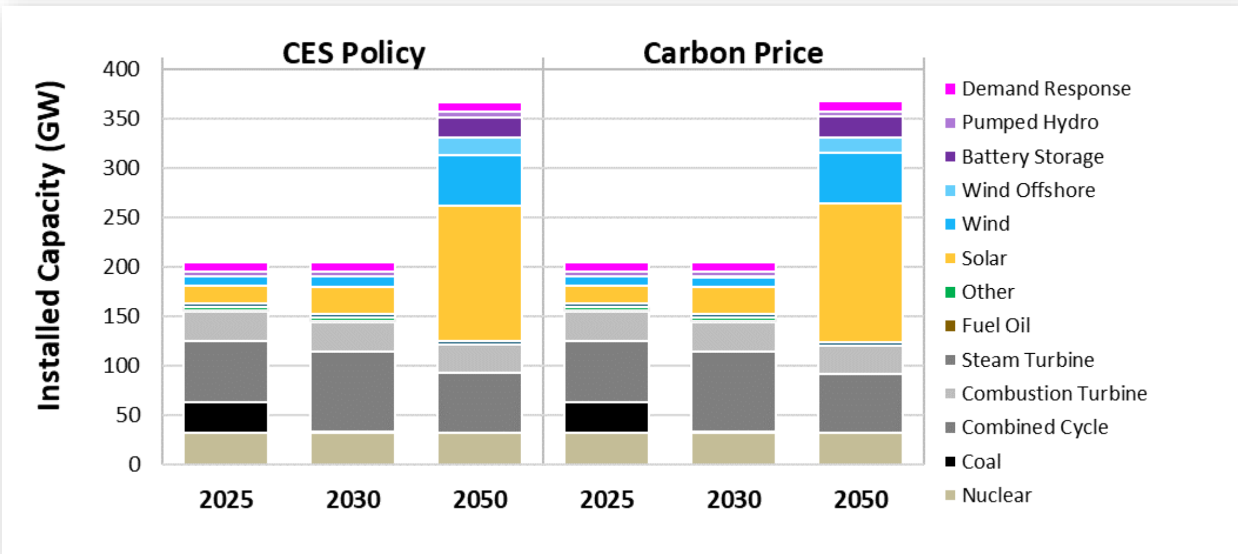


In addition to comparable unit economics, a CES and carbon price will also drive nearly identical patterns in economic dispatch of the power system. Based on E3 modeling, the hourly generation patterns, annual generation, and installed capacity that are economic in each policy scenario are also in clear alignment. This result is intuitive because both the carbon penalty and clean energy incentive effectively encourage the same strategies: switch from high-emitting generators like coal to lower-emitting generators like gas, renewables, or nuclear. The figure below shows dispatch across representative days from each season, followed by the annual generation and installed capacity.

Figure 16: Modeled Hourly Economic Dispatch and Long-Term Capacity Expansion under Carbon and CES Policy Scenarios







Under these two policies, the operational strategy for achieving decarbonization is the same, generators will receive nearly identical incentives and margins, and total system costs are nearly identical as well. This similarity illustrates a valuable feature of a BCEM: it enables a smooth transition to carbon pricing. In fact, a carbon price can coexist alongside a BCEM and offer complementary outcomes or can be introduced over time to slowly transition away from a BCEM towards policy focused solely on carbon.

This flexibility minimizes the risk of conflicts among overlapping policy regimes and facilities simpler adoption for future policy changes. Suppose a BCEM is implemented in one region in the U.S., which later becomes subject to a national carbon cap program. The region could negotiate several options to comply with the national carbon policy with minor invasiveness:

1. The region could keep the BCEM program for use in federal compliance by ensuring carbon emissions under BCEM targets fall within the national carbon targets. The above analysis suggests that this strategy would have a similar efficiency to compliance via carbon pricing and would allow

the existing program to stay intact. This would reduce administrative transition costs and challenges for market participants.

2. **The region could set up a transition policy** to adopt the new carbon price regime. In the transitionary period, the BCEM value could be set to phase out, while the carbon price could be set to ramp up over time. This would allow any “banked” BCEM credits to be used and would give market participants time to get accustomed to the carbon price with less risk of an overnight change in market dynamics. Over time, the BCEM target percentage would ramp down, while the carbon price would ramp up until the transition to carbon pricing would obviate the need for the BCEM market. The resulting margins for generators during this transition should stay consistent because the carbon price should increase bids, and the CES value should decrease bids, resulting in different wholesale market prices but ultimately the same margins for each type of generator.
3. **The region could immediately adopt the national carbon price** without market participants needing to worry that their margins will change dramatically. This will require generators to quickly adapt to the new policy, but the above analysis suggests their bottom lines will not be affected.

In summary, a BCEM provides a consistent set of incentives to carbon pricing and can coexist with carbon pricing to enable a smooth transition period to future carbon-driven policy. This characteristic makes the BCEM an ideal policy mechanism to scale the energy transition over the next decade. It is both simple to implement today via incremental policy improvements and foundational to a future focused on reduced carbon emissions economywide

APPENDIX A: Detailed Recommendations for Energy, Ancillary Service and Capacity Markets

The general theme of this report is that a significant redesign of wholesale electricity markets is not needed to facilitate deep decarbonization of the electric grid, provided a few targeted but important changes are implemented. The most important change is the creation of a stable, robust external funding source that reflects the value that society places on carbon reductions – the BCEM. However, reforms to the energy, ancillary service, and capacity markets are also critically important to ensure that these markets can reliably and efficiently integrate large quantities of clean energy resources. If the formation of the BCEM is the "meat and potatoes" of this report, the reforms described in this section are the salad and vegetables – important for a balanced meal and to ensure the continued health of electricity markets in the future. We believe these recommendations address most if not all of the concerns that have led other observers to suggest much more comprehensive market design changes.

A.1 Recommendations for Reform of Energy and Ancillary Service Markets

A.1.1 Evaluate Operating Reserve Needs Dynamically

Ancillary service procurement requirements today are largely static and based on crude estimates of potential net load variability. System operators are, understandably, conservative in their estimates of the flexibility characteristics needed in a given time period, often relying on rules of thumb to ensure that sufficient dispatchable resource – usually fossil-fuel generators – are operating to provide upward and downward ramping capability. However, as the proportion of variable generation on the system increases, developing more sophisticated methods of calculating the necessary reserves will allow the system to operate more efficiently and reliably by reducing the amount of thermal generation held online to provide reserves during time periods when variability and uncertainty are low, and increasing the system's overall response capability during periods when variability and uncertainty are high.

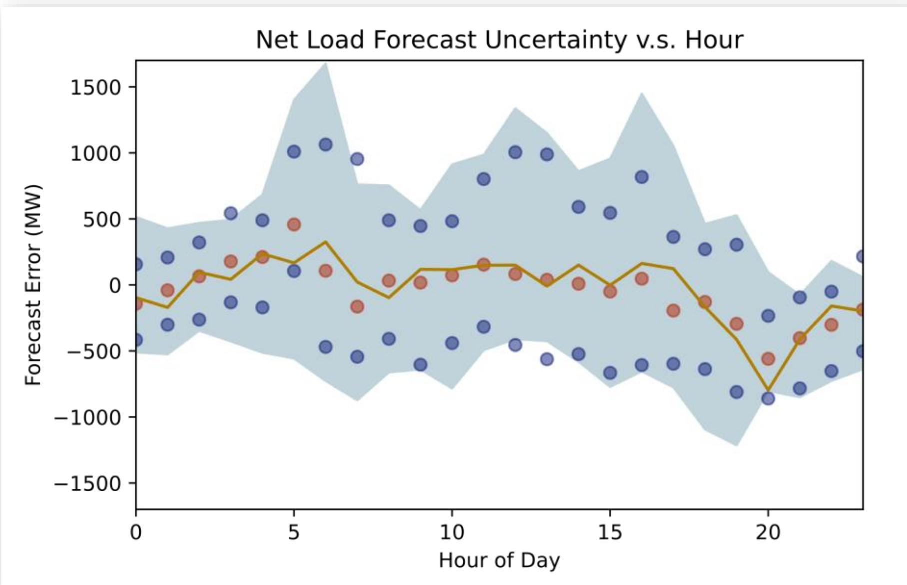
While wind and solar generation contribute to increased operating reserve requirements generally, these requirements can change significantly depending on grid conditions. For example:

+ Operating reserve requirements during nighttime hours need not consider solar forecasting error.
+ When wind and solar production are very low, there is little need for upward reserves due to the potential for sudden drop-offs in production.
+ When wind and solar production are very high, there is little need for downward reserves due to the potential for sudden increases in production.
+ Operating reserve needs are highest for solar during sunrise and sunset when production changes rapidly.

+ Weather systems moving across a region can lead to sequential instances of high wind speed cutouts as wind projects are affected in succession by the advancing front.

Newer methods to determine ancillary services, such as those being developed by E3[59] and the Electric Power Research Institute (EPRI)[60] may enable integrating high levels of renewables at lower costs and higher system reliability. **Figure 17** below shows that the size of the reserve needs may vary significantly from hour to hour, even across a single day, depending on the level of solar and wind production as well as diurnal patterns of load variability. The figure shows calculated flexible ramping reserve needs caused by net load forecast error during July of 2019 in CAISO's 15-minute Energy Imbalance Market. The blue shaded area is the range of dynamic hourly reserve requirements predicted by a machine learning tool that E3 is developing with support from the U.S. Department of Energy's ARPA-E program. The chart shows that reserve needs are highest during sunrise and sunset as more than 20,000 megawatts (MW) of solar generation ramps up and then down with the sun. However, net load uncertainty is not uniform throughout the day; it dips to very low levels during the late morning, increases again around noon, and dips again in mid-afternoon. This can be a function of forecasted cloud cover, variable wind conditions, or hourly changes in load variability.

Figure 17. *Range of net load forecast error by hour of day for California Independent System Operator in July 2019*



Source: E3

Carrying the same level of operating reserves across each hour on this day is clearly suboptimal, either failing to recognize the increased need for reserves during certain periods of the day or the decreased need during other periods. As wind and solar penetration grows, it will be increasingly important for system operators to have good, real-time information about potential sources of variability and to incorporate this information into reserve procurement decisions. This will mean gathering real-time performance data from

[59] https://arpa-e.energy.gov/technologies/projects/deploying-e3s-reserve-tool-enable-advanced-operation-clean-grids

[60] https://eprijournal.com/a-win-win-for-grid-operators-and-customers/

loads and resources across the system and using advanced computing techniques such as machine learning to discern patterns that are more likely to lead to higher upward or downward ramping needs.

A.1.2 Unlock the Full Flexibility of Wind, Solar, and Other Inverter-Based Resources Through Dynamic Market Dispatch

While wind and solar generation are a cause of increased system flexibility needs, they can themselves be operated very flexibly. A 2017 demonstration by the CAISO with First Solar and the National Renewable Energy Laboratory found that a 300 MW solar resource responds much more quickly and accurately to dispatch signals than a conventional generation and can provide an array of essential grid services, including regulation, fast frequency response, and voltage control[61]. A second study completed in 2020 with National Renewable Energy Laboratory (NREL), General Electric (GE), and Avangrid showed similar capabilities for a 131 MW wind farm.[62]

Figure 18 demonstrates the accuracy of the wind project's response to 4-second dispatch signals issued through the ISO's Automated Generation Control (AGC) system. Figure 19 compares the accuracy of wind and solar response to a variety of conventional generating sources.

Finally, a 2018 study prepared by E3 with support from First Solar demonstrates the economic benefits of flexible solar power plant operation for the Tampa Electric Company system.[63] The study considered four operating modes: Must-Take, Curtailable, Downward Dispatch, and Fully Flexible, finding that flexible operations significantly increase the value of solar power plants at penetrations exceeding 20% of annual energy needs. This occurs because flexible solar operation both (1) reduces net load uncertainty and the need for higher operating reserves and (2) provides a source of flexibility to meet operating reserve needs. This reduces the need to commit thermal generation for operating flexibility, which, in turn, reduces fuel costs and CO2 emissions by enabling the system to absorb more solar generation.

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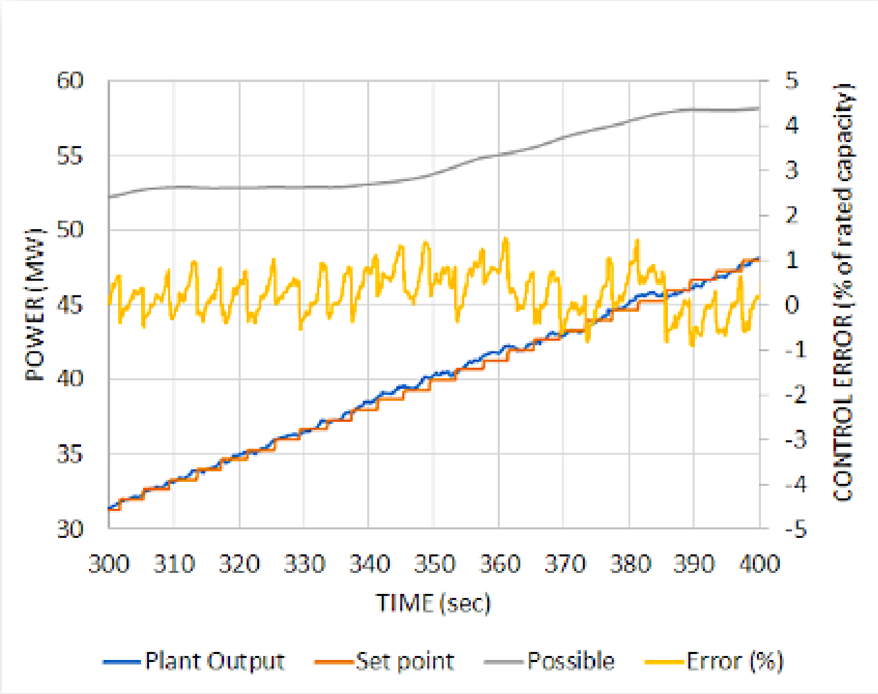
[61] Loutan, et al., *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*, https://www.nrel.gov/docs/fy17osti/67799.pdf

[62] California ISO, Avangrid Renewables, GE, NREL, *Avangrid Renewables Tule Wind Farm: Demonstration of Capability to Provide Essential Grid Services,* http://www.caiso.com/Documents/WindPowerPlantTestResults.pdf

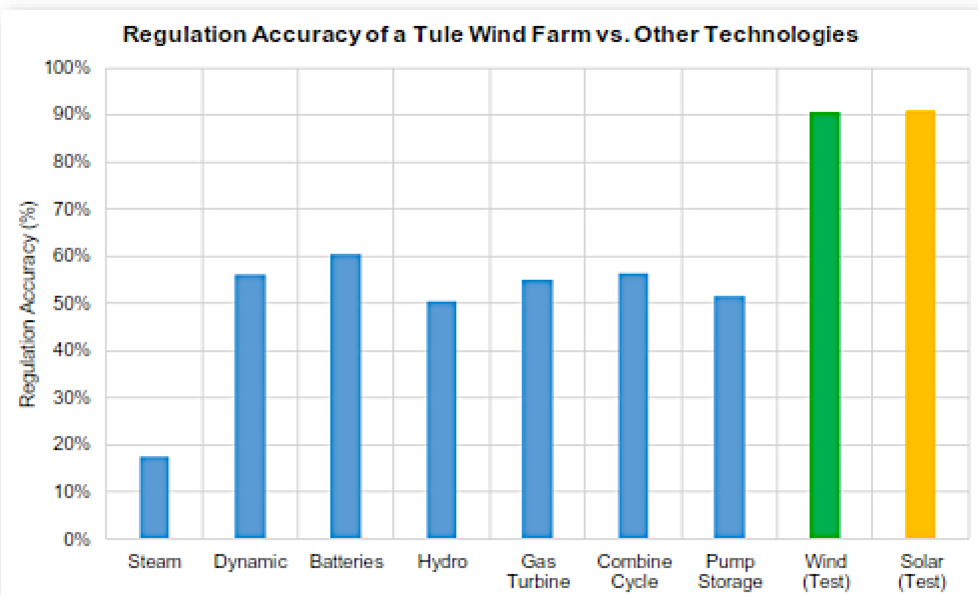
[63] E3, *Investigating the Economic Value of Flexible Solar Power Plant Operation*, https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

Figure 18: *Operational Test Data for Wind Power Dispatch Accuracy*



Source: California ISO, Avangrid Renewables, GE, NREL, Avangrid Renewables Tule Wind Farm: Demonstration of Capability to Provide Essential Grid Services, *http://www.caiso.com/Documents/WindPowerPlantTestResults.pdf*

Figure 19: *Wind and Solar Dispatch Accuracy Versus Other Power Generators*

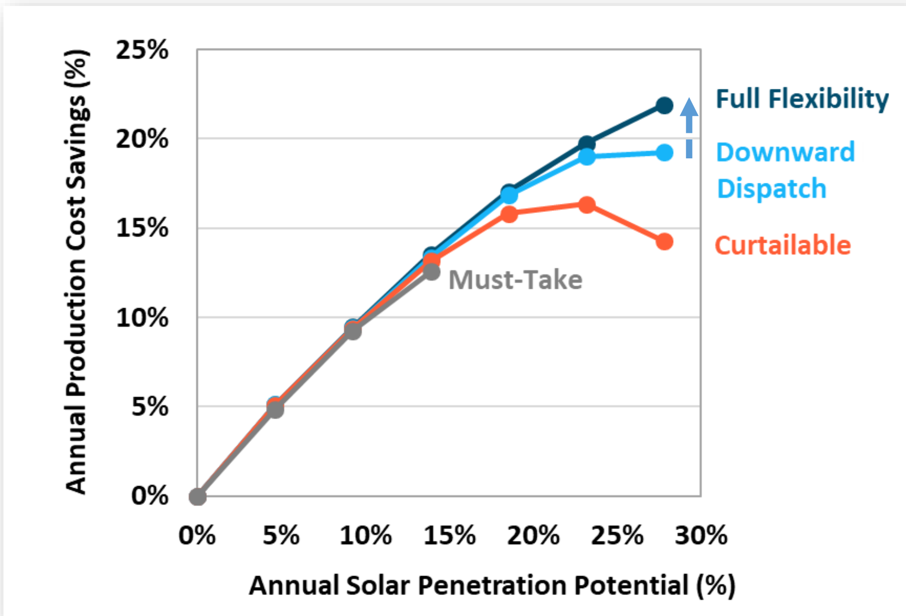


Source: California ISO, Avangrid Renewables, GE, NREL, Avangrid Renewables Tule Wind Farm: Demonstration of Capability to Provide Essential Grid Services, *http://www.caiso.com/Documents/WindPowerPlantTestResults.pdf*

Figure 20 below shows the dispatch cost savings at increasing levels of PV penetration under each operating mode, indicating the increasing importance of flexible solar at higher penetrations.

Given their operational flexibility, it is intuitive that wind and solar generation would be asked to take on more of the grid balancing burden as their share of total generation increases. However, few wind and solar resources are operated flexibly today. As the need for operating flexibility increases, market operators should work with wind and solar developers to identify barriers to providing AGC capabilities and bids for energy and ancillary services. This would require structuring power purchase agreements in ways that enable this type of flexible operation, perhaps by compensating based on potential rather than metered production.

Figure 20. Cost Savings from Flexible Solar Dispatch as a Function of Solar Penetration



Source: E3, Investigating the Economic Value of Flexible Solar Power Plant Operation, https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

A.1.3 Separate Upward and Downward Reserve Products

Some, but not all, markets procure Regulation as a single product in which a generator commits to being available for either upward or downward dispatch at a symmetric price. As renewable share and reserve needs grow, potentially incorporating new flexibility reserve products, distinguishing between upward and downward reserve products will enable more efficient dispatch of renewable and conventional generators. As discussed in the previous section, wind and solar generators are technically capable of providing both upward and downward reserves. However, their ability and cost to provide upward and downward reserves is highly asymmetric:

+ Downward reserves: Wind and solar can nearly always provide downward reserves up to the expected production quantity. Their cost of providing downward reserve is a function of their lost opportunity to generate energy and renewable energy certificates (RECs) or ETCs for any energy dispatch associated with reserves provision.

+ **Upward reserves:** Wind and solar can provide upward reserves if their energy dispatch is curtailed to a level below their maximum potential output level. Their cost of providing upward reserves is therefore the lost energy and REC/ETC margin from the lower hourly dispatch, *less* any margin from energy dispatch associated with upward reserve provision.

The following table demonstrates the asymmetric availability and cost for wind and solar to provide upward and downward reserve products.

Figure 21. Opportunity Cost of Providing Upward and Downward Reserve Products with a Renewable Generator

	Upward	Downward
Assumed Energy Price ($/MWh)	$25	
Assumed REC/ETC Price ($/MWh)	$20	
Maximum/Scheduled Output Potential (MW)	100/80	
Reserve potential (MW/h)	20	80
Assumed energy dispatch due to reserve provision (percent of offered MW quantities for each interval)	20%	20%
Cost of providing reserves (lost energy and REC/ETC revenue, $/MW/h)	**$36** ($25 + $20) * (1-20%)	**$9** ($25 + $20) * 20%

Reserve provision is also asymmetric for energy storage. For example, a battery project whose charge is fully depleted is unable to offer upward reserves. However, it can offer downward reserves equal to its maximum charging capability. Similarly, a battery that is fully charged can offer upward but not downward reserves. Moreover, a battery that is partially charged and is scheduled to charge at its maximum capacity can offer upward reserves equal to **200% of its maximum discharge capacity** by switching instantly from charging at maximum capacity to discharging at maximum capacity. The following table shows the quantities of reserve products that can be offered by energy storage projects, depending on the state of charge and scheduled use.

Figure 22. Capacity to Provide Upward and Downward Reserve Products with Battery Energy Storage

	Upward	Downward
Battery Nameplate Capacity (MW)	100	
Reserve potential if battery is fully charged (MW/h)	100	0
Reserve potential if battery is fully depleted (MW/h)	0	100
Reserve potential if battery is partly charged and scheduled to neither charge nor discharge (MW/h)	100	100
Reserve potential if battery is scheduled to charge at max capacity (MW/h)	200	0
Reserve potential if battery is scheduled to discharge at max capacity (MW/h)	0	200

Additionally, although not demonstrated here, batteries may also have asymmetric opportunity costs for provision of reserve services. Battery opportunity costs are a function of anticipated future arbitrage opportunities. If the project operator expects energy costs to increase during the battery's storage horizon, it may be scheduled to charge and its willingness to provide upward reserves is a function of the lost opportunity to earn additional arbitrage revenues by charging at low cost. Conversely, a project owner that expects prices to fall may be scheduled to discharge and will be willing to provide downward reserves only if the price is compensatory for the lost revenue from delayed discharge.

A.1.4 Fully Optimize Energy Storage During Market Operations

Energy storage is one of the most flexible resources available on a power system. It can charge or discharge, shift energy to different time periods, and, as discussed above, provide a variety of grid services. The optimal utilization of energy storage over a given time period is likely to vary significantly based on grid conditions. The figure below shows the average optimal charge and discharge hours by month-hour time slice for day-ahead energy delivered at the SP15 market hub in California, based on E3 simulations conducted using our RESTORE generation dispatch model. As can be seen in the charts, the optimal dispatch varies depending on market conditions, including the availability of excess solar output. The simulations used to develop the chart are based on hourly energy prices; however, optimal charge-discharge patterns would be much more variable if ancillary services or real-time energy market participation were considered.

Today, most ISO market software optimizes resource dispatch to minimize total costs over a 24-hour time period. This is significantly longer than the storage horizon of most commercial batteries today. As substantial quantities of batteries are added to a power system (for example, as much as 10 GW of battery storage is expected in California by 2030), it will be increasingly important for market software to optimize the use of energy storage. This means that:

+ The market software should determine when energy storage is charged and discharged;
+ The market software should determine which reserve products are provided by energy storage; and
+ The market software should be able to calculate endogenously the energy storage opportunity costs based on market-clearing prices for energy and ancillary services and should fully compensate the project owner for the value of all services provided.

To the extent that the storage horizon extends beyond the market optimization window (e.g., at midnight during the day-ahead time period or all the time for real-time market settlements), the software must use proxy values based on energy storage resource bids for the opportunity cost of upward or downward dispatch. These bids should be flexible enough to incorporate all relevant drivers of storage variable costs. Storage bids may need multiple price dimensions that reflect different opportunity costs for different use cases (i.e., used for hourly energy arbitrage versus frequency regulation) and associated degradation factors (e.g., target state of charge, depth of discharge, and cycling constraints) that all influence the cost to operate and maintain energy storage assets.

Figure 23. Example of Economically Optimal Charge and Discharge Hours in Day-Ahead Markets for 4-hr Battery

Top 4 / Discharge Hours - 2020 SP15

M/H	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Avg
Jan							40											48	44	42					44
Feb							39											39	44	39					40
Mar																		34	43	38	34				37
Apr																		28	38	35	29				33
May																		29	42	39	31				35
Jun																		37	52	42	34				41
Jul																	36	55	81	47					55
Aug																	160	306	293	131					222
Sep																	82	159	95	55					98
Oct																48	107	118	65						84
Nov																	57	74	55	49					59
Dec							51											66	57	53					57
																						Discharge Avg			67

Bottom 4 / Charge Hours - 2020 SP15

M/H	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Avg
Jan												21	20	19	22										21
Feb												12	12	11	13										12
Mar											14	13	12	13											13
Apr										6	6	6	6												6
May									4	4	4	5													4
Jun								10	9	9	11														10
Jul							18	13	14	16															15
Aug			31					26	27	30															28
Sep								24	21	22	26														23
Oct									24	23	24	27													25
Nov										22	21	20	20												21
Dec											26	24	23	24											24
																						Charge Avg			17

Source: E3 simulations using the RESTORE energy storage dispatch model

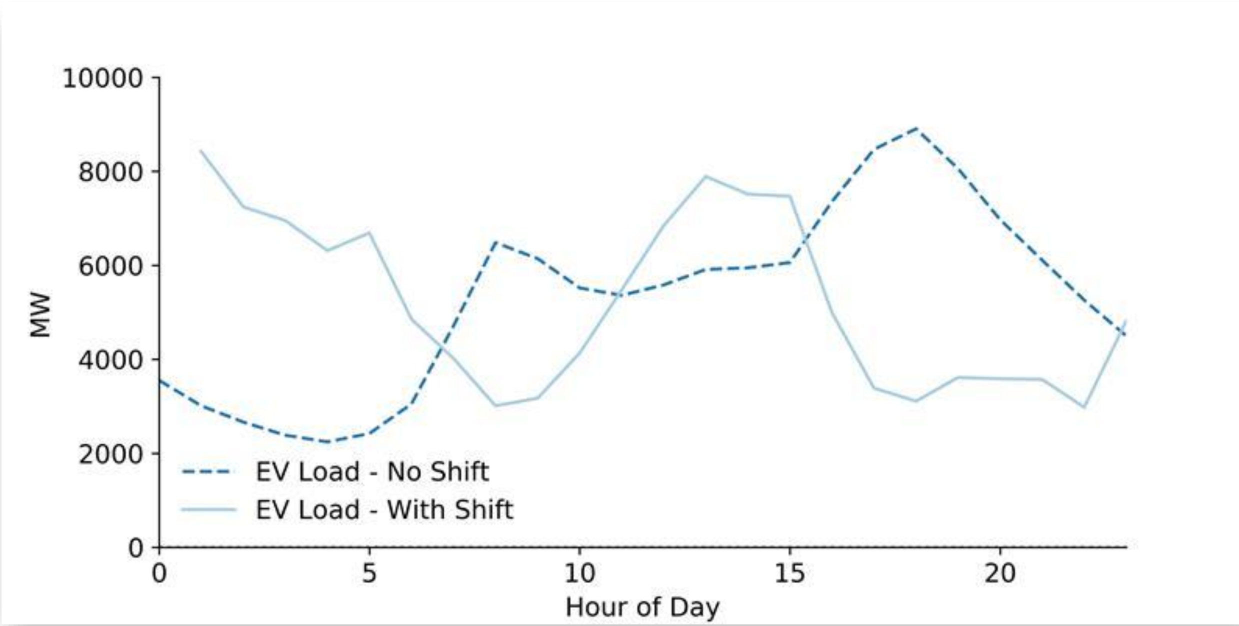
A.1.5 Incorporate Price-Responsive Demand in Energy Markets

In most energy markets today, there is very little demand that is price-responsive, meaning that, while the supply curve might take on a familiar, upward-sloping shape, the demand curve is essentially vertical. "Bending the demand curve" by allowing loads to participate in wholesale markets offers multiple benefits to the electricity system as a whole.

First, it will allow loads to contribute to the balancing needs of a system that relies heavily on variable renewable resources. A deeply decarbonized electricity system that relies heavily on variable resources whose capabilities are driven by the weather will alternate between periods of abundant supply and periods of relative scarcity. End uses like electric vehicle charging and water heating are good candidates to shift electricity demand from the latter period to the former, serving as a form of virtual storage to facilitate the integration of renewable resources. Figure 24 shows an example of unmanaged vs. grid-optimal electric vehicle charging patterns.

Second, it provides for a more efficient mechanism to ration electricity supply during periods of true scarcity. If demand exceeds supply, the market cannot clear and energy prices might rise to very high levels. Price caps place a limit on the financial damage to consumers who retain power, but do not help to avoid the need for rotating blackouts. Literature suggests that the value of lost load varies widely across different market segments and according to the duration of lost load events. Under scarcity conditions, load participation in energy markets will allow market segments that place a lower value upon lost load to reduce their demand voluntarily, allowing those with a higher value of lost load to avoid interruption of service.

Figure 24. Example of Unmanaged (Dashed Lined) vs. Grid-optimal Electric Vehicle Charging Pattern (Solid Line) That Avoids Expensive Ramping Hours



Source: E3 simulations using the RESHAPE energy load shaping model

We are not the first to suggest that price-responsive demand be deployed to help achieve better electricity market outcomes, and we appreciate the enormous logistical, regulatory, and equity challenges associated with potentially exposing retail electricity consumers to the volatility of the wholesale energy market. Nevertheless, we believe there is great promise in technology to automate building load response to grid conditions, and the electrification of new end uses – driven by the economywide effort to decarbonize – will expand options for the application of demand-side flexibility.

A.2 Recommendations for Reform of Capacity Markets

A.2.1 Keep Capacity Markets Focused on Capacity

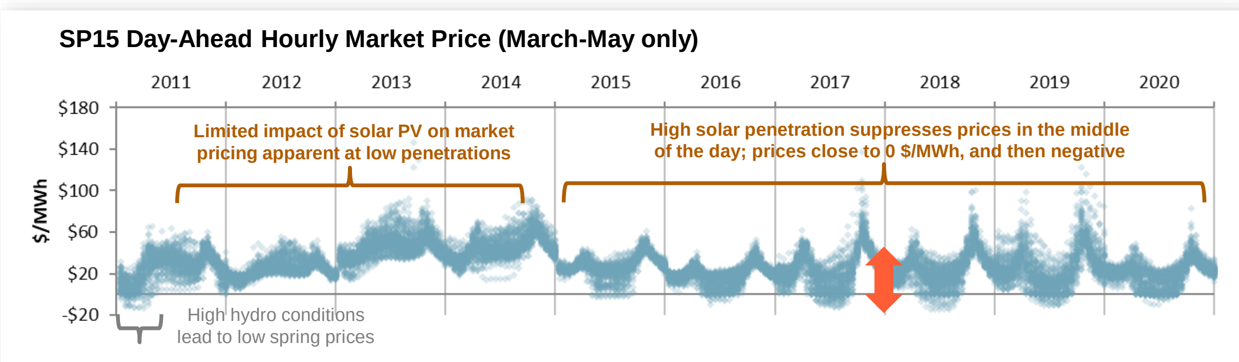
A number of suggestions have been made for expanding capacity markets to procure "flexibility" or clean energy. However, our review finds that these suggestions are unnecessary and perhaps counterproductive to ensuring efficient, scalable markets for clean energy.

With regard to flexibility, while markets with high penetrations of wind and solar will assuredly have a greater need for flexibility in multiple forms, including hour-to-hour ramping, provision of regulation or flexibility reserves, and other grid services such as frequency response and voltage control, they will also have many more tools at their disposal to ensure reliable operations. As discussed above, wind and solar can provide nearly all grid services, and inverter-based resources can respond to dispatch signals much faster and more accurately than conventional generation. Increasing penetrations of battery storage or hybrid solar-storage projects will provide another significant source of flexibility.

Moreover, we have not seen evidence that prices in daily and real-time energy and ancillary service markets will inhibit the deployment of this inherent flexibility. On the contrary, energy market prices have become more volatile over time in California as solar penetration has increased, as indicated in Figure 25, which shows hourly prices by the hour of day during the March through May period from 2011 through 2020. As can be seen in the chart, mid-day prices have been suppressed by the combination of declining natural gas prices and increasing solar generation. However, the chart also shows the increasing frequency of high-price events in the early evening after sundown as solar production declines and gas generators and imports ramp up. Flexible resources that can turn off or operate at very low levels during the daytime and then ramp up quickly as the sun sets will earn significantly higher revenues than resources that are inflexible.

In addition, California expects to add significant quantities of battery storage to help address looming capacity shortfalls. These resources will provide a vital source of flexibility to the CAISO system at little to no incremental cost since the batteries will be needed for resource adequacy. Even if gas plants were the preferred capacity resources, newer turbine technologies can operate very flexibly to take advantage of the pricing dynamics seen in the chart below. In short, we believe that the combination of forward capacity markets and daily energy and ancillary service markets will be sufficient to provide enough flexibility for reliable operations, provided that wind and solar generation are equipped to operate flexibly, as we describe above.

Figure 25. Increased Volatility of Energy Market Prices in CAISO



Source: E3

A.2.2 Use ELCC for Accurate Capacity Accreditation

The higher the penetration of non-firm resources such as wind and solar, the more important it will be for market operators to use robust methods to evaluate the contribution these resources can make toward capacity needs. However, capacity accreditation is significantly more complex for a power system with a high proportion of non-firm resources. Planners must have a thorough understanding of the system conditions that can lead to loss of load and the statistically likely performance of variable resources such as wind and solar during those events. Characterizing the severity and frequency of events that may occur only once every several years requires tremendous amounts of data and computing power. This complexity is compounded by the fact that non-firm resources have interactive effects — solar, wind and storage resources often complement each other, meaning that a system with all three resources present will be more reliable than a system with just one or two. [64]

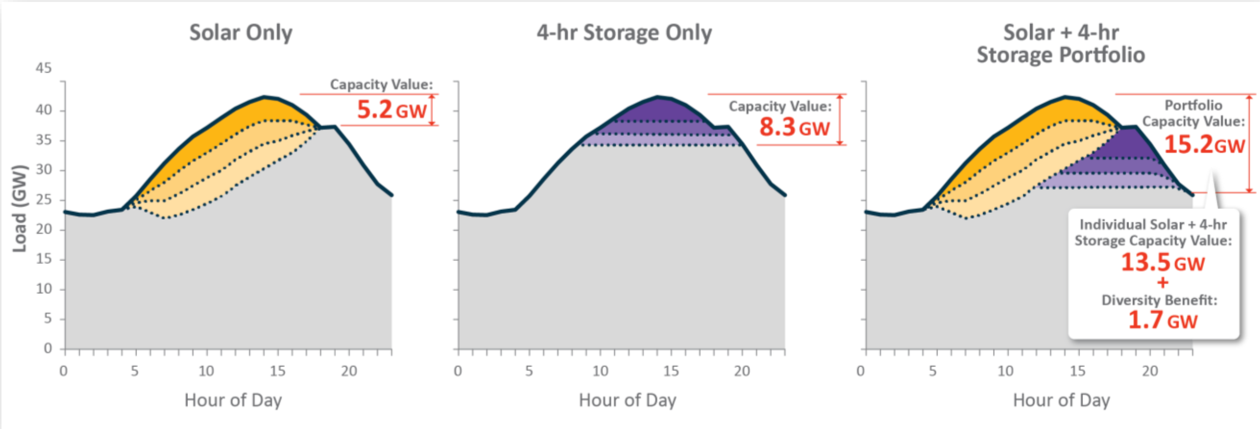
ELCC is increasingly preferred as the best method of measuring the capacity contribution of non-firm resources. ELCC is a natural extension of the "loss-of-load-probability" modeling methods to the problem of non-firm resources. As such, it builds on tools and methods already used by most market operators and electric utilities to measure resource adequacy, which consider the widest possible range of weather and resource outage conditions. ELCC measures the performance of non-firm resources during the times when it matters most — when the system is close to experiencing a capacity shortfall. ELCC is calculated using an "in-out" methodology — a small quantity of a given resource is added to a system, then "perfect capacity" is removed until the system achieves the starting level of reliability. The quantity of perfect capacity removed is the ELCC.

Although ELCC is conceptually simple, complex interactions among non-firm resources make the exercise of assigning an ELCC to each individual resource challenging. One key interaction that is important to capture is the diminishing returns to scale of a specific resource type. This effect can be visualized through the impact of increasing solar penetrations pushing net peak demand into the evening, an effect that is already apparent in places like California and Hawaii. Energy storage experiences diminishing returns due to duration limits; this means that the marginal ELCC of storage with a fixed duration will continue to decline as more is added to the system. The phenomenon can also occur with different resource types; the presence of storage reduces the ELCC of demand response and vice-versa since both provide similar short-duration services.

While resources with similar operating characteristics yield diminishing returns, combining resources with complementary characteristics can produce the opposite effect: a total ELCC that is greater than the sum of its parts. There are many combinations of resources that produce this "diversity benefit"; solar and storage provide an intuitive illustration, where solar squeezes the net peak into fewer evening hours, making it easier to meet with storage. These phenomena are illustrated in the following chart, which shows both solar and storage ELCC declining as more of each resource is added, yet adding both solar and storage yields a higher combined ELCC than the standalone values for each resource.

[64] Schlag N., Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang, "Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy," Energy and Environmental Economics, Inc., Aug. 2020, https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

Figure 26. Portfolio Effects of Solar and Storage Capacity on Ability to Serve Peak Load



Source: E3

Because the interactive effects mean that the total portfolio ELCC is generally greater than the sum of the individual marginal ELCC values for each resource type, there is no single correct method for determining the ELCC contribution of an individual resource within a system. Instead, all potential methods have benefits and drawbacks depending on the defined objective for the exercise. The problem strongly resembles retail rate design, and rate design principles such as those postulated by Bonbright may also be useful here. We have articulated the relevant principles as:

1. **Reliability:** The market operator must calculate the quantity of capacity to procure based on the Portfolio ELCC; i.e., the combined ELCC of all non-firm resources. It follows that individual ELCC credits should sum to the Portfolio ELCC, such that the total revenue received by resource owners is equal to the total capacity value those resources provide.

2. **Fairness:** ELCC credits should be technology-neutral and properly reward resources for their characteristics. In other words, the ELCC credit for a specific resource should be purely a function of its inherent capability and not a product of an arbitrary classification by the system administrator that unduly creates different credits for similar resources. Additionally, resources should be fairly credited for their interactions with other resources, either positive or negative.

3. **Efficiency:** Credits should send signals that encourage economically efficient planning and procurement decisions. To both minimize societal costs and encourage efficient entry and exit from the capacity market, new resources should be sent an ELCC credit signal that aligns with their marginal contribution to resource adequacy.

4. **Acceptability:** Credits should be transparent, tractable, understandable, and stable for planners and market participants. This principle ensures that theoretical purity is not held in higher regard than the practical aspects of implementation. The system administrator must be able to reasonably manage any system, and resource owners must be able to reasonably understand and forecast the market signals in order to respond appropriately.

These interactive effects complicate the application of ELCC to individual resources, but they do not obviate the need to use the Portfolio ELCC to determine the total quantity of firm capacity that is avoided due to the presence of dispatch-limited resources. The need for system-level firm resources to ensure reliability is independent of the allocation method.

While ELCC is increasingly used for wind and solar generation, no resource provides "perfect capacity" – all resources are limited in some way, whether due to energy supply or simply the potential for a random forced outage. ELCC can be used for conventional generation as well and may be important for smaller systems in which a single resource outage can be large enough to significantly increase the probability of lost load. However, for larger systems, ELCC for firm resources can be approximated by a deterministic method that incorporates factors such as changes in thermal ratings due to ambient temperature and forced outage rates during peak load periods.

A.2.3 Ensure that "Firm" Resources are Truly Firm

Most conventional resources are considered "firm," meaning they can be turned on when needed and operated for as long as needed to ensure reliability. Performance requirements and penalties for non-performance are used by market operators to provide a financial incentive to ensure that these resources perform when needed. It should be noted that firm resources would necessarily have specific performance requirements that differ to a degree from the performance requirements for non-firm or dispatch-limited resources. Both classes of resources should be required to be available to produce energy up to their maximum capabilities, and subjected to penalties for non-availability. Firm resources must also actually produce energy up to their certified capacity when called upon by the system operator, whereas non-firm resources would be required to produce up to the quantity of energy available.

However, firm resources are not truly firm if lack of fuel prevents them from operating when needed. Capacity markets have long grappled with the question of whether or how to approach fuel supplies for thermal resources, e.g., whether they should be required to have firm fuel supplies[65] or whether they should have 90 days of on-site fuel storage[66]. We do not attempt to settle these debates here. However, we do note that the importance of assuring fuel availability and firm resource performance has been brought into stark relief with the February 2021 events in ERCOT. Disruptions to upstream gas supplies — a major cause of the ERCOT events — are beyond the scope of electricity capacity markets to solve, but weatherization to ensure gas plants with access to fuel can perform could be addressed in capacity market certification processes. More generally, market operators should reexamine current practices related to generator certification and performance requirements, as well as central assumptions about peak load forecasts, in light of the increasing evidence that a changing climate is resulting in more frequent and severe extreme weather events. We note that ISO-NE and PJM have reformed markets rules to incentivize capacity performance and ensure seasonal reliability constraints can be met in the wake of 2013-14 winter outages and fuel shortages.

[65] https://www.utilitydive.com/news/iso-ne-files-short-term-fuel-security-plan-to-relieve-gas-constraints/551427/

[66] https://blogs.scientificamerican.com/plugged-in/energy-secretary-rick-perry-proposes-new-regulation-to-prop-up-coal-nuclear-plants/

A.2.4 Account for Price-Responsive Demand When Assessing System Needs

The principal role of a forward capacity market is to procure sufficient capacity to enable supply and demand to match in real-time, thereby avoiding the need for firm load curtailment (except in extremely rare circumstances that are expected to occur no more frequently than once in 10 years). The inherent challenge is that capacity procurement decisions must be made on a forward basis, as much as three years ahead, when the precise level of demand is highly uncertain. Additionally, in most markets, there is very little demand that is price-responsive, meaning that, while the supply curve might take on a familiar, upward-sloping shape, the demand curve is essentially vertical. If demand exceeds supply, the market cannot clear, and energy prices might rise to very high levels. Price caps place a limit on the financial damage to consumers who retain power but do not help to avoid the need for rotating blackouts. However, if a significant portion of demand were able to respond to prices and reduce consumption during high-priced hours, the quantity of capacity that would need to be procured on a forward basis could be reduced substantially.

Not all competitive electricity markets have a forward capacity market. ERCOT famously eschews capacity markets while allowing energy market prices to rise to $9,000/MWh in hopes of encouraging both price responsive demand and sending a price signal through the energy market for entry of new capacity resources. However, we note that encouraging price responsive demand through high energy price caps is not mutually exclusive with a capacity market. To the extent that an ERCOT-like energy market increases revenues available to generators from that market, prices in the capacity market would be correspondingly lower due to less "missing money." Indeed, a market with both a forward capacity auction and a high energy price cap that is successful at driving new generation might see the forward capacity market clear near $0/kW.

APPENDIX B: Example BCEM Design

A scalable clean energy market will likely evolve in several stages. In this Appendix, we outline a possible approach for designing and implementing a more scalable clean energy program in the near future. While this approach assumes continued leadership by states and local jurisdictions in the absence of strong federal climate policy, it does not preclude a federal approach. Indeed, a federal approach could likely drive a more rapid and beneficial transition to a scalable clean energy market by enforcing a more standardized and coordinated market design, as proposed in Section 4.

B.1 BCEM Structure with Partial Crediting Option

B.1.1 Standardization of Crediting

Given their central role in clean energy policy today, states will likely be the best candidates to set rules, harmonize clean energy program definitions, and ensure reciprocal eligibility. This would require coordination among multiple states similar to what was required for the creation of the RGGI in the Northeast. For example, many states feature interchangeable REC criteria today that effectively standardize the definition of a "Class 1" REC in certain markets, such as ISO-NE. These fungibility features could be formalized and reinforced through a memorandum of understanding (MOU) or other collaborative framework among participating states to adopt a common definition.[67] Such a centralized framework should define accounting standards for different resource types (e.g., How many clean energy credits does biomass receive per MWh when using a specific fuel source?), any baseline emissions rates and partial ETCs awarded to incentivize carbon reductions via fuel switching, and consistent rules in each participating state regarding ETC retirement.

B.1.2 Compliance Obligation

RPS programs have arisen due to state action in keeping with the state's statutory role in regulating the activities of local load-serving entities (LSEs). The BCEM would not interfere with the state's traditional role in regulating LSEs. Rather, it would enable LSEs to seek out more competitive compliance options in a deep, liquid, multi-state market for ETCs.

B.1.3 Baseline and Target Setting

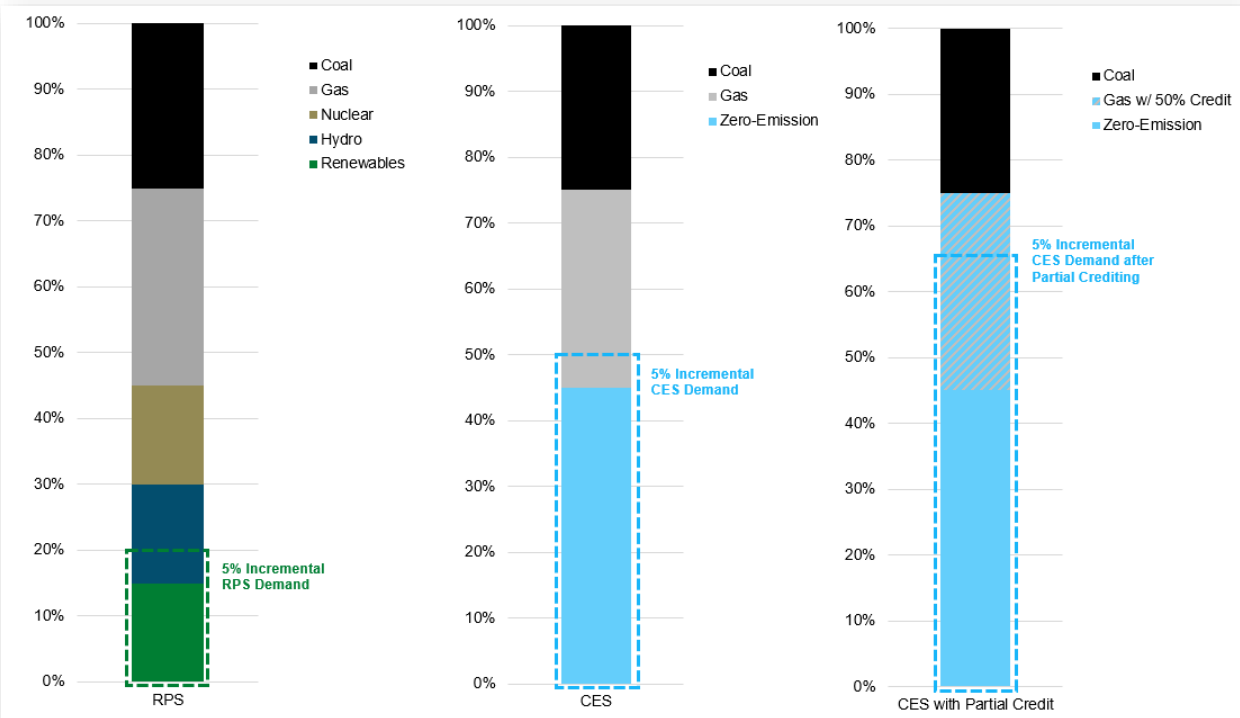
Covered entities and compliance targets could be set independently by states similarly to RPS programs today. The pooling of demand for a more standardized compliance instrument would facilitate more liquid trading and deeper markets for clean energy credits.

[67] Other such multi-state organizations, such as the TCI and RGGI already exist to facilitate coordination on regional climate policy. One benefit of the BCEM is that it does not necessitate a new governing body or formal joint-powers agreement with jurisdiction over multiple states.

To set compliance targets that drive incremental clean energy generation, each state would need to ensure that demand exceeds the existing supply. For example, consider a market that currently derives 15% of its electricity from renewable energy and is targeting a 20% RPS. If zero-emission nuclear and hydropower account for 30% of energy supply in this market, then a target of "50% Clean" would yield a similar incremental demand for clean energy.

Similarly, for markets that implement an ETC that incentivizes fuel switching, the demand for such instruments would need to be set to reflect credits for *incremental* fuel switching; i.e., dispatch of plants that reduces emissions versus a baseline without a fuel-switching incentive. This would necessitate a higher target that incorporates current generation from lower-emitting resources as a baseline to ensure that all partial credits lead to realized emissions reductions.

Figure 27: Target-Setting for a BCEM under Different Eligible Resources and Existing Supply



An example of the interplay between energy supply sources, partial crediting to lower-emission resources, and the resulting emissions reductions are shown below in Figure 28. In this example, targets would be set by a program administrator based on the current grid emissions and a targeted future emissions reduction as follows:

1. Administrator tracks the percent of energy from zero-emission resources today (e.g., 45%) and the average grid emissions rate (e.g., 0.37 tons/MWh).
2. From these inputs, Administrator calculates the weighted average emissions rate for emitting resources (e.g., 0.67 tons/MWh in the example for a mix of coal and gas).

3. Administrator then sets the partial ETC based on emissions reductions from fuel-switching. For example, if gas generation emits carbon at a rate of 0.4 tons/MWh (41% lower than the system average of 0.67 on the grid where the resource is located), it would receive 0.41 credits per MWh.

4. Administrator then calculates the total credits produced with this partial ETC under the status quo energy mix. In a case with 45% clean energy supply earning 1 credit/MWh and 30% gas earning 0.41 credits/MWh, the average credit would be 1.0 * 45% + 0.41 * 30% = 57% average credit per MWh. This implies that there is a remaining gap of 43% needed to reach 100% credits per MWh, or zero emissions.

5. Administrator then sets a target for emissions reductions for the next year, such as 5%. This emissions reduction would be directly proportional to a reduction in the percent of average "emitting" MWh. In our example, reducing the percent of average emitting MWh by 5% would entail a reduction in uncredited MWh from 43% to 41% (43% * 0.95) and a corresponding target of 59% credit per MWh in the following year. This target would be clearly linked to an emissions reduction and could be accomplished through either increases in supply from either zero emissions or lower-emitting resources.

As supply from relatively higher-emitting resources like coal fall to zero, fuel switching opportunities would fall by a corresponding amount leading to a phase-out of any fractional ETCs granted to lower-emitting resources. This would lead to a non-linear change in compliance targets during years when fuel switching opportunities are available. For example, in Figure 28 the compliance credit target remains around 65% for several consecutive years despite driving falling carbon emissions. However, emissions reductions can be targeted more directly via this approach and would serve as a more appropriate benchmark for target setting. For future systems that approach a homogenous emissions rate for all emitting resources (i.e., all emissions come from gas generation), compliance credit percentages and carbon reductions would converge to a directly proportional relationship.

Figure 28: Example Energy Supply Mix and Emissions Reductions with Temporary Energy Transition Credit

Year	Share of Annual Energy Supply (% of MWh)					Avg Grid Emissions Rate	Avg Emissions Rate (Emitting Resources)	Gas ETC per MWh	Compliance Credit Target	Emissions Reduction from 2020
	Renewables	Hydro	Nuclear	Gas	Coal					
Emissions rate (ton/MWh)	0.0	0.0	0.0	0.4	1.0					
2020	15%	15%	15%	30%	25%	0.37	0.67	0.41	57%	0%
2021	17%	15%	15%	31%	23%	0.35	0.66	0.39	59%	6%
2022	19%	15%	15%	31%	20%	0.33	0.64	0.37	60%	11%
2023	20%	15%	15%	32%	18%	0.31	0.61	0.35	61%	17%
2024	22%	15%	15%	33%	15%	0.28	0.59	0.32	63%	23%
2025	**24%**	**15%**	**15%**	**33%**	**13%**	**0.26**	**0.57**	**0.29**	**64%**	**30%**
2026	26%	15%	15%	34%	10%	0.24	0.54	0.26	65%	36%
2027	28%	15%	15%	35%	8%	0.22	0.51	0.21	65%	41%
2028	29%	15%	15%	36%	5%	0.19	0.48	0.16	65%	47%
2029	31%	15%	15%	36%	3%	0.17	0.44	0.10	65%	54%
2030	**33%**	**15%**	**15%**	**37%**	**0%**	**0.15**	**0.40**	**0.00**	**63%**	**60%**
2031	35%	15%	15%	35%	0%	0.14	0.40	0.00	65%	62%
2032	37%	15%	15%	33%	0%	0.13	0.40	0.00	67%	65%
2033	39%	15%	15%	31%	0%	0.12	0.40	0.00	69%	67%
2034	41%	15%	15%	29%	0%	0.12	0.40	0.00	71%	69%
2035	43%	15%	15%	27%	0%	0.11	0.40	0.00	73%	71%

Differences in baseline emissions rates and fuel mixes by jurisdiction would create challenges in standardizing any partial crediting framework across independent BCEM jurisdictions. These challenges could be addressed via state coordination; otherwise, they may necessitate the creation of additional market products that apply only to a subset of BCEM parties. Alternatively, this tradeoff between improved carbon efficiency and additional coordination challenges and complexity could be solved via federal policy, which would obviate such issues.

B.2 Tracking and Trading Clean Energy Credits

B.2.1 Eligible Generators

Ideally, a BCEM should award credits to as many eligible generators as possible while ensuring that clean energy targets incentivize incremental generation that reduces emissions in a truly additive manner. There is no fundamental reason that suppliers of clean energy credits must be located within the area of regulatory compliance. Instead, credits should be issued to a wider, ideally a national pool of clean energy resources to harness the most cost-effective supply options. For example, if wind power in North Dakota can generate clean energy more cost effectively than in Michigan, then Michigan can benefit from buying clean energy credits generated in North Dakota.[68] As long as total policy demand is set to be incremental to current eligible supply, market incentives will drive additional procurement of clean energy that reduces total carbon emissions.

An ideal policy would credit both dispatchable resources that reduce emissions through fuel-switching in the short run (e.g., lower-emitting generators) and zero-emission resources that replace emitting resources in the long run. Because both types of run emission reductions are perfect substitutes (a ton saved is a ton saved), both should be incentivized and credited as consistently as possible.

B.2.2 Measurement, Monitoring, and Tracking of Clean Energy Credits

Implementation of a BCEM can leverage existing generation and emissions monitoring services to track clean generation, assess emissions intensity on an annual basis, and place emitting resources in "tiers" for partial crediting.

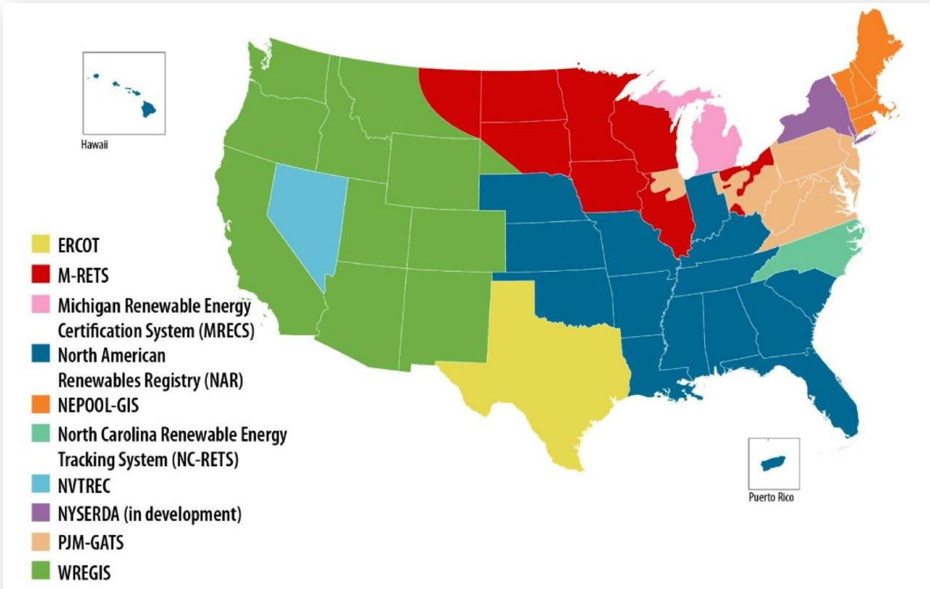
There are currently around ten major systems for tracking and trading energy generation characteristics in the U.S., each of which features some level of compatibility with other tracking systems. These systems currently facilitate trading of RECs. All tracking systems have the same definition of a REC: 1 MWh of renewable generation produces one REC.[69] In the U.S., there are four regional REC tracking systems (Western Renewable Energy Generation Information System (WREGIS), Midwest Renewable Energy Tracking System (M-RETS), PJM Generation Attribute Tracking System (PJM-GATS), and New England Power Pool Generation Information System (NEPOOL-GIS)) and five state-level REC tracking systems (Electric Reliability Council of Texas (ERCOT), New York State Energy Research and Development Authority (NYSERDA), Michigan Renewable Energy Certification System (MIRECS), Nevada Tracks Renewable Energy Credits (NVTREC), and North Carolina Renewable Energy Tracking System (NC-RETS)). There is also one national REC tracking system (The North American Renewables Registry, or NAR) that covers any regions not included in an existing regional or state tracking system.

Figure 29 shows a map of the current U.S. REC tracking systems.

[68] This opportunity for interregional trading of credits would be greatest when clean energy targets are well below 100%. For example, one region with high-quality renewables and low-cost integration options may be able to reach 60% clean energy at lower cost than other more constrained regions face to reach 30%. In this case, the regions would benefit from trading credits to incentivize the least-cost mix of low-carbon resources. However, in a future where all regions must approach 100% clean, there would be fewer opportunities for trading of credits to reduce costs after the transition to clean energy is complete.

[69] The only exceptions are Arizona and Nevada, which define a REC as 1 kWh of renewable generation.

Figure 29: Map of Renewable Energy Tracking Systems in the U.S.



Source: Updated from ETNNA 2011
Note: NAR covers states not covered by a APX, Inc. tracking system
Note: Nevada uses both NVTREC and WREGIS

All tracking systems have an online web-based platform that is used to track RECs. Some tracking systems own and operate their own electronic platform, while others use an online platform provided and operated by APX (WREGIS, NC-RETS, NEPOOL, NY-GIS, and MIRECS use an APX platform). The utilization of an APX electronic platform does not inherently allow for import and export of credits between other APX-run online platforms and tracking systems. The allowable flow of credits between registries is shown in Figure 30 below.

PJM-GATS, NEPOOL-GIS, and NYGATS track all electricity generation in their service territory as opposed to tracking only renewable generation. All tracking systems generate certificates that include information on the resource type and location of the renewable generation. WREGIS, PJM-GATS, NEPOOL-GIS, NYGATS, and NAR include avoided emissions with each credit and use various sources of emission rates, including the United Nations Intergovernmental Panel on Climate Change, U.S. Environmental Protection Agency (EPA) default values, and EPA Continuous Emissions Monitoring Systems (CEMS), to calculate avoided emissions. Other information commonly tracked with credits includes generating unit vintage, generating unit nameplate capacity, interconnected utility, and credit RPS eligibility by state.

Price transparency will be important to ensure smooth functioning of the market for clean energy credits. However, most REC tracking systems do not track REC prices; the only tracking system that tracks REC prices is PJM-GATS. The need for transparency could be remedied in a number of ways. One option would be for existing REC tracking systems to be enhanced to incorporate price discovery. Another option would be for ETCs to be traded on a market platform such as Intercontinental Exchange which facilitates price discovery for many other bilaterally traded commodities. Increased market depth and trading volume, whether via exchange or bilateral, would naturally catalyze the development of a more competitive broker-dealer market like those that exist for other major "over-the-counter" (OTC) products, such as interest rate, credit, currency, and commodity derivatives.

Figure 30: Allowable Inter-registry Imports and Exports of RECs

Source: APX

Tracking systems require Revenue-Quality Meters for collecting data on renewable generation. For generation within a balancing authority's jurisdiction, metered data used for balancing area settlements can be used for tracking clean energy credits. For generating units that do not participate in balancing area settlements, including customer-sited distributed generation, separate electronic or manual metered data can be submitted to tracking systems to earn RECs. Obtaining the status of a "Qualified Reporting Entity" may be required for a generating unit to report its own metered data. Metered data is often verified by the registry before being used to generate RECs.

A BCEM could rely directly on existing tracking systems to facilitate measurement, monitoring, and verification of clean energy credits. Potential areas for enhancement to promote wider clean energy trading would include better integration between tracking systems and more standardized tracking of emissions characteristics to support crediting under any ETC mechanisms.

B.2.3 Retirement of Clean Energy Credits

State policymakers that implement a BCEM would track the "retirement" or consumption of credits by load-serving entities like utilities to ensure they are meeting energy supply requirements. Other voluntary purchasers of clean energy could retire credits outside of the compliance framework to ensure that their purchases represent additional carbon reductions above and beyond state requirements.

Figure 31: Existing Energy Attribute Tracking Systems Today

	WREGIS	ERCOT	M-RETS	PJM-GATS	NEPOOL-GIS	NYGATS	NAR
Attribute	RECs	RECs	RECs	RECs	RECs	RECs	RECs
Attribute definition	1 MWh of renewable generation	1 MWh of renewable generation	1 MWh of renewable generation	1 MWh of renewable generation	1 MWh of renewable generation	1 MWh of renewable generation	1 MWh of renewable generation
Attribute tracking system	Electronic web-based tracking system	Electronic web-based tracking system	Electronic web-based tracking system	Electronic web-based tracking system	Electronic web-based tracking system	Electronic web-based tracking system	Electronic web-based tracking system
Type of generation tracked	Renewable generation only	Renewable generation only	Renewable generation only	All generation	All generation	All generation	Renewable generation only
Resource type tracked?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Tracks location?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Avoided emissions tracked?	Yes	No	No	Yes	No	Yes	Yes
Avoided emissions rate source	UN IPCC (CA)	N/A	N/A	Default emission rates from EPA (can be changed by user)	N/A	UN IPCC	Two options: Green-e Climate Protocol or U.S. EPA Climate Leaders Protocol
Total emissions tracked?	No	No	No	Yes	Yes	Yes	No
Total emissions source	N/A	N/A	N/A	EPA, supplemented by other sources	CEMS	CEMS	N/A
REC prices tracked?	No	No	No	Yes	No	No	No

	WREGIS	ERCOT	M-RETS	PJM-GATS	NEPOOL-GIS	NYGATS	NAR
Metering	Revenue-Quality Meter required.	Electronic meter that meets ANSI C12 standards and is separate from billing meter.	Uses data from control area settlements (generators that do not go through a control area settlements process or customer-sited distributed generation can enter meter data through a Qualified Reporting Entity); Revenue-quality meter required.	Meter data is provided by PJM Market Settlement System, entered by the Account Holder, or provided by the Generation Reporting System; Revenue-quality meter required.	Uses data from NE-ISO's Settlement Market System (MSS). If not in MSS: DG must provide meter data, Account Holders must provide meter data.	Uses data from control area settlements (generators hat do not go through a control area settlements process or customer-sited DG can enter meter data through a Qualified Reporting Entity); Revenue-quality meter required.	Receives meter data from partners such as Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and Northern Maine Independent System Administrator (NMISA).