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Wholesale Power Market Design in a Future Low-Carbon Electric System:

A Proposal for Consideration

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Acknowledgments

This is an independent white paper prepared by Susan Tierney at the request of World Resources Institute ("WRI") and Resources for the Future ("RFF") as part of their joint initiative to explore wholesale electricity market designs for a very low-carbon, reliable and affordable electric-system future. The WRI/RFF initiative is designed to further develop, analyze, model, and socialize among experts and stakeholders various design concepts for wholesale power markets in the long term future.

This paper builds off of a 2018 paper that Tierney wrote a about future wholesale power market design for California ("Resource Adequacy and Wholesale Market Structure for a Future Low-Carbon Power System in California," July 10, 2018). That paper reflected her thinking at that time about possible revisions in California's wholesale market structure that might reasonably position the state to accomplish its goals for the future electric system, given California's particular industry and regulatory structure. As part of the current WRI/RFF joint initiative, the project leaders solicited review and comments on Tierney's 2018 paper from several electric industry experts: Dr. Peter Fox-Penner, Dr. Ezra Hausman, Dr. Jacob Mays, and an anonymous reviewer. Additionally, WRI and RFF requested peer views of Tierney's July 8, 2020 draft of this current paper and received comments from Dr. Bethany Frew, Mr. Cliff Hamal, Mr. Travis Kavulla, Mr. Rana Mukerji, Dr. Carl Pechman, Dr. Arnold Quinn, and an employee of Exelon Corporation. Tierney appreciates their thoughtful comments and her final paper has benefitted from their comments (as summarized in the table on the following page).

Tierney prepared this paper on a pro-bono basis, which constituted a practical constraint on its level of technical detail. For disclosure purposes, she is a member of the boards of directors of RFF and of WRI and of other organizations focused on mitigating the emissions that lead to climate change. Her analyses, observations and recommendations reflect her independent judgment and not those of WRI, RFF, others at Analysis Group, her other affiliations, or the reviewers.

About the Author

Sue Tierney is a Senior Advisor at Analysis Group, where she has consulted to energy suppliers and consumers, grid operators, state regulatory commissions and other government agencies, tribes, environmental groups, utilities, foundations, financial institutions, universities, and other organizations. Previously, she served as the Assistant Secretary for Policy at the U.S. Department of Energy, and in Massachusetts she was Secretary of Environmental Affairs, Commissioner at the Department of Public Utilities, and Executive Director of the Energy Facilities Siting Council. She chairs the ClimateWorks Foundation Board and the Board of Resources for the Future. She is a trustee of the Barr Foundation, and a director of World Resources Institute and the Energy Foundation. She serves on several committees of the National Academies of Sciences, Engineering and Medicine: The Future of the Electric Grid; and Accelerating Decarbonization in the United States. She recently chaired the Department of Energy's Electricity Advisory Committee, chairs the External Advisory Council of the National Renewable Energy Lab, was co-lead author of the energy chapter of the National Climate Assessment, and served on the U.S. Secretary of Energy Advisory Board. She earned her Ph.D. and M.A. in regional planning at Cornell University.

About Analysis Group

Analysis Group is one of the largest international economics consulting firms, with over 1,000 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, analytics, and strategy to top law firms, Fortune Global 500 companies, government agencies, and other clients. The firm's energy and environment practice area is distinguished by its expertise in economics, finance, market modeling and analysis, regulatory and policy analysis, and infrastructure development. Analysis Group's consultants have worked for a wide variety of clients, including energy suppliers, energy consumers, utilities, regulatory commissions, other federal and state agencies, tribal governments, power system operators, foundations, financial institutions, start-up companies, and others.

Thematic Responses to Comments from Reviewers

<table>
<tr><th>Tierney paper reviewed</th><th>Comment or critique or observation from reviewer</th><th>Tierney response</th></tr>
<tr><td colspan="3">Note: The following comments reflect substantive critiques, comments and questions; reviewers' positive statements about the papers are not reflected in this table.</td></tr>
<tr><td>7/2018 paper re: resource adequacy in California</td><td>The author's approach is anti-market with too little reliance on strong energy market price signals to reward suppliers for the desired outcomes, and too much trust in government policy makers.</td><td rowspan="4">The author appreciates the important roles of markets and regulation in the provision of electricity service, and that various experts hold different views on the appropriate, if not best, combination of mechanisms to achieve desired outcomes for consumers and suppliers.
The author's experience as a utility regulator and energy policy maker, an analyst of retail and wholesale electricity markets, and an observer of the complex ways in which local, regional and national electricity systems, institutions and policies have evolved over the past decades, has shaped her views in developing this proposed market design for a low-carbon electric system in the future.
She has sought to rely on market forces where possible and to rely on government policy and regulatory decisions where markets are not accomplishing the multiple objectives for the electric system (i.e., affordable, efficient and reliable supply, assuring appropriate incentives for investment that are consistent with the transition to a low-carbon electric system). One consideration is whether the current market designs are moving the energy transition fast enough to accommodate states' decarbonization policies.
Her proposal does allow for bilateral contracting.
The proposal anticipates that the "optimal mix of resources" at various points in time will reflect the influence of: economic, financial and policy incentives; technological considerations; risk appetites and preferences of investors, consumers, electric companies, and regulators; and other factors. Accomplishing such approaches may require new legislative authority for federal regulators to give great weight to state carbon-reduction policies as part of determining what constitutes just and reasonable rates.</td></tr>
<tr><td>7/2018 paper re: resource adequacy in California</td><td>The paper does not adequately wrestle with the character of electricity—that is, that it is unlike any other product because society has multiple objective functions for the electric system, not just economic efficiency. Nor does her discussion address the perspective that the gold standard for managing the provision of this multi-objective, policy-driven service is the vertically integrated related electric utility. Unlike other market participants, utilities are obligated to "do whatever it takes" to meet all system requirements.</td></tr>
<tr><td>7/2020 draft of this paper for WRI/RFF Initiative</td><td>The author's proposal does not accommodate bilateral contracting between a load-serving entity (e.g., a utility, a retail supplier) and sources of supply.</td></tr>
<tr><td>7/2020 draft of this paper for WRI/RFF Initiative</td><td>The notion of an "optimal mix" of resources is a false goal.</td></tr>
<tr><td>7/2020 draft of this paper for WRI/RFF Initiative</td><td>The paper does not answer the question of which alternative market design meets customer needs at lowest costs.</td><td>The author recognizes that this is and will continue to be a critical analytic question, but the limited scope of this paper did not allow for quantitative analysis of alternative models. That said, the author considered qualitatively some potential challenges in existing market designs for accommodating a market with extremely deep reliance on zero-variable cost/relatively high capital cost resources.</td></tr>
<tr><td>7/2020 draft of this paper for WRI/RFF Initiative</td><td>The three RTO regions with centralized capacity markets are performing well at present, and can co-exist (as the author has said elsewhere) with both a carbon price and other state mechanisms to support entry of zero--carbon and renewable resources.</td><td>The author agrees but also recognizes that, at present, none of these regions relies on zero-carbon resources at the levels consistent with much-lower emissions from the power sector.* These RTO markets still have fossil generating units on the margin for the majority of hours as of 2018 and 2019 and thus set locational marginal energy prices. Current conditions do not demonstrate the ability of these markets to perform successfully in the future.
* Zero carbon generation: ISO-NE = 45% (2019 Facts); NYISO = 58% (2020 Power Trends); PJM = 34% (2019 Annual Report)</td></tr>
<tr><td>7/2020 draft of this paper for WRI/RFF Initiative</td><td>The paper should have address concerns about the opportunity for political intrusion into electricity markets (e.g., the recent lobbying violations in Illinois and Ohio).</td><td>The author thinks that no market design is entirely immune from gaming and abuse (e.g., the Enron abuse of Western markets two decades ago), and any market design requires diligence.</td></tr>
<tr><td>7/2020 draft of this paper for WRI/RFF Initiative</td><td>The author finds advantages in MISO, SPP and CAISO market designs (e.g., they can more directly reflect the resource preferences of states given that their utilities are vertically integrated with IRP processes), as contrasted with the three RTOs with restructured electric industries and centralized capacity markets. The author does not explore whether changes in governance rules in the latter RTOs would help to address the concern.</td><td>The author addresses this point in the final paper.</td></tr>
</table>

7/2020 draft of this paper for WRI/RFF Initiative	FERC would have to (and would not likely) accept a tariff that gives states a role in establishing resource adequacy issues. The paper should not undermine economic efficiency goals by giving larger roles to the states.	The author is aware that in many RTOs, FERC has recognized the states' role in establishing resource adequacy (and preferred resource portfolio mixes). In the RTOs with centralized capacity markets as a mechanism for assuring resource adequacy, there is a growing tension in which many states see to re-exert the ability to influence resource portfolio outcomes beyond those resulting from the capacity market. The author has tried to develop a proposal that respects states' role in resource adequacy within FERC-approved wholesale markets.
7/2020 draft of this paper for WRI/RFF Initiative	The author does not consider how comprehensive national energy policy might address some of the tensions she sees as arising across states and between states and the federal government.	As a long-time observer/analyst of energy and environmental policy (and a former federal policy official, and former state utility regulator, state cabinet officer responsible for environmental affairs, and head of a state's energy facility siting council), the author does not believe that there will ever be a "comprehensive national energy policy." She is keenly aware of legacy jurisdictional divisions: state jurisdiction over various activities in the energy domain (e.g., over aspects of: oil and gas production; retail elements of utility service; siting of power plants and transmission lines; land-use regulation; building standards) and federal jurisdiction over and/or programmatic involvement in others (e.g., permitting of gas pipelines; regulation of power sales and transmission in interstate commerce; support for research and development; tax policies; access to development of energy resources on federal lands and offshore regions; environmental regulation over various pollutants; policies relating to rural electric cooperatives). Even if the Congress were to enact legislation changing one or another element of jurisdictional splits (e.g., to adopt a uniform national policy to price carbon or otherwise limit GHG emissions from the power sector (or the economy)), her view is that this would not constitute a comprehensive national energy policy.
7/2020 draft of this paper for WRI/RFF Initiative	The author does not fully explain her concerns about market power (e.g., whether the concerns arise in the context of long-term resource procurement and operation of energy markets) or whether active demand-side resources can mitigate these concerns.	The author addresses this point in the final paper.
7/2020 draft paper on wholesale market design	The commenter urges the author to consider ERCOT as the preferred power market design.	The author addresses this point in the final paper.
7/2020 draft of this paper for WRI/RFF Initiative	The paper does not discuss the role of transmission planning.	The paper discusses FERC-ordered transmission planning processes. The author appreciates that expansion of the high-voltage transmission system will be an essential element of the transition to and achievement of a reliable decarbonized electric system at a reasonable cost, but discussion of such issues are beyond the scope of this paper .
7/2018 paper re: resource adequacy in California	The model fails to address actions on the customer side of the meter, and presents an overly expensive and risky, supply-side-dependent power system	The author agrees, and has included discussion of demand-side issues as part of the market design in this paper.
7/2020 draft of this paper for WRI/RFF Initiative	The author makes a valid case for the need to animate demand but several models for doing that (e.g., retail transactive energy market constructs) may introduce risks to reliability.	
7/2018 paper re: resource adequacy in California	The paper does not address how the grid-operator would decide which resource(s) to dispatch among the many that might offer the same $0/MWh prices.	This is a good question and deserving of greater technical attention than was available within the scope of this paper.
Both papers	The paper does not provide a sufficiently detailed description of how the system would work in practice or the technical elements of the approach.	The author agrees, but that was beyond the scope of what could be done on this pro-bono paper.
7/2018 paper re: resource adequacy in California	The paper needs a companion process pathway to get from the current market design to the next	Such process pathways are important, but the 2018 paper addressed a specific question posed by state regulators with regard to a sensible end-state model and so the paper did not address process pathways.

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I. Executive Summary

This white paper aims to inform the on-going discussions among public and private-sector stakeholders who are exploring changes that may be needed in centralized wholesale power market designs in the future. Everywhere in the U.S., future electric systems will need to provide reliable, reasonably affordable and efficient power supply, and will rely much more deeply on zero-carbon energy resources[1] than do most U.S. wholesale power systems today.[2] Such transitions will likely necessitate changes in at least some aspects of those market rules and many experts and analysts have proposed approaches to address these transitions.

In drafting this paper, the author's intent has been to promote conversations among market participants, economists, policy makers, investors, and other stakeholders as they consider possible market designs that satisfy the multiple goals of successful wholesale power systems in a low-carbon future. As such, and given the early stages of such discussions, this paper focuses on conceptual issues and market structure, rather than the important technical details that will need to accompany any real transitions to new wholesale market designs and rules in the future.

A. Assumptions and context

An underlying premise of this paper is that many U.S. states, cities, companies, regions, and others[3]—and perhaps even the national government at some point before long—will take further action to reduce and eventually eliminate greenhouse gas ("GHG") emissions in the power sector.

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1 In this paper, "zero-carbon resources" include current conventional hydroelectric, wind, solar, geothermal, and nuclear generation. It also anticipates that fossil generation with carbon capture and/or hydrogen generation could also qualify as zero-carbon generation in the future, depending upon the technology and fuel configurations for such resources.

2 Many U.S. states currently rely on zero-carbon resources for a significant portion (i.e., more than 60%) of their in-state power generation in 2019: for example, Illinois (at 62%), Idaho (at 74%), South Dakota (at 74%), Washington State (at 77%), New Hampshire (at 81%), Vermont (at 81%)). These states' electric systems depend primarily on nuclear and conventional hydro resources for most of that zero-carbon generation. For some number of years into the future, incremental zero-carbon power supply is likely to come from wind and solar generation, which have lower capacity factors and with less dispatchable generation with seasonal variation in output as compared to other existing zero-carbon supply (i.e., nuclear, conventional hydropower, and geothermal generation). Data sources: Energy Information Administration ("EIA"), Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923), at https://www.eia.gov/electricity/data/state/.

3 At present:

- 19 states and the District of Columbia have clean electricity commitments. Lori Bird and Tyler Clevenger, "2019 Was a Watershed Year for Clean Energy Commitments from U.S. States and Utilities," World Resources Institute, December 20, 2019, these RTO markets still have fossil generating units on the margin for the majority of hours as of 2018 and 2019 and thus set locational marginal energy prices.
- Investor-owned electric utilities with commitments to significantly reduce (if not eventually eliminate) GHG emissions account for nearly two-thirds of power delivered in 2019. Edison Electric Institute (EEI), Electric Company Emissions Database (2019), https://www.eei.org/Pages/CO2Emissions-Access.aspx, and EIA 861 database, https://www.eia.gov/electricity/data.php.
- 68% of retail customer accounts in the U.S. are served by a utility with a carbon or emission reduction goal. https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.
- The Deal Tracker hosted by the Renewable Energy Buyers Association (REBA) indicates that corporate members have entered into transactions amounting to 25 GW of renewable capacity between 2016-2020, at https://rebuyers.org/deal-tracker/. Additional corporate commitments are reported in Solar Energy Industries Association (SEIA), "2019 Solar Means Business Report," 2020, at https://www.seia.org/sites/default/files/2020-10/SEIA-SMB-2019-FINAL_0.pdf.

The scientific consensus holds that global GHG emissions need to be net zero by 2050 in order to limit global temperature increases to 1.5°C. Increasingly, public and private-sector actors are taking steps to reduce emissions, consistent with this goal.

Further, informed by the literature on how to lower carbon emissions from the economy more generally, another premise of this paper is that the electric system will grow and play an increasingly larger role in providing energy services, including to move vehicles, heat buildings and supply many other energy needs that now directly use fossil fuels.

Accomplishing those outcomes will depend increasingly on low-carbon electric resources with relatively high upfront capital costs and very low (or no) fuel and variable operating costs.[4] These conditions, combined with an outlook for continued low natural gas prices, will challenge (if not fundamentally undermine) the sustainability of wholesale market designs as currently configured in many parts of the U.S. This paper offers a market design intended to be better fit for purpose in light of these future conditions.

Over the past two decades, regional wholesale power markets have produced many benefits for consumers.[5] They have enabled efficient dispatch of generating units and other resources. They have delivered bulk-power supply with a high degree of reliability. With the help of low gas prices, they have helped to reduce the cost of wholesale power production and the carbon emissions from electricity production and use.

In particular, it is generally (although not universally) observed that organized energy and ancillary-service markets have performed efficiently and competitively across all of the seven regions with those markets administered by Regional Transmission Organizations ("RTOs") or Independent System Operators ("ISOs").[6] To date, these markets have helped to satisfy the long-standing core societal objectives for electric service: reliable and affordable electricity production.

The combination of energy, ancillary services and centrally organized capacity markets in the PJM footprint, New York and New England, however, has proven more challenging in terms of producing a resource mix that comports with many states' policy preferences for decarbonizing the power system. Without a

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4 Utility-scale generating capacity additions require upfront capital investment; but, by comparison to new fossil-generating technologies at present, capacity costs associated with utility-scale wind and solar capacity, for example, are higher on a $/Mw basis and as a percentage of total levelized cost of energy. EIA, "Average U.S. construction costs for solar and wind generation continue to fall," *Today in Energy*, September 16, 2020, at https://www.eia.gov/todayinenergy/detail.php?id=45136; Lazard, "Levelized Cost of Energy," October 2020, at https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf.

5 See, for example: REBA, https://rebuyers.org/programs/market-policy-innovations/organized-markets/; Judy Chang, Johannes Pfeifenberger and John Tsoukalis, "Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers," Brattle Group, April 2019, at https://brattlefiles.blob.core.windows.net/files/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf.

6 See the reports of the market monitors for each of the ISOs/RTOs for detailed technical assessments of the performance of these markets: Potomac Economics for ERCOT, ISO-NE, MISO, and NYISO (https://www.potomaceconomics.com/); Monitoring Analytics for PJM (https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml); the SPP Market Monitoring unit for SPP (https://spp.org/markets-operations/market-monitoring/); and the ISO Department of Market Monitoring for CAISO (http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx). For a critique of the periodic market performance assessments published by staff of the Federal Energy Regulatory Commission (FERC), see Elise Caplan, "Measuring the Performance of Wholesale Electricity Markets A Review of the Primary Market Assessments and Recommendations for Improvement," American Public Power Association, March 2020, https://www.publicpower.org/system/files/documents/Measuring-the-Performance-Wholesale-Electricity-Markets.pdf.

meaningful price on carbon within such markets, the suppliers of wind, solar and nuclear generation receive little (if any) compensation for the zero-carbon attribute of their power production, and revenues in those organized wholesale markets alone are neither high enough to retain some high-quality suppliers of zero-carbon supply nor sufficient to accelerate entry of renewables and storage on the pace required to meet the relevant states' energy and climate goals.

As of 2020, over half of the electricity consumed in the lower 48 U.S. states occurs in a state with policy commitments to significantly reduce and/or fully eliminate GHG emissions over the next decades.[7] For the most part, these states are served by five RTO/ISO energy markets (Midcontinent Independent System Operator ("MISO"), PJM Interconnection ("PJM"), New York Independent System Operator ("NYISO"), Independent System Operator - New England ("ISO-NE"), and California Independent System Operator ("CAISO") with its affiliated Western Energy Imbalance Market ("Western EIM").[8] In these regions, zero-carbon resources need to enter the market in unprecedented quantities and at an unparalleled pace that is not likely to be accomplished with by today's wholesale market designs.

Looking ahead, a combination of probable conditions will render PJM's, NYISO's, and ISO-NE's current energy and capacity market designs unworkable and will not drive down GHG emissions fast enough to meet those states' climate objectives. The conditions include:

- low prices in electric energy and ancillary-service markets;
- the absence of a meaningful price on carbon emissions;
- a growing missing money problem such that the organized wholesale markets do not produce sufficient revenues to support retention and/or entry of resources needed for a combination of resource-adequacy and low-carbon supply;
- some states' policies that are driving the adoption of low-carbon resources through out-of-market mechanisms;
- increasing tensions between federal wholesale market policies and state preferences for resource portfolio outcomes in the three RTOs;
- large electricity customers' goals to accelerate changes in the region's power supply mix;
- states' and electricity consumers' interest in the adoption of distributed energy resources ("DERs");
- many states' reluctance (to date) to implement mechanisms that cause a broad base of consumers to see and have the opportunity to respond to real-time prices; and
- chronic challenges in siting multi-state transmission facilities.

Because of the vertically integrated character of many of the load-serving entities ("LSEs") in the other RTO regions (like MISO, CAISO, and SPP, in particular), the states in those regions tend to have a more direct role in driving resource portfolios of the utilities that serve customers in their states. There is no RTO-

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[7] Analysis Group calculation based on states with a policy to reduce GHG emissions and the retail sales of electricity in each of those states, using EIA 861 data.

[8] For the most part, states in the SPP footprint have not adopted formal commitments to reduce GHG emissions, although (as described later in this paper), some of the electric utilities in the states served by SPP have made such commitments.

administered organized capacity market to identify, in combination with power-market economic fundamentals, those supply resources that will enter or exit the market to serve customer requirements. The utilities in these states rely on some combination of long-term resource planning, utility and non-utility project proposals, utility or third-party investment, competitive resource procurements, and long-term contracting approaches to determine the portfolios of resources that satisfy state, consumer and utility preferences. In these other RTOs, as in parts of the country states without RTOs, the RTO market mechanisms play a supporting but not decisive role in shaping the resource mix serving the consumers of the state. Even in Texas ERCOT—which relies on a restructured electric industry structure, retail competition, and a wholesale market design without a formal resource adequacy requirement or organized capacity market, a formal transmission planning, siting and construction planning process—the outcomes are the result of state policy determinations.

Assuming that many states and regions—not to mention many federal-government leaders —are serious about achieving their goals to decarbonize and grow the electric system to help lower GHG emissions in their broader economies, then states will need to be able to rely on regulatory tools in both retail and wholesale electric industry jurisdictions to support lower GHG emission as a key electric-sector goal, along with economic efficiency and reliability. And notably, in states that participate in RTOs, future wholesale market designs will need to align market rules so that they row in the direction of these same multiple goals.

As the penetration of electric resources with zero fuel costs increases and affects locational marginal prices in more and more hours of the year, energy prices will decline and may make it harder for investors in resources with high upfront capital costs to be willing to finance in the absence of long-term contracts for capacity and/or attributes credits. To address this and other related concerns (including the need to accelerate entry of zero-carbon resources to satisfy in-state policy requirements), some RTOs may choose to introduce carbon pricing mechanisms, or in the case of PJM, NYISO and/or ISO-NE, longer-term centralized capacity markets, or other approaches that evolve their market designs.

Alternatively, these RTOs might find that other revisions to their market designs are warranted, including through a combination of rules that allow for, if not encourage, long-term bilateral contracting between load-serving entities and suppliers and centralized auctions for long-term agreements for capacity and/other zero-carbon attributes. In this regard, these RTOs may look more like other RTOs (e.g., MISO, CAISO) with both efficient dispatch in short-term markets and long-term planning and multiple means for long-term contracting for zero-carbon resources.

The bottom line is that today's organized and relatively short-term capacity markets, combined with energy and ancillary service markets with low prices, will not be up to the task of supporting fast-enough or deep-enough investment in zero-carbon energy resources. A variety of tools to internalize carbon prices into the market rules, and to allow for long-term contracts to be "in-market" mechanisms, will be needed.

Further, there needs to be a much-more animated and price-responsive demand in order to meet the other core objectives of around-the-clock reliability and reasonably affordable power. Without active, flexible demand that responds to price and other signals from the RTO, much-more capacity will be needed, and it will be a more costly system for all consumers.

B. Proposed low-carbon wholesale market design: Three building blocks

What could a sustainable, low-carbon wholesale power market look? It would undoubtedly vary in its details from one state/region to another, because of the fundamental differences in industry structure, natural resource endowment, legacy and evolving electric system topology, cultural/political/policy preferences for relying on markets versus regulation versus some combination of the two, and other factors.

That said, common elements might include three core building blocks: (1) wholesale energy and ancillary services markets with security-constrained economic dispatch and locational prices; (2) a resource-adequacy approach influenced directly by state policy that would establish the criteria for selecting resources, and supported by regional resource planning and a combination of market-based mechanisms to support the exit of GHG-emitting fossil generation and the entry and retention of low-carbon-emitting and flexible resources from both the supply side and demand side of the market; and (3) sufficient resource capability for price-responsive demand from end-use customers in different geographic parts of the region.

This paper describes what those building blocks might look like:

- First, **competitive co-optimized wholesale energy and ancillary service markets** to ensure efficient dispatch of supply-side and demand-side resources.
    - These would be based on the well-proven approach of relying upon bid-based day-ahead and real-time markets, with locational clearing prices.
    - The wholesale market tariff, which would need to be approved by the Federal Energy Regulatory Commission ("FERC"), would account for state directives for carbon-pricing mechanisms for the resources located in their states, along with provisions for how the energy market would incorporate such mechanisms into price formation, dispatch, prices paid by loads, and compensation to suppliers.
    - The expectation is that even though there may be many hours of the year where zero-variable cost resources are on the margin, there will likely times and locations where prices rise to signal need for, say, flexibility services that might be provided by fossil generation and by price-responsive demand. There will also likely be times and locations where an oversupply of generation (e.g., from solar) creates negative prices, sending signals for flexible demands to rise (e.g., by filling storage). The market rules would need to determine how the auction and offer acceptance criteria in both the day-ahead and real time markets would make decisions among competing offers with similar prices (e.g., $0/MWh, or even similar negative prices).
- Second, a **resource-adequacy approach** for ensuring capacity of the right types and in the right places to provide reliable electricity from a portfolio of low- and zero-carbon resources. The key

elements are:

- Revised wholesale market rules proposed by each RTO and in tariffs approved by FERC. The rules would need to provide for important new roles for states with respect to governance and various market-design elements so that states' carbon policies are given weight in rules that also support system reliability and economic efficiency. For example, the tariff would allow each state to identify its preferred approach to resource adequacy (e.g., relying on LSEs' resources or relying on the RTO as the central buyer for capacity, or relying on a combination of approaches). The rules would give states the ability to identify attributes (e.g., zero-carbon emissions profile) that would be part of the specifications for capacity resources procured by the RTO on behalf of those states' LSEs. Each state would have the ability to impose a price or cap on carbon emitted within its boundaries. (These changes may require Congressional direction to authorize and direct FERC to consider the federalism structure of the electric industry and the role of states in expressing different preferences for resource attributes, as FERC determines whether wholesale market rules produce just and reasonable rates.)
- New definitions of resource adequacy beyond today's definition tied to the assurance of enough capacity to cover peak load and reserve requirements. These criteria could include, as today, the type(s) of resources needed to be located in particular constrained areas; but in the future, with much deeper and more diverse distributed energy resources on the system, these locations may need to be more granular than they are today. And to the extent that ancillary service products do not induce entry and retention of flexible resources where they are needed on the grid and providing grid services necessary for system reliability (e.g., ramping capability, system inertia, var support), the RTOs' procurements of resources would address such needs and allocate the costs to all load-serving entities.
- New roles and responsibilities of the RTO, the states and LSEs in ensuring resource adequacy. As is done today in RTOs in the context of long-term transmission planning, the RTO would conduct long-term (e.g., 10-year) resource planning. The RTO's resource plan would identify such things as: incremental amounts of various resource-adequacy products needed over the planning period; new transmission enhancements and non-transmission alternatives needed for reliability, supporting public policies, and/or economic efficiency; and expected carbon-emission trajectories based on commitments of LSEs, compared to levels consistent with states' policies. The RTO will need to integrate the results of distribution planning into resource planning for the grid.
- There would be a new resource-procurement approach for ensuring near-term and long-term capacity.
    - The RTO would conduct annual competitive procurements of resources to meet incremental capacity that is required for either of two resource-adequacy purposes: (a) any resources needed to be located in particular places and (b) any resources needed to

assure that the system has sufficient capability to provide flexibility services. Offer prices would reflect bidders' $/MW requirements over the expected term of a long-term contract, net of each bidders' expected revenues in future energy and ancillary services markets. The RTO would select winners based on best-fit/cost-minimized portfolio of offers that together satisfy the particular resource need(s) identified in the solicitation. Winning projects would enter into long-term performance-based contracts, with costs assigned to relevant LSEs. The annual procurement would be used to fill increasing proportions of capacity needs over the years of a planning period (e.g., 10 years) so that commitments starting in distant years are limited to only those preferred resources that require very long lead times. The RTO would conduct interim reconfiguration procurements to account for changes in resource availability, loads, etc.

- All other system-wide resources needed for resource adequacy beyond those centrally procured capacity products would be procured by LSEs through ownership and/or long-term bilateral contracting or the RTO procurement process for system-wide resources.
- To the extent that an LSE owns or has bilaterally contracted for resources that are eligible for some combination of local and flexible resources, the LSE would offer those resources into the RTOs' central procurement process for those products. If those offers are not selected for local or flexible resource adequacy needs, those resources can be applied to meet that LSE's share of system requirements. And the LSE could offer any resources into the RTO's procurement to supply surplus capability to the system.

- Third, **retail pricing to enable loads to see dynamic electricity prices** to ensure that the system can mine economic opportunities for flexible resources and efficiency on the demand side and that consumers can better manage their electricity use and bills as conditions change on the system.
  - Retail pricing policies and the availability of metering and communications technologies for enabling retail loads to see and respond to real-time locational prices are subject to state regulation, so decisions to enable such capabilities would fall outside of FERC jurisdiction. But FERC would oversee the aspects of wholesale market rules that enable such loads to see real time price signals and decide whether to participate directly in wholesale markets. Decentralized flexible loads might participate in wholesale markets either directly (e.g., with pricing signals seen directly by end-use customers) or indirectly (through utility or third-party load aggregators which manage the interactions between end uses and the wholesale market). Some states might even choose to implement "transactive energy"[9] models on local

[9] As explained in a report published by the National Association of Regulatory Utility Commissioners ("NARUC"), transactive energy ("TE") is both a "'technical architecture' and an 'economic dispatch system.' TE relies on price signals, robust development of technology on both the grid and customer side, and rules that allow markets to develop; therefore enabling a wide variety of participants to provide services directly to each other. TE facilitates the coordination of customer-sited resources, such as demand response (DR), storage, and other on-site resources, that are responsive to price or other signals." NARUC Staff Subcommittee on Rate Design, "Distributed Energy Resources Rate Design and Compensation," NARUC, November 2016, at http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0.

distribution systems with much-deeper penetration of distributed energy resources; but considerable technical work will be needed to address important communications, system coordination, controls, and other protocols to assure that the distribution-system and bulk-power system operators understand and can enforcement expectations about which system (or which consumer) has priority call on which resources at any point in time and space.

- That said, as the demand side of the electric system evolves with innovation, the RTO's tariff will likely need to include new products to enable DERs to provide services to the wholesale market.

This three-part market design is premised on the need for market designs to satisfy multiple objectives: reliability, economic efficiency, and an electricity system with significantly fewer and eventually no GHG emissions. The wholesale power market designed to accomplish those outcomes has to accommodate trade-offs across these objectives. In such a system, a foundational principle should be to exploit market-based mechanisms in service of cost-effective, low-carbon and reliable electricity supply.

This approach draws from the strength of different models that exist around the country, and it refashions them to be fit for purpose for a wholesale electric system that provides reliable, efficient and reasonably affordable power, and relies much more deeply on low-carbon energy resources. Doing so requires considerable judgment as well as the horsepower of market forces to ensure that the electric system is one that attracts and maintains the right type of resources in the right place in a future system that is quite different from the one that existed when the current electric-market structures were put in place.

C. Conclusions and caveats

The focus here is on an "end-state" structure for resource adequacy and for the operations of the bulk power system, rather than on the elements of the transitional steps or policies that will be needed to get from here to there. Although achieving a low-carbon electric system is now on the front burner in many states, cities, and regions, much more policy, political and technical work is needed to evolve wholesale power market design (and other policy elements, including retail regulation) to align with the changes that are needed to mitigate climate change. This paper has suggested the features of a potentially workable end-state design, as part of helping the discussion about how to get there.

This white paper describes (in Section II) today's baseline conditions as of 2020 that set the stage for why changes are needed in wholesale market design (as well as retail system operations). In Section III, the paper explains the assumptions about future goals for a low-carbon future electric system that have affected the core elements of a revised market design, which is described in more detail in Section IV.

What is not addressed in this white paper:

This report examines, on a high-level conceptual basis, the key elements of a potential wholesale power market design that might be appropriate for future electric systems in those parts of the U.S. that will rely increasingly on zero-carbon electricity resources with relatively high up-front capital costs and extremely low variable power production costs.

The report outlines features of a specific proposal, recognizing that there likely will be other reasonable approaches that suit the particular requirements of regions with different industry structures, regulatory priorities, and cultural norms.

This white paper does not directly address many policy and technical issues that are key to a successful evolution of wholesale markets. For example, the paper focuses on an end-state power system market with very-low carbon emissions, and does not look at many important issues such as:

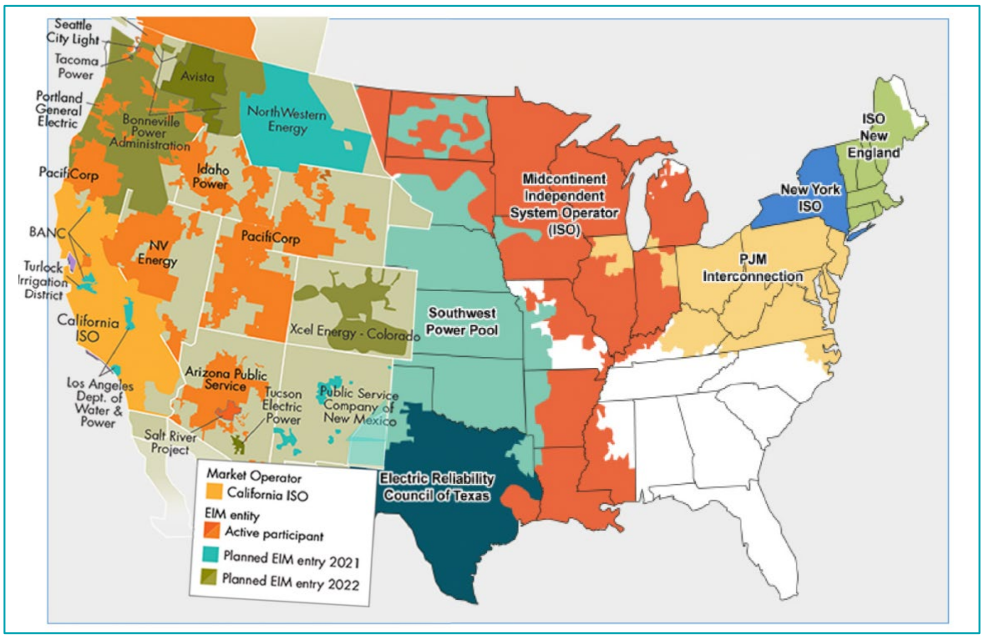
- How the current market designs in various U.S. electrical regions might transition to new market structures in parallel with federal and state policy actions to lower the carbon emissions of the power sector.
- How legal, economic, technical, and policy issues—and current tensions between the decisions of the FERC and state actions affecting resource portfolios in today's organized wholesale markets—will be resolved, including whether Congress will enact any new statutory authorities to address such issues.
- What level of electrification of buildings, vehicles and the industrial sector will occur, and what combination of decentralized distributed energy systems and much-larger bigger geographic bulk power systems will develop over time.
- What combination of climate-mitigation policy mechanisms will continue to develop and influence the pace and character of how the electric system lowers its carbon emissions and grows to help other parts of the economy lower their own GHG emissions.
- What the technical details of energy, ancillary and capacity markets would be needed to support the overall conceptual market design described in this paper.
- Whether the market design outlined here would provide cost, policy and other advantages over other alternative designs, based on modeling and other quantitative analyses.

II. Today's Power Markets, Portfolios, and Policies

A. Power markets in 2020

Over time, organized wholesale power markets have come to cover more and more of the U.S. electric system. As shown in Figure 1, few states are not touched by one of the nation's RTOs/ISOs—CAISO, Electric Reliability Council of Texas ("ERCOT"), ISO-NE, MISO, NYISO, PJM, and the Southwest Power Pool ("SPP")—or the enlarging Western Energy Imbalance Market ("Western EIM") administered by CAISO. There are indications that several utility companies in the Southeastern region of the U.S. are considering whether to establish an energy imbalance market there.[10]

Figure 1:
RTOs, ISOs and the Western Energy Imbalance (EIM) Market



Note: The Western EIM map is superimposed on the RTO/ISO map in this figure.
Source: Western EIM at https://www.westerneim.com/Pages/About/default.aspx; RTOs/ISOs at U.S. General Accountability Office, "Electricity Markets," December 2017, at https://www.gao.gov/assets/690/688811.pdf.

Although today's wholesale market designs vary in many ways across these regions, all of the RTOs/ISOs operate bid-based day-ahead and real-time markets for energy and ancillary services, with security-constrained economic dispatch and locational-marginal pricing ("LMP") mechanisms.[11] There is strong

[10] Darren Sweeney and Justin Horwath, "Duke Energy, Southern confirm talks on creation of regional energy market," S&P Global Market Intelligence, July 14, 2020, at https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/duke-energy-southern-confirm-talks-on-creation-of-regional-energy-market-59430762.

[11] The Western EIM relies upon a real-time security-constrained economic dispatch after taking into account resource schedules submitted by each participant.

consensus across the industry that such markets offer the gold standard for efficient operations of a portfolio of resources in place at any point in time.[12]

The biggest difference among the RTOs/ISOs is how they address resource adequacy and the entry, retention and exit of resources. Differences in industry structure and the cultural norms among market participants and other stakeholders greatly affect these varied approaches to resource adequacy.

Three RTOs—ISO-NE, PJM, and NYISO, all of which operate in places where most if not all of the states restructured their electric industries two decades ago—have mandatory forward capacity markets.[13] ISO-NE and PJM have a three-year forward commitment period and NYISO has a 6-month forward commitment period. All three of these regions include states with aggressive renewable energy and carbon emissions-reduction policies (see below), with a modest price on power-sector carbon emissions through participation in the multi-state market-based cap-and trade program—the Regional Greenhouse Gas Initiative ("RGGI"). These three RTOs also provide electricity in states (e.g., New York, Connecticut, Massachusetts, Maryland) that have adopted policies and practices to procure particular resources (e.g., storage, off-shore wind) through out-of-market contracts, which are the object of growing tensions between FERC, state utility regulators, and many market participants and other stakeholders.[14]

ERCOT, which also has a restructured electric industry, has no installed capacity market and relies upon voluntary bilateral contracting (among retailers, marketers, and/or generating companies, among others) and revenues in the energy and ancillary services markets for entry, exit and retention of capacity resources.

And the three RTOs/ISOs—CAISO, MISO and SPP—that operate in states that largely did not restructure their electric industries also have no mandatory centralized capacity market administered by the RTO. Rather,

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[12] Peter Fox-Penner, *Power After Carbon: Building a Clean, Resilient Grid,* Harvard University Press, 2020; Paul Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation*, MIT Press, 1983; Paul Joskow and Richard Schmalensee, MIT Energy Initiative's Energy Markets podcast, Episode #14 (2020), at http://energy.mit.edu/podcast/electricity-markets/; Paul Joskow, "Lessons Learned From Electricity Market Liberalization," *Energy Journal*, 2008, at https://economics.mit.edu/files/2093; William Hogan, "Electricity Market Design Interactions of Multiple Markets," presentation at RFF's Workshop on the Future of Power Markets in a Low Marginal Cost, September 14, 2017, at https://media.rff.org/documents/170914_PowerMarkets_WilliamHogan.pdf; Jaquelin Cochran, et al., "Market Evolution: Wholesale Electricity Market Design for 21st Century Power Systems," 20th Century Power Partnership Project, National Renewable Energy Laboratory Technical Report, October 2013, https://www.nrel.gov/docs/fy14osti/57477.pdf; Steven Corneli, et al., "Wholesale Electricity Market Design for Rapid Decarbonization: Long-Term Markets, Working with Short-Term Energy Markets," Energy Innovation, June 2019, https://energyinnovation.org/wp-content/uploads/2019/06/Wholesale-Electricity-Market-Design-For-Rapid-Decarbonization-Long-Term-Markets-Working-WIth-Short-Term-Energy-Markets.pdf.

[13] James Bushnell et al., "Capacity Markets at a Crossroads," Energy Institute at Haas Working Papers, April 2017, https://hepg.hks.harvard.edu/files/hepg/files/wp278updated.pdf.

[14] Calpine Corp. et al., v PJM Interconnection, 169 FERC ¶ 61,239, Order Establishing Just and Reasonable Rate, Docket Nos. EL16-49-000 and EL18-178-000 (Consolidated), December 19, 2019, at https://www.pjm.com/-/media/documents/ferc/orders/2019/20191219-el16-46-000-el18-178-000.ashx; Jeff St. John, "FERC Denies Rehearings on PJM Capacity Orders, in a Blow to States' Renewables Plans: There's a silver lining for renewable energy, however: The unexpectedly swift denial opens the door to legal challenges," GTM Research, April 16, 2020, at https://www.greentechmedia.com/articles/read/ferc-denies-rehearings-on-its-pjm-capacity-rulings-opening-door-for-legal-challenges; Catherine Morehouse, "Maryland taking a 'serious look' at exiting PJM capacity market through FRR, says PSC Chair," *Utility Dive*, April 29, 2020, at https://www.utilitydive.com/news/maryland-taking-a-serious-look-at-exiting-pjm-through-frr-says-psc-chair/576957/.

they rely on a combination of utility-owned generating resources, utility contracts with suppliers, and state-supervised integrated-resource-planning processes for entry and exit of capacity resources into the system.[15]

These regions have taken different tacks on planning for and adding new transmission: Perhaps the most deliberate transmission-expansion planning process and development program undertaken by an RTO for opening up regions for development and export of renewables was Texas' Competitive Renewable Energy Zone ("CREZ") process,[16] which spanned roughly the period from 2005 through 2013 and added 2,400 miles of transmission lines capable of carrying 18,500 megawatts of west Texas wind generation to major load centers in ERCOT.[17] This particular initiative was driven by state law and regulatory action, and was not subject to FERC jurisdiction. It benefited from having a single state govern decisions with regard to siting eminent domain, determination of need and public benefit and other decision-making for project approvals, and cost recovery allocated broadly to loads in ERCOT.

But other RTOs under FERC-approved transmission tariffs have adopted other programs to support transmission expansion for reasons other than reliability:[18] Over the past decade, for example, MISO has implemented a process to identify, plan for and provide cost allocation/recovery for "multi-value projects," including ones to connect regions with renewables and load centers.[19] California[20] and New York[21] have similarly adopted transmission-expansion planning processes and support for transmission to break the chicken-and-egg challenges of transmission expansion and renewable development and other state public policy outcomes.

B. State policies to lower carbon emissions in the power sector as of 2020

Nearly all of the states served by RTOs/ISOs have adopted goals to introduce increasing shares of renewable energy into the wholesale electric resource portfolio, and in several FERC-jurisdictional RTOs (notably CAISO, NYISO, ISO-NE, a large portion of PJM, and the upper U.S. portion of MISO), many states have also adopted explicit targets to lower GHG emissions from the power sector. Figure 2 shows the states with some form of policy pushing more renewables into the electric system, and Figure 3 shows those states with statutory or executive orders to reduce GHG emissions from the economy.

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[15] CAISO provides a back-stop reliability. MISO operates a voluntary annual Planning Resource Auction which provides market participants with an option for procuring capacity resources. SPP has a requirement that LSEs demonstrate that they have met the SPP planning reserve margin.

[16] Nathan Lee, et al., "Renewable Energy Zone (REZ) Transmission Planning Process: A Guidebook for Practitioners," National Renewable Energy Laboratory, September 2017, at https://www.nrel.gov/docs/fy17osti/69043.pdf.

[17] http://www.ettexas.com/Projects/TexasCrez#:~:text=All%20CREZ%20projects%20were%20scheduled,major%20load%20centers%20in%20ERCOT.

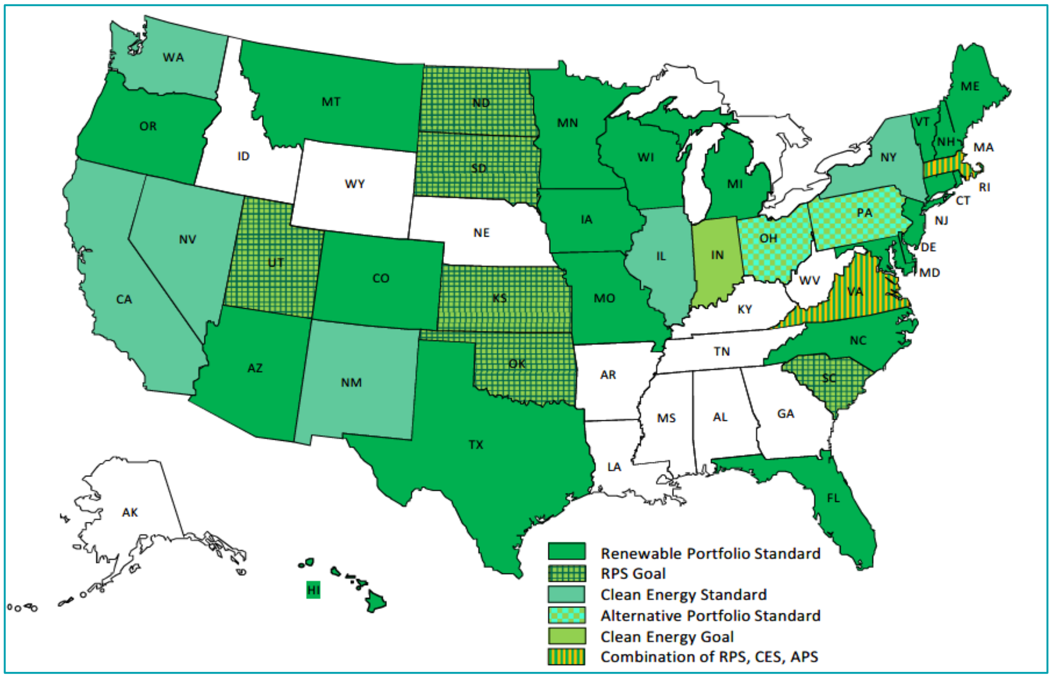
[18] ScottMadden, "Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States," prepared for The WIRES Group, January 2020, at https://wiresgroup.com/wp-content/uploads/2020/01/ScottMadden_WIRES_Informing-the-Transmission-Discussion_2020_0113_FINAL.pdf.

[19] https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/#t=10&p=0&s=&sd=.

[20] Ross Baldick, et al., "A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles A White Paper Prepared by The Blue Ribbon Panel on Cost Allocation," prepared by the Working Group for Investment in Reliable and Economic Electric Systems for the WIRES Group, September 2007, pages 42-43, at https://hepg.hks.harvard.edu/files/hepg/files/rapp_5-07_v4.pdf.

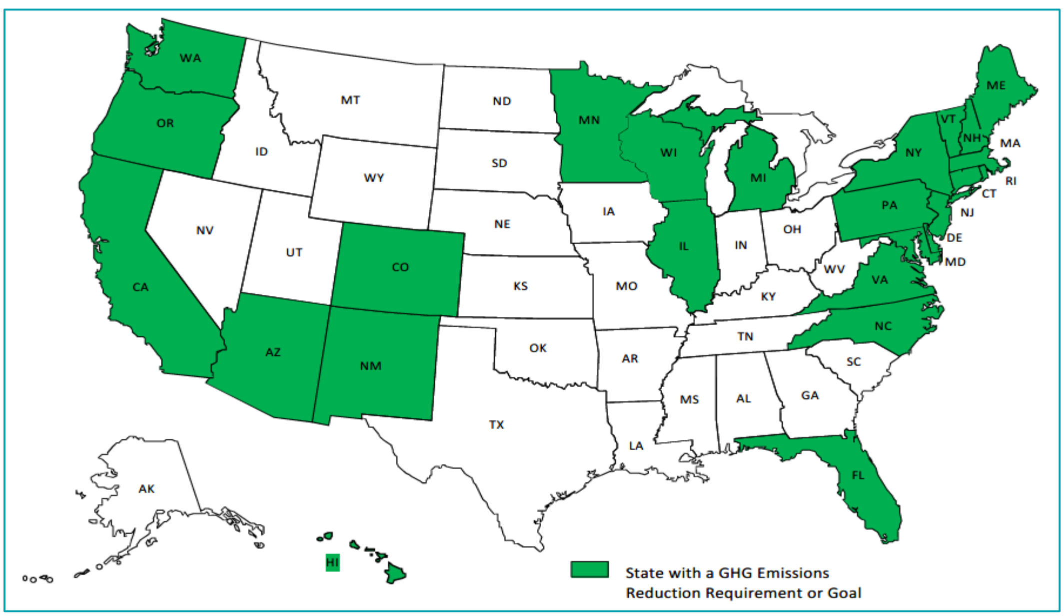
[21] NYISO, "AC Transmission Public Policy Transmission Plan: A Report from the New York Independent System Operator," April 8, 2019, at https://www.nyiso.com/documents/20142/5990681/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf.

Figure 2:
States with Mandatory and/or Aspirational Targets for Renewable Energy in the Electric System



Sources: Center for Climate and Energy Solutions (C2ES), State Climate Policy Maps, at https://www.c2es.org/content/state-climate-policy.

Figure 3:
States with Statutory and/or Executive Branch Policies to Reduce Greenhouse Gas Emissions

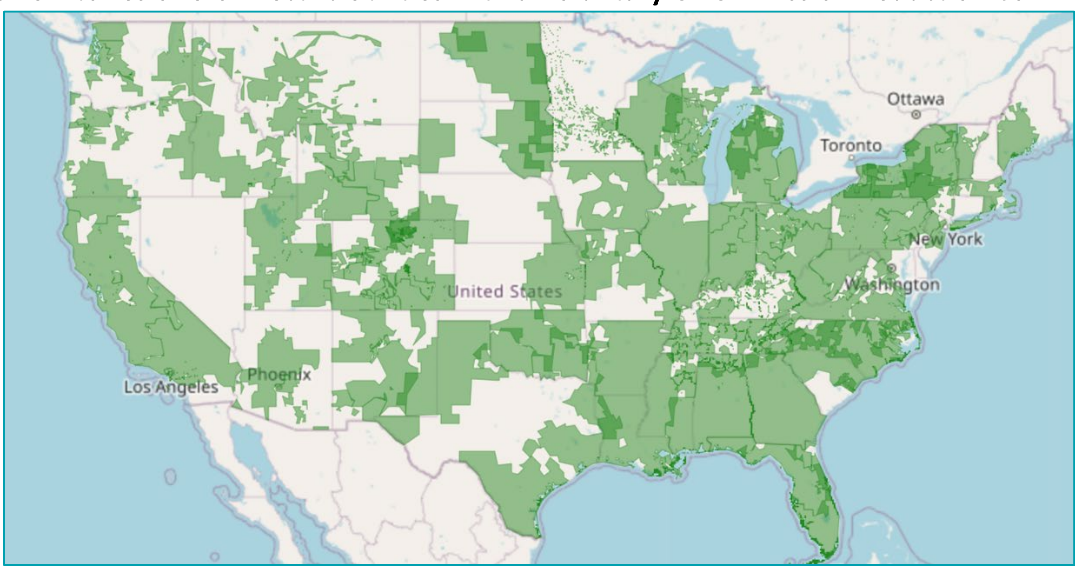


SOURCE: Center for Climate and Energy Solutions (C2ES), State Climate Policy Maps, https://www.c2es.org/content/state-climate-policy, updated with information about Virginia and Wisconsin.

These GHG-emission reduction policies, combined with many states' policies promoting DERs (and rooftop solar in particular), many states' integrated resource planning processes affecting electric utility resources portfolios, and declining costs and improving efficiencies for new wind and solar projects, together have led to increasing entry of renewables (as described further below).

Many of the nation's largest electric utilities themselves have committed to reducing, and in some cases, eliminating, GHG emissions from their power supply. As of this writing, 68 percent of retail electricity customers are served by an electric utility with a carbon-reduction commitment, which is to be a net-zero emitter by 2050 at the latest.[22] As shown in Figure 4 in conjunction with the information in Figure 3, many of these utility service territories are in states without a state-imposed carbon-reduction policy. Taking into consideration the coverage of states that do have such policies (Figure 3) and these voluntary utility commitments (Figure 4), must of the nation's electric system will move toward a lower-carbon profile over the next decades.

Figure 4:
Service Territories of U.S. Electric Utilities with a Voluntary GHG-Emission Reduction Commitment



https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/

Going forward, these zero-carbon and renewable electricity commitments from utilities, states, corporations, and others will lead to significant transitions in the resource portfolios across the RTO regions, with those power systems depending much more deeply on non-dispatchable and variable generating and storage technologies with high upfront fixed costs and low variable costs. Such a system has low and, in many hours, zero (or even negative) energy-market prices, which will require further attention to operate sustainable market designs and operations in many RTO markets.

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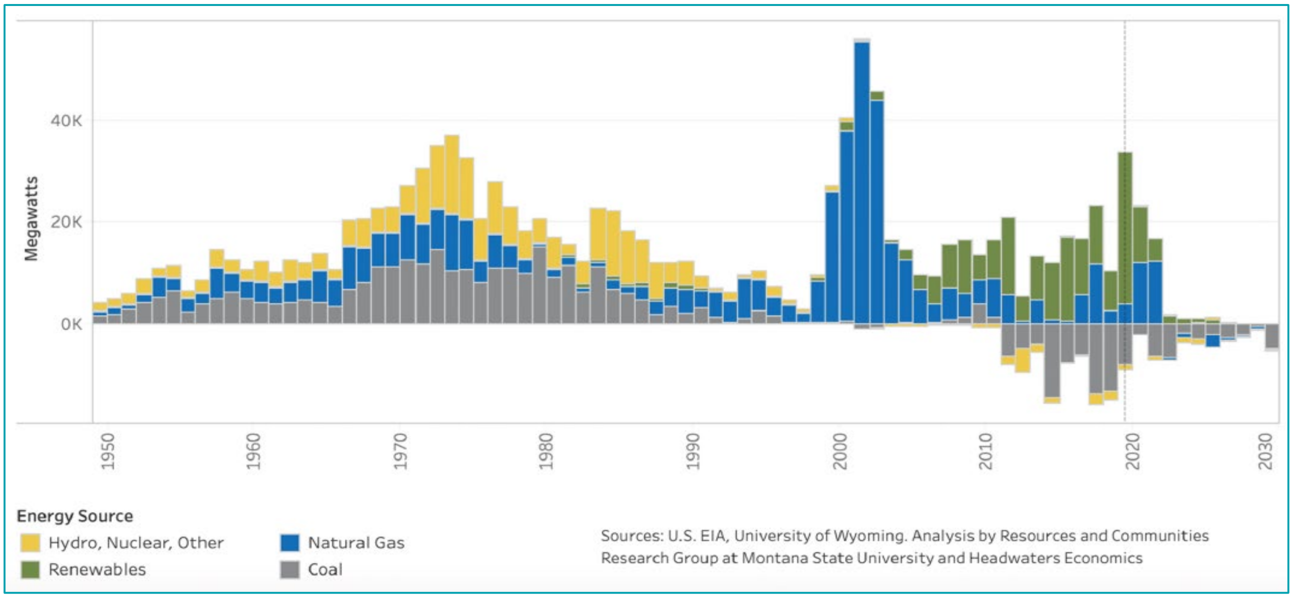
22 As of the 3rd quarter of 2020, 68 percent of retail electricity customers in the U.S. is served by an electric utility with a carbon-reduction commitment. https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.

C. Power market portfolios in 2020

Across the RTO regions (and even outside of them), electric resource portfolios have changed dramatically in recent years. For more than two decades, almost all of the new generating capacity that has been added is either at new gas-fired generating units or new wind and solar projects (as shown in Figure 5, below). In fact, no new coal capacity has been added since 2010, and significant quantities of older and particularly inefficient coal-fired generating capacity has retired since then.

Figure 5
U.S. Generating Capacity Additions and Retirements by Year: 1950-2019



Source: Mark Haggerty, "The Evolution of U.S. Electricity Generation Capacity," Headwaters Economics, April 2020, at https://headwaterseconomics.org/economic-development/evolution-electricity-generation/

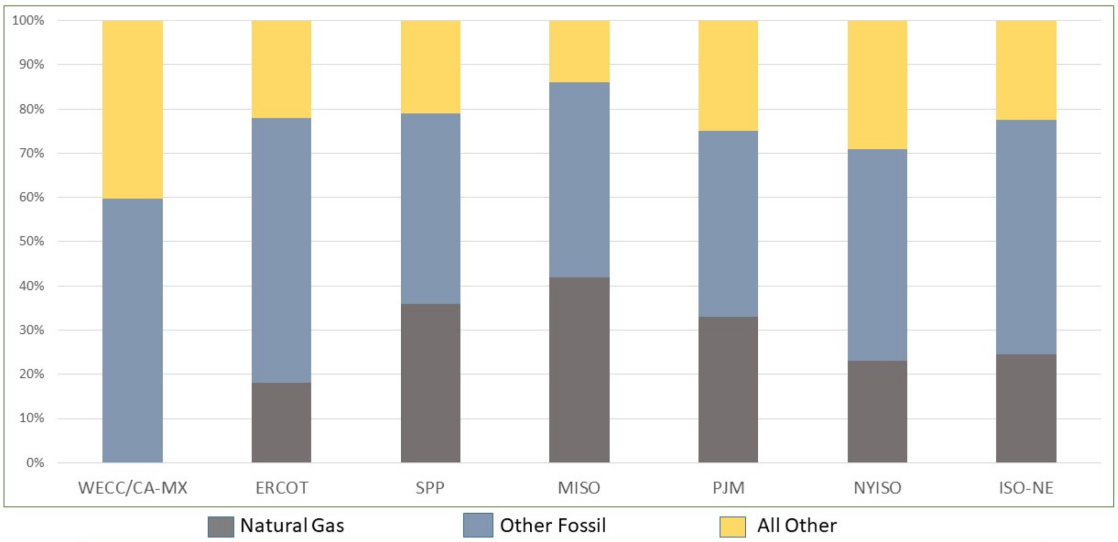
Low natural gas prices since the shale-gas revolution took hold starting around 2007/2008 have had a significant impact on electric-sector conditions. Gas-fired generation now produces the highest percentage of power around the nation, and is damping down coal-fired generation around the country. In parts of the MISO and SPP regions with state-mandated integrated resource planning processes, new renewable projects are competing favorable with new gas projects. Around the country, other renewable resource additions are driven more by state renewable portfolio standards ("RPS") and federal tax policy as much as by new resource need (because renewable capacity addition continues to move forward even in the absence of tight reserve margins in most regions[23]).

[23] The author's conclusions based on various documents, including: North American Electric Reliability Corporation ("NERC"), "2019 Long=Term Reliability Assessment", at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf; EIA, 860 database on existing, planned, and retiring generating units; EIA, "New electric generating capacity in 2020 will come primarily from wind and solar," *Today in Energy*, January 14, 2020, at https://www.eia.gov/todayinenergy/detail.php?id=42495#:~:text=New%20electric%20generating%20capacity%20in%202020%20will%20come%20primarily%20from%20wind%20and%20solar,-Source%3A%20U.S.%20Energy&text=According%20to%20the%20U.S.%20Energy,start%20commercial%20operation%20in%202020;

At present, there is sufficient flexible generating capacity in most RTOs to accommodate and balance intermittent renewable supply, as well as to produce power across the many hours of the year. As shown in Figure 6, all of the RTO regions have a resource mix dominated by fossil generating capacity. The retirement of many coal plants and the entry and dispatch of gas-fired capacity has reduced carbon emissions from the direct production of electricity. But states' climate and renewable policies, along with other conditions in the wholesale markets, will drive more and more fossil capacity out of the markets over time.

Figure 6:

Summer 2020 Capacity by Reliability Region: Percent by Gas, Other Fossil, and Other



NERC Summer 2020 Reliability Assessment

Note: "All other" includes nuclear, wind, solar, and other renewables. Figure prepared with data from NERC, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf.

Relatively flat electricity demand, entry of increasingly amounts of DERs and renewables, combined with low gas prices and high resource reserves relative to peak demand, are putting pressure on many older and inefficient fossil-fuel power plants to exit the market. Retirements of uneconomic coal and gas-fired power plants are consistent with competitive wholesale market principles.

But when energy and capacity prices in RTO markets threaten to (and in some cases do) put a financial squeeze on certain zero-carbon-emitting facilities that might provide value to the system in ways that are not fully recognized and/or compensated in current wholesale markets, then this can complicate the ability to achieve carbon-reduction and long-term affordability goals for electricity. The prime example is the case of existing nuclear plants that produce zero-carbon electricity supply and whose retirements (in the content of required reductions of GHG emissions) would require that their output be replaced in the near term and long term with carbon-emitting generation.[24]

These outcomes create tensions for the performance of wholesale markets going forward, especially where the MWh markets do not include a meaningful (or any) price on carbon emissions. In some regions, states are stepping in to provide compensation for zero-carbon supply in order to keep large nuclear plants in the mix (as with Illinois' and New York's zero-emissions credit programs[25] and Connecticut's contract for power from the state's two nuclear plants[26]), particularly in recognition that replacing the significant quantities of generation from these stations with wind and solar and storage capacity would be much more expensive than providing compensation for the zero-carbon attribute of these nuclear plants. In other instances, RTOs are arranging for reliability-must-run ("RMR") contracts or tariff provisions to keep fossil generation in certain zones in order to provide flexibility, other reliability services, or fuel security in a system with relatively high shares of renewable generation.[27]

D. The case for redesign of wholesale electricity markets

Thus, these conditions—increasing entry of renewable resources, surplus capacity in many RTO regions, a relatively flat supply curve, declining capacity factors at existing fossil units, low revenues, and long-term contracts for some facilities and not for others—will create significant "missing-money"[28] challenges for many existing power plants, especially related to recovery of fixed costs for those units without long-term contracts and with little practical opportunity for true scarcity pricing in most energy markets (except ERCOT).

And, yet, there are countervailing trends with respect to the interactions across wholesale and retail parts of the electric system. Some states with climate and renewable goals aspire for more such interactions, and some RTOs have taken steps to open up energy and capacity markets to energy efficiency, demand response,

[24] The author's commentaries on this point include: https://thehill.com/opinion/op-ed/247858-dont-let-nuke-plants-go-too-fast; https://www.wsj.com/articles/is-nuclear-power-vital-to-hitting-co2-emissions-targets-1479092761; https://www.nj.com/opinion/2019/04/retiring-our-nuclear-plants-would-be-a-costly-mistake-former-federal-energy-official-says.html.

[25] Nuclear Energy Institute, "Zero-Emission Credits," April 2018, at https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/zero-emission-credits-201804.pdf.

[26] https://portal.ct.gov/Office-of-the-Governor/News/Press-Releases/2019/09-2019/Governor-Lamont-Applauds-PURA-Approval-of-Millstone-Contract#:~:text=The%20contract%20requires%20the%20utilities,of%20the%20plant's%20environmental%20attributes.

[27] CAISO has been entering into reliability-must-run ("RMR") contracts and Capacity Procurement Mechanism ("CPM") contracts to retain resources on the grid where they are needed for local reliability. *See*, for example, http://www.caiso.com/StakeholderProcesses/Reliability-must-run-and-capacity-procurement-mechanism-enhancements.

[28] In essence, the "missing money" issue relates to situations where the revenues in an organized RTO's energy and ancillary service markets "may not fully reflect the value of investment in the resources needed to meet customers' expectations for reliable electric service. While the analysis behind these claims is often muddled, there can be legitimate concerns about the quality of implementation of electricity markets and whether prices in these markets adequately reflect demand for reliability. The possibility that money is "missing" from the market can, in turn, impede needed investment." Michael Hogan, "Follow the missing money: Ensuring reliability at least cost to consumers in the transition to a low-carbon power system," *The Electricity Journal,* 30 (2017), at https://reader.elsevier.com/reader/sd/pii/S1040619016302512?token=ECE11EED5334A35DD2644F39543F205DF0F7DD0739227C4CCAC3E469F939F7BA649642681431659A71E168C7890FC6C8.

and other DERs. FERC's September 2020 Order 2222 will require all RTOs to accommodate DER supply into wholesale markets.[29] But even recognizing that there are many technical challenges associated with integrating DERs into bulk-power system operations[30] and having grid operators see the resources of retail customers, progress on creating the right conditions on the retail side of these system has been slow. For example, in some states, like New York and Massachusetts, both of which have relatively aggressive carbon-reduction goals, there has been very low deployment of advanced meters. As of 2018, 3 percent of all retail meters in New York were advanced meters, and the percentage was 5 percent in Massachusetts.[31]

In some sense, these challenges and other out-of-market mechanisms (in the form of government-directed long-term contracts with individual generators) are what Professor Richard Schmalensee has recently characterized as patches on an RTO market design to "preserve some sort of a market."[32] In a recent interview in advance of the nearly 40-year-old anniversary of their influential book[33] on setting up competitive wholesale markets for power, Dr. Paul Joskow ("PJ" in the excerpt below) and Dr. Schmalensee ("RS" in the excerpt below) commented how well organized markets are working and their outlook for future market designs.

> PJ: I think the missing money problem is going to become more and more important because, especially as solar diffuses into the market at high volumes, you get a lot of hours during the day when you have very, very low prices. Those prices not only aren't high enough to support conventional generation, they're not high enough to support renewable generation, which raise finance basically outside the market through subsidies or contractual agreements with distribution companies…. I think the whole issue of how you generate quasi-rants [sic], short run margins to cover the capital costs of these facilities, if you're going to do it through the market, becomes more and more challenging….
>
> RS: [On whether a solar mandate is distorting the market] It is and it isn't. The fact that solar is being pulled into the market by government policy, the policy makers would argue that's not a distortion, that's a response to climate change. That's a response to CO_2 emissions and our desire to own distort. We don't have a price on carbon. We don't tax the bad thing so we subsidize the good thing. But it then makes it hard for markets to work. The FERC has wrestled with this. You have some resources that are subsidized by the state, competing in a capacity market with other resources that aren't subsidized. How should that work? They don't have an answer.
>
> PJ: I think some of these challenges have been hidden by the fact that there is this large stock of existing dispatchable fossil generation. Basically wind and solar could free ride on them, in a

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[29] FERC, "Order 2222: A new day for Distributed Energy Resources," at https://www.ferc.gov/sites/default/files/2020-09/E-1-facts.pdf.

[30] See, for example, Rich Seguin, Jeremy Wolak, David Costyk, Josh Hambrick, and Barry Mather, "High-Penetration PV Integration Handbook for Distribution Engineers," National Renewable Energy Laboratory, January 2015, at https://www.nrel.gov/docs/fy16osti/63114.pdf.

[31] EIA data on advanced retail meters. Notably, in PJM, a small portion of customers in Ohio and New Jersey have AMI; in NYISO, most customers do not have AMI; in ISO-NE, virtually no retail customers in Connecticut, Massachusetts, and Rhode Island have AMI. EIA, https://www.eia.gov/electricity/data/eia861m/.

[32] MIT Energy Initiative, MITEI Electricity Markets podcast, Interview #14, with Paul Joskow and Richard Schmalensee, interviewed by Francis O'Sullivan, at http://energy.mit.edu/podcast/electricity-markets/.

[33] Paul Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation*, MIT Press, 1983.

> sense. They provided the backup services. They were getting paid enough to cover their operating costs, but not much in the way of covering what would have been their ongoing capital costs. They're exiting the market slowly. At some point, enough will exit the market where this issue is going to have to be confronted. How are we going to incent storage backup generation to come into the market given the current structure that we have? The current structure is unlikely to work. I see this whole thing potentially unraveling where you have mandates for wind and solar subsidies, required contractual arrangements with distributors, then you're going to do it for storage, then you're going to do it for rapid response gas turbines, and before long, we're going to have two markets, a contract market and an energy market.
>
> RS: I think we're getting there. You see patches on the current system when Utility A or Generating Entity A says, we're going to retire this plant. The system operator says, you can't retire that plant, we'll pay you to keep that plant going. What kind of market is that? That's central planning. There are more and more of those.
>
> PJ: Does it make any sense to have this period of very low energy prices and very low capacity prices where they have capacity markets and start having the nuclear plants retiring? Which are zero carbon emitters. While at the same time you're subsidizing more zero carbon emitters to come into the market for exactly that reason. That's kind of what's happening.
>
> RS: It seems to me the answer has to be, you're putting patches on patches to try to preserve some sort of semblance of a market. The question is, are we institutionally and politically capable of biting the bullet and saying, [the ISOs really need to do integrated resource planning at a regional level and think about the most efficient way to have the capital stock they need regionally, have debates about what that capital stock is, procure it efficiently. Instead of trying to tweak a market design that is plainly not working, that's a big leap politically. But it may be a necessary leap.
>
> PJ: It's also easier to do in the states that have single state ISOs like New York and California and Texas. Where the public policies and the behavior of the ISO can be coordinated in many dimensions. Think about a large ISO RTO [Regional Transmission Organization] like PJM with states on the one hand, like New Jersey, which wants to go all green, and Maryland, and states like Ohio that don't want any part of that. How are you going to harmonize all of these different public policies in one electric power system? I think it's a real challenge for the multi state ISOs….

As they say, some multi-state RTOs may be more challenged than others, because some like those in SPP and MISO already have a hybrid model with LSEs responsible for resource adequacy, whereas PJM and ISO-NE (also multi-state regions) rely on organized energy and capacity markets that are under stress.

III. Looking Ahead: Assumptions and Goals for Wholesale Market Design in a Future Low-Carbon Electric Grid

These many trends that are underway create a compelling case that changes are needed in wholesale market design especially in those RTOs with centrally organized capacity markets. But what will the future look like? And how will that affect what's needed ahead in wholesale market design?

A. Assumptions about the future low-carbon electric system

The author's proposed wholesale market design has been informed by her assumptions about characteristics of the future electric system, its operations, its participants, and the many policies and other factors affecting the power-sector transitions. These assumptions include:

- **No one knows what the bulk-power and local electric systems will look like in 2030 or thereafter**, so the design of future wholesale market structures needs to accommodate many possible futures that will unfold in different ways around the country. There are lively and more-or-less polite arguments about the extent to which there will be a largely decentralization grid comprised of countless microgrids, other DERs, and so forth, versus a largely centralized and much-bigger regional wholesale markets supported by more interstate high-voltage transmission lines, or some combination of the two. These uncertainties extend to technical issues, such as how a centralized structure can accommodate an increasingly decentralized grid.
- **The electric system will continue to transition toward significantly lower-carbon resources**, driven at least by economics and technological change, state RPS and climate policies, actions of local communities, corporations and others, utility decarbonization commitments, and investor and consumer preferences. Federal policy—including at least tax incentives and financial support for research and development ("R&D") on advanced energy technologies, if not more direct policies to limit GHG emissions—will also influence the transition. These and other forces will continue to pull more and more renewable resources and storage into the power system, presumably through long-term contracts for attributes (such as renewable energy credits or zero-emission credits) or for bundled electricity products. Early entrants of some zero-emissions technologies (e.g., offshore wind, advanced zero-carbon technologies such as carbon capture, utilization and long-duration storage[34]) will likely require contracts in order to gain financing for project construction and operations, as long as the outlook continues to anticipate low wholesale energy market prices and the absence of a meaningful price on carbon.
- **No one knows what the pace and pathways of change will be,** because of the tension between the urgency of addressing climate change, the mandates for accelerated change, the stickiness of long-lived capital stock (on the electric system, in buildings, and in the transportation sector), incentives in financial

[34] Heidi Bishop Ratz, et al., "The Role of Long-Duration Energy Storage in Deep Decarbonization: Some Policy Considerations," World Resources Institute Issue Brief, September 2020, http://www.indiaenvironmentportal.org.in/files/file/role-long-duration-energy-storage-deep-decarbonization-policy.pdf.

markets to focus on near-term returns and less on climate-related risks (and opportunities), utility and regulatory concerns about maintaining affordable electricity rates, and the uncertainty about investment, consumer behavior, business models, and so forth.

- **State policies will affect the extent to which the demand side of the market is part of the mix.** FERC's new directives that RTOs remove barriers the prevent DERs from competing in organized wholesale markets is helpful in encouraging development of demand-side resources, but it is not sufficient. For utilities, other load-serving entities, entrepreneurs, and consumers themselves to change electricity usage patterns, states will need to support building out the metering, rate-design, communications, and operational controls that together are needed to animate demand and integrate flexible demands into wholesale markets.
- **There'll be lots of tools that will be used on the path to change.** Because of their renewable energy and carbon-reduction goals, many states will need to support a combination of approaches to bring about change, including through market-based and administrative approaches. Some policy makers may have greater allegiance to the goal of reducing carbon emissions, maintaining electric reliability and local job creation than to the efficient design of wholesale markets, and the challenge will be to find sufficient market-based mechanisms to support reasonably affordable transformation of the electric system.
- **The electric system will grow in importance as a share of the energy system.** Consistent with states' policies for decarbonizing their economies, it is likely that electricity will expand in many if not most regions' energy mixes, including through electrified transportation, buildings and industrial processes. To play that role, the electric system will need to remain reliable, and electricity will need to be affordable so that policy makers, electricity providers and consumers switch their appliances, heating systems, and vehicles to those that use electricity rather than a fossil fuel.
- **The organized forward capacity markets in the PJM, NYISO, ISO-NE regions are not sustainable as currently configured.** A majority of the states in those regions have carbon-reduction mandates, and will seek to use means to accelerate the entry of zero-carbon resources faster than these markets will deliver on their own. Even assuming that some of these states will seek to add some sort of mechanism to add a meaningful price on carbon in the power sector, the combination of low natural gas prices and the entry of resources needed for zero-carbon generation but not necessarily for resource adequacy will tend to keep energy and capacity-market prices at relatively low levels, with increasing numbers of hours with zero-carbon resources on the margin. FERC has taken steps to mitigate the impacts of states' actions in regions with organized capacity markets, and several states in those regions have indicated that they are considered whether to exit the capacity market in their RTO region.[35]

[35] See, for example: Jeff St. John, "FERC Order Will Restart PJM's Capacity Market," GTM Research, October 15, 2020, at https://www.greentechmedia.com/articles/read/ferc-order-restart-pjms-capacity-market-but-state-subsidized-resources-remain-challenged; Catherine Morehouse, "Maryland taking a 'serious look' at exiting PJM capacity market through FRR, says PSC Chair," Utility Dive, April 29, 2020, at https://www.utilitydive.com/news/maryland-taking-a-serious-look-at-exiting-pjm-through-frr-says-psc-chair/576957/.

- **Regional preferences for electric industry structure will continue to shape wholesale market designs.** Although many economic experts in the electric industry point to the success of the ERCOT market design as a model that should be adopted and implemented in other regions, it is unlikely that that approach—with its mandatory retail competition and an energy-only centralized wholesale market—will be taken up in most (if any) other regions of the U.S. ERCOT a single-state RTO not subject to FERC regulation and where Texas has had the ability to align its retail and wholesale market designs and direct and oversee the planning for and socialized recovery of costs for the expansion of the high-voltage transmission system utility.[36] Under current FERC-regulated RTO market rules elsewhere, not very many states could unilaterally propose, plan, and cause transmission to be built out with socialized cost recovery. There is little indication that other states seek to institute the ERCOT-style of retail choice (in which each consumer must choose its preferred competitive retail supplier without having the option to take service from the utility as the back-stop supplier of bundled electricity service). The climate goals of many states, with the inherent need to accelerate and deepen reliance on zero-carbon supply beyond what is being delivered by electricity markets alone, makes it further unlikely that those other states will see Texas' market design as the model to rely upon going forward.[37]
- **The definition of resource adequacy needs to transition** to provide different capabilities to assure that the electric system of the future has the tools—e.g., sufficiently flexible resources, sufficient capacity to cover peaks that may shift from summer peaking systems to winter peaking systems in parts of the country that move to much-more electric heating, sufficient capacity to enable the system to withstand the effects of extreme weather events, and so forth.
- **The bundle of resources that together provide the system with adequate services, cost minimization, and needed functionalities and attributes will not necessarily result from auctions that consider price alone, especially in the absence of a price on carbon within the market design.** Other considerations may include location, deliverability, dispatchability, and increasing/accelerated reliance on zero-carbon supply (including from some resources that may have above-market costs). Some but not all of these attributes may be incorporated into markets as they are currently configured.
- **Some specific resource/technology types at specific locations may need to remain in operation until other alternatives provide the needed reliability services.** Presumably it will be necessary to retain some dispatchable "24/7" (e.g., gas-fired) capacity on the system in the future, to provide energy in decreasing quantities over time and moreover to serve as a reliability-backstop/insurance policy in the event that short-duration and long-duration storage and sufficiently animated demand do not develop

[36] For a description of ERCOT's reliance on state-designated "competitive renewable energy zones" and the development of transmission plans and projects to deliver renewable power from CREZ to distant customer load centers in Texas, see: https://cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/.

[37] Texas does not have a carbon-emission reduction mandate and much of the ERCOT region is served by companies without voluntary GHG-emission reduction targets. As of 2019 and based on EIA data, 73 percent of Texas's power supply was produced at fossil generating units, with 27 percent of its generation from zero-carbon resources. It is not clear how the ERCOT market design would work in states where the shares of power from fossil versus zero-emitting sources were flipped.

on the timing and location needed for operational reliability. (In some locations, it would be economic to add new gas-fired capacity to replace retiring coal plants, with the expectation that such new fossil capacity would have a limited lifetime, as tighter emission-reduction requirements become binding.) This will likely require that there be a wholesale market mechanism to compensate owners of such capacity to keep it available, without expecting it to operate very often outside of certain emergency conditions or extenuating circumstances.

- **FERC approval is key, of course**. Wholesale market-design changes would need to be crafted in a way to gain approval by the FERC for those aspects of the approach that would fall under its jurisdiction under the Federal Power Act ("FPA"). FERC has approved very different market designs over time and in different regions, taking into account local stakeholder preferences, variations in electric industry structure, and the requirements under the FPA. It is possible that statutory changes may be desirable, if not required, to resolve new or increasingly aggravating federal/state jurisdictional tensions—e.g., with regard to transmission planning and siting, or the value of low-carbon generation—should they worsen in the future.

B. Goals for tomorrow's electric system

As a student of electric systems in the U.S. over many decades, the author acknowledges the bedrock goal for the future electric system is that it must be capable of supplying and delivering reliable, affordable *and* low-carbon electricity to consumers. From a market-design point of view, this means that the market structure should:

- ***Support public policy objectives***: The market design should incorporate elements that directly or indirectly allow for market participants to respond to federal and states' policy goals (such as supplying economically efficient power supply, while also taking into consideration the multiple other goals of reducing GHG emissions from the power sector and the broader economy, reducing inequities associated with adverse impacts of generating resources on local communities, assuring reliability and resilience).
- ***Promote efficient electric-resource investment and operations***: Any market structure should create incentives for efficient operations in the short run and investment in the long run. At the same time, the structure must also support the achievement of additional statutory/regulatory mandates to incorporate policy-preferred resources/infrastructure that are otherwise uneconomic (in the absence of mechanisms to incorporate carbon pricing or the relative value of zero-carbon emitting sources of supply). The structure must support cost recovery and should do so through market-based means to the extent possible, create incentives for efficient performance of the elements on the system, send appropriate signals to capital markets, and encourage operations that use the lowest-cost resources first.
- ***Assign risk fairly and efficiently***: Power markets and regulation should provide equitable treatment with respect to risk across producers and consumers, including for consumers who lack the resources and options to bypass the grid for part or all of their service. To the extent reasonable and practicable, financial risk should be assumed by those market participants best positioned to mitigate it. But where

reliance on financial markets and competitive wholesale (and retail) markets are not producing a portfolio of resources capable of satisfying emission-reduction mandates, some investment risk may need to be assigned to electricity consumers to hasten that outcome.

- ***Mitigate the exercise of market power***: Markets and regulation should avoid the presence of, or mitigate the exercise of, market power so as not to undermine markets and competitive prices. Where market power cannot be eliminated, regulation must step in to avoid unjust and unreasonable prices.
- **P*romote innovation and be robust to alternative futures***: Markets and regulation should accommodate and promote innovation. The investment climate will benefit from establishing a market structure/construct that can perform well under a diverse set of possible future electricity sector configurations.
- **Unleash much-more animated demand with decentralized/retail market(s) on the local distribution system**, with active participation of price-responsive demand and flexible loads. State regulators and boards of publicly owned utilities need to take more timely steps to allow (if not require) diverse and innovative service offerings, prices that reflect real-time variation in local and wholesale markets, advanced metering, and new incentives for innovation. This may also require broader deployment of broadband services into geographic areas that are poorly served at present, in order for consumers in those regions to be able to participate more dynamically in the power system (among other things).

IV. A Proposal for a Low-Carbon Wholesale Electric Market Design

A. Overview

The proposed wholesale power market design rests on three important building blocks: (1) **competitive, co-optimized wholesale energy and ancillary service markets** to ensure efficient dispatch of supply-side and demand-side resources; (2) a **resource-adequacy approach** for ensuring capacity of the right types and in the right places to provide reliable electricity from a portfolio of low-carbon resources; and (3) **retail pricing to enable loads to see and decide whether to respond to dynamic electricity prices,** to ensure that the system can mine economic opportunities for flexible resources and efficiency on the demand side and that consumers can better manage their electricity use as conditions on the system change over time.[38]

This three-part market design is premised on the need to dramatically reduce carbon emissions from the power sector. This goal is as critical to the successful performance of the power system as is its reliability and its economic efficiency, and the market designed to accomplish those multiple outcomes has to accommodate imperfect trade-offs.[39] In such a system, a foundational principle should be to exploit market-based mechanisms in service of cost-effective low-carbon and reliable electricity supply.

The proposed approach aims to ensure that adequate resources are available to provide each type of electricity service or attribute: e.g., coverage of peak loads and installed reserves; flexibility and other capabilities needed for operational security; local capacity in constrained areas; declining emissions profile of the resource portfolio over time and in a sustained way in the future.

B. Energy and ancillary services markets

These markets would be based on the well-proven bid-based security-constrained markets now operating in RTOs around the country. These would include day-ahead and real-time clearly-price markets, with locational marginal prices and transmission congestion prices.

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[38] As described further below, the first two building blocks would be directly subject to FERC jurisdiction and the third would be directly subject to state jurisdiction for investor owned utilities and other load-serving entities (and to the boards of electric cooperatives, municipally owned utilities, and other publicly owned utilities). FERC has a role creating opportunities for wholesale demand response in energy and ancillary service markets and for distributed energy resources participating in wholesale capacity markets.

[39] Various groups, scholars and analysts have begun to characterize appropriate designs for electricity markets with high penetration of high-capital-cost, low-variable-cost and low carbon emission resources. These papers start with common premises about the changes underway in various wholesale (and retail) electric systems, and land on different ways to satisfy the goal of providing reliable, efficient, and low-carbon electricity supply. Examples include: Paul Joskow, "Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience," *Oxford Review of Economic Policy*, Summer 2019; Sonia Aggarwal, et al., "Wholesale Electricity Market Design for Rapid Decarbonization," Energy Innovations, June 2019; Steve Corneli, "Efficient Markets for High Levels of Variable Renewable Energy," *Forum*, The Oxford Institute for Energy Studies, June 2018; David Bielen et al., "The Future of Power Markets in a Low Marginal Cost World," Resources for the Future, RFF WF 17-26, December 2017; Eric Gimon, "On Market Designs for a Future with a High Penetration of Variable Renewable Generation," September 8, 2017; Brendan Pierpont and David Nelson, "Markets for low carbon, low cost electricity systems," Climate Policy Initiative, September 2017; Monisha Shah, et al., "Clean Restructuring: Design Elements for Low Carbon Wholesale Markets and Beyond: A 21st Century Power Partnership Thought Leadership Report," National Renewable Energy Laboratory, May 2016; Ela et al., "Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation," NREL/TP-5D00-61765, September 2014; Richard Green, "Electricity Wholesale Markets: Designs Now and in a Low-carbon Future," *The Energy Journal*, September 1, 2008; and.

Some resources would participate in these markets on a must-offer basis: these would include any resources procured by the RTO and any storage, generation, net DERs, and other flexible loads that are part of LSEs' resource portfolios relied upon to meet their resource adequacy obligations. Other available resources (e.g., imports, other injections from DERs, other dispatchable and non-dispatched resources that are not counted for resource-adequacy purposes) could participate in the RTO energy and ancillary service markets on a voluntary basis. These energy and ancillary service market rules should provide open access to any technology that can demonstrate its ability to satisfy technical performance requirements.

Unless federal legislation is enacted to establish a national GHG emission-reduction target and/or carbon pricing mechanism, FERC-approved tariffs would account for the ability of states to provide directives on whether they elect to include actual or shadow carbon-pricing mechanisms, with states permitted to choose different approaches and different price levels for any carbon adder. The RTO's energy market rules and operations would take any such carbon pricing mechanisms into account. The tariff would set forth the terms and conditions of how the carbon price would influence dispatch, prices paid by loads and to suppliers in such states, and the use of any excess revenues collected above the compensation paid to suppliers.[40]

C. The resource-adequacy approach

The key elements of this resource-adequacy building block are as follows:

- **The FERC tariff:** Wholesale market rules (revised from today to account for and accommodate the changing resource mix) would be proposed by each RTO and approved by FERC.
    - The rules would define multiple resource-adequacy products which take into account the different types of attributes of resources needed to assure that the system has the kinds of resources available to it that are needed to supply different reliability services. These products include such things as ensuring the availability of: adequate local resources in particular zones with transmission constraints ("Local RA"); sufficient resources with capability for flexible operations ("Flexible RA"); and adequate capacity on the system to meet peak load and reserve requirements ("System RA"). The RTO would set RA requirements for a multi-year period. This new resource-adequacy program would ensure that the LSEs in constrained zones support any Local RA needed in that zone, and that each LSE in the RTO footprint supports its pro-rata share of System RA and Flexible RA.
    - Additionally, the RTO would determine whether there are other types of resource-adequacy products beyond Local RA that cannot be practically or efficiently procured through a

[40] The NYISO's proposed carbon-pricing mechanism for its energy market is a concrete and workable model for addressing such issues. See various documents on the proposal and its potential impacts and support, at https://www.nyiso.com/carbonpricing. Such an approach could accommodate state-by-state differences in pricing carbon in multi-state RTOs, and could be compatible with other state policies that accelerate entry of zero-carbon resources as well as retention of existing ones. Susan Tierney and Paul Hibbard, "Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets," Analysis Group, October 3, 2019, at https://www.analysisgroup.com/globalassets/uploadedfiles/content/news_and_events/news/2019-analysis-group-nyiso-final-report.pdf.

decentralized approach and/or fairly allocated to all benefitting customers and which would need to be satisfied through a centralized procurement process.

- **RA roles and responsibilities:** The FERC-approved tariff would be designed to identify roles for the states and for the RTO in ensuring resource adequacy:
  - **State policy direction:** FERC-approved market rules would include provisions that set out roles for the states with respect to various resource-adequacy market elements, for example:
    - Each state's preferred approach to resource adequacy (e.g., relying on load-serving entities' resources for certain resource-adequacy products; relying on the RTO as the central buyer for certain resource-adequacy products; or relying on a combination of approaches for some or all of those products).
    - Each state's ability to identify attributes to include in the RTO's procurement of resources (e.g., zero-carbon emissions, renewables).
    - Each state's ability to impose a price and/or cap on carbon emitted from generating resources within its state.
  - **Long-term planning:**
    - The RTO would conduct long-term (10-year) resource planning, with inputs:
      - From each state: specifications on what attributes (e.g., allowed carbon emissions trajectories) will be required of resources needed to serve loads in each state;
      - From each LSE and for each year in the forward planning period: detailed information about any commitments[41] it has in place for entry of any new committed-to resources (supply-side and demand-side) that would operate in the wholesale market, any planned retention of existing resources, or any planned retirement of resources during the planning period. There may be years in this planning horizon in which the LSE reports no committed-to resources.
      - From each LSE: detailed information about gross and net load requirements taking into account organic changes in loads, planned incremental energy efficiency, other DERs to be dedicated to uses within the local system, plans

[41] An assumption of this future power system is that there may be advanced zero-carbon technologies with relatively long lead times that states want to include in the mix, as compared to the relatively short lead times for committing to and developing wind, solar, storage, or gas-fired technologies, and demand-side resources. Also, there may be announcements of asset retirements in future years beyond the near-term planning horizons (e.g., 6 months; 3 years) how incorporated into many FERC-approved wholesale capacity markets.

for adding loads through beneficial electrification of buildings, transportation, or industry.

    - With stakeholder engagement, the RTO would model the performance of the bulk power system, with assumptions representing different perspectives about technology performance, fuel prices, economic conditions, and other key variables.
    - The plan would identify such things as:
        - Expected carbon-emission trajectories based on commitments of LSEs, compared to levels consistent with states' policies;
        - New transmission enhancements needed for reliability, supporting public policies, and/or economic efficiency or to support state policies;
        - Incremental amounts of resource-adequacy products needed over the planning period, beyond those that are included in LSEs' committed-to resources.
- **Capability requirements and capability values**:
    - Using information gathered through the resource planning process, the RTO would set the certain capability requirements for meeting different resource-adequacy product requirements (System RA, Local RA, and Flexible RA).[42]
    - The RTO would establish the capability value for different technologies in different time periods (e.g., seasonal, across the hours of a day, at the time of system peak) and, depending upon the size of the RTO footprint, potentially the value of different technologies within broadly defined energy resource zones (e.g., where wind quality might affect capacity value and might vary across a large geographic region).
    - The RTO would identify resources eligible to supply capacity for current and future RA purposes: supply-side (including with or without transmission) and demand-side (planned energy efficiency and other DERs with firm commitments to deliver under particular local or system conditions on the bulk power system).
    - The RTO would establish protocols and other business practices that establish the terms under which the RTO versus a local distribution system would have priority call on the resources on the demand side of the meter where such are offered for resource adequacy at the RTO level.
- **Resources eligible for resource adequacy:**

[42] Note that in today's RTOs in California and in New York, the state establishes the resource adequacy requirements. Also, in ERCOT, Texas has decided that there is pre-determined resource adequacy (or installed reserve) requirement; thus, state policy establishes the resource adequacy approach.

    - LSEs may own resources and enter into bilateral contracts, with the requirement that if the LSE seeks to have those resources count directly or indirectly for the purpose of satisfying resource adequacy obligations, then those resources must offer into the RTO's procurement of Local RA and/or Flexible RA (where the character of those resources makes them eligible for providing either or both of those services). Those resource may be counted toward an LSE's share of System RA or offered into the System RA procurement. To the extent that the LSE is long on any resource-adequacy product, then these would be available to the rest of the system.
    - Competitive suppliers may enter into bilateral contracts with LSEs, and/or participate in the RTO's resource procurement processes.
  - **Procurements of RA Products:** The RTO's rules would account for competitive procurements of resources for near-term and long-term purposes:
    - The RTO would conduct annual central competitive procurements of resources to meet forward Local RA and Flexible RA resource needs, as well as any amount of System RA that any LSE elects to be centrally procured on its behalf.
      - The annual procurement would be used to fill increasing proportions of capacity needs so that distant years (e.g., 10 years) commit to only those attractive offers resources that satisfy multi-value objectives (e.g., resource adequacy using low-carbon technologies) and that require very long lead times. Examples of the latter might include: a transmission expansion to remove special Local RA procurement needs; procurement of an early commercial version of an advanced zero-carbon technology. For the near-term years, the RTO would procure higher percentages of needed resources relative to the needs for each RA product.
      - The RTO would structure the procurement process to enable competitive offers from all types of resources eligible to supply a particular RA product. Suppliers of existing and new resources would be eligible to offer resources into the solicitation; this would include utilities and other LSEs whose asset ownership or bilateral contracting render them long on Local RA and Flexible RA or System RA for any future year covered by the solicitation.
      - Eligible suppliers would compete for the opportunity to become part of the winning portfolio for an RA product and enter into a long-term contract for delivery of that capacity (with relevant locational and performance attributes and requirements) in that year. The offer prices would reflect bidders' $/MW requirements to be available to the market over the expected term of a long-term contract, and net of the supplier's anticipated revenues in future MWh markets. Offers would include information about lead-times, permitting and

operational status, location, and other relevant information that will be used in selecting the portfolio of awarded contracts.

- The RTO would select winners based on best-fit/minimized-cost portfolio of offers that together satisfy the particular resource need(s) identified in the solicitation. Selection of the portfolio of winning bids would be based not solely on minimizing costs in a single year but rather on optimizing a portfolio taking into account the multiple attributes being procured over a designated planning window. The RTO would evaluate the competitiveness of the solicitation, including the impact of any exercise of market power, and set contract amounts based on administratively determined $/MW costs where such market power exists.
- The costs of such contracts would be assigned to specific LSEs in the case of Local RA or all LSEs in the case of Flexible RA.
- Some individual resources that are selected may qualify for more than one type of RA product. Any resource procured by the RTO for Local RA and which is capable of providing other collateral RA products (i.e., Flexible RA, System RA) would be required to sell those other RA products as part of the procurement.
- Those centrally procured products would have capacity value applied to the RTO's System RA needs, using the capacity value assigned to different technology types by the RTO.
- The RTO would conduct interim (e.g., seasonal, monthly) reconfiguration procurements to account for changes in resource availability and loads.
- The RTO's annual resource solicitation would also procure any incremental RA products for each of the nearer-term forward years, reflecting updated information from results of prior years' RA procurements and from the LSEs' demonstrations for the relevant year (which may include any assets owned or bilaterally contracted-for by an LSE). Existing resources that are not successful in the central RA procurement process can decide whether to retire or remain in operation, with or without long-term supply agreements with LSEs.
- The RTO would periodically evaluate and identify any existing resources that have market power with respect to one or another attribute (e.g., location; flexibility; operating period) and that are needed for system operations in a particular location or time. Such resources would be required to offer into the RTO's solicitation, and would enter into a cost-of-service contract with the RTO. The amount of capacity (of a particular type and at a location)

associated with that resource would reduce the amount of other RA resources that are otherwise to be assigned to and procured by the LSE or the RTO (depending upon the particular RA products provided by this resource with market power).

- The RTO's procurement solicitation could also include emerging technologies and other policy-driven resources that the states might want to demonstrate.

▪ Any additional amount of System RA needed beyond those centrally procured RA products would be procured by LSEs through ownership and/or long-term bilateral contracting, except where (a) there are advantages of a central procurement entity arranging for the resource to be available to the system or (b) an LSE elects to have its share of System RA procured by the RTO on that LSE's behalf.

- The LSEs would make periodic demonstrations that they have met their allocated portion of System RA commitments. The LSEs' periodic demonstration submissions would be required to show committed-to resources to satisfy their share of System RA (e.g., demonstrating 100% for the upcoming year, declining over the future years to, say, 50% in forward year 5). The declining commitments for the later forward years would accommodate uncertainty with regard to future customer loads served by an LSE. And the annual demonstration would be to reconcile changes in loads or resources that would have occurred from one year to the next.

o **Supplier obligations with respect to energy production:** Any resource that sells its RA to the RTO or to an LSE for the purpose of providing RA services would take on must-offer obligations to supply energy and/or ancillary services. A DER providing RA products would need to firmly commit, as appropriate, to either reducing load or injecting supply into the system as dispatched by RTO.

D. Retail pricing for dynamic and flexible loads

This third building block of wholesale market design is an essential feature of enabling the whole system to operate reliably and minimize the amount of supply-side capacity that will be needed to meet local, flexible and system resource adequacy needs.

This element of the market would be grounded in actions by state regulators and boards of publicly owned utilities to establish rate-design decisions to enable retail customers to see and decide whether to respond to real time prices. The rates could be accomplished through mandatory or opt-in approaches, but would need to be enabled by advanced metering, power electronics and other communications and controls.

Participation of retail loads in demand response could be carried out through a customer's direct participation in the RTO's Day Ahead or Real Time markets (which might be of interest to large, sophisticated electricity customers) or through load aggregators (e.g., a third party aggregator or the distribution utility) that offers a portfolio of potential responsive demand into those wholesale markets.

As the demand side of the electric system evolves with innovation, FERC should ensure that the RTO's tariff does not include barriers to enabling DERs to provide services to the wholesale markets. For example, resources that use invertors (including batteries, solar systems and wind turbines) have software and other power electronic that may enable them to provide frequency response; the RTO's market for frequency-response services should not discriminate against such DERs where they are technically capable of providing a needed service.

To open up a more lively demand side of the electric system (and one that may be well-aligned with deployment of much deeper amounts and types of DERs), some states might choose to structure their retail, distribution-level industry/market structures in ways that mimic the structure of wholesale markets. This could allow either the utility that owns and operates the wires or some independent third party to serve as the "distribution system operator," to take on the types of planning, market-enabling and operational roles and responsibilities provided by RTOs in for wholesale markets and the bulk-power systems related to them. It is anticipated that LSEs and third party aggregators and others would develop varied products and services to mine and manage such RT price signals and resources on customer premises through different service offerings that fit consumer preferences and profiles.

Using the phrase "transactive energy," observers point to the combination of (a) economic and market-based structures and (b) technical control systems and capabilities to improve reliability and efficiency in grid with high penetration of DERs. NARUC refers to transactive energy ("TE") as both a

> 'technical architecture' and an 'economic dispatch system.' TE relies on price signals, robust development of technology on both the grid and customer side, and rules that allow markets to develop; therefore enabling a wide variety of participants to provide services directly to each other. TE facilitates the coordination of customer-sited resources, such as demand response (DR), storage, and other on-site resources, that are responsive to price or other signals.[43]

Most discussions of transactive energy markets usually focus on what happens at the distribution level, rather than its relationship to the wholesale market and bulk power system. But both of them depend upon the interplay among the physical elements and operations of the grid, as well as the economic, financial, and regulatory systems that support the system. In the future, both will have more non-dispatchable resources and will need both pricing mechanisms (such as those that vary over time and location) and other important operational protocols to enable DERs to participate in distribution-level and/or wholesale markets.

Such local markets barely exist anywhere in the U.S., much less in active form. At a minimum, they will require customers to see real-time prices, enabled by advanced metering and communications. Such

[43] NARUC Staff Subcommittee on Rate Design, "Distributed Energy Resources Rate Design and Compensation," NARUC, November 2016, at http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0.

markets will also require rules for bidding, dispatch, and electronics and control systems to govern the interaction of DERs with local and/or wholesale markets. Considerable technical work will be needed to address important these many communications, system coordination, control systems, and other protocols to assure that the distribution-system and bulk-power system operators understand and enforce the expectations about which system (or which consumer) has priority call on which resources at any point in time and space.

As many distribution utilities, regulators, economists and power engineering experts, and other stakeholders have already discovered, developing such local markets is a complex undertaking. But states with aggressive climate goals and an expectation to rely in the future on deep penetration of centralized and decentralized variable resources need to accelerate actions to ready the demand side of the power system for a different future. Without a much-more animated market that includes flexible and price-responsive demand, the system will need to rely on substantially more supply-side capacity—something that will be expensive for consumers and the economy as a whole.

E. Concluding observations

Tomorrow's electric system will be counted on to supply and deliver reliable, affordable and low-carbon electricity to consumers, under very different conditions than exist today. The proposed three-part market structure outlined in this white paper has been offered as a possible way to support those goals. It will assist in accomplishing public policy goals for dramatic reductions in the power system's GHG emissions while relying upon market-based mechanisms where possible. It will help promote the substantial capital investment needed to bring new zero-carbon technologies into the system at a pace never experienced in recent history. There will be sharing of risk, between suppliers and consumers, in order to move that capital more quickly than will occur through the current RTO market designs alone. And it will avoid a much-more expensive power system by leveraging technology, innovation, and consumer preferences to animate the demand side of the market.