Price Formation in Zero-Carbon Electricity Markets

The Role of Hydropower

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HydroWIRES

In April 2019, WPTO launched the HydroWIRES Initiative[1] to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. While increasing deployment of variable renewables such as wind and solar have enabled low-cost, clean energy in many U.S. regions, it has also created a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy but also a source of large-scale flexibility and a force multiplier for other renewable power generation sources. Realizing this potential requires innovation in several areas: understanding value drivers for hydropower under evolving system conditions, describing flexible capabilities and associated tradeoffs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

HydroWIRES is distinguished in its close engagement with the DOE national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio, as well as broader DOE and national laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES Initiative are designed to benefit hydropower owners and operators, independent system operators, regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

[1] Hydropower and Water Innovation for a Resilient Electricity System ("HydroWIRES")

More information about HydroWIRES is available at https://energy.gov/hydrowires.

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Executive Summary

ES.1 Motivation

With the decreasing costs of clean energy generation technologies and increasing concerns about greenhouse gas emissions, the United States is likely to see a rapid expansion of zero-carbon electricity generation over the next decades. One important characteristic of many zero-carbon generation resources is that they do not have a direct fuel cost, and in some cases, they have essentially zero marginal costs of generation (Table ES-1). As a result, a power system dominated by zero-fuel-cost generation resources— such as hydropower, wind, and solar—may be characterized by frequent and extended periods of low or zero electricity prices. Lower and less predictable energy prices could make the risk of developing new generation sources prohibitive. Therefore, the changing resource mix creates a need to re-think how electricity markets operate, and how prices in these markets provide incentives for operations and investment.

Table ES-1 Categorization of Zero-Carbon Electricity Resources by Marginal Cost and Fuel Cost

	Zero Fuel Cost	Non-Zero Fuel Cost
Non-Zero Marginal Cost	**Opportunity Cost** Reservoir hydro Pumped storage hydro Batteries Other storage Demand response	**Variable Fuel Cost** Bioenergy Hydrogen gas with CCS[a] Coal with CCS
Zero Marginal Cost	**No Opportunity Cost** Wind Solar Run-of-river hydro Geothermal	**Fixed Fuel Cost** Nuclear

[a] CCS = carbon capture and sequestration

Challenges around revenue insufficiency and price uncertainty are, in part, a consequence of electricity markets that were not designed for systems dominated by zero-marginal-cost generation resources. So, there is a need to revisit dispatch logic, price formation, and corresponding incentives for electricity market participants in zero-carbon systems. To better understand and mitigate revenue insufficiencies and price uncertainties associated with zero-marginal cost resources, we need to identify the vulnerabilities in current electricity market structures. At the same time, regulators and policy makers need to consider the pros and cons of alternative market mechanisms. The goal of this paper is to set the stage for such a discussion by providing background information about relevant energy trends, current market paradigms, and possible design changes for future markets. In particular, the paper focuses on the evolving role of hydropower resources, as a large-scale, flexible, renewable resource, in future zero-carbon systems.

ES.2 Summary

ES.2.1 Proposed Solutions for Zero-Carbon Systems

Most proposed solutions for zero-carbon systems are intended to enhance existing market designs and can be classified into two categories. The first category of solutions provides for enhancements to energy and ancillary service products. Examples include the following:

- Updating pricing mechanisms by, for example, implementing scarcity pricing and establishing price floors to improve operational and investment incentives for flexible resources and mitigate overgeneration.

- Updating representations of resource operational costs (e.g., the opportunity cost for flexible resources) or incorporating capital cost into energy market bids and market clearing prices.

The second category of solutions focuses on implementing new, long-term energy and capacity remuneration measures to ensure resource adequacy; reduce investor price risk; and enable long-term, low-cost financing to support investments in capital-intensive resources with low operating costs. This category includes long-term energy markets, auctions for new capacity, and enhanced capacity markets or obligations.

Other proposed solutions depart further from current market design practices, including a return to traditional cost-based regulation. In this report, we summarize the different market design options by reviewing their intended goals, as well as potential challenges associated with each.

ES.2.2 Implications for Hydropower Resources

This report illustrates that hydropower has a unique set of characteristics among zero-carbon resources: dispatchability, firm capacity, and long-duration storage. These characteristics will allow hydropower to benefit from emerging market conditions for zero-carbon power systems. Hydropower resources—in particular, reservoir hydro and pumped storage hydro plants—are likely to play a more dominant role in electricity price formation because of their opportunity cost, which is based on expectations of future prices. However, it is hard to predict future price dynamics in zero-carbon electricity markets, including the frequency of both very low prices and high-scarcity prices, and how such dynamics will affect different technologies, including hydropower.

ES.3 Key Findings

- In a zero-carbon system, market prices are expected to be low, but they might not necessarily be zero all the time, especially when scarcity pricing mechanisms are in place and the system includes resources with opportunity costs. Price dynamics driven by opportunity costs have already been observed in some existing markets that include significant hydropower resources (e.g., Norway, Brazil, and Colombia).

- Many studies in the literature suggest market enhancements to supplement current practices with long-term energy procurement (contracts, markets) or adjustments to long-term capacity compensation mechanisms to address market challenges in zero-carbon power systems.

- We noted common themes across ongoing market design enhancements that are relevant to the transition toward a zero-carbon grid, including the following:

    a. Replacing fixed operating reserve requirements with demand curves that reflect the economics of system reliability needs;

    b. Accommodating state policies and incentives, particularly related to their impacts in capacity markets;

    c. Analyzing the impacts of implementing either carbon pricing or a clean energy procurement mechanism at the independent system operator/regional transmission organization (ISO/RTO) level;

    d. Implementing new market products that address changing system needs and contribute to meeting the flexibility requirements of systems increasingly dominated by variable renewable energy (VRE); and

    e. Developing new methodologies to determine the resource adequacy accreditation of different resources to ensure that these values reflect their relative reliability contributions.

- Hydropower is likely to play a critical role in zero-carbon systems as a zero-carbon, dispatchable resource that can

    a. Support system flexibility and storage requirements in systems with large shares of VRE;

    b. Take advantage of new price dynamics because of its flexible operating characteristics;

    c. Become more important for price formation in future zero-carbon systems because the value of stored hydropower is dictated by its opportunity cost to the system; and

    d. May be able to exert market power under certain market conditions due to their flexible and dispatchable operating characteristics.

- Studies of market interactions in zero-carbon systems are few and mostly focused on conceptual discussions with limited quantitative analysis. Within the limited number of quantitative studies, most investigate the tipping points at which current market designs begin to lose their efficiency as zero-carbon resource penetrations increase. Therefore, additional quantitative analyses that can help to identify hydropower impacts and inform new market design initiatives and enhancements are important.

ES.4 Open Research Questions

The existing body of research lacks detailed quantitative investigations of price formation impacts under potential market designs for future zero-carbon systems. Such studies will be important to better address multiple questions regarding zero-carbon electricity market design and price formation. The most critical research questions include the following (a more complete list is provided in Section 5):

- To what extent can energy-only markets ensure market efficiency and resource adequacy and provide sufficient incentives for new investment in a zero-carbon system?
- What are the contributions of a long-term energy market or capacity remuneration mechanisms to resource adequacy and risk mitigation for generation asset cost recovery in a zero-carbon system?
- What are the main value drivers for hydropower resources in a future zero-carbon system?
- Are these value drivers fundamentally different from those in current power systems or possible future power systems with more moderate penetrations of zero-carbon resources?

Acronyms and Abbreviations

CAISO	California Independent System Operator
CCS	carbon capture and sequestration
CPUC	California Public Utilities Commission
DER	distributed energy resource
DOE	U.S. Department of Energy
DOJ	U.S. Department of Justice
E3	Energy and Environment Economics
EEM	European Energy Market
EIA	Energy Information Administration
ELCC	effective load carrying capacity
ELMP	extended locational marginal price
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GW	gigawatt
GWh	gigawatt-hour
HHI	Herfindahl-Hirschman index
HOEP	Hourly Ontario Electricity Price
HydroWIRES	Hydropower and Water Innovation for a Resilient Electricity System
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronic Engineers
IESO	Independent Electricity System Operator
ISO	independent system operator
IS-ONE	Independent System Operator – New England
km	kilometer
kW	kilowatt
kWh	kilowatt-hour

LMP	locational marginal price
LP	linear program
LSE	load-serving entity
MILP	mixed integer linear program
MISO	Midcontinent Independent System Operator
MOPR	Minimum Offer Price Rule
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Council
NetCONE	net cost of new entry
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
ORNL	Oak Ridge National Laboratory
ORDC	operating reserve demand curve
PJM	PJM (Pennsylvania, New Jersey, and Maryland) Interconnection
PSH	pumped storage hydropower
PUC Texas	Public Utility Commission of Texas
REC	renewable energy credit
RGGI	Regional Greenhouse Gas Initiative
RPS	renewable portfolio standard
RSI	residual supply index
RTO	regional transmission organization
SPP	Southwest Power Pool
STR	short-term reserve
VOLL	value of lost load
VRE	variable renewable energy
WECC	Western Electricity Coordinating Council
WPTO	Water Power Technologies Office

ZMC	zero marginal cost
ZFC	zero fuel cost

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1.0 Introduction

With sharp decreases in the cost of renewable generation technologies and concerns regarding greenhouse gas emissions from fossil fuel generation, installation of zero-carbon electricity generation capacity has increased rapidly around the world in the last decade. One important characteristic of many zero-carbon generation resources is that they do not have a direct fuel cost, and in some cases, they have essentially zero marginal cost of generation.[2] This characteristic differentiates them from conventional fossil fuel generation technologies, such as coal or natural gas, that consume fuels with non-zero cost to generate electricity.

While many zero-carbon technologies have zero marginal generation cost (e.g., wind and solar), that is not the case for all such technologies. For example, operators of hydropower facilities that include reservoirs may not pay directly for the water they use as a fuel source, but because water supply is limited and water can be stored, hydropower facility operators face opportunity costs when releasing water through their turbines to generate electricity: the water may be more valuable if saved to provide generation at a later time. Other zero-carbon resources do directly consume fuel with non-zero cost, either a carbon-neutral fuel such as biomass or green hydrogen[3] or a carbon-intensive fuel combined with carbon capture and sequestration (CCS). Nuclear resources incur fuel costs, but these costs are generally a fixed-cost element because re-fueling typically occurs at a fixed interval regardless of the dispatch of the plant (Jenkins et al., 2018). Table 1-1 illustrates this categorization of fuel and marginal costs for zero-carbon electricity resources.

Table 1-1 Categorization of Zero-Carbon Electricity Resources by Marginal Cost and Fuel Cost

	Zero Fuel Cost	Non-Zero Fuel Cost
Non-Zero Marginal Cost	**Opportunity Cost** Reservoir hydro Pumped storage hydro Batteries Other storage Demand response	**Variable Fuel Cost** Bioenergy Hydrogen gas with CCS Coal with CCS
Zero Marginal Cost	**No Opportunity Cost** Wind Solar Run-of-river hydro Geothermal	**Fixed Fuel Cost** Nuclear

2 With incentives, such as the production tax credit, some of these resources can operate profitably under negative market clearing prices; in essence, paying the system so that they can generate electricity and claim the tax credit in return.

3 Green hydrogen is hydrogen gas that is produced through an electrolytic process that is powered entirely by carbon-free electricity. The resulting hydrogen gas can then be combusted to drive a turbine and generate electricity.

In this paper, we focus on how a large-scale expansion of resources that have *either* zero marginal cost (ZMC) or zero fuel cost (ZFC) (i.e., both the left column and the bottom row in Table 1-1) might impact price formation in electricity markets. We consider this specific set of resources because their increasing presence collectively represents a potential shift in price formation and market outcomes compared with traditional thermal-dominated power systems. It is certainly possible that a future zero-carbon power generation system will draw a significant power generation from resources that are not included in either the ZMC or ZFC classification (i.e., those in the upper right box of Table 1-1). However, it is very likely that ZMC and ZFC resources will play a dominant role in a zero-carbon future, at least in the near or intermediate term, based on their current level of deployment, technology maturity, and forecasted cost trajectories.

Therefore, for simplicity we will use the general term "zero-carbon" throughout this paper, with the implicit understanding that we are specifically referring to market issues that may be caused by relatively high — but not necessarily exclusive — contributions from ZMC and ZFC resources. This is because most of the market issues we discuss are also not exclusive to systems entirely comprising ZMC and ZFC resources; such issues are likely to present themselves with increasing frequency and impact as the system approaches such a composition. Similarly, such issues are also expected to materialize in *low*-carbon systems with the level of impact dependent on the relative role of ZMC and ZFC versus other resources in each system. Therefore, while our language will emphasize the extreme, zero-carbon case for convenience and readability, we are also implicitly reviewing more moderate impacts that may manifest throughout the transition towards this end state.

In an electric power system, generation units are typically dispatched according to their economic merit order, which means that the system operator dispatches available generation resources in order of their variable operating costs (lowest to highest) to match supply with demand.[4] This process is typically optimized across a regional system subject to a number of security and technical constraints, such as locational availability, transmission congestion, unit commitment status, and ramping capabilities. The last unit dispatched to serve load in each system node or price zone is called the marginal unit, and its variable generation cost, as offered to the market, determines the electricity price under most conditions.[5] The resulting price is equal to the locational marginal cost (i.e., the cost of supplying an additional unit of electricity demand at the given location and point in time). In a zero-carbon system, the traditional merit-order-based economic dispatch method may be challenged because of large amounts of zero (or close to zero)-marginal-cost generation from multiple units producing at the same time. This zero-cost generation could lead to low or zero prices for extended periods. Additional dispatch criteria may be needed on top of the economic merit order based on variable operating cost as offered to the market, if those offer costs are identical for most electricity producers.

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[4] In competitive electricity markets, resources are dispatched based on cost-quantity offer curves that each resource provides to the system operator. It is often assumed that these resource offers reflect the resource's true marginal costs. In reality, however, resource operators have some ability to deviate from this practice if they desire, although market monitoring rules are in place to prevent strategic behavior.

[5] Note that other resources, such as demand response, could also set the price.

At the same time, because many zero-carbon generation technologies are weather dependent, their resource availability is variable and uncertain. This variability and uncertainty could lead to supply shortages and corresponding system scarcity unless other resources are available to meet the demand. For instance, flexible resources with storage capabilities (e.g., batteries, hydropower with reservoirs) will become more important in a 100% decarbonized power system because they can facilitate the balance of variable renewable generation and electricity demand over time (i.e., during both normal and scarcity conditions). In scheduling these flexible resources, plant owners and system operators must consider whether to dispatch immediately or to delay dispatch to maximize plant profits and reduce overall system costs by leveraging their storage capabilities. This opportunity cost, which occurs any time energy storage resources are dispatched, must be accounted for when operating the power system. So, although storage resources do not have a direct fuel cost, their opportunity cost can be considered a non-zero generation cost. When storage resources are the marginal producer in the system, the system's marginal cost and price would equal the storage opportunity cost, which would often be non-zero, even in systems dominated by zero-carbon resources. In this paper, we argue that the principles behind optimal scheduling and dispatch of energy storage become critical in understanding energy price formation in zero-carbon systems.

A power system requires continuous matching of electricity supply and demand in real time. A power system with a significant amount of variable renewable energy (VRE) (mainly wind and solar power resources) will therefore require more flexibility to accommodate weather-driven fluctuations in VRE output. A range of solutions is currently being developed, tested, and applied to address flexibility needs in both short-term operations and long-term planning. For example, for short-term operations, market operators have implemented new reserve requirements to acquire flexible ramping capacity in some U.S. markets (Xu and Tretheway, 2012; Navid and G. Rosenwald, 2013). In addition, rules to determine system requirements for both existing and new types of ancillary services are being updated to better capture system reliability needs, which are more dynamically impacted by the variability and uncertainty of VRE. In long-term capacity planning, system flexibility has been introduced as a newly required characteristic of generation capacity in some systems (Loutan and Motley, 2019), defining the amount (or percentage) of total resource capacity that must meet certain flexible requirements, so that the system will have sufficient flexibility in the future.

As a zero-carbon source of both energy and flexibility that is already widely deployed, hydropower will likely play an important role in any future zero-carbon system. Like other renewable generation technologies, hydropower is subject to location-dependent siting restrictions and has a high investment cost and a low operating cost. However, most hydropower resources, including reservoir hydro and pumped storage hydro (PSH), have a high degree of dispatchability and less short-term variability and uncertainty in resource availability than wind and solar (Harby et al., 2013). In contrast, run-of-river hydropower resources are highly dependent on instantaneous water availability, with limited control or dispatchability, similar to other VRE resources.

With a water reservoir, a hydropower operator can manage its generation to better match electricity demand or respond to market prices across timescales ranging from hours to months. Pumped-storage hydropower is essentially an energy storage asset that is not subject to water availability constraints like other hydropower resources. As key providers of zero-carbon generation that offer storage and flexibility, both reservoir and pumped-storage hydro are likely to play a more important role in price formation in future decarbonized electricity markets. However, the use and remuneration of these resources will depend on electricity market design and how the market will compensate flexibility in future systems.

This discussion illustrates that we are likely to see profound changes in the generation resource mix during the transition to a zero-carbon electricity supply. The likely dominance of resources with zero marginal or fuel costs triggers a need to revisit dispatch logic, price formation, and corresponding incentives for electricity market participants. There are currently extensive discussions around the key elements of electricity market design to ensure market efficiency, system reliability, and resource adequacy as resource mixes evolve.

In the remainder of the report, we discuss electricity market design and price formation challenges that may become more prominent in a zero-carbon power system, as well as proposed solutions. In Section 2, we briefly introduce general electricity market design concepts and elaborate on the challenges of a zero-carbon system. In Section 3, we introduce different proposals from the literature to design electricity markets to operate efficiently with such a resource mix and briefly contrast these with initiatives in current U.S. electricity markets. Section 4 provides a review of these challenges, specifically from the perspective of hydropower resources, and discusses how the role and impact of hydropower may evolve in future zero-carbon systems. Section 5 presents our conclusions. Appendix A provides a brief overview of electricity markets and market products.

A companion paper (Bhatnagar et al., 2022) discusses compensation mechanisms for long duration storage, also in the context of the transition towards zero-carbon electricity markets.

2.0 Electricity Market Design and Price Formation in a Zero-Carbon Grid

U.S. electricity markets have evolved since the onset of industry restructuring in the 1990s. Although there are differences between regional markets, they largely follow the same principles for scheduling, dispatch, and market clearing. Appendix A provides a brief overview of the main principles of electricity markets and the most important market products (i.e., for energy, ancillary services, and capacity). Below, we discuss market challenges in zero-carbon power systems.

2.1 Market Design Challenges in a Zero-Carbon System

As discussed previously, an electricity market built on zero-carbon generation resources will face some fundamental changes. Figure 2-1 illustrates the market clearing process in a typical current market. The market clearing illustration in Figure 2-2 provides some examples that may materialize in a zero-carbon system. As low- or zero-marginal cost resources dominate the resource mix, most of the supply curve shifts downwards toward a zero price compared with the curve that is more representative of current conditions in Figure 2-2 (Appendix A provides a more detailed explanation of the market clearing process). As a result, the market will clear with zero or low prices more frequently. However, on occasion, the system may still face a supply shortage and clear at the scarcity price, leading to periods of very high prices; how frequently such scarcity prices occur is of particular importance in these systems. As a result, generation units will rely more on scarcity pricing to recover long-term costs. There is an open question whether existing market designs can adequately function under a radically different resource mix. Below, we discuss some of the key market challenges that may materialize in zero-carbon systems.

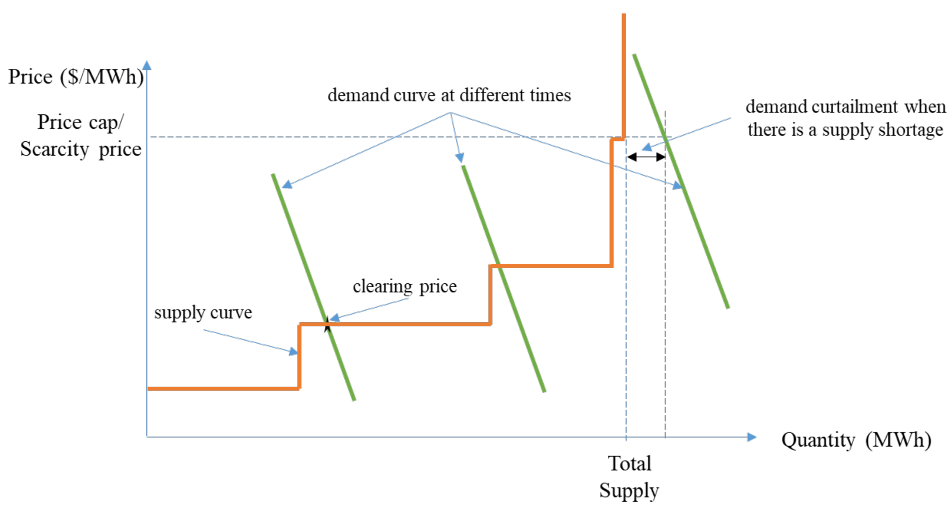

Figure 2-1 Market Clearing with Aggregated Supply and Demand Curves with Conventional Supply Mix

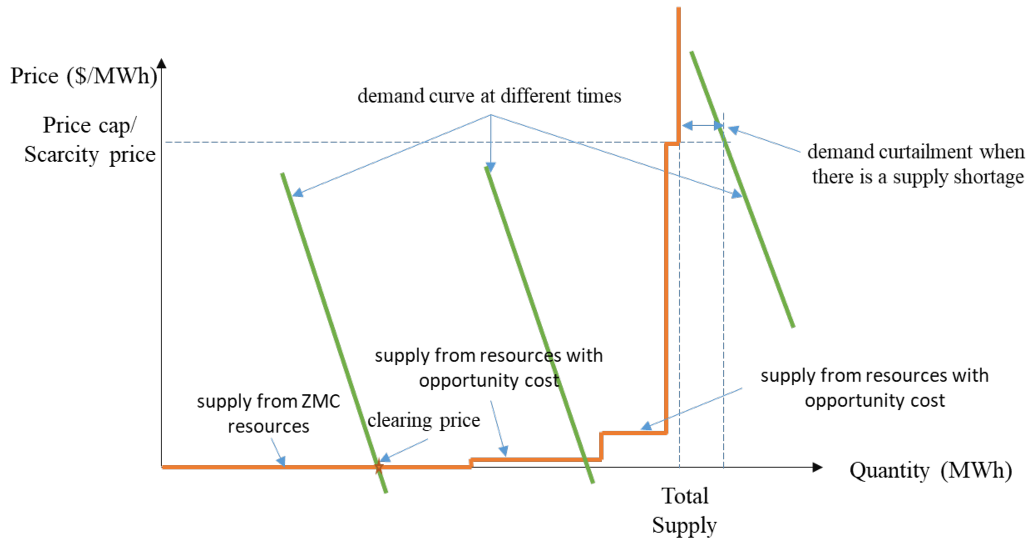

Figure 2-2 Market Clearing with Aggregated Supply and Demand Curves in a Zero-Carbon System

2.1.1 Ensuring Revenue Sufficiency

Generation asset owners need to recover their total cost (i.e., fixed and variable) from energy, ancillary services, and long-term capacity remuneration processes to justify their investments. In a well-functioning electricity market, price signals would ensure that competitive power generation plants collect sufficient revenue to stay in the market and attract investment in new capacity when needed, while generation technologies that are no longer economically viable are incentivized to retire.

Currently, U.S. market designs determine energy prices based on locational-based marginal costs, which is a well-accepted approach in systems dominated by controllable, non-zero-marginal cost generation assets that can be dispatched based on their economic merit order. However, in a zero-carbon system, marginal cost-based pricing could generate prices that are zero most of the time, as illustrated in Figure 2-2. In this case, power plants, regardless of technology, must collect most of their revenues during periods of supply shortages (i.e., when prices are typically set by administratively determined scarcity prices) to recover investment costs. Because such scarcity pricing occurs infrequently, revenues for generation units that rely on sales to the energy market may be insufficient to recover their cost. Similarly, high volatility and unpredictability around the occurrence of such high-price periods may create unacceptable risks for investors even if mean revenues are expected to cover costs. For example, Djorup et al. (2018) simulated a 100% renewable energy system in the current electricity market structure and concluded that the current structure cannot financially sustain the amount of wind power necessary for the transition to a 100% renewable energy system.

A key question in zero-carbon electricity market design, therefore, is whether the new price dynamics that follow from current dispatch logic can provide sufficient incentives to enable efficient market entry and exit of generation resources. Moreover, as the system integrates large shares of VRE, it will need more flexible resources (e.g., from generation, demand, and energy storage) to balance generation and demand in real time. However, while "flexibility" may provide critical value to power systems, it is a difficult attribute to monetize. Some U.S. wholesale markets have introduced specific flexibility products, whereas others are relying on existing market products to remunerate flexibility providers in the system, including from price fluctuations in the energy market and provision of existing ancillary services.

There is also a need to rethink reliability criteria (e.g., does N-1 still work under a radically different resource mix?), as well as the operating reserve requirements and capacity procurement mechanisms needed to ensure reliability. Specifically, market designs for operating reserves need to be tailored to address different system requirements and the increasing need for flexibility across different timescales. For capacity procurement, refined capacity credit calculations for different generation technologies are needed to account for the fact that the capacity contribution of an individual resource may depend on the overall resource mix and on synergies between different technologies (Byers and Botterud, 2020). Moreover, there is a need to rethink whether current market operations practices based largely on deterministic scheduling and dispatch will continue to function in a system with higher levels of uncertainty and variability.

With new price dynamics in the energy market and the possibility of substantial changes in ancillary services markets, it is hard to predict whether power plants will generate sufficient revenues to recover costs in future zero-carbon markets. Contrary to the conclusion in Djorup et al. (2018) — that a system cannot financially sustain the transition to a 100% renewable energy system with existing market structures — Korpås and Botterud (2020) argue that an energy-only market with high shares of VRE and energy storage can provide an optimal generation mix and cost recovery for all market participants. However, the analysis in Korpås and Botterud (2020) assumes that there is still a resource with positive marginal cost that impacts price formation and that scarcity prices are set to the true value of lost load (VOLL).

In addition to the possibility of extended periods with low or zero prices in the energy market, the corresponding increase in price uncertainty in a zero-carbon system may increase risk exposure for investors in both supply- and demand-side technologies at transmission and distribution levels. If this increased risk translates to higher capital costs, the appetite for investment will wane and the overall cost of electricity will increase. So, implementation of adequate instruments and mechanisms that allow investors to hedge against future price uncertainty will become more important in a zero-carbon electricity market.

2.1.2 Market Power Monitoring and Mitigation

Electricity markets are vulnerable to market power because of the inelasticity of demand, lack of storage capacity, and relatively concentrated generation supply. Some studies have shown that market power grows for flexible units when renewable generation capacity increases, particularly during peak periods when a system relies more on firm generation capacity (Browne et al., 2015). For instance, hydropower resources with reservoirs may have the potential to exercise market power by withholding generation during peak hours. Reservoir hydro may have more advantages in a zero-carbon system, especially during periods with low generation from renewable resources that require more firm capacity (Bigerna et al., 2016; Ritz, 2016; McRae and Wolak, 2018; Newbery, 2018).

Resource operators exercising market power could lead to substantial market inefficiencies, so it is critical to mitigate this possibility through effective electricity market design. In general, market power is measured by three primary metrics: (1) the degree of supplier concentration, typically measured by the Herfindahl-Hirschman index (HHI) (DOJ, 2021), which is 0 when the market is perfectly competitive and 1 when it is a monopoly; (2) market price markup, typically measured by the Lerner index (Elzinga and Mills, 2011), which measures the percentage markup that a firm can bid over its marginal cost; and (3) the difference between total supply and supply from the largest seller, measured by the residual supply index (RSI) (CAISO, 2002). RSI measures the ratio of residual supply to total demand, which is used to predict price-cost markup.

A commonly used market power mitigation mechanism is to set caps on market offers from generation resources. These caps are typically linked to the assumed variable cost of the resource. However, if inadequately designed, such offer caps may cause insufficient cost recovery for certain generation suppliers, who rely heavily on revenue during scarcity events. This challenge could be more prominent if prices consistently fall more frequently in a future zero-carbon system. Moreover, the optimal competitive offer for energy storage resources will depend largely on their opportunity cost. Because the opportunity cost is not observable, but rather a complex function of the current state of the system and its uncertain future outlook, introducing adequate offer caps for these resources will be challenging. Overall, there is clearly a need to revisit market power monitoring and mitigation in future zero-carbon systems.

2.1.3 Impacts of Non-Convexities on Dispatch and Pricing

Non-convexities in costs and operational constraints are well-known challenges for electricity markets, as they lead to market prices that are not necessarily incentive compatible[6] and the need for make-whole payments for certain generators to recover their full operating costs (Schiro et al., 2015). Examples of such non-convexities include unit startups and shutdowns, required up and down times, commitment status, and corresponding costs. In a zero-carbon system, conventional generation technologies with non-convex costs and constraints will likely become less prominent. So, this change in resource mix will reduce the complexity caused by non-convexity and nonlinearity in system and market operation. Likewise, under such a shift, electricity market operators may choose to revisit the need for current unit scheduling and commitment processes and for market clearing stages, because these are largely designed to accommodate the operational constraints of conventional generation technologies.

However, non-convexities that stem from other resources may become more prominent in a zero-carbon market. Examples include the following:

- Energy storage resources, which may introduce the need for integer variables and nonlinear constraints in dispatch and pricing formulations to adequately consider their technical characteristic (e.g., state of charge status, dynamic charging efficiencies, degradation), as well as preventing simultaneous charge and discharge;

[6] Incentive compatible markets induce all participants to truthfully reveal the private information in their offers to the market and to have no incentive to deviate from the market clearing solutions.

- Hybrid resources (e.g., wind/solar with co-located storage), which may also introduce non-convexities in a market clearing process; and
- Hydropower resources, which typically also involve non-linear operational complexities, such as non-continuous operating zones and non-linear relationships between reservoir head and reservoir volumes.

Electricity markets are cleared by solving a linear optimization problem, which makes it possible to designate the values of dual variables for certain constraints as market clearing prices. As a result, non-convexities in the system must be transformed and linearized to be considered in the market clearing process. These approximations may have impacts on market outcomes and lead to substantial inefficiencies because they may introduce inaccurate price signals and cause market distortions or deviations in dispatch from the optimal schedule. For example, Helseth et al. (2017) show different economic outcomes when hydropower resource decision making processes are modeled using a mixed integer linear program (MILP) versus a linear program (LP). Specifically, the study shows that models with LP formulation tend to overestimate revenues from energy and reserve provision compared with those using MILP formulation because of relaxed constraints.

A key question is whether ISO/RTOs should directly reflect these types of non-convexities in their scheduling formulations or whether market participants should resolve them internally as part of their operational procedures and offer strategies. The former approach may represent the system more accurately at the cost of modeling and solution complexity, while the latter could leave more flexibility for market participants to determine their strategies but require more sophisticated models for market participation.

3.0 Potential Market Designs in a Zero-Carbon World

3.1 Proposed Market Design Solutions

Several different electricity market designs have been proposed to help ensure resource adequacy, security of supply, reliability, and accurate price signals for long-term investment and short-term operations as systems continue to adopt more zero-carbon resources. Most of the proposed designs are direct extensions of existing market designs, enhancing either the energy-only market design or hybrid designs that include a combination of short-term markets and long-term capacity remuneration mechanisms. Other proposals constitute more radical departures from current practice. Below, we briefly review some key electricity market design elements and solutions that are currently being considered or discussed in the context of the ongoing resource mix transition and the possibility of a future system dominated by zero-carbon resources.

3.1.1 Energy-Only Markets

In an energy-only market (e.g., Electric Reliability Council of Texas [ERCOT]), a generation asset investor recovers costs mainly by selling energy and ancillary services in short-term markets, possibly supplemented with long-term contracts. Some studies investigate price dynamics in systems with existing energy-only market design for future high renewable penetration scenarios. One study based on the North European power system (Helisto et al., 2017) shows that systems with zero-carbon resources and large amounts of energy storage can still produce high electricity prices. Ekholm and Virasjoki (2020) model market competition and price formation in a system with 100% VRE, storage, and elastic demand. They observe that prices are determined by operational decisions from demand and energy storage resources because of the ZMC characteristics on the generation side. Moreover, market power could be exerted by storage assets or by hybrid resources consisting of a combination of renewables and storage. Hirth (2018) analyzes European electricity market data in Germany and Sweden from 2008 to 2015 and finds that significant shares of hydropower and renewable energy would depress electricity prices. Leslie et al. (2020) shows that grid-scale energy storage, active demand-side participation in the market, and scarcity pricing could result in non-zero prices in a zero-carbon system.

As discussed above, in energy-only markets, investors rely heavily on scarcity prices during supply shortages to recover fixed costs. However, with increasing VRE shares, the frequency of scarcity pricing events becomes more uncertain. Depending on the specific capacity mix and market structure, some studies (e.g., Leslie et al., 2020) show that scarcity pricing occurs more frequently with increasing renewable generation, while others (e.g., Barroso et al., 2021) find that a system may have very low prices continually for more than a year. In a recent example of extensive electricity shortages, after the February 2021 extreme weather event in Texas, which exposed some consumers to extremely high scarcity prices ($9,000/MWh) in the spot market for 3 consecutive days, ERCOT is now reviewing its rules for pricing during scarcity conditions (PUC Texas, 2021).

Flexible resources could play a key role in price formation in zero-carbon, energy-only markets. Resources with storage capability (e.g., batteries, pumped-storage hydro, and hydropower plants with reservoirs) have the option of dispatching resources immediately or later, depending on expectations regarding when the profit would be higher. Aaslid et al. (2021) argue that this opportunity cost is an operational cost that should be reflected in the dispatch logic for these resources. However, the operational cost used in market clearing algorithms may not accurately reflect the true opportunity cost at any given time, which is a complex function of the future uncertain state of the system.

As an alternative to pricing based on short-term marginal costs, mechanisms have also been proposed (Stevenson et al., 2018; Ministry of Business, Innovation and Employment, 2019) to use long-run marginal cost to determine the dispatch order. In this case, the long-run levelized costs of individual assets are intended to provide prices that better remunerate investors because the average expected spot price would equal the long-run marginal cost of generation and storage investments. However, one important concern is that pricing based on long-run marginal costs may lead to inefficient operations, because long-run marginal costs do not efficiently reflect costs incurred by generators over the time scales during which they are making operational decisions, leading to more expensive dispatch solutions than the conventional approach based on short-run costs.

In addition, to reduce the risk of extremely low prices caused by a supply surplus from VRE resources, the concept of price floors has been implemented in some markets. These floors could potentially become more important in future zero-carbon systems. For example, California Independent System Operator (CAISO) has a price floor of -$150/MWh (CAISO, 2020b), while New York Independent System Operator (NYISO) has one of -$1,000/MWh (NYISO, 2018). Such floors would reduce the magnitude of negative pricing events, which increase with the level of VRE generation in some markets (Mills et al. 2020).

Several studies investigate future power systems with high VRE penetration operated under existing market designs. These studies suggest that some long-term energy or capacity remuneration mechanisms are necessary to ensure capacity and revenue adequacy (e.g., Helisto et al. 2017; Ekholm and Virasjoki, 2020; Gholami et al. 2021). Specifically, the studies propose market designs with supplemental long-term energy procurement (via contracts or markets) or long-term capacity compensation, as discussed in the following sections.

3.1.2 Long-Term Energy Auctions and Contracts

To mitigate the risk of relying entirely on revenue from short-term energy markets (e.g., day-ahead and real-time energy market in current market structures), long-term energy procurement through long-term, auction-based markets or bi-lateral contracts are also used. These mechanisms allow investors to partially recover their expected costs before electricity is generated and delivered, and they may play more prominent roles in future zero-carbon systems. Pierpont et al. (2017) proposed a combination of a long-term energy market and a real-time delivery market. In their proposed strategy, forward energy (MWh) over a specified period is determined in the long-term energy market (e.g., months or years ahead of delivery) without consideration of delivery time and location, while time and locations of energy delivery are still determined in a short-term delivery market based on short-run locational costs and scarcity values. This approach would reduce investor price risk and enable long-term, low-cost financing to support investments in capital-intensive resources with low operating costs. The prices in a long-term energy market are based on long-run, levelized costs of generation technologies, while those in the short-term delivery market are based on short-run locational costs and scarcity values. Similarly, Wolak (2021) proposes a standardized, fixed-price-forward contract approach that requires retailers to hold hourly fixed-price-forward contract obligations for energy that sum to the hourly value of system demand. This approach ensures that all suppliers can maximize their expected profit by minimizing the cost of meeting their hourly fixed-price-forward contract obligations. The sum of all such obligations for any given hour will equal the system demand in that hour. Fabra (2021) assesses market outcomes through auctions of long-term, legally enforceable contracts that reduce electricity market price risk. Competition among investors prior to the investments can drive forward prices down to the average levelized costs of the best available technologies.

Overall, the potential shift toward reliance on long-term energy contracts may increase competition among investors. For example, long-term auctions have been applied successfully to procure large-scale investments in generation capacity, including hydropower, in Brazil (IEA, 2021). At the same time, these mechanisms rely on the ability to project future loads, which is not a straightforward exercise. Moreover, it is important that the long-term investment market and the short-term operations market work together seamlessly and efficiently.

3.1.3 Capacity Mechanisms

Another representative market type is a hybrid of a short-term energy market and a long-term capacity remuneration mechanism; this is the current structure used across most of the U.S. ISO/RTOs. These markets have an energy price cap that may be below true societal VOLL (e.g., $3,500/MW in MISO [MISO, 2020]), which may contribute to the missing money problem discussed previously. A capacity remuneration mechanism can be implemented to provide an additional source of revenue to alleviate the missing money problem and support long-term capacity sufficiency.

While capacity remuneration can be implemented in various ways (e.g., competitive mandatory capacity markets, capacity obligations with voluntary markets, or fixed capacity payments), changes in these mechanisms will likely be needed in future zero-carbon systems. Tierney (2018) proposes an enhanced-capacity mechanism for California in which three existing resource adequacy products (CPUC, 2021) are offered to ensure that system peak load is met: (1) a system-wide resource adequacy requirement; (2) adequacy requirements for resources with flexible operations; and (3) local resource adequacy requirements in zones with transmission constraints. The capacity can be procured through either a decentralized or a centralized process as “centrally procured RA products,” according to Tierney (2018). Resources that are selected to provide capacity would also have must-offer obligations to supply energy and/or ancillary services in short-term markets.

Doorman (2005) and Gui et al. (2020) propose a capacity subscription-based mechanism that is similar to the demand-charge mechanisms in distribution systems where a load-serving entity (LSE) needs to procure sufficient capacity to cover its peak demand. The subscription can be implemented through long-term contracts or within a market framework. A key feature of capacity subscription mechanisms is that consumers are given the option to determine how much capacity is being served with certainty, thereby reflecting their reliability preferences in the capacity market clearing. During scarcity situations, their electricity demand may be curtailed to the subscribed capacity, but not below. This approach contrasts with existing capacity remuneration mechanisms, in which the demand for capacity is determined by forecasts of aggregate peak demands, without considering varying preferences among consumers.

3.1.4 Other Market Design Proposals

As an alternative approach, a linked swing-contract wholesale market design has been developed in a series of studies (Tesfatsion, 2013; Tesfatsion, 2020; Heo, 2015; Li, 2018; Ma et al.,2018). The proposed design consists of a collection of linked swing-contract markets whose purpose is to ensure the availability of reserves with sufficient flexibility to permit continual net-load balancing. Each swing-contract market is an ISO/RTO-managed forward reserve market for some future operating period with a look-ahead horizon ranging from years to minutes. A reserve bid or offer consists of demand or supply of power path delivery during a specific period. A power path is a sequence of power injection and/or withdrawals (MW) at some designated grid location. The ISO/RTO conducts a contract-clearing optimization for each swing-contract market. The objective is to determine which reserve offers and price-sensitive reserve bids to clear in order to maximize the expected net benefit of market participants, subject to the usual types of security constrained economic dispatch system constraints. When a resource submits a swing contract with its energy and reserve offers parameterized by several characteristics over an extended period, the system operator can dispatch the resource in any path that is physically and financially feasible within the energy and ramping ranges. Figure 3-1 illustrates one among many possible power-paths that an ISO/RTO could dispatch a resource if its reserve offer clears the corresponding advanced swing-contract market. Under this solution, the exchange of information between market participants and the system operator fundamentally changes compared with the status quo. This approach provides greater flexibility for a system operator when dispatching resources to meet both energy and ancillary services requirements. The model has been validated on small test systems and was demonstrated to achieve market efficiency in terms of defined cost metrics (Ma et al.,2018).

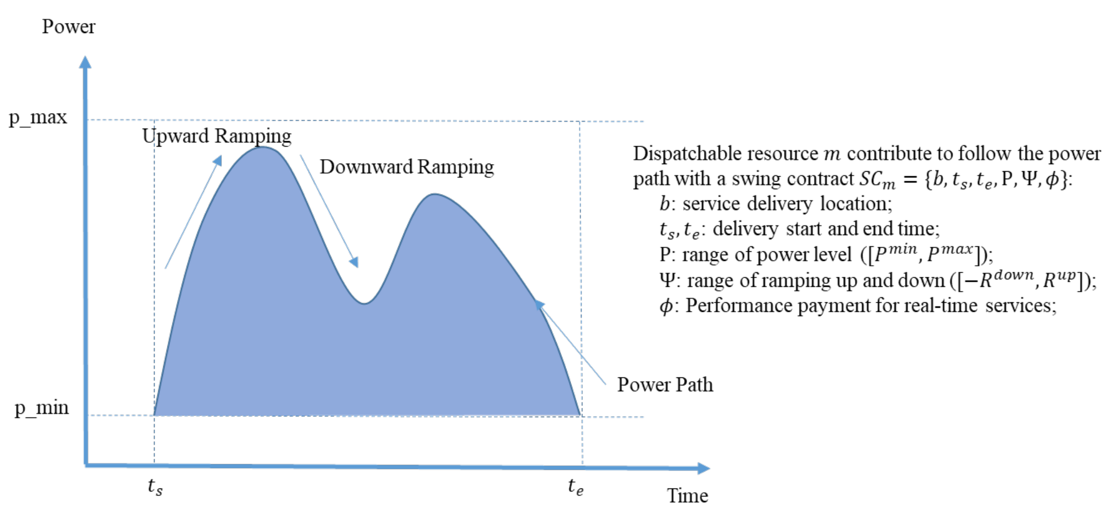

Figure 3-1 Contract Parameters and Possible Dispatch Path for a Resource Submitting a Swing Contract

Another possible fundamental shift in electricity market operation in a zero-carbon future would be a return to traditional cost-based regulation (Joskow, 2021), in which generation companies are remunerated based on their costs. Under this scenario, the responsibility of generation expansion planning and resource adequacy will be shifted from the market participants to the ISO/RTO and achieved through regulation instead of competition. This would, of course, be a departure from the belief that markets introduce efficiency gains in the power system, which underpinned the transition toward market-based solutions in ISO/RTO regions over the last three decades.

3.1.5 Summary

Table 3-1 summarizes the possible market design features and enhancements related to electricity market operations and planning that were discussed above and briefly describes the challenges facing these proposed solutions in a zero-carbon future. In reviewing different market design solutions, it is important to keep in mind that there is no universal design that works best under all circumstances; the optimal approach will depend on the available supply and demand side resources, as well as the regulatory landscape and societal preferences in a given region.

Table 3-1 Summary of Proposed Market Design Solutions for Zero-Carbon Systems

Proposed Solution	Goal of Solution	Potential Challenges	Reference(s)
Scarcity Pricing	Improve operational and investment incentives for flexible supply, demand, and storage resources. Mitigate the missing money problem.	Challenging to set appropriate scarcity pricing rules that adequately reflect (1) system reliability condition; (2) consumers' preferences (e.g., VOLL).	Leslie et al., 2020 Aaslid et al., 2021 Pierpont et al. 2017
Price floor	Mitigate over-generation and low/negative prices.	Could distort price signals and operational incentives during energy surplus situations.	CAISO, 2020b NYISO, 2018
Long-term marginal cost	Incorporate capital cost into energy market bids and market clearing prices to ensure revenue adequacy.	Negatively impacts operational efficiency of system scheduling and dispatch.	Stevenson et al., 2018 Ministry of Business, Innovation and Employment, 2019 Pierpont et al. 2017
Improved representation of opportunity cost in dispatch logic	More realistically reflect operational costs incurred by flexible resources, accounting for future system states, particularly for energy storage.	May require an extended dispatch horizon to adequately capture opportunity cost. Moreover, opportunity cost is hard to estimate because it depends on a number of uncertain factors.	Aaslid et al., 2021
Long-term energy market	Reduce investor price risk and enable long-term, low-cost financing to support investments in capital-intensive resources with low operating costs.	Hard to forecast energy demand for multiple years into the future.	Pierpont et al. 2017
Long-term contract auctions	Reduce generation investors' exposure to electricity market price risk in short-term markets. Drive forward prices down to the average levelized costs of the best available technologies	Hard to determine future capacity needs. May need centralized planning to determine capacity demand for different technologies in auctions.	Wolak, 2021 Fabra, 2021

Proposed Solution	Goal of Solution	Potential Challenges	Reference(s)
Enhanced capacity market	Better ensure capacity adequacy, for example through: (1) adequacy requirements for resources with flexible operations; and (2) local resource adequacy requirements in zones with transmission constraints, in addition to current system-wide requirement.	Hard to determine future capacity and flexibility needs. Relies heavily on administrative parameters. Limited consumer interaction.	Tierney, 2018
Capacity subscription	Procure sufficient capacity to cover consumer peak demand based on their preferences. Produce capacity prices that reflect consumer choice. Can be implemented through long-term contracts or a market framework.	Need ability to physically curtail individual consumers during scarcity situations. Potential concerns about energy equity (i.e., socially vulnerable consumers may bear the burden of curtailment).	Doorman, 2005 Gui et al., 2020
Cost-based regulation	Eliminate investor exposure to volatile and depressed short-term prices in zero-carbon systems.	Must determine optimal investment pathways through centralized planning, challenging to provide economically efficient signals for new investment. A full return to the old system, which was oftentimes considered inefficient.	Joskow, 2021
Linked swing-contract market design	Facilitate increased reliance on renewable power resources through fundamental changes in product definition, contract design, and settlement rules for current ISO/RTO wholesale power markets.	Significant departure from current market designs. Places greater responsibilities on resource operators to reflect their operational characteristics and costs to the system operator.	Tesfatsion (2020)

3.2 Incentives During the Energy Transition

To begin the transition toward a zero-carbon energy system and incentivize investment in clean generation resources, many policy measures have been implemented and proposed in the United States through markets, federal regulations, and state policies. These policies may have substantial impacts on the price formation in electricity markets (Levin et al. 2019; Botterud and Auer, 2020), and they must also be considered in the market design. We briefly review some of these measures and how they interact with electricity markets in the following sections.

3.2.1 Clean Energy Markets

The purpose of a forward clean energy market is to procure a quantity of clean electricity generation or capacity that is based on administratively determined societal demand. Different implementation frameworks have been proposed (e.g., auction mechanism [Spees et al., 2019] and bilateral market [E3, 2021]). Certified clean energy resources would receive additional incentives through the new markets to improve their financial competitiveness. Such a market could be implemented within existing electricity markets and would provide a new revenue stream for clean energy resources.

3.2.2 Carbon Pricing

Carbon pricing is a mechanism that imposes a cost on resources that emit carbon pollution. It can be implemented through a direct tax on emissions or a cap-and-trade framework. With a carbon tax, all resources that produce carbon emissions pay the same rate for their carbon emissions (e.g., per ton), as determined by a regulator. Under a cap-and-trade framework, a system emissions cap is determined by regulators, and emissions credits are allocated to resources either through administrative or economic methods (e.g., auctions or bilateral contracts). Emitters must obtain permits to cover their emissions. In this way, generation resources that produce emissions will experience higher costs from either purchasing equipment to remove their emissions or paying the carbon price and, as a result, will become less competitive in the market. A carbon price would be relatively easy to implement within existing electricity markets and would lead to higher operating costs for carbon-emitting resources.

3.2.3 Renewable and Clean Portfolio Standards

A renewable portfolio standard (RPS) is a regulatory mandate to increase the relative production of electricity from specific renewable resources, such as wind, solar, and hydro. Clean energy portfolios may include a wider set of alternatives to fossil fuels (e.g., nuclear generation). Specific RPS targets are usually determined at the state level in the United States and are intended to ensure that a certain fraction of electricity generation in a given region comes from a specific set of generation technologies; this fraction is typically designed to increase over time until a final target is reached. Renewable energy credits (RECs) are typically allocated to eligible resources, and these RECs can be sold to utilities or other entities that need to satisfy specific RPS obligations.

3.2.4 Production and Investment Tax Credits

Production and investment tax credits have been the most important federal incentive to support investments in wind and solar power in the United States. These policies incentivize expansion of clean energy resources by giving tax credits to the investor, either based on the electricity delivered to the grid or based on the installed capacity. Production tax credits and RECs both effectively reduce the operating costs of the generators that receive them, making it economical to offer energy at a negative cost. Such an approach may contribute to depressed energy prices.

3.3 Current/Emerging Solutions in U.S. ISO/RTO Electricity Markets

As the U.S. power system continues to transition to increasing penetration of zero-carbon resources, the seven competitive wholesale electricity markets in the United States are considering a range of market enhancements and rule changes to help facilitate the transition. Some of these initiatives relate directly to the ZMC or ZFC attributes of renewable power technologies, while others are tied to decarbonization objectives or resource adequacy targets that are impacted by the shifting generation mix or the increasing need for operational flexibility. This section briefly summarizes a range of ongoing market initiatives being considered or implemented by the U.S. ISO/RTOs related to price formation, incentivizing flexibility, decarbonization, and resource adequacy. While these market enhancements are not tailored specifically for fully decarbonized systems, many of them are intended to support the clean energy transition more generally. Although it is valuable to consider optimal market design elements for future zero-carbon systems, it is also important to understand the incremental enhancements that are currently being pursued and considered in real-world markets. It is likely that markets will evolve incrementally over time to eventually support future decarbonized systems, rather than being redesigned from scratch in a short period at some point in the future.

While specific initiatives and proposed enhancements differ across the U.S. ISO/RTOs, a number of common themes are relevant to the transition to zero-carbon power systems.

At least one, and sometimes several, markets are considering or implementing one or more of the following approaches:

- Adopting an operating reserve demand curve (ORDC) approach to procuring operating reserves rather than establishing fixed targets or revising their current ORDC formulations.
- Revising mechanisms to accommodate state policies and clean energy incentives, particularly related to their impacts in capacity markets.
- Analyzing the potential impacts of implementing either a carbon pricing policy or a clean energy procurement mechanism at the ISO/RTO-level.
- Adopting new market products that address changing system needs and contribute to meeting the flexibility requirements of increasingly VRE-dominated systems (e.g., the flexible ramping products in CAISO and MISO).
- Updating their methodologies for determining the resource adequacy accreditation of different resources to ensure that values are reflective of their relative reliability contributions.

The following sections summarize a range of key ongoing market initiatives at each U.S. ISO and RTO. This summary, based on a more extensive review and discussion of these issues and initiatives in Sun et al. (2021), is by no means intended to be an exhaustive review of all current activities. EPRI (2019) provides a more complete review of current ancillary service products and definitions in U.S. ISOs and RTOs; Parent et al. (2021) provide a review of current resource adequacy constructs.

CAISO has proposed adding two new products to its day-ahead market: imbalance reserves and a reliability energy product. The former is intended to extend the CAISO flexible ramp product from real time to a day-ahead timeframe, while the latter would replace CAISO's residual unit commitment process. CAISO is also exploring various enhancements to its resource adequacy framework, including consideration of forced outage rates in net qualifying capacity calculations, a new flexible resource adequacy framework, and improved deliverability through must-offer provisions. California already has a carbon cap-and-trade framework that has implications for the CAISO market.

ERCOT is currently redesigning its ancillary services markets, having introduced new primary frequency response and fast frequency response products in 2020. An additional new product, ERCOT contingency reserve service, has also been proposed and approved. This product must respond within 10 minutes to help correct frequency deviations and will eventually replace the current responsive reserve service. ERCOT has also developed a Battery Energy Storage Initiative that is addressing a range of topics to increase operator awareness of storage resources and facilitate their integration. Finally, ERCOT is continually refining its ORDC approach to ensure that reliability targets are achieved efficiently through an energy-only framework.

Independent System Operator – New England (ISO-NE) has proposed a forward clean energy market as an auction framework that could allow for the joint procurement of capacity and clean energy. ISO-NE is also in the process of updating its ancillary services markets to procure some reserve products in the day-ahead market that are currently only procured in real time. ISO-NE is further exploring options to implement a rolling, multiday-ahead market to help mitigate medium-term uncertainty and enhance fuel security — although a recent proposal was rejected by the Federal Energy Regulatory Commission (FERC). They have embarked on a price-responsive demand project that will enable demand response to fully participate in day-ahead and real-time markets, provide reserves, and participate in the forward capacity market on equitable terms with other resources. ISO-NE has implemented Competitive Auctions with Sponsored Resources to help accommodate state incentives into the forward capacity market. Finally, ISO-NE has conducted some analysis around the potential impacts of carbon pricing and has advocated for carbon pricing as a coordinated solution to efficiently price emissions without impairing price formation (ISO-NE, 2020). Several states in the ISO-NE territory currently participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based carbon reduction effort that is coordinated across a number of states in the Northeast.

MISO has implemented alternative pricing for fast-start resources and is continually working to improve its extended locational marginal price (ELMP) framework, which enables resources to set prices that include their commitment costs. MISO has also proposed a new 30-minute short-term reserve (STR) product that was planned for implementation in December 2021. Finally, MISO is working to improve its reliability requirements and capacity accreditation methods to better reflect the resource adequacy contributions of different resources.

NYISO has proposed changes to its ancillary services markets that would increase geographic granularity and reevaluate current scarcity prices and demand curves. Specifically, a new reserve zone was created in 2019 to provide locational price signals for New York City. NYISO is also exploring new distributed energy resource (DER) aggregation models that will set a single schedule for all resources behind an interconnection point; this step is intended to help accommodate hybrid resources. NYISO is also reviewing capacity credit ratings for renewable resources to ensure alignment with reliability contributions and reviewing ways to better accommodate state polices into the market. Finally, while the state of New York currently participates in RGGI, NYISO has also issued a proposal to integrate carbon pricing into electricity market operations.

PJM Interconnection (PJM) is currently proposing changes to its ancillary services markets, most notably through the implementation of an ORDC, while also aligning service definitions between day-ahead and real-time markets and updating penalty prices. An initiative to relax PJM's Minimum Offer Price Rule (MOPR) took effect at the end of September 2021. The MOPR was initially implemented to prevent market participants from offering artificially low offers into the PJM capacity market, with a particular focus on resources receiving state incentives. However, motivated in part by concerns that this rule impeded states from fulfilling their clean energy goals, renewable and nuclear energy resources are now exempt from the MOPR. In addition, PJM is considering a range of different carbon pricing and associated leakage mitigation mechanisms. Finally, PJM has initiated a task force charged with improving model representation of complex resources in market-clearing software, including pumped storage hydro, as well as a task force to explore fuel and resource security issues.

Southwest Power Pool (SPP) has proposed two new market products to address forecast uncertainty: a ramp product in real-time operations with a 20-minute horizon and an uncertainty product to account for forecast uncertainty. The latter product is being considered across a range of forward horizons from 30 minutes to 4 hours. A recent SPP report has also recommended considering approaches to mitigate low energy offers from VRE resources because negative offers from wind resources have driven congestion in some regions. SPP has also proposed adopting updated effective load carrying capacity (ELCC) methods to determine the capacity credits of VRE resources.

Overall, like most of the proposed market design solutions for zero-carbon, the ongoing developments in ISO/RTO markets tend to represent refinements to existing rules rather than large departures from the status quo. An interesting observation is that most of these current ISO/RTO initiatives address issues in the short-term markets for energy and ancillary services. In contrast, the proposed solutions from the research literature, as summarized in Table 3-1, tend to deal more with long-term planning and solutions for resource investment and capacity adequacy.

4.0 Hydropower's Roles and Impacts in Zero-Carbon Markets

4.1 Key Characteristics of Hydropower

Hydropower is the largest source of clean and renewable energy in the world; it is projected to supply almost half of global renewable electricity in 2025 (EIA, 2020), and it is the predominant generation resource in some regional systems, for example, in Norway (Statistics Norway, 2022) and Brazil (EIA, 2021). Like wind and solar, run-of-river hydropower resources have limited dispatchability, meaning their generation output depends on water availability. However, hydropower plants with water reservoirs mitigate this uncertainty by allowing dispatch of hydropower generators, thereby providing the system with much-needed flexibility and predictability. Pumped-storage hydro is by far the largest source of utility-scale energy storage in the world (Uria Martinez, 2021) and is likely to play a more important role when VRE resources become dominant. Hydropower resources have several characteristics that may provide value relative to conventional or other renewable generation technologies that are expected to dominate in a zero-carbon system. While hydropower resources may not be the only technology that offers one or more of the following characteristics, they are unique in possessing all of them.

(1) *Responsive to price signals.* Hydropower is more dispatchable and able to respond to electricity price signals than wind and solar because of the flexibility provided by reservoirs. Even run-of-river plants typically have less variability in output than wind and solar resources, and often include some operational flexibility that can be used to respond to prices. In addition, hydropower can respond to ancillary service price signals with its fast response capability. This will give hydropower a market advantage compared with other renewable generation resources with less dispatchability.

(2) *Firm capacity.* A typical dispatchable reservoir hydropower plant can be relied upon to provide most of its installed capacity during peak demand conditions. In contrast, wind and solar resources are limited by their weather-driven resource availability during periods of peak demand. For example, currently in ERCOT, hydro resources are allocated a capacity value of 86% (i.e., 86% of installed hydro capacity is credited toward satisfying resource adequacy targets). Solar and onshore wind resources are allocated capacity values of 80% and 19%, respectively (ERCOT, 2021). The relatively high-capacity value of solar is a result of the fact that peak load conditions are typically aligned with periods of high temperatures and therefore high solar availability. However, research has also suggested that the marginal capacity value of additional solar resources will decrease as solar penetrations increase and there is a temporal shift in the occurrence of peak net demand[7] conditions (Mills and Rodriguez, 2019; Munoz and Mills, 2015; Ella et al. 2018). Therefore, because it can consistently provide firm capacity during future peak demand conditions, hydropower resources will play an important role in maintaining resource adequacy in a zero-carbon future.

[7] Net demand is defined as demand that must be served by fully dispatchable resources, typically total demand minus coincident wind and solar generation.

(3) ***Long-duration storage.*** PSH units can cost-effectively store larger quantities of energy than most other energy storage systems (roughly 10 hours or more). Moreover, reservoir hydro may store energy for weeks, seasons, or even years, allowing hydropower assets to provide multiple services simultaneously and serve as a valuable asset for mitigating the impacts of long-duration extreme weather events (e.g., multi-day periods of low wind/solar resource availability).

(4) ***Opportunity cost.*** PSH and hydropower plants with reservoirs have an opportunity cost associated with their operational decisions. This cost stems from their ability to schedule generation based on the expectation of the future value of water (i.e., generating now may be profitable but doing so foregoes the opportunity to generate in the future, when conditions may be even more profitable).

(5) ***Potential exertion of market power.*** Given the characteristics outlined above and the often large scale of hydropower plants, hydropower resources may be able to impact market prices through their scheduling and market offers, possibly exercising market power. This ability may increase in a future zero-carbon grid with the increased variability that results from high VRE levels (McRae and Wolak, 2018), especially during situations of supply scarcity.

4.2 Impacts to Hydropower in a Zero-Carbon Market Framework

Energy arbitrage and price following. Compared with most other renewable resources, hydropower resources have relatively certain capacity availability and are more flexible and responsive to system conditions. So, hydropower is typically in a better position to take advantage of price fluctuations and spikes compared with wind or solar, especially in markets with relatively frequent scarcity pricing for energy and reserves. However, under a proposed long-run, marginal-cost-based dispatch framework in which prices tend toward levelized cost of generation, hydropower may not maintain this advantage compared with wind and solar, despite being much more flexible (Sertac et al. 2020).

Ancillary service provision. Because of its reliable capacity availability and flexible operating characteristics, a hydropower resource can provide ancillary services. For example, in the PJM market, hydropower provides less than 5% of total installed capacity, but provides about 20% of regulation reserves, 30% of non-synchronized primary reserve, and 15% of day-ahead scheduling reserve on average between 2014 to 2019 (Uria Martinez, 2021). As the demand for reliability services increases in zero-carbon systems to help balance variable wind and solar generation, the ability of hydropower to provide these services will also likely be increasingly valuable.

Capacity remuneration. Because it can provide firm capacity across all hours of the day, hydropower will likely be allocated a higher capacity credit[8] than many other zero-carbon technologies such as wind or solar. This higher credit will result in correspondingly higher capacity payments in systems that have resource adequacy remuneration mechanisms. In

[8] For example, based on proposals in current U.S. markets, resources with firm capacity to meet peak system demand for more than a certain duration (e.g., a 4-hour rule for NYISO) of service would be fully compensated with capacity payments (Denholm et al. 2020). Most PSH plants will have an advantage in this value stream compared with wind, solar, and short-duration battery storage.

addition, if market designs evolve to require specific types of capacity (e.g., flexible generation capacity), hydropower will have a competitive advantage compared with other renewable energy resources because of its flexibility.

While these potential hydropower impacts can be generalized to some extent, the specific impacts to individual resources will depend on their operational characteristics, market design elements, and other system conditions. Schillinger et al. (2017) show that the market performance of hydropower resources may depend on the size and type of the resource, market size and structure, price dynamics, and participation strategies. Generally, the more operational flexibility a hydropower resource can provide (e.g., in terms of larger reservoirs, more certain inflow, and faster ramping capability), the better it will perform in a market.

4.3 Impact of Hydropower on Price Formation in a Zero-Carbon Market

Hydropower will also likely play an increasingly prominent role in price formation in a zero-carbon system, though the impact will depend on the specific zero-carbon generation portfolio that emerges. While hydropower has no direct fuel cost, its opportunity cost can be become a critical element in price formation. Hydro resources with storage are likely to offer their energy to the market based on their so-called water value,[9] which will likely be non-zero under most conditions. So, in systems dominated by resources with no fuel costs or opportunity costs (e.g., wind, solar), hydropower may increasingly establish the market clearing price. This impact will be most pronounced during periods when ZMC resources in the system are fully dispatched and hydropower generation is needed to meet system demand. Hydropower resources are also likely to impact the formation of ancillary service prices, which also depend on opportunity costs. Specifically, hydropower will likely become a more significant provider of ancillary services as conventional thermal generation retires and ancillary service requirements increase as a result of the expansion of VRE. Finally, because it can provide firm capacity, hydropower will likely play an important role in price formation for long-term energy and capacity markets as well.

4.4 International Case Studies from Hydro-Dominated Systems

While the ISO/RTO regions in the U.S. currently generate a relatively modest portion of their generation from zero-carbon resources, some insights can be drawn from the Independent Electricity System Operator (IESO), which is responsible for operating the electricity market in the province of Ontario in Canada. Historical market data from IESO indicate that there is a relationship between the quantity of zero-carbon resources in a system and its market clearing prices, as shown in Figure 4-1. Over the past 15 years, the IESO system has seen a substantial growth in zero-carbon generation (mostly from hydropower and nuclear power[10]), which have

[9] Generally, the water value reflects the opportunity cost of selling hydropower currently versus storing water in reservoirs for future use. The water value could also factor in different uses (e.g., agriculture, recreational, electricity generation), but we focus here on the use for electricity. The value of hydropower generation varies by time, along with the water value.

[10] IESO major generation resources include wind, solar, hydropower, biofuel, nuclear, gas, and coal. Based on the categories in this paper, ZFC resources then include wind, solar, hydropower; ZMC resources include wind, solar, and nuclear power; zero-carbon resources include wind, solar, hydropower, biofuel, and nuclear power.

steadily replaced coal generation since 2005. The average fraction of generation from zero-carbon resources has been increased from 85.4% to 95.1% between 2011 and 2020.[11] Figures 4-1 through 4-4 illustrate the relationship between increasing zero-carbon electricity dispatch resources and market prices. Specifically, Figure 4-1 shows that the monthly average Hourly Ontario Electricity Price (HOEP) between 2011 and 2020 has generally decreased as the percentage of dispatch from zero-carbon resources has increased. Moreover, negative prices have occurred more frequently in recent years, as shown in Figure 4-2. However, ancillary service prices (10-minute synchronized operating reserve in Figure 4-3 and 30-minute operating reserve in Figure 4-4) do not show a similar decreasing trend over the same period. Of course, other factors influence price formation for energy and ancillary services and therefore a more comprehensive statistical or modeling analyses is required to draw any firm conclusions regarding correlations or causal relationships. However, this glimpse at historical market outcomes from IESO may offer some insights into what the future holds for other zero-carbon systems and markets.

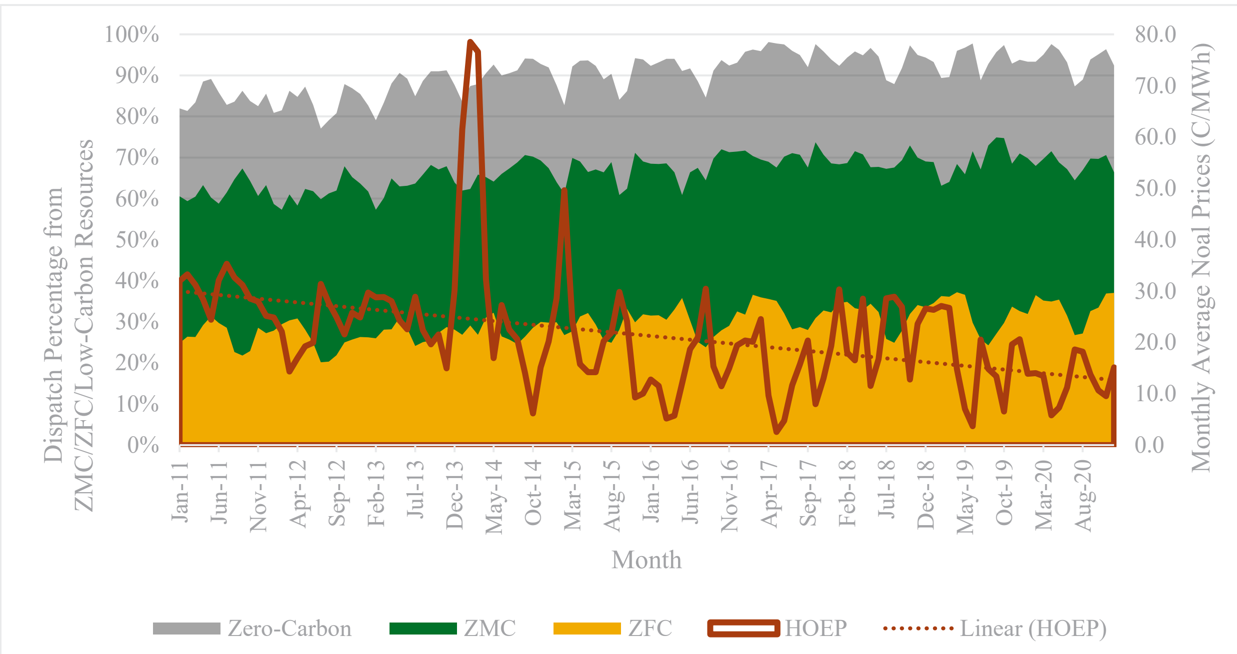

Figure 4-1 IESO Monthly Average HOEP Price Increases as Low-Carbon Resources Dispatch Percentage Increases between 2011 and 2020

11 The average fraction of dispatch from ZFC and ZMC has been increased from 62.7% to 70.2%, and 26.2% to 32.7% between 2011 and 2020, respectively.

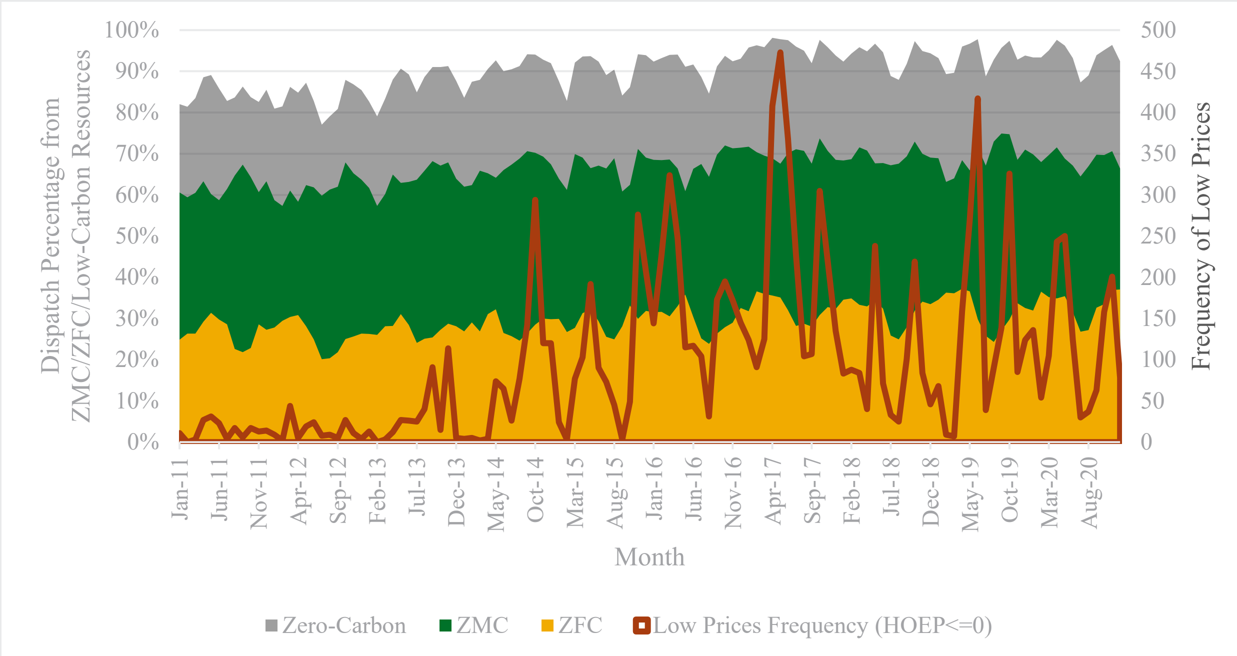

Figure 4-2 More Frequent Periods of Zero or Negative Electricity Prices as Low-Carbon Resources Dispatch Percentage Increases between 2011 and 2020

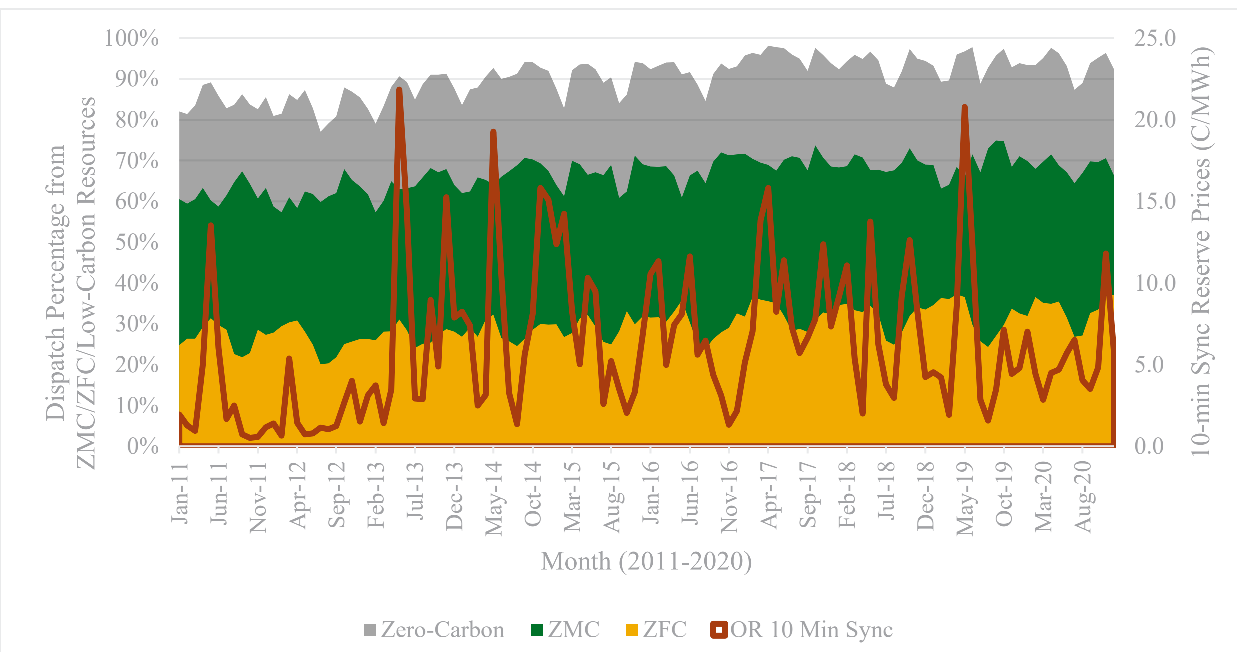

Figure 4-3 No Significant Trend on IESO Monthly Average 10-Minute Sync Reserve Price as Low-Carbon Resources Dispatch Percentage Increases between 2011 and 2020

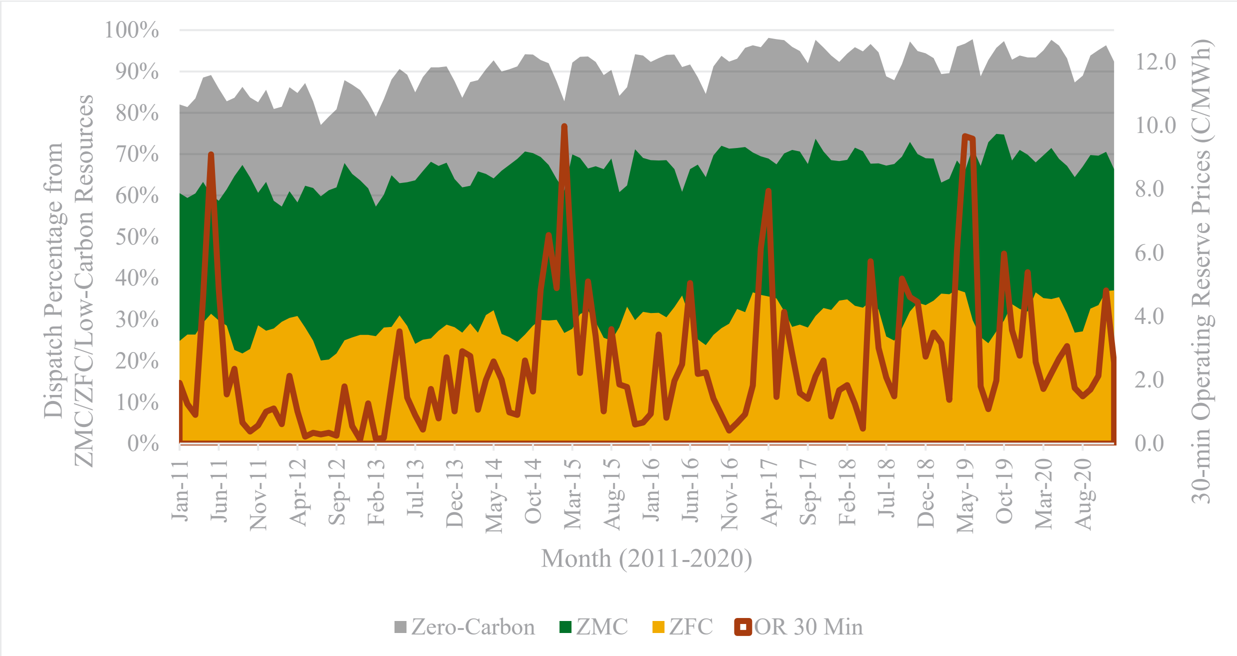

Figure 4-4 No Significant Trend on IESO Monthly Average 30-Minute Reserve Price as Low-Carbon Resources Dispatch Percentage Increases between 2011 and 2020

A number of studies have analyzed interactions between hydropower resources, power system operations, and price formation in other hydro-dominated systems (e.g., Norway and Brazil), largely based on current market designs. For example, Graabak et al. (2017), Machado and Bhagwa (2020), and Zapata et al. (2018) all find that high hydropower generation contributes to lower electricity prices. Graabak et al. (2017) investigate a Norwegian system with 100% renewable energy supply and conclude that as hydropower generation increases, average prices decrease along with the frequency of price spikes. At the same time, the available transmission capacity between hydropower generation and major load centers also impacts prices. Machado and Bhagwa (2020) compare two hypothetical Brazilian systems, generating 70.5% and 51.6% of their generation, respectively, from hydropower. The study finds that the system with more hydropower has a higher incidence of low electricity prices and a lower incidence of high electricity prices compared with the other systems. In addition, Zapata et al. (2018) conduct an analysis based on the Colombian electricity market, showing that including a large hydropower component in a 100% renewable energy system reduces prices and increases energy efficiency relative to a system with less hydropower.

Focusing on cross-border trade between Canada and the United States, Rodríguez-Sarasty et al. (2021) study the possibility of close integration of hydropower resources from Canada (e.g., Ontario and Quebec) with the Northeastern region of the United States. The study shows that there is a significant decrease in operational cost and incremental investment cost in a 100% decarbonization scenario under closer cross-border integration. In addition, increased cross-border integration reduces short-run marginal costs in both NYISO and ISO-NE under a high-decarbonization scenario. The average reduction (compared with the reference case without integration) can be as high as 47.2% for ISO-NE and 52.8% for NYISO. Price volatility and maximum prices are reduced as well.

5.0 Conclusion and Recommendations

5.1 Key Findings

We briefly summarize key findings that emerged from the review and discussion presented in this report, with a particular focus on those relevant to hydropower resources.

- In a zero-carbon system, market prices are expected to be low, but they might not necessarily drop to zero all the time, especially when scarcity pricing mechanisms are in place and the system includes resources with opportunity costs. Although price dynamics driven by opportunity costs have already been observed in some existing markets with significant hydropower resources (e.g., Norway, Brazil, Colombia), it is hard to predict price outcomes in future zero-carbon systems.
- A transition to a zero-carbon power system will involve multiple challenges from a market design perspective, including (1) ensuring resource adequacy under different price dynamics in energy, reserve, and capacity market; (2) market power monitoring and mitigation for resources that base offers on opportunity costs; and (3) addressing non-convexities in pricing and dispatch from emerging resources such as energy storage.
- Many studies in the literature suggest market enhancements to supplement current practices with long-term energy procurement (i.e., contracts, markets) or adjustments to long-term capacity compensation mechanisms to address market challenges in zero-carbon power systems.
- A number of common themes across ongoing market design enhancements are relevant to the transition to a zero-carbon grid, including: (1) replacing fixed operating reserve requirements with demand curves that reflect the economics of system reliability needs; (2) accommodating state policies and incentives, particularly related to their impacts in capacity markets; (3) analyzing the impacts of implementing either carbon pricing or a clean energy procurement mechanism at the ISO/RTO-level; (4) implementing new market products to address changing system needs and contribute to meeting the flexibility requirements of increasingly VRE-dominated systems; (5) developing new methodologies to determine the resource adequacy accreditation of different resources to ensure that these values are reflective of their relative reliability contributions.
- Hydropower is likely to play a critical role in zero-carbon systems as a zero-carbon, dispatchable resource that can support the system flexibility and storage requirements for systems with large shares of VRE. Hydropower is also in a good position to take advantage of new price dynamics because of its flexible operating characteristics.
- Because the value of stored hydropower is dictated by its system opportunity cost, hydropower resources are likely to become more important for price formation in future zero-carbon systems. However, estimating this opportunity cost becomes more challenging as conventional resources with marginal costs are retired.
- Some studies find that hydropower resources, especially PSH and resources with large reservoirs, may be able to exert market power under certain market conditions because of their flexible and dispatchable operating characteristics.

- The market impacts facing hydropower resources in zero-carbon systems may not be generalizable across different markets. These impacts depend on many factors, including the size and type of the hydro resources, the size and structure of the market, market design elements that impact price dynamics (e.g., energy only versus capacity market frameworks), and the participation strategies used by all market participants.
- Studies of market interactions in zero-carbon systems are few and are mostly focused on conceptual discussions with limited quantitative analysis. Within the limited number of quantitative studies, most investigate the tipping points at which current market designs begin to lose their efficiency as zero-carbon resource penetration increases. Therefore, additional quantitative analyses that can help identify hydropower impacts and inform new market design initiatives and enhancements are important.

5.2 Open Research Questions

As discussed in this paper, the existing body of research lacks detailed quantitative investigations of price formation impacts under potential market designs for future zero-carbon systems. Such studies will be important to better address multiple questions regarding zero-carbon electricity market design and price formation. Key research questions include the following:

- To what extent can energy-only markets ensure market efficiency and resource adequacy and provide sufficient incentives for new investment in a zero-carbon system?
- What is the role of a long-term energy market or capacity remuneration mechanism in resource adequacy and risk mitigation for generation asset cost recovery in a zero-carbon system?
- What is the best way to design remuneration mechanisms for resource adequacy in a future zero-carbon system, which may be more constrained by energy than capacity?
- How can effective market power mitigation and monitoring strategies be implemented in electricity markets, especially for resources whose optimal operational strategy depends on its opportunity costs?
- To what extent can hydropower improve its market performance in a zero-carbon system by (1) more accurately representing its opportunity cost, or (2) more efficiently responding to highly polarized price signals (e.g., periods of either very low or very high prices)?
- How can opportunity costs for hydropower be calculated in systems that lack conventional thermal resources with a well-defined marginal cost of generation?
- What are the main value drivers for hydropower resources in a future zero-carbon system? Are these value drivers fundamentally different from those in current power systems or potential future power systems with more moderate penetrations of zero-carbon resources?

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Appendix A: General Concepts and Considerations in Electricity Market Design

Following the deregulation and restructuring of the power industry over the past three decades, wholesale electricity markets have been established in many regions of the United States. There are currently seven distinct regional electricity markets, each operated by an Independent System Operator (ISO) or a Regional Transmission Organization (RTO) (hereafter jointly referred to as an ISO/RTO). Each ISO/RTO manages the transmission infrastructure in its service territory, administers markets for energy and ancillary services, and is responsible for ensuring that system reliability requirements are met. Such requirements are established by the North American Electric Reliability Corporation (NERC). Roughly two-thirds of all energy demand in the United States currently falls in territories served by an ISO/RTO.

A.1 Objectives

A wholesale electricity market matches electricity supply and demand with the objective of maximizing total net surplus, measured as the sum of buyer net surplus, seller net surplus, and ISO/RTO net surplus that manifests as congestion rent (Tesfatsion, 2020). The role of the ISO/RTO is to coordinate and monitor the operation of the wholesale markets and ensure system reliability and generation capacity adequacy in a cost-effective manner. In these electricity markets, market prices serve as critical signals to incentivize efficient system operations, entry of new generation capacity, and retirement of the least-efficient generation units. Market price formation processes are critical to achieving efficient electricity markets and result from many factors, including market structures, products, regulations and policies, and coordination with other systems and markets.

A.2 Market Design and Price Formation Principles

To ensure sufficient supply and accommodate the physical constraints of generation units, electricity markets are structured with *multiple scheduling and settlement processes*. The typical approach in the United States is a so-called “two-settlement market” with a day-ahead forward market and a real-time balancing market for physical delivery. The purpose of the day-ahead market is to commit generation units to ensure that there is sufficient generation capacity available to meet the electricity demand forecasted for the next day; this method corresponds with the day-ahead unit commitment process. The real-time market serves to adjust the scheduled generation from the day-ahead market to meet the updated load forecast in close to real-time (e.g., 5 minutes before the operating time). The two markets generate day-ahead and real-time prices; the latter is used to mitigate deviations from the day-ahead schedule. In either market, generation units are scheduled according to an economic merit order, based on supply offers from different resources. The ISO/RTO collects offers from all suppliers to construct an aggregated supply curve for each time step. The operator also constructs a demand curve on behalf of the electricity customers. The intersection of the aggregated supply and demand curves sets the market clearing price for the time step, as illustrated in Figure 2-1. The marginal cost of the generation unit that supplies the last unit of electricity at each system node is augmented by costs associated with transmission congestion and losses to determine locational marginal prices

(LMPs). LMPs collectively reflect the state of the transmission network at any given point in time. Supply shortages may lead to shortfalls in operating reserves and, ultimately, load curtailment. In these situations, the market operator applies a curtailment penalty to set the price. In principle, this penalty should reflect the value of lost load (VOLL) to consumers, but the actual scarcity prices depend on the rules governing the individual markets and are often capped well below the true social VOLL (Ovaere, 2019). Furthermore, research has indicated that VOLL can vary by an order or magnitude or more depending on the end use and location in the system (Peter, 2019).

Some generators withhold some of their generation capacity to provide operating reserves that help ensure supply sufficiency under grid uncertainties (e.g., forecasting errors for load and variable renewable energy [VRE], as well as generation or transmission outages). Depending on the purposes and corresponding requirements for response time, duration, and speed, reserves can be categorized into four major types: regulation and frequency response, spinning reserve, non-spinning reserve, and flexible ramping reserve (in some markets). Reserves may be acquired through wholesale market clearing processes, and reserve provision is often co-optimized with the electricity dispatch, in principle leading to an efficient market outcome. The reserve requirements are determined by the ISO/RTOs based on reliability standards established by NERC and/or regional coordinating councils, such as the Western Electricity Coordinating Council (WECC). The reserve requirements can be applied for the whole system or to a specific zone to ensure deliverability. A generator that submits bids to supply specific types of reserves can be compensated for both generation and reserve provision in the same period, provided the capacities allocated to each do not overlap. Table A-1 provides a summary of major ancillary service and capacity market products in the seven U.S. wholesale markets.

Table A-1 U.S. ISO/RTO Wholesale Markets Major Products in Addition to Energy (based primarily on CAISO, 2020; Navid, 2013; Byers et al., 2018)

Organization[a]	Ancillary Services				Capacity
	Spinning Reserve	Non-Spinning Reserve	Regulation	Ramping	
CAISO	Spinning	Non-spinning	Regulation-up Regulation-down Regulation mileage-up Regulation mileage-down	Flexible ramp-up Flexible ramp-down	Capacity Obligation
ERCOT	Responsive	Non-spinning	Regulation-up Regulation-down	No	No
ISO-NE	10-minute sync	10-minute non-sync 30-minute operating	Regulation	No	Centralized market/forward capacity auction
MISO	Spinning	Supplemental	Regulation	Ramp-up Ramp-down	Bilateral contract or voluntary centralized market

Organization[a]	Ancillary Services				Capacity
	Spinning Reserve	Non-Spinning Reserve	Regulation	Ramping	
NYISO	10-minute spinning 30-minute spinning	10-minute non-sync 30-minute non-sync	Regulation	No	Centralized market/auction
PJM	Synchronized	Primary	Traditional regulation signal (RegA) Faster regulation signal (RegD)	No	Centralized market/auction
SPP	Spinning	Supplemental	Regulation-up Regulation-down	No	Capacity obligation

[a] CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; ISO-NE = Independent System Operator – New England; PJM = PJM (Pennsylvania, New Jersey, and Maryland) Interconnection); MISO = Midcontinent Independent System Operator; SPP = Southwest Power Pool

In addition to markets for electricity and ancillary services, additional resource adequacy mechanisms have been implemented in most U.S. wholesale markets in response to revenue sufficiency challenges that may result from price caps and the so-called "missing money problem" (i.e., revenues obtained from energy and reserve markets are insufficient to cover operating and investment costs) (Joskow, 2008). These resource adequacy mechanisms take the form of mandatory capacity markets (PJM, NYISO, ISO-NE), voluntary capacity markets (MISO), or capacity obligations (CAISO, SPP). In the United States, ERCOT is the only ISO/RTO that does not have a distinct resource adequacy mechanism and therefore relies on price signals generated under a so-called "energy-only" market framework to support long-term resource adequacy.

A capacity market essentially compensates a resource system operator for promising to generate electricity when called upon to do so throughout the specified performance period. Like the energy market, the capacity market is also an auction-based mechanism that matches supply and demand curves to determine a clearing price. The planning horizon, auction setup, and frequency vary between markets, with planning horizons ranging from months to years ahead (Byers et al., 2018). The demand curve for capacity is determined by the ISO/RTO, and each market has a different demand curve (Byers et al., 2018). As illustrated in Figure A-1, the most critical parameter of the demand curve is called the net cost of new entry (netCONE), which is an estimate by a system operator of the capacity revenue needed by a new generator of a specific technology (e.g., gas turbine) to recover its capital and fixed costs. In addition to netCONE, a system-wide unforced capacity[12] target is used to define a demand curve (Byers et al., 2018). Figure A-1 illustrates a set of representative capacity demand curves based on examples from three U.S. ISO/RTO markets. The system supply curves for capacity are based on offers from individual units. All resources are allocated capacity credits that determine the fraction of their installed capacity that is eligible for compensation through each capacity market; the methods

[12] Unforced capacity is installed capacity that is adjusted to account for forced outages or forced de-ratings.

used to determine these credits for VRE (hydro and energy storage in particular) can vary between markets. Resources that clear the capacity market receive compensation that is independent from any additional revenues operators may receive for providing generation or ancillary services throughout the year, provided that they meet performance obligations and satisfy must-offer rules, which differ depending on the market and resource type.

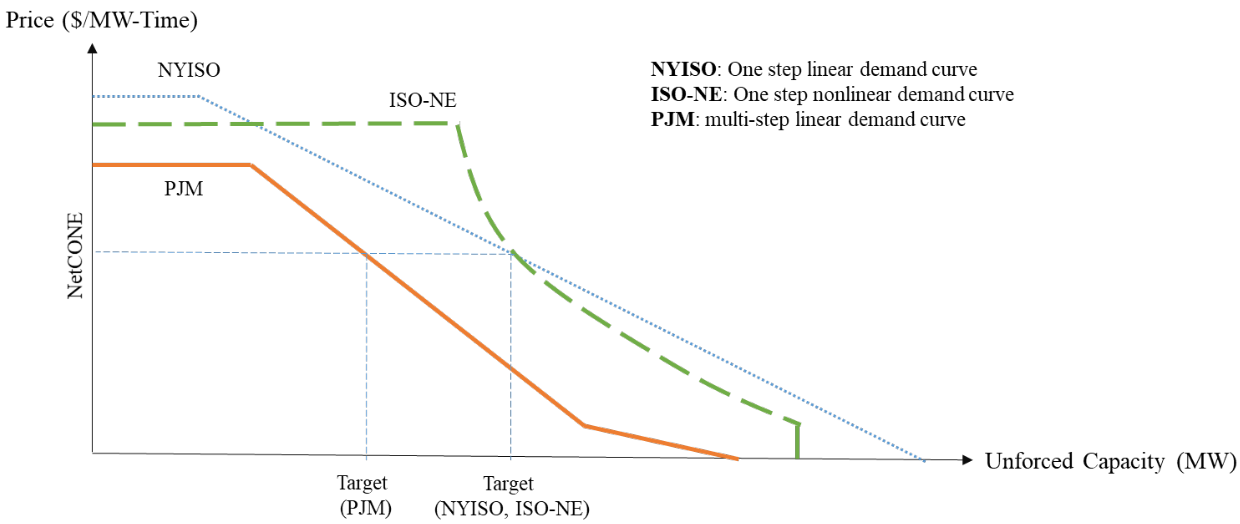

Figure A-1 Capacity Market Demand Curves in Three U.S. Electricity Markets (ISO-NE, NYISO, and PJM) (Source: Byers et al., 2018)

Some markets use other mechanisms to ensure resource adequacy in the long run. For instance, the CAISO market has a capacity obligation mechanism with capacity payments that are not part of a centralized capacity market. ERCOT is an energy-only market that relies on the prices in short-term energy and reserve markets to provide incentives for investment and resource adequacy. Short-term markets are also supplemented by voluntary long-term markets, where market participants can hedge their risks (e.g., through forward and option contracts, as well as power purchasing agreements). Moreover, there are several other relevant market mechanisms that also impact the revenues and profitability of market participants, including incentives to reduce carbon emissions (e.g., carbon markets or taxes) and support schemes for clean energy (e.g., production and investment tax credits for VRE). Electricity markets also interact closely with other parts of the energy system (e.g., the natural gas network that supplies fuel to gas-fired generation in the power system). The integration among different energy carriers is expected to grow in importance with the ongoing efforts toward end-use electrification and the transition toward cleaner energy system solutions where electricity plays a more dominant role.

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