# Capacity Markets in the U.S. Electric Industry, the Effects of Deregulation and the Push to Renewables

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**Abstract**

In response to the effects of deregulation and the emergence of renewable energy sources, capacity markets have emerged as a construct to ensure system reliability and adequate generation capacity. The capacity market is a market-wide and price-based approach to capacity remuneration mechanisms, in which a central regulator sets the price at which to procure generation capacity through a capacity auction. Price caps in the energy-only market prevent the sufficiency of scarcity pricing during blackouts to generate sufficient revenues to provide for investment of plant assets. In analyzing worldwide fuel diversity, we see that coal is the predominant energy source used worldwide in 2022. The U.S. has already begun the process to move away from coal, and sees natural gas as the primary energy source of its energy zones. Wind power has made more progress than solar power in the United States, and worldwide. Maybe China is correct that utilizing coal as a cheaper fossil fuel energy source than natural gas is a smarter idea than transitioning so quickly to clean energy and cleaner burning gas.

Keywords: capacity markets, electricity markets, deregulation, renewable energy sources

## I. Introduction

A major question to ask in the advent of electricity market deregulation is whether the restructured electricity markets sufficiently incentivize investments in new generating capacity, or if capacity remuneration mechanisms such as capacity markets are necessary to ensure adequate investment of plant generation, fixed assets, and sunk costs. Since deregulation, or liberalization, the US electric grid has seen the emergence of Independent System Operators (ISO) and Regional Transmission Operators (RTO). Some of the US has maintained a traditional regulated electric industry with generation, transmission, and distribution of electricity being controlled by one electric utility, while some areas have transitioned to ISOs and RTOs where a central authority regulates prices. Further, some of the ISOs have created capacity markets to ensure resource adequacy, while some have continued to rely just on the energy-only market. Thus, it can be stated that the capacity market construct is a creation of deregulation.

The push to renewables in the electric industry has created upheaval in the markets and for prices of electricity. Renewables such as wind and solar have zero marginal cost, or fuel cost, so they tend to bring down spot prices in the energy-only market. Electric utilities must therefore find a way to effectively price renewables into the spot market. The futures market is typically used for risk hedging. Voluntary Renewable Energy Certificates (REC) prices in the U.S.

increased from $0.31/MWh in August 2017 to $0.70/MWh in August 2018.[1] Renewable energy purchases can either be voluntary or mandatory. Some states have mandatory requirements for percentage of energy used, and also impose penalties if the quotas are not met. In the energy only market, the merit order effect describes the lowering of power prices at the electricity exchange due to an increased supply of renewable energies. In capacity markets, renewables share contributes to the missing money problem of investment in fixed assets for power plants.

Liberalized electricity markets have been questioned due to reliability concerns resulting from increasing energy demands, the decommissioning of conventional power plants, and the steady growth of renewable energy sources (RES) (Gailani et al., 2020). It is thus a relevant question to ask whether capacity markets can help to distribute revenue in the face of the increased use of renewable energy sources. Two RES characteristics pose problems to traditional electricity market design: low marginal costs and intermittency. In an energy-only market with marginal cost bidding, renewables push into the merit order from the left and consequently price high marginal cost conventionals out of the market. This includes peak-load generation, such as gas-fired generation, which suffers from running fewer load hours leading to decreasing profitability. Considering the intermittent nature of RES, since there are neither grid-scale storage technologies nor large-scale demand response programs available, the same amount of conventional generation capacity is needed as without the RES feed-in to still ensure generation adequacy, even though RES provide a significant share of energy to the market (Hach and Spinler, 2018).

The emergence of renewable energy sources has been accelerated by the development of capacity markets. Many of the new generators providing capacity market services use lithium-ion batteries (LIBs) to store the energy due to their high energy density and long life cycle (Lee et al., 2019). In fact, batteries can enhance new generators by providing capacity services ranging from 40% to 100% of their nameplate capacity, thus reducing the number of shortage events in the capacity market (Sioshansi et al.,2014). Stafell and Rustomji (2016) find that the revenue from energy storage devices can be tripled if LIBs are utilized to provide energy reserve services in the electricity markets. Teng and Strbac (2016) find that batteries participating in the capacity market can secure substantial upfront revenue, while only marginally reducing profits from other markets.

In Europe, they have transmission system operators (TSO) and distribution system operators (DSO). In the United States, they have independent system operators (ISO) and regional transmission operators (RTO). The ISO and RTO are effectively the same thing in the United States. The TSO and DSO are different functions in Europe. TSOs utilize system-wide flexibility services in order to follow load and/or generation variations close to real-time to maintain the system frequency within a permissible level (Khajeh et al., 2019). DSOs, conversely, utilize local flexibility services to fulfill their responsibilities. DSOs can purchase flexible energy resources connected to these networks to regulate voltage and manage congestion (Khajeh et al., 2019).

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[1] US EPA, U.S. Renewable Electricity Market, Retrieved July 19, 2023. https://www.epa.gov/green-power-markets/us-renewable-electricity-market

**Failures of Current Electricity Market Design (Komorowska, 2021)**

1) Electricity supply and demand, can't store electricity without batteries
2) Low short-run price elasticity of demand, consumers can't respond to hourly fluctuations in price in real-time
3) Lower operating costs for renewable energy generators, resulting in lack of capacity payments to conventional generators for new investment
4) Price caps during periods of peak demand, which restricts market signals during these periods which could result in better capacity payments without price caps

In the United States, the Federal Energy Regulatory Commission (FERC) approves and regulates capacity markets by independent system operators and regional transmission operators in the restructured competitive markets that serve 70% of electricity customers in the U.S. California, Texas, and New York are restructured competitive markets. The ISO includes the RTO. About half of the United States is still traditional regulated markets, where the electric utility controls the generation, transmission, and distribution of electricity. In the United States, there are three interconnections for the electric grid. The Eastern Interconnection comprises the area from the Great Plains states eastward to the Atlantic coast. The Western Interconnection comprises the area west of the Great Plains to the Pacific coast. The Electric Reliability Council of Texas (ERCOT) covers most of the state of Texas. Seven RTOs operate across the United States: the California Independent System Operator (CAISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent ISO, PJM Interconnection, New York ISO (NYISO), and ISO New England (ISO-NE). These RTOs cover part or all of 38 states and the District of Columbia.

Capacity markets are a form of an economical construct known as a reserve market which are used in the electricity industry to ensure resource adequacy of power plant generation. In the world of increasing electricity demand and increased use of renewable energy sources, ensuring adequate reserves of generation capacity is a critical need. An issue which rises to the forefront however is that of whether capacity markets and the capacity auctions which they entail are truly the best economic construct to achieve resource adequacy, as challenges arise with their complexity and high cost relative to benefit (Rusco, 2017). The four RTOs with capacity markets which FERC has approved to maintain resource adequacy are: ISO New England, Midcontinent ISO, New York ISO, and PJM. The three RTOs without capacity markets are: California ISO, Southwest Power Pool, and Texas ERCOT. The two regions that are still regulated markets for electricity are the West and the Southeast.

The evolution of these U.S. capacity markets includes the creation of separate markets for flexible capacity, geographical definition of market sub-regions, and modifications to market clearing mechanisms (such as use of demand curves). CAISO imposes a resource adequacy requirement on load serving entities, but has not created a centrally coordinated market to facilitate efficient trading of resources to meet that requirement (Bhagwat et al., 2016).

The Federal Energy Regulatory Commission (FERC) is responsible for overseeing Regional Transmission Organizations' (RTOs) development and operation of capacity markets. Only an

RTO has the organizational means to create a capacity market, which is a conglomeration of financial contracts from different regions and operators. Thus, a capacity market is wholly an RTO creation, as a regulated utility has neither the means nor the need to create a capacity market. It does not have the means because it is not a grid operator for several different regions and zones, and it does not have the need because its regulated rates already provide a return to ensure resource adequacy and generator capacity reserves.

Issues plaguing capacity market design in the United States include: the role of demand response, whether locational constraints should be imposed, how far forward such markets should be run, and whether separate markets should be created for flexible capacity to back up intermittent renewables (Bhagwat et al., 2016). Another issue that arises with capacity markets, as seen in the European Union, is seams issues (US) or cross-border effects (EU). Cross-border effects means that inefficiencies might arise when wholesale electricity markets with different capacity markets are interconnected or when regions with capacity markets are interconnected with energy-only markets, which could lead to sub-optimal performance of the capacity markets and spillover of benefits or costs to neighboring markets (Bhagwat et al., 2016).

**<u>RTOs Facilitate Integration of New Technologies and Market Participants</u>**

-Yoo and Blumsack (2018)

1) Renewable power generation
2) Energy storage
3) Demand response

**<u>II. Capacity Remuneration Mechanisms (CRMs)</u>**

The goal of capacity remuneration mechanisms is to increase the level of security of supply in the system and to ensure that there is sufficient generation capacity to meet a certain reliability standard. In a CRM scheme, the operators of capacity resources receive financial compensations for keeping their generation units available. Certified capacity is the capacity to be available during crucial hours, and is determined by calculating the de-rating factors, which differ within different capacity mechanisms (Pugl-Pichler et al., 2020). CRMs provide an incentive for new entrants to locate in regions where there is a need for additional resources (Miller et al., 2012). CRMs help to maintain existing capacity or invest in new installations, and address generation capacity and flexibility adequacy concerns (Leiren et al., 2019).

**Image 1. Capacity Remuneration Mechanisms**

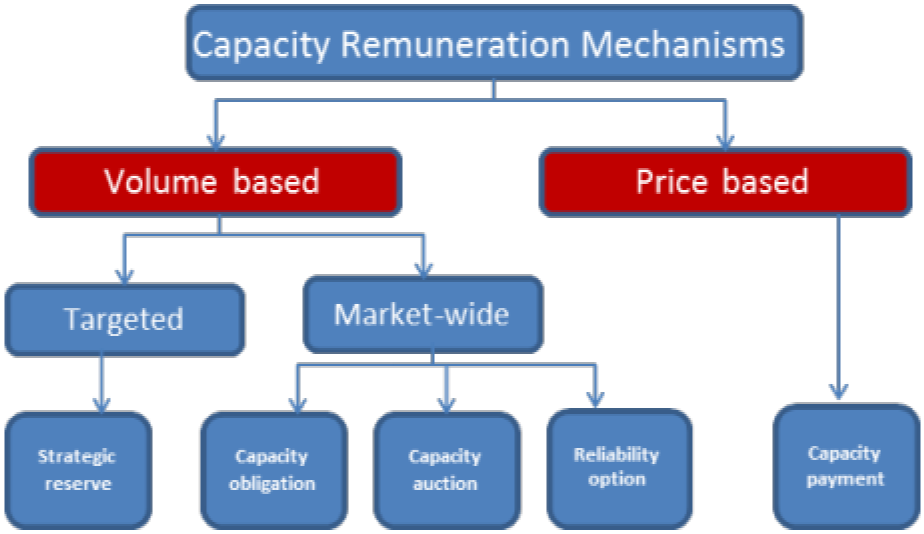


Image 1: Taxonomy of CRMs, Published in 2017, THE AGENCY FOR THE COOPERATION OF ENERGY REGULATORS reports on: CAPACITY REMUNERATION MECHANISMS AND THE INTERNAL MARKET FOR ELECTRICITY.

There are two essential categories of CRMs: (1) price-based capacity mechanisms: capacity payments and (2) volume-based capacity mechanisms: strategic reserve, reliability options, capacity obligations, and capacity auctions. Targeted capacity remuneration mechanisms address only a part of the market, whereas market-wide approaches target the entire market. Price-based capacity mechanisms utilize capacity payments set by the regulator, and set the price first before determining volume. The set capacity remuneration should not exceed the Value of Lost Load (VoLL) reduced by the revenues from the energy market. VoLL is the willingness of consumers to pay to avoid a supply disruption (Cramton et al., 2013). Volume-based capacity mechanisms involve the regulator stipulating the required capacity, or volume first, then setting the price of this capacity through auctions or contracts. The last bid accepted to cover the required capacity then becomes the capacity price paid to all generators.

**CRMs**

(1) tender for new capacity; (2) strategic reserve; (3) reliability options; (4) targeted capacity payment; (5) market-wide capacity payment; (6) central buyer; (7) de-central obligation.

A tender for new capacity is a targeted mechanism and volume-based approach. In a tender, financial support is granted to capacity providers in order to ensure the required additional capacity. The tender could be for either financing the construction of new capacity or long-term power purchase agreements.

Strategic reserves are targeted and quantity-based mechanisms. In a strategic reserve system, a capacity reserve is formed outside the energy markets and is only activated if the supply on the wholesale market is not able to meet the demand, or if no market clearing takes place (Pugl-Pichler et al., 2020). Strategic reserves is a construct consisting of generators with high operating costs and/or demand-side resources that are contracted by the TSO or RTO and are dispatched when the market does not provide sufficient generation capacity (Bhagwat et al., 2016). In a strategic reserve system, control of some power stations is transferred to the transmission system operator TSO or RTO, and the RTO dispatches the strategic reserve at a price above the variable costs of the generation units in the event there is not enough available generation capacity, which causes the average electricity price to increase and thus stimulate investment in generation capacity. Strategic reserves may be dispatched in case of shortage of supply in the spot market or a price settlement above a certain electricity price (Söder et al., 2020).

When discussing the value of strategic reserves versus capacity markets, Lambin and Léautier (2019) find that the direct, upfront cost of capacity support is greater when the security of supply (SoS) standards are met with capacity markets instead of a strategic reserve, although the energy prices are (weakly) higher with a strategic reserve. Therefore, the higher upfront cost of implementing support through a capacity market, relative to a strategic reserve, is offset through smaller electricity bills. Strategic reserve is similar to central capacity markets, because the procurement and compensation of capacities is done via a central body. However, strategic reserve only comes into play in emergency situations, and these installations are not entitled to participate in the energy-only market or the balancing energy market (Monjoie, 2021).

Reliability options are a market-wide and volume based approach to CRMs. In a reliability option scheme, physical capacity is bundled with a financial option to supply energy at spot prices above a strike price, with the market pricing capacity from the bids of competitive new entry in an auction. Two major advantages of reliability options are that the capacity payment (a) hedges load from high spot prices and (b) reduces supplier risk by replacing peak energy rents (the rents derived from selling energy at high spot prices during periods of scarcity) with a constant capacity payment (Cramton et al., 2013).

Administrative capacity payments for specific plants represent a targeted and price-based mechanism, where a central authority determines the price of the capacity. Usually, only a group of market participants, such as operators of a certain generation technology, such as flexible peak load power plants, receive capacity payments (Pugl-Pichler et al., 2020). Market-based capacity payments constitute a market-wide and price-based scheme, whereby all generators and demand response providers receive a predetermined price, which is set by a central regulator.

The centralized capacity market is a market-wide and volume based approach, where all market participants, except those already receiving state aid, are allowed to participate in the capacity market with their guaranteed capacity. The required volume is determined in advance by the operator (TSO or RTO) of the capacity market and the price is determined by the market (the clearing price in capacity auctions). Decentralized capacity obligations also represent a market-wide and volume-based approach. In contrast to the single buyer model, however, there is no centralized bidding process to determine the compensation for generators. Instead, suppliers are obliged to contract sufficient capacity to securely meet the consumption of their customers (Pugl-Pichler et al., 2020).

Capacity markets can be either centrally regulated by the government or demand-driven (decentralized). In centrally regulated models, there can be either comprehensive capacity markets where all electricity generators can participate, or targeted capacity markets where only those institutions that fulfill certain criteria can participate. In a demand-driven capacity market, balance group managers determine the pricing of capacity, which is wholly determined by the demand side. The demand-driven model must be both the creation of products such as the “provision of reliable capacity” and “backup capacity” and also of sufficient demand for capacity products.  In a centralized design the fundamental question is how the cost is allocated to final consumers. In a decentralized design, the fundamental question is how retailers value a marginal capacity. In a decentralized demand model, retailers must buy the capacities directly in the capacity market to cover their sales, with the penalty system used to enforce the obligation (Monjoie, 2021).

A capacity market is a type of capacity remuneration mechanism. Capacity markets improve the resource adequacy of the system by maintaining sufficient reserve margins, which are calculated from the loss of load expectation (LOLE) requirement of the ISO. LOLE is the expected number of hours during which resources are insufficient to meet the demand needs in a given zone during a given time period. One argument for capacity markets is that because only the supply side and not the demand side actively participate in the electricity market, there will always be imperfections such as exercise of market power or regulatory interventions in an energy-only market (Cramton and Stoft, 2005). A second argument is that an increasing share of RES feed-in exacerbates the adequacy problem because RES provide price-inelastic supply due to the low marginal costs, thereby intensifying fluctuations in prices and demand for conventional generation. The attractiveness of conventional generation investments decreases with rising RES feed-in due to decreasing load factors (Cramton et al., 2013).

In a capacity market, the regulator determines the required capacity and the market establishes the price through an auction. Capacity markets have gained increased prominence over strategic reserves and capacity payments. All capacity markets include capacity payments as remuneration, though not all capacity payment mechanisms are capacity markets. The capacity payment construct can be defined as separate from the capacity market construct. One major difference in capacity markets is the timing of when they procure capacity. Some obtain commitments from plant owners 3 years before electricity is needed (ISO New England and PJM Interconnection), while some obtain commitments closer to when electricity is needed (NYISO and Midcontinent ISO). Level of resource adequacy refers to the availability of adequate power plants and other resources to meet customers’ electricity needs. Reasons for the need of a capacity market for electricity include: fixed costs, uncertainty, technical constraints, political intervention, and unpriced externalities.

The PJM and NYISO use a demand curve capacity auction, where an administratively set demand curve is established. The demand curve establishes the price that load serving entities (LSE) will pay for various quantities of capacity, with the price of capacity increasing as the demand for such capacity increases. The final price that LSEs pay in this type of auction, the clearing price, is based on the price of capacity on the demand curve line that is equal to the amount of capacity offered for sale in the auction (Miller et al., 2012). Buyer-side mitigation refers to offer floors that have been put in place by the FERC to deter large net buyers and local governments from subsidizing new entry and artificially depressing capacity market prices (Miller et al., 2012). There is little empirical evidence that capacity markets result in lower electricity costs for consumers, such as by expanding the number of available generators (Drom, 2014).

Buyer-side market power mitigation has been implemented by FERC to improve capacity markets' long-term performance by meeting load-serving entities' needs for diverse resource portfolios, enabling states' efforts to pursue policy goals, satisfying generators' need for stable revenues, and ensuring resource adequacy (Morrison, 2016). However, the author continues that buyer-side mitigation cannot serve the FERC's goals because the centralized capacity constructs to which they have been appended are inherently incapable of doing all that the FERC asks of them. Thus, centralized capacity constructs must include bilateral capacity markets and LSEs' self-build options.

In terms of improving capacity markets, RTOs have periodically changed the boundaries of capacity zones in their regions to better reflect transmission constraints. The auction's underlying design can also be changed, for example, in 2014 and 2015, ISO New England and PJM separately received approval from FERC to modify their capacity markets to better ensure that power plants with capacity commitments were available to generate electricity when they agreed to be. Reasons for differences in capacity auction prices include: differences in the availability and type of resources across regions, differences in regional energy market and fuel prices, and differences in overall market design (US GAO, 2017).

**Interaction of Inaccurate Capacity Credits**

A) Energy Price Caps
B) Renewable Portfolio Standards
C) Renewable Energy Tax Credits

1) Generation Mixes
2) Efficiency Losses
3) Distortions among Competing Wind and Solar Developments

Energy price caps can create inaccurate capacity credits because price caps distort the true cost of electricity, and thus could result in lower capacity credits that divert resources away from the energy generation source and create a missing money in investment problem. Renewable Portfolio Standards (RPS) require that a specified percentage of the electricity utilities sell comes from renewable resources. Renewable energy tax credits are a variety of indirect federal subsidies to finance the investment and production of renewable energy. The generation mix is the combination of thermal and renewable generators, while efficiency losses result from using thermal over renewable sources. Efficiency losses in electricity generation result from burning fuel to generate electricity, which creates waste heat that siphons off most of the energy. In fact, for thermal generation like coal, natural gas, and nuclear, by the time electricity reaches your outlet, around two-thirds of the original energy has been lost in the process. Renewables like wind, solar, and hydroelectricity don't need to convert heat into motion, so they don't lose energy.

Defining capacity credits for resources that may be limited, such as renewables, can be difficult, though capacity factors for solar are typically 15-25% 25-35% for wind, and 100% for thermal generators. Too much capacity credit for a particular resource is an implicit subsidy that may lead to overinvestment, while too little credit could divert investment away from a resource. Inaccurate capacity credits can subsidize or penalize different resources, and consequently distort investment between renewables and non-renewables, and also among different types and locations of renewables (Bothwell and Hobbs, 2017). Capacity credit is only used when calculating endogenous capacity additions. The capacity value is defined as the fraction of the rated capacity considered firm for the purposes of calculating the module reserve margin. For thermal power plants the value is normally 100%. Lower values can be used for intermittent and hydro renewable power plants reflecting their lower average availability. Some plants assumed to have no firm capacity can even have zero values (for example imported electricity may sometimes have no firm capacity).[2]

**Affect Capacity Auctions**

1) Increasing share of renewable energy
2) Varying carbon emission costs
3) Existing capacity mix

The increasing share of renewable energy is affecting capacity auctions for capacity markets because they are $0 bids, which exacerbates the issue of long-term investment for generators. These $0 bids drive down prices, which results in less money available for investment, or missing money. Varying carbon emission costs are affected by carbon emissions caps set by the government, and result in higher prices at auction.

**Four Functions of Capacity Markets**

1) Provide capacity payments as reservation payments to ensure that a generator will be able to provide energy over a specified period of time, to meet peak load plus a reserve margin
2) Missing money from capacity market, capacity revenues can provide generators with the missing money when they do not receive enough money to cover fixed and variable costs from selling energy and ancillary services; aggravated by the introduction of renewable energy generators

[2] Leap Help, retrieved May 7, 2023, https://leap.sei.org/help/Transformation/Capacity_Value.htm

3) Capacity payments provide an incentive for new entrants to locate in regions where there is a need for additional resources
4) Price signals to build new power plants or reduce demand

**Functions of Capacity Markets**

1) Maintain reliability
2) Encourage the economic development of new capacity resources
3) Moderate electricity price swings

A) Meet peak load demand
B) Provide adequate reserve margins

**Capacity Market Design Issues**

1) The role of demand response
2) Whether locational constraints should be imposed
3) How far forward such markets should be run
4) Whether separate markets should be created for flexible capacity to back up intermittent renewables

**Ways to Improve Capacity Reserves**

1) Energy storage
2) Improving market design
3) Enhancing system operation

There are three ways to improve capacity reserves: energy storage, improving market design, and enhancing system operation. Energy storage can be facilitated through the use of renewable resources and batteries to store their power, like wind and solar. Market design can be improved by focusing on demand side and supply side characteristics. The demand side in the PJM is characterized by energy efficiency resources and demand resources. Energy efficiency (EE) resources are load resources that are offered in an RPM auction as capacity and receive the relevant resource clearing price. EE resources are designed to achieve a continuous reduction in electric energy consumption during peak periods. Demand resources (DRs) are interruptible load resources that are offered in an RPM auction as capacity and receive the relevant clearing price.[3] The NYISO breaks down the supply side of capacity markets into three categories, installed capacity suppliers (ICAP Suppliers), capacity suppliers with duration limitations, and other capacity suppliers. Other capacity suppliers, which remain at a 4 hour duration requirement for participation in the Capacity Market, and performance-based generators (Wind, Solar, RoR Hydro), which will continue to be Installed Capacity Suppliers if qualified.[4] System operation can be enhanced with new and improved electrical capacity generating resources, often financed via capacity payments. Electric suppliers must upgrade the

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[3] Bowring, J. (2013) The Evolution of the PJM Capacity Market, *Evolution of Global Electricity Markets*
[4] Lavillotti, M. and Smith, Z. (2019). DER Energy & Capacity Market Design, https://www.nyiso.com/documents/20142/6128534/04%20DER%20Market%20Design%20Presentation.pdf/f457a835-9a6c-5281-fa1f-35683282f5df

electric grid periodically, and more importantly must find the financial resources to fund these improvements over time.

**Goals of Capacity Markets**

1) Remunerate new electrical generators
2) Reduce investment risks
3) Avoid electricity blackouts

Capacity markets have three primary goals: remunerate new electrical generators, reduce investment risks, and avoid electricity blackouts. They remunerate new electrical generators by ensuring a capacity payment to ensure new investment in plant assets for the future. This serves to reduce investment risks, because the electric utility is getting an external payment for its investments, instead of having to rely on internally generated funds. Avoiding electricity blackouts is another function of capacity markets, in that the capacity market determines how much power is needed and where it should be located in order to prevent widespread power outages when demand for electricity is high. Formulas are developed to predict a region's peak total energy usage for the year, plus a cushion. The cushion is usually provided by expensive, fossil-fueled power plants, and thus electric customers often end up paying too much for dirty power they don't need when the cushion is inflated. A 2020 Sierra Club study found consumers are paying $4.4 billion in over-procurement costs to keep 77 gas and coal plants online in PJM territory.[5]

**Design Elements of a Capacity Remuneration Mechanism**

-Ilak et al. (2021)

1) Market orientation
2) Insurance of long-term power system adequacy
3) Optimal cross-border generation capacity utilization

The objective of a capacity remuneration mechanism is to propose a financially fair pricing mechanism that will guarantee enough new capacity and not present state aid (Ilak et al., 2021). Generation adequacy means ensuring that in the medium and long term the power system can supply the aggregate electricity demand at all times while accounting for scheduled and reasonably expected unscheduled outages of power system elements (Llak et al., 2021).

**Ilak et al. (2021) Design Elements**

1) Security of supply
2) Different amounts of newly installed firm capacity
3) Different short-run marginal costs of newly installed firm capacity
4) Different capacity factors of newly installed firm capacity

A) Electricity prices
B) Electricity load

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[5]Citizens Utility Board. (2022). CUB explainer: What are Capacity Markets? https://www.citizensutilityboard.org/blog/2022/07/22/cub-explainer-what-are-capacity-markets/

Capacity factor is the measure of how often a power plant runs for a specific period of time. It's expressed as a percentage and calculated by dividing the actual unit electricity output by the maximum possible output. This ratio is important because it indicates how fully a unit's capacity is used. Capacity factor is the actual generation in a period divided by the maximum potential if the generator was producing at its installed capacity during the entire period.

**Regulatory Designs**

-Le Coq et al. (2017)

1) A baseline price cap system that restricts scarcity rents
2) A price spike regime that effectively lifts these restrictions
3) A capacity market that directly rewards the provision of capacity

A) Market design
B) Capacity provision
C) Pricing in electricity markets.

Le Coq et al. (2017) defines three available regulatory designs for an electricity market to price its electricity. One, a baseline price cap system that restricts scarcity rents. Scarcity rents represent the market mechanism needed to signal resource shortages and provide incentives for new investment in resources. Two, a price spike regime that effectively lifts these restrictions, which allows for higher prices to provide for investment funds. Three, a capacity market that directly rewards the provision of capacity.

**Calculations Taken into Account in Reserve Margins**

1) Normal maintenance problems
2) Extreme acts of nature (hurricanes and ice storms)
3) Unanticipated losses of fuel (delivery limitations)
4) Any variable that may prevent generation assets from being fully available during peak demand periods

The reserve margin is the amount of unused available capability of an electric power system, at peak load for a utility system, as a percentage of total capability. Normal maintenance problems affect reserve margins because when the system is down for maintenance, there has to be sufficient reserve capacity to meet demand until the generator is fixed.

Lambin and Léautier (2019) find that capacity markets may spread due to their negative cross-border effect on investment incentives. They find that a capacity market is ineffective unless transmission capacity is small, if TSOs and RTOs can’t reduce export capacity and neighbors stay energy-only. Further, If TSOs and RTOs can reduce export capacity, the capacity market attracts investments and security of supply (SoS) of non-domestic markets shrink. Thus, a neighboring energy-only or strategic reserve market will be influenced in the long-run and may have to implement a capacity market as well in order to meet its SoS standard. Capacity markets often aim at capacity levels of around 115% of peak load (Le Coq et al., 2017).

## III. Economics of Electricity

There are two markets for electricity. The wholesale energy-only market where electricity is sold on the spot, intraday, and future markets; and the capacity market, where capacity auctions are the balancing market which ensures short-run security of supply. Investment decisions using the energy-only market are plagued by long lead times for generation investments and the absence of demand response prevents reaching a situation of market equilibrium. Electricity as a consumer good has high requirements for security of supply since power interruptions can be extremely costly. This need can be considered in the context of the value of lost load (VoLL) which expresses a consumer's willingness to pay for an uninterrupted supply of electricity (Pugl-Pichler et al., 2020). Energy security and the security of electricity supply can be framed in different ways: fuel adequacy, generation capacity adequacy, balancing and flexibility, as well as network adequacy–all with the ultimate goal of uninterrupted, resilient supply at lowest possible cost (Cherp and Jewell, 2014). Resource adequacy in electricity markets can emphasize supply-side elements (generation infrastructure), transmission (interconnectors) as well as demand-side responses and energy efficiency (Leiren et al., 2019).

Market prices in the energy-only market must be high enough to finance the operational and fixed costs by stimulating adequate investment on the supply side. Bublitz et al. (2019) state several market-related and physical barriers to generation adequacy in the energy-only market. Market-related barriers in the energy-only market include: price caps, the inelasticity of demand for electricity, and supply side balancing of the electricity market. Physical barriers to generation adequacy include: balancing of consumption and generation, battery storage, the free-rider problem and reliability contracts, and spot market clearing process and fulfillment for short-term trading. Recent developments affecting generation adequacy in the energy-only market include the rise of renewables and the merit order effect and missing money problem, and the phase out of specific fuel types and technologies, like coal and nuclear.

The energy-only market is sufficient to meet generation adequacy demands if three economic conditions are met: (1) the market is perfectly competitive, (2) market participants have rational expectations and (3) follow a risk-neutral strategy (Cepeda and Finon, 2011). However, all three of these assumptions do not hold, as power markets are usually oligopolies (Schwenen, 2014). Further, investors may not have rational expectations, which leads to investment cycles of over- or under-investment (Ford, 2002). Also, investors are typically risk-averse, building less capacity than risk-neutral investors would (Neuhoff and de Vries, 2004).

The energy-only market neglects the energy adequacy problem, because it assumes that the energy demand and supply are always balanced. Thus, when the supply side becomes scarce, there must be a load reduction from the demand side to ensure market clearance. However, due to the inelastic nature of the demand side and rational customer responses, electricity markets do not guarantee a demand response or market clearance (Gailani et al., 2020). Additionally, despite the scarce capacity and the peak demand, generators do not earn money in blackout events. Pugl-Pichler et al., (2020) notes the energy policy objective triangle of affordability, sustainability and security of supply, which is espoused in the European Union, to provide customers with a secure, clean, and affordable supply of electricity.

The RTO may perform an adequacy assessment to evaluate capacity reserves and system reliability, and can be performed for different time horizons (week-ahead, seasonal, mid-term, years-ahead), scenarios (for example normal conditions, or rare extreme weather conditions, different forecasts of load growth, political agendas)), approaches (hourly, stochastic, probabilistic) (Söder et al., 2020). Reliability standards include the Loss of Load Probability (LOLP) (0.1) or the Loss of Load Expectation (LOLE) (1 day in 10 years). Energy-related reliability metrics include the Expected Energy Not Served (EENS), which captures the severity of the outages in terms of the energy that is shed. Time-dependent reliability metrics include the Loss of Load Frequency (LOLF) and the Loss of Load Duration (LOLD) which capture the expected frequency and duration of outage events. A "loss of load event" is defined as: "an event where the system requires import (if available) from outside the area/country in question to serve the demand".

A cost-benefit analysis, based on Value of Lost Load (VoLL), can be applied to derive some of the reliability standards based on observations of the decreasing marginal value of adding more capacity beyond a certain level of reliability. Value of Lost Load (VoLL) is a parameter that represents the customer damage from an outage event with a direct monetary value. VoLL, however, is hard to estimate, because it is likely to vary from customer to customer, and it is highly dependent on the timing, the frequency and duration of an outage (Söder et al., 2020). The implementation of the different reliability standards by the local practitioners in question often varies with subjective input assumptions, modeling methods, and choice of sensitivity analyses (Söder et al., 2020). Other sources of dIscrepancies between jurisdictions for reliability analysis are which units are included in the adequacy evaluation, whether the demand is considered to be price sensitive, and whether the reserves are included. Reliability standards in place in many regions are seen as a worst-case lower bound rather than a legally binding target.

**<u>Characteristics of Electricity</u>**

-Bernstein (n.d.)

1) Consumers require electric power on demand in volumes that fluctuate widely over the course of the day, week and year
2) Electricity, because it cannot be stored economically, must be generated simultaneously with its consumption; supply and demand must thus be maintained in instantaneous and continuous balance
3) The balance of supply and demand is maintained across a common power grid; generators of electricity supply the common grid, and consumers of electricity draw their power from it
4) An imbalance between supply and demand on the grid of even a few minutes' duration can cause a system blackout. The actions of individual generators and consumers to

supply or withdraw power from the grid can thus affect the reliability of supply to all consumers.

***Electricity Markets, Homogenous Good Auction Types***

-Vasin et al., (2013)

1) Uniform price auction; Producers submit their supply functions that determine the amount of supplied good depending on the market price. These bids are typically sealed, in that they are not revealed to the other agents until the auction closes. The cut-off price balances the total supply and demand, and each agent sells or buys at this price according to their bid.
2) Pay-as-bid auction; Differs in that each producer gets payment according to their bid while consumers pay the average price of the good.

**<u>Wholesale Electricity Market Principles</u>**

-Panfil and Zakaria (2020) discuss wholesale electricity market principles.

1) Wholesale market revenues should predominantly flow from well-designed energy and ancillary services markets.
2) When altering market design, FERC and ISOs should focus on only those services that are clearly needed and ensure that any market design change does not unduly discriminate between resources.
3) Minimize interventions that distort transparent and accurate pricing.
4) The just and reasonable standard strongly favors rate decreasing outcomes.
5) FERC and ISOs should facilitate and not undermine state public policy preferences.

Electricity is the only commodity delivered to customers with a separate capacity payment. Electricity is unlike other market goods, in that supply has to be stored to be released when demand arises. There has to be infrastructure to create and store electricity, as well as market mechanisms to regulate its price in the absence of national regulation. Electricity is like healthcare in that it has inelastic demand, which means that demand is not dependent on price, people will pay more money for electricity if they have to.

A reserve market is a market for essential goods where we need to have sufficient investment to produce them during peak demand, or when needed. In electricity markets, the energy-only market, which relies on private incentives, or wholesale prices, is sometimes not efficient enough to provide sufficient investment for generation reserves, for reasons such as: fixed costs, uncertainty, technical constraints, political intervention, and unpriced externalities. The answer is a reserve market, in which the producer sells the availability of its investment in return for additional funds, such as capacity markets in which electricity producers offer their power plant availability (Monjoie, 2021).

**<u>Problems Facing Energy-Only Markets</u>**

1) Asymmetric information resulting in price caps
2) High investment risk for generators

Schafer and Altvater (2019) note that energy-only markets face two problems: 1) asymmetric information resulting in price caps, and 2) high investment risk for generators. One, asymmetric information which results in price caps occurs when the regulator does not know if a power plant is not running because of unforeseen maintenance or because market power is used to provoke a scarcity event. This asymmetric information is why most spot markets have a price cap to limit the spot price, thereby preventing market power abuse in times of high demand. In the scenario of a too low price cap, the peak energy rent (PER) may be cut thereby resulting in missing money to cover capital costs. Asymmetric information prevents the regulator from introducing an optimal price cap, which depends on the spot market level and is thus not constant. A price cap which is optimal in one situation might result in missing money in a second or in market power abuse in a third situation. Two, there is also a high investment risk for generators, in that electricity producers must rely on a sufficient number and intensity of scarcity events to cover capital costs. Scarcity events are not predictable, are volatile and depend on actions of other generators, so this induces a high investment risk.

**Market Failures for which Capacity Markets Must Compensate**

CRMs assume that in electricity markets the spot markets for energy are characterized by two market failures for which capacity markets must compensate (Bhagwat et al., 2016).

1) Missing money problem- The missing money problem is a situation in an energy-only market where low power prices and few price spikes do not provide sufficient long-term investment incentives in new flexible generation capacity. Price caps result in an absence of shortage, or scarcity, pricing, and long averaging periods. This means that energy and ancillary service prices may fail to reflect the full value of energy generation, which in theory would result in underinvestment in capacity and inadequate remuneration for investors. Revenues from capacity markets enable generators with high variable costs that under normal circumstances would be dismantled to remain available.
2) Absence of a long run contract market- A long run contract market might be necessary to induce risk-averse investors to build new, long lived generation capacity. Stronger investment price signals are provided for new generation capacity additions from the additional revenues from capacity markets.

**Reasons for Capacity Mechanisms, the Missing Money Problem**

Lynch and Devine (2017) discuss reasons why low-load reserve units would not prove viable in the absence of a capacity remuneration mechanism.

1) The absence of an active demand-side in electricity generation markets, which means that consumers cannot signal their desired level of reliability of supply (Cramton and Stoft, 2005). There is therefore a weaker price signal for reliable supply, and consequently for electricity generation capacity. There is also opportunity and incentive to exercise market power, particularly the period close to real time.
2) The shared nature of the electricity network, which introduces a ‘free-rider’ problem, whereby it is not possible to differentiate between consumers who had entered into a contract for reliable supply.
3) Price caps

4) Electricity has public good characteristics (Abbott, 2001), and so policy-makers may be reluctant to leave the secure supply of generation capacity to market forces.

**Why Price Spikes have failed to provide the necessary incentives for generators to invest**

-Bernstein (n.d.)

1) First, power plants take years to develop and build, so price spikes during periods of scarcity occur too late to provide a timely signal to developers that capacity additions are required
2) Second, price spikes are triggered by capacity shortages; their very occurrence, in other words, signals an inadequate supply of capacity on the system and thus an increased probability of power cuts
3) Finally, price spikes are often subject to mitigation measures by independent system operators that limit the revenues available to recover capital invested. These measures include price caps designed to limit the exercise of market power by generators during periods of capacity scarcity; bidding rules that restrict bids too far in excess of cost; and the granting of special, out-of-market uplift payments to plants whose capacity is essential to system reliability (“reliability-must-run” units) that benefit these plants but create no revenues for other inframarginal generators.

In wholesale energy markets, the capacity market has been described as the missing money from the energy-only and ancillary services markets. Two of the functions of capacity markets is to prevent a black swan event, or loss of generation capacity, and the missing money problem, or lack of sufficient investment resources. The black swan event, the widespread loss of power to many customers that is caused by a lack of sufficient generating capacity, is unlikely, as loss of power to customers is rarely the result of generation-capacity deficiencies. This low probability of customer electricity loss is due to the extensive number, size, and diversity of generation resources (and significant reserve margins) across the nation. This means that the primary function of the capacity market is solving the missing money paradigm, where there are insufficient incentives to invest in new resources, or a failure to meet their long-term revenue requirements. The missing money problem is where the electricity market revenues are too low to cover the total costs of power generation units. Komorowska (2021) further defines the missing capacity dilemma, where the market signals do not provide a sufficient incentive for investors to build new power units, which can have implications for the entire economy and society. The missing money problem is created when spot market prices for electricity are depressed with price caps in times of scarcity, and is exacerbated by the increased use of renewable energy sources.

There are two ways to address the missing money problem in electricity markets. One, the price-based approach in the energy-only market, is to raise scarcity prices paid during blackouts. Two, the quantity-based approach in the capacity market, is to pay every supplier of capacity the same amount per MW of capacity.

**Measuring Security of Electricity Supply**

-Cherp and Jewell (2014); Goal of uninterrupted, resilient supply at the lowest possible cost

1) Fuel adequacy
2) Generation capacity adequacy
3) Balancing and flexibility
4) Network adequacy

**Ways to Measure Electric System Adequacy**

A) Loss of load probability, 1 day in 10 years for North American grid; an outage, some customer loads are not being served
B) Expected unserved energy

1) Spot market energy prices
2) Bilateral energy contracts

Loss of load describes the situation when in an electric grid the available generation capacity is less than the system load. Loss of Load Probability (LOLP) is a probabilistic reliability index that characterizes a probability of a loss of load occurring within a year. Loss of load events are calculated before the mitigating actions (purchasing electricity from other systems, load shedding) are taken, so a loss of load does not necessarily cause a blackout.[6] Expected unserved energy (EUE) is the expected amount of energy not supplied by the generation system during the period of observation, due to capacity deficiency.

The spot market for energy is a commodities market where the energy commodity is sold for cash and is delivered to a specific location for a specific time period that occurs on the day of the sale or on the day after the sale. Contracts bought and sold in a spot market are effective once agreed to. The spot price tells generators how much electricity the market needs at any moment in time to keep the physical power system in balance. When the spot price is increasing, generators ramp up their output or more expensive generators turn on to sell extra power to the market. When the spot price is decreasing, more expensive generators turn down or off. In electricity markets, spot markets may include day-ahead energy, intra-day energy, and/or real-time energy. Natural gas spot markets are typically for day-ahead transactions (or even multiple days ahead on weekends), although some intra-day spot trading does occur. Typical market participants in spot markets include wholesale marketers, brokers, suppliers such as gas producers and electric generators, utilities, large consumers, and retail marketers. Spot transactions are often performed using centralized exchanges or, in certain regions of the world with Independent System Operators (ISOs), using electric markets.[7]

A bilateral contract is a private trade between two parties. Bilateral transactions usually occur on the phone with two individuals negotiating and agreeing upon a price or via electronic trading exchanges. For shorter transactions, the use of electronic exchanges such as the Intercontinental Exchange (ICE) has become common. Longer-term transactions are typically negotiated face to face. A bilateral trade specifies key terms including delivery point, volume,

[6] Wikipedia, retrieved September 29, 2022, https://en.wikipedia.org/wiki/Loss_of_load
[7] Energy Knowledge Base, retrieved May 5, 2023, https://energyknowledgebase.com/topics/spot-market.asp

time of delivery, price, and whether the transaction is firm. Trades are done for specified blocks of time.[8]

## IV. Merit Order Effect of Renewables

A primary goal of modern electricity generation is to provide a cost-minimizing portfolio of resources that meet reliability and environmental standards. This means an electricity provider must manage the confluence of traditional thermal generators and new renewable generators which are increasing in volume and replacing conventional thermal power plants. Government agencies also must be cognizant of issuing mandates that push for more renewable generators and balance the needs of the modern electrical society between thermal and renewable sources. The generation mix thus becomes an important concept, as we must strive to include more renewable energy sources that don't have the efficiency losses of converting fuel into heat that thermal generators produce. There is also the issue of distortions among competing wind and solar projects, as renewable sources compete against each other.

The contribution of renewable energy sources to cover the electricity demand is less certain than conventional power sources; therefore, the capacity value of renewables is smaller than that of conventional plants. Critical for intermittent renewable energy sources is capacity value, which more accurately captures a generator's contribution to the generation capacity adequacy of a power system than by its installed capacity through considering factors such as forced or planned outages, seasonal ratings and temporally limited primary energy supply (Söder et al., 2020). The capacity value of a new generator is the maximum amount that the load in the system, including this generator, can be increased by while keeping the reliability of the system at the same level as before this generator was included (Garver, 1966).

The equilibrium generation mix should meet reliability and environmental standards. Three markets are the energy, capacity, and renewable credit markets. Traditionally the third market is known as the ancillary services market, though the emergence of the renewable credits market cannot be discounted. Renewable credit markets are here to stay and are a big part of the electricity market structure, and include diverse factors such as renewable generator capacity and the subsidies and tax schemes that promote their investment. The U.S. Energy Information Association projects that renewables share of the generation mix will double from its current 21 percent to 42 percent by 2050 (Wells, 2021).

The impact of renewables on the energy markets is evident through falling wholesale electricity prices and lower investment stability (Leiren et al., 2019). De Miera et al. (2008) notes the merit order effect of renewable energy in energy markets. This economic concept concerns the marginal costs of different forms of electricity, and their effect on the average spot price in the energy-only market. Marginal cost pricing is a consequence of spot markets with perfect competition, and renewable energy sources display lower marginal costs because they do not face fuel costs. Further, energy markets are characterized by relatively inelastic demand, and

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[8] Energy Knowledge Base, retrieved May 5, 2023, https://energyknowledgebase.com/topics/bilateral-electric-contract.asp#:~:text=A%20bilateral%20contract%20is%20a,or%20via%20electronic%20trading%20exchanges.

thus the more energy is secured from renewable sources the less is needed from traditional peaking fossil fuel sources. This means that fossil fuel peak-load plants which show higher marginal costs will be squeezed out of the market by renewables like solar, wind, and nuclear. Eventually the average spot price level will decrease in the energy-only market, which is called the merit order effect of renewable energy.

Base-load power plants run all the time, while peak-load power plants run only when needed. Intermittent renewable sources servicing base-load plants consequently need flexible plants for peak-load services. Flexible plants can ramp up and down quickly at a low cost, which means gas or coal. This means that the merit order effect of renewable energy creates a price signal at spot markets in the short run which counteracts the optimal capacity mix with more flexible power plants in the long run (Schäfer and Altvater, 2019). Wissen and Nicolosi (2008) suggest that the merit order effect will vanish in the long run because the power plant mix adjusts and at a certain point missing flexibility will lead to increasing spot prices. Mays et al. (2019) notes that CRMs favor peaking technologies like coal, oil and gas over wind, solar, or nuclear technologies.

Schäfer and Altvater (2019) note that In an ideal energy-only market, all generators bid prices corresponding to their marginal costs under perfect competition, which forms the merit order, with bids ordered from lowest to highest. In the energy-only market, spot market auctions follow uniform pricing so that the last power plant needed to satisfy demand sets the price for all successful generators. The infra-marginal rent (IR) is then gained when generating electricity by successful generators except for the price-setting generator. This rent is used to cover capital costs. Different power plants will be price-setting, since supply and demand vary over time. Peak-load power plants which face comparatively high marginal costs gain an IR less often than base-load power plants, although peak-load power plants display lower capital costs than base-load power plants. The peak-load power plant with highest marginal costs is never able to obtain an IR because it forms the right end of the merit order, and consequently covers its capital costs via a peak energy rent (PER) in times of scarcity. When demand is high, but supply is limited, the spot price rises above marginal costs of the last unit in the merit order so that all generating power plants gain a PER. An example why a power plant is not generating electricity, although the spot price exceeds its marginal costs, is unforeseen maintenance. Caramanis (1982) suggests that price signals in the context of IRs and PERs of an ideal energy-only market are sufficient to cover generators' capital costs and incentivize necessary capacity investments.

## Renewable Energy Tax Credits

Under the Consolidated Appropriations Act of 2021, the renewable energy tax credits for fuel cells, small wind turbines, and geothermal heat pumps now feature a gradual step down in the credit value, the same as those for solar energy systems.

***Tax Credit:***

A) 30% for systems placed in service by 12/31/2019
B) 26% for systems placed in service after 12/31/2019 and before 01/01/2023

C) 22% for systems placed in service after 12/31/2022 and before 01/01/2024

## V. Economics of Deregulated Markets

Many countries have introduced wholesale electricity markets in favor of regulated monopolies in the energy sector. A deregulated electricity market system creates problems in recouping costs through rates, as the assurance that the cost of maintaining system reliability will be recovered in rates is eliminated, for two reasons. One, the cost of ensuring adequate levels of system reliability is primarily a fixed cost. Two, system reliability is a common good, from which all consumers benefit though no one can be held accountable. Consequently, a competitive electricity market is one in which the recovery of investments in reserve capacity or fixed or sunk costs, although necessary to ensure system reliability, is not assured. Liberalized markets have ambiguity regarding the responsibility for adequacy determination.

### Issues with Liberalized Electricity Markets

1) Increasing energy demands, fast demand growth
2) Decommissioning of conventional power plants
3) Steady growth of renewable energy sources, RES

One, fixed or sunk costs for generation capacity means that much of the capital invested in a generation plant is expected to go unutilized in normal circumstances. In a regulated environment, rates are set to cover the average cost of supply, including both fixed and variable costs, and thus also provide for recovering the generation investment, or sunk costs. In a competitive deregulated market competing suppliers bid prices down to levels that reflect the unavoidable, variable costs of supply, with no allowance made for sunk costs. These sunk costs include the recovery of previous investments in generating capacity.

Two, system reliability is a common good, from which individual consumers are not held responsible but one in which all consumers benefit. In a competitive deregulated market, consumers have the ability to switch suppliers to whoever offers the best current price. This means that no electricity retailer has the incentive to ensure that his customers are paying their fair share for system reliability or fixed costs in the form of generating capacity. In periods of high demand, inadequate generation capacity may result in an outage, but all consumers will be affected, including competitors. When utilities were regulated monopolies this problem of securing fees for fixed costs did not arise, as customers had to pay rates that allowed the utility to recover its cost of ensuring reliable power supplies, or otherwise face a cutoff of service.

In the advent of deregulation, much new power plant capacity was built in the 1980s, though we have pretty much used up all that spare capacity along with the associated transmission. In the deregulated era, construction of new power plants falls mostly to non-utilities. Renewables will be the largest generation source supported by an upgraded grid, supported by natural gas and nuclear to keep electricity affordable and reliable. Liberalization of the electricity industry brought about the introduction of market-based mechanisms to replace national planning, including capacity remuneration mechanisms to directly remunerate installed capacity, and not only energy (Lambin and Léautier, 2019).

## VI. Results

Tables 1 and 2 show the results of the regression analysis finding significance of different energy variables with world GDP and world population since 1965. Table 1 uses values for fuel sources since 1965, and Table 2 uses values for fossil fuels since 1998. Other renewables, biofuels, solar, oil, coal, and traditional biomass are significant with world GDP since 1965. Other renewables, hydropower, nuclear, oil, coal, and traditional biomass are significant with world population since 1965. Brent oil, China coal, Japan coking coal import, and Nigeria oil are significant with world GDP and world population since 1998. All data was taken from Our World in Data.

### Coal Indices

1) Asian Marker Price Coal
2) China Qinhuangdao Spot Price Coal
3) Japan Coking Coal Import CIF Price
4) Japan Steam Coal Import CIF Price
5) Japan Steam Spot CIF Price Coal
6) Northwest Europe Coal
7) US Central Appalachian Coal Spot Price Index

### Oil Indices

1) Brent Crude
2) Dubai Oil
3) Nigerian Forcados Oil
4) West Texas Intermediate Oil

### Natural Gas Indices

1) German Import Natural Gas
2) Canada Alberta Natural Gas
3) LNG Japan CIF
4) UK NBP (ICIS NBP Index) Natural Gas
5) US Henry Hub Natural Gas

Graph 1 shows the worldwide fuel diversity consumption for 2022. Coal is the leading resource being used still, at 35.8%. This figure is contrasted with Table 3, which shows U.S. fuel diversity, where natural gas is the leading resource used. Natural gas is number two worldwide, whereas coal is number two in the United States. These results show how the United States has made a concerted effort to diversify from coal plants in recent years to more clean burning natural gas. Number three worldwide is hydro power, followed by nuclear at four and wind at five. In the United States, all three, hydro, nuclear, and wind, are about equal. Solar is still making inroads both worldwide and in the U.S.

Table 5 and Graph 3 show the fuel diversity and energy generation portfolio of Texas ERCOT from 2014 to 2022. Coal and natural gas were almost even in 2014, but natural gas is more than twice coal by 2022. Wind is second in Texas, followed by coal, nuclear, and solar. Tables 8, 9, and 10 show NYISO energy sources from 2014 to 2020. In the NYISO, natural gas is the biggest resource source, at 35%, followed by nuclear use at 29%. Hydro power is third in the NYISO at 22%, followed by wind at 3%, coal at 1%, and solar at 1%. The NYISO is ahead of the market in weaning itself off coal, though still has not embraced large-scale wind power.

Table 6 shows the output-weighted average price by generation type based on the generators' specific locational prices in 2022 for Texas ERCOT. Gas peakers is the highest cost at $189.86 per MWh, followed by gas steam at $140.51 per MWh. Coal is relatively cheap, only costing $70 per MWh. Wind is the cheapest, at $34.09 per MWh, and solar is $73.09 per MWh. Nuclear is also relatively cheap, only costing $60.78 per MWh. Hydro costs $87.76 in 2022 per MWh. If coal is cheaper, then we could benefit from using more coal, even though coal produces more emissions for the environment.

Per Table 7, NYISO does not report prices per fuel source in either the Gold Book on the NYISO website or in their annual market reports in Potomac Economics. They do report natural gas prices per zone using indexes, which averaged to around $7.50. In 2022, average all-in prices rose to the highest levels observed in more than a decade, ranging from $58 per MWh in the North Zone to nearly $127 per MWh in Long Island. All-in prices rose 50 to 100 percent from 2021.

Tables 8, 9, and 10 show NYISO energy sources per GWh and percent from 2014 to 2020. Coal use decreases from 3% in 2014 to 1% in 2020. Nuclear use remains constant at around 30% use from 2014-2020. Solar is 1% and wind is 3% in all years, and natural gas use is around 35% in all years.

Table 11 and Graph 4 show PJM Interconnection wholesale costs from 2018 to 2022. For 2022, energy market cost is $54.16 per MWh, capacity market cost is $11.71 per MWh, and total cost is $79.37 per MWh. 2022 was the most expensive year since 2018.

Table 12 and Graph 5 show 2014 fuel diversity for capacity markets for the 6 RTOs, not including Texas ERCOT. These include ISO-NE, CAISO, MISO, NYISO, PJM and SPP. Table 13 and Graph 6 show 2014 fuel diversity for the energy-only market. This information is obtained from a singular 2015 ISO/RTO Metrics Report, which was only published for that year, and was published by the New England States Commission on Electricity. The fuel mix for capacity markets and energy-only markets mirror each other. For coal, MISO, PJM, and SPP each use coal for around 50% of their energy mix. CAISO used 0% coal, NYISO uses 3% coal, and ISO-NE uses 5% coal. These are major differences from our cheapest fossil fuel energy source, coal. Natural gas use is significant in all 6 markets. Nuclear use is around 30% in ISO-NE, NYISO, and PJM, and nuclear use is around 10% in CAISO, MISO, and SPP. Hydro and renewables use is significant in ISO-NE, CAISO, NYISO, and SPP.

Tables 14-17 display capacity auction results from the four U.S. capacity markets. Table 18 displays that PJM Interconnection is the largest capacity market in the U.S., followed by Midcontinent ISO, with NYISO and ISO-NE being about the same size. Per Table 19, energy costs were highest in CAISO and Lowest in SPP for 2018.

## VII. Conclusion

China has said that regarding its use of coal fired power plants, it is important to embrace the future, but we cannot forget the past at the same time. In Texas ERCOT, coal is the cheapest form of fossil fuel energy, at $70 per MWh compared to natural gas at $140.51 per MWh. It is also relevant to note that wind energy has not caught on and advanced in all U.S. regions at the same pace. In 2020, wind usage nationwide was at 9.8% and solar usage was at 4%. In 2014, CAISO used 0% coal and 29% hydro and renewables. The 0% coal is significant, because it represents a clear denunciation at an early date from a major zone in use of our cheapest fossil fuel energy source. Capacity markets have emerged since deregulation as a means to secure system reliability and maintain operating reserves, but are needed in every market. In some markets, like Texas ERCOT, they utilize the energy-only market by itself to generate sufficient revenues for plant generation investments. Europe is a similar situation, with a few countries utilizing capacity remuneration mechanisms but some still only using energy-only markets. Thus we can say that having a capacity market or using CRMs at all is a political decision, and not needed in every situation.

**Table 1. Fuel Source Significance per GDP and Population**

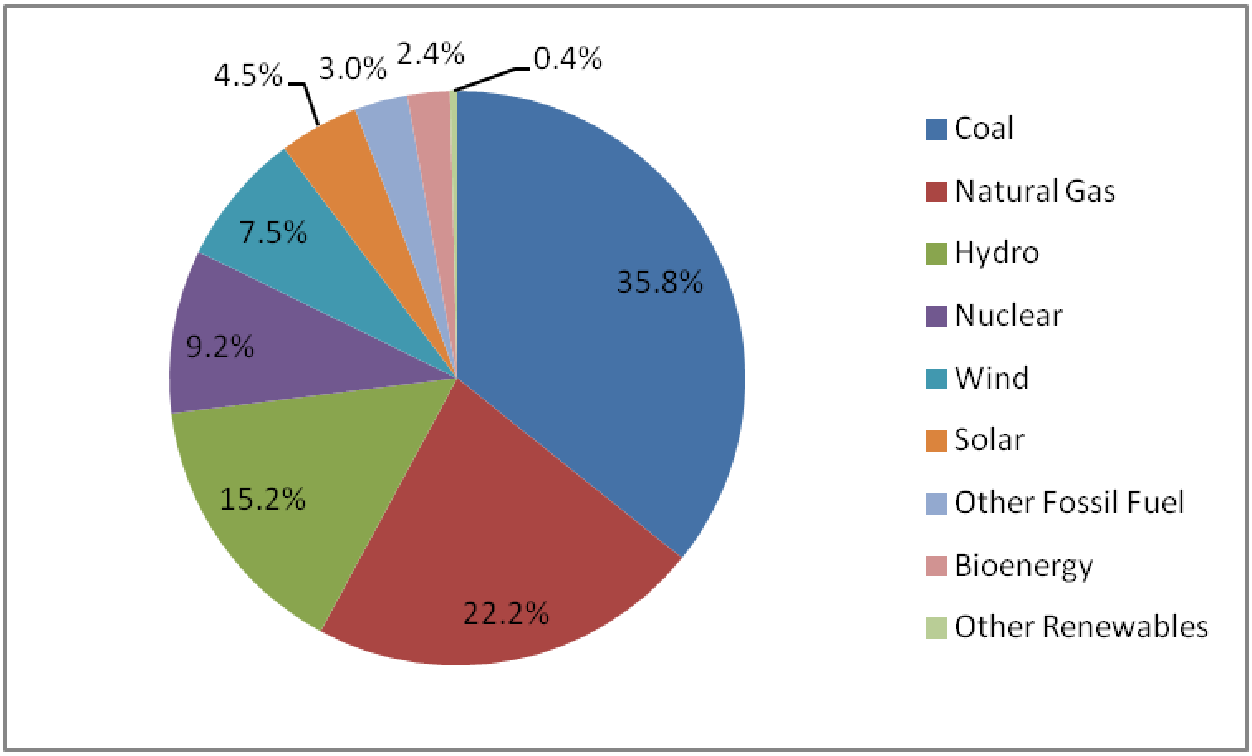
| | **GDP** | | **Population** | |
|---|---|---|---|---|
| **Variable** | **Estimate** | **Significance** | **Estimate** | **Significance** |
| **Other renewables (TWh, substituted energy)** | 5.77 | *** | 3.18 | *** |
| **Biofuels (TWh, substituted energy)** | -1.76 | * | | |
| **Solar (TWh, substituted energy)** | -2.64 | ** | | |
| **Hydropower (TWh, substituted energy)** | | | 6.74 | *** |
| **Nuclear (TWh, substituted energy)** | | | 3.22 | *** |
| **Oil (TWh, substituted energy)** | 3.86 | *** | 3.52 | *** |

| | | | | |
|---|---|---|---|---|
| **Coal (TWh, substituted energy)** | 6.08 | *** | 4.5 | *** |
| **Traditional biomass (TWh, substituted energy)** | 3.08 | *** | 6.12 | *** |

**<u>Table 2. Fossil Fuels Significance per GDP and Population</u>**

| | **GDP** | | **Population** | |
|---|---|---|---|---|
| **Variable** | **Estimate** | **Significance** | **Estimate** | **Significance** |
| **Brent Oil** | -2.09 | * | -1.99 | * |
| **China Coal** | 1.85 | * | 2.03 | * |
| **Japan Coking Coal Import** | -2.28 | * | -2.36 | ** |
| **Nigeria Oil** | 2.16 | * | 2.05 | * |

**Graph 1. Worldwide Fuel Diversity 2022**




Source: Statista Research

**Table 3. U.S. Fuel Diversity in Megawatts**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Coal | 289,429 | 278,224 | 263,570 | 247,289 | 233,129 |
| Gas | 517,327 | 527,956 | 542,762 | 547,583 | 556,485 |
| Nuclear | 104,791 | 104,792 | 104,270 | 102,877 | 100,899 |
| Oil | 39,446 | 38,122 | 36,896 | 35,988 | 31,935 |
| Wind | 87,464 | 94,020 | 100,483 | 104,334 | 118,728 |
| Hydro | 101,020 | 101,238 | 101,786 | 101,661 | 101,865 |
| Other | 37,707 | 42,592 | 47,634 | 20,539 | 20,860 |
| Solar | - | - | - | 37,790 | 48,339 |

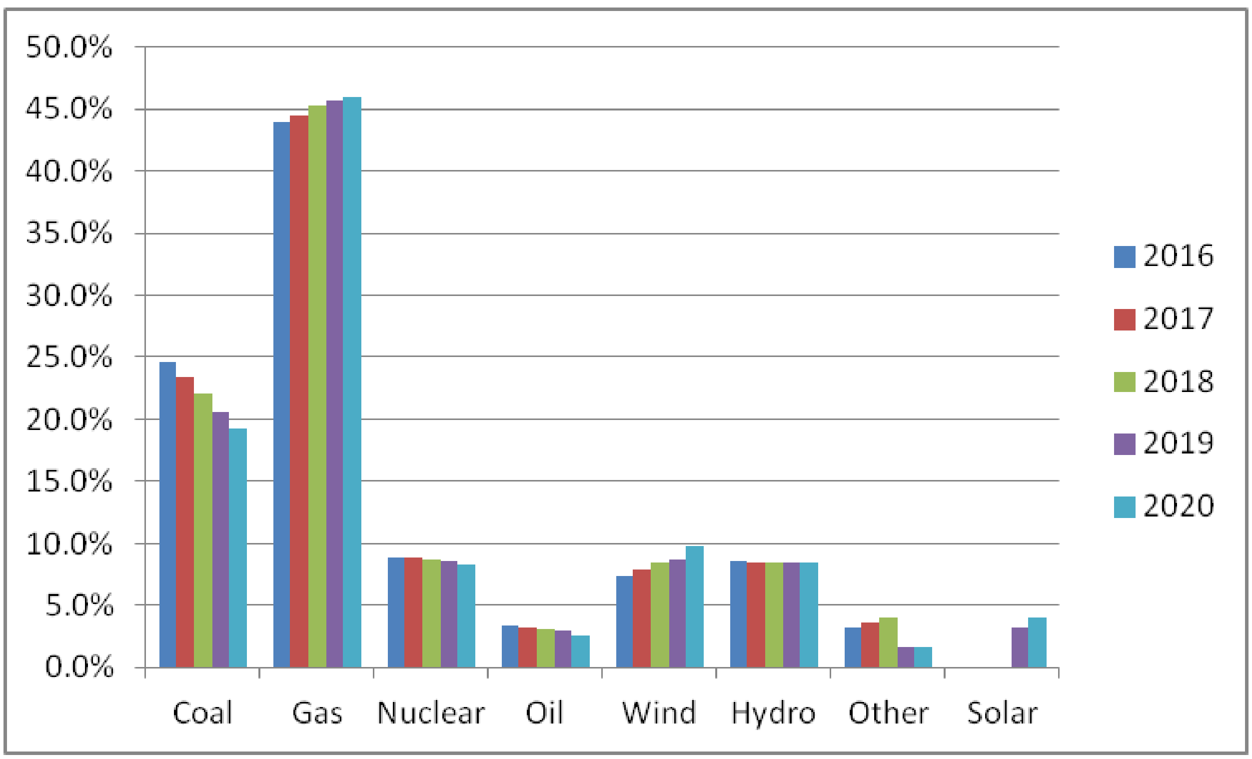
Source: Public Power Magazine

**Table 4. U.S. Fuel Diversity by %**

| | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| **Coal** | 24.6% | 23.4% | 22.0% | 20.6% | 19.2% |
| **Gas** | 43.9% | 44.5% | 45.3% | 45.7% | 45.9% |
| **Nuclear** | 8.9% | 8.8% | 8.7% | 8.6% | 8.3% |
| **Oil** | 3.4% | 3.2% | 3.1% | 3.0% | 2.6% |
| **Wind** | 7.4% | 7.9% | 8.4% | 8.7% | 9.8% |
| **Hydro** | 8.6% | 8.5% | 8.5% | 8.5% | 8.4% |
| **Other** | 3.2% | 3.6% | 4.0% | 1.7% | 1.7% |
| **Solar** | - | - | - | 3.2% | 4.0% |

Source: Public Power Magazine

**Graph 2. U.S. Fuel Diversity by %**



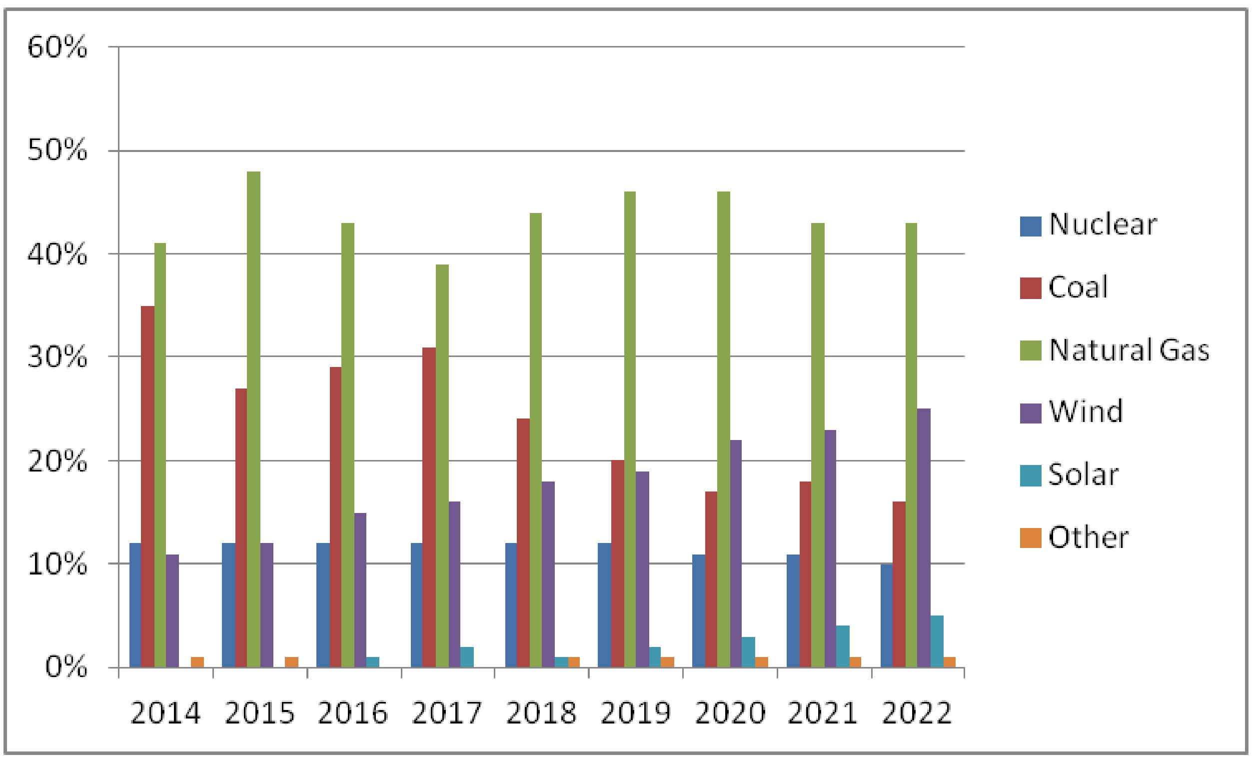

Source: Public Power Magazine

**Table 5. Texas ERCOT Energy Generation Portfolio**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|
| **Nuclear** | 12% | 12% | 12% | 12% | 12% | 12% | 11% | 11% | 10% |
| **Coal** | 35% | 27% | 29% | 31% | 24% | 20% | 17% | 18% | 16% |
| **Natural Gas** | 41% | 48% | 43% | 39% | 44% | 46% | 46% | 43% | 43% |
| **Wind** | 11% | 12% | 15% | 16% | 18% | 19% | 22% | 23% | 25% |
| **Solar** | 0% | 0% | 1% | 2% | 1% | 2% | 3% | 4% | 5% |
| **Other** | 1% | 1% | 0% | 0% | 1% | 1% | 1% | 1% | 1% |

Source: Potomac Economics, 2022 State of the Market Report

**Graph 3. Texas ERCOT Energy Generation Portfolio**




Source: Potomac Economics, 2022 State of the Market Report

**Table 6. Texas ERCOT Settlement Point Price by Fuel Type**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| **Coal** | $24.84 | $148.06 | $70.00 |
| **Combined Cycle** | $24.60 | $207.84 | $80.71 |
| **Gas Peakers** | $60.26 | $1,023.09 | $189.86 |
| **Gas Steam** | $41.90 | $405.10 | $140.51 |
| **Hydro** | $23.88 | $305.15 | $87.76 |
| **Nuclear** | $20.31 | $137.71 | $60.78 |
| **Power Storage** | $80.50 | $109.29 | $92.64 |
| **Private Network** | $24.08 | $176.76 | $74.46 |
| **Renewable** | $35.23 | $43.54 | $83.00 |
| **Solar** | $25.49 | $75.97 | $73.09 |
| **Wind** | $11.45 | $60.53 | $34.09 |

Source: Potomac Economics, 2022 State of the Market Report

**Table 7. Natural Gas Prices, NYISO**

| | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| **Tennessee Zn6** | $3.26 | $2.13 | $4.68 | $9.20 |
| **Iroquois Zn2** | $3.04 | $2.09 | $4.36 | $8.82 |
| **Transco Zn6** | $2.59 | $1.64 | $3.49 | $7.04 |
| **Tenn Z4 200L** | $2.26 | $1.69 | $3.38 | $5.75 |

Source: Potomac Economics, 2022 State of the Market Report

**Table 8. NYISO Energy Sources GWh**

| | **2020** | **2019** | **2018** | **2017** | **2016** |
|---|---|---|---|---|---|
| **RSolar** | 48.5 | 52.1 | 48.8 | 47.3 | 53.7 |
| **RWind** | 4,161.90 | 4,453.60 | 3,985.10 | 4,219.20 | 3,943.30 |
| **RSteam Turbine Refuse** | 1,619.70 | 1832.3 | 1,878.40 | 1,900.10 | 1,840.90 |
| **RSteam Turbine Wood** | 0 | 154.6 | 203.4 | 288.3 | 292.5 |
| **RInternal Combustion Methane** | 612.9 | 660.9 | 647.6 | 730.1 | 747.7 |
| **RConventional Hydro** | 29,521.30 | 30,140.90 | 29,045.10 | 29,554.20 | 26,314.10 |
| **NSteam BWR Nuclear** | 22,236.70 | 23,099.60 | 21,962.50 | 22,215 | 21,448.80 |
| **NSteam PWR Nuclear** | 16,200.30 | 21,688.30 | 21,040.60 | 19,959.60 | 20,188.70 |
| **PPumped Storage Hydro** | 635.5 | 583.1 | 810.8 | 795.3 | 835.6 |
| **FInternal Combustion Gas** | 26.1 | 28.5 | 1.7 | 1.4 | 1.1 |
| **FInternal Combustion Oil&Gas** | 0.9 | 0.9 | 2 | 1.8 | 1.8 |
| **FInternal Combustion Oil** | 2.8 | 2.5 | 2.2 | 1.3 | 2.1 |
| **FCombustion Turbine Gas** | 737.7 | 541.9 | 732.9 | 671.3 | 905.3 |
| **FCombustion Turbine Oil&Gas** | 396.8 | 325.9 | 432.1 | 408.8 | 854.8 |
| **FCombustion Turbine Oil** | 82.8 | 26.2 | 36 | 18 | 45.8 |
| **FJet Engine Gas** | 88.1 | 118.9 | 140.8 | 99.6 | 211.9 |
| **FJet Engine Oil&Gas** | 451.4 | 741 | 916 | 728.7 | 1,284.10 |
| **FJet Engine Oil** | 112 | 71.1 | 89 | 36.2 | 70.6 |
| **FCombined Cycle Gas** | 8,556.70 | 5,580.40 | 5,465.10 | 4,887.40 | 5,555.10 |
| **FCombined Cycle Oil&Gas** | 37,235.70 | 36,894 | 37,099.60 | 35,355.60 | 39,017.10 |

| | | | | | |
|---|---|---|---|---|---|
| **FSteam Turbine Coal** | 145.9 | 425.6 | 692 | 567.4 | 1,492.80 |
| **FSteam Turbine Gas** | 1,120.90 | 1003.2 | 1,253.30 | 1,037.70 | 1,114 |
| **FSteam Turbine Oil&Gas** | 7,455.40 | 6,106.70 | 9,075.80 | 7,640.60 | 11,292.60 |
| **FSteam Turbine Oil** | 11.6 | 4.2 | 24.4 | 18.1 | 17.1 |
| **Total** | 131,461.6 | 134,536.3 | 135,585.2 | 131,182.9 | 137,531.5 |

Source: NYISO Gold Book, Load and Capacity Data Report

**Table 9. NYISO Energy Sources GWh**

| | **2020** | **2019** | **2018** | **2017** | **2016** | **2015** |
|---|---|---|---|---|---|---|
| **Gas** | 10,530 | 7273 | 7594 | 6697 | 7787 | 9,737 |
| **Oil** | 209 | 104 | 152 | 74 | 136 | 146 |
| **Gas and Oil** | 45,540 | 44068 | 47526 | 44135 | 52450 | 52,028 |
| **Coal** | 146 | 425 | 692 | 567 | 1493 | 2,046 |
| **Nuclear** | 38,437 | 44788 | 43003 | 42175 | 41638 | 44,620 |
| **Pumped Storage** | 636 | 583 | 811 | 795 | 836 | 825 |
| **Hydro** | 29,521 | 30141 | 29045 | 29554 | 26314 | 25,879 |
| **Wind** | 4,162 | 4454 | 3985 | 4219 | 3943 | 3,984 |
| **Solar** | 49 | 52 | 49 | 47 | 54 | 52 |
| **Other** | 2,233 | 2648 | 2729 | 2919 | 2881 | 3,028 |
| **Total** | 131,462 | 134,536 | 135,585 | 131,183 | 137,532 | 142,345 |

Source: NYISO Gold Book, Load and Capacity Data Report

**Table 10. NYISO Energy Sources %**

| | **2020** | **2019** | **2018** | **2017** | **2016** | **2015** | **2014** |
|---|---|---|---|---|---|---|---|
| **Gas** | 8% | 5% | 6% | 5% | 6% | 7% | 6% |
| **Oil** | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| **Gas and Oil** | 35% | 33% | 35% | 34% | 38% | 37% | 36% |
| **Coal** | 1% | 1% | 1% | 1% | 1% | 1% | 3% |
| **Nuclear** | 29% | 33% | 32% | 32% | 30% | 31% | 30% |
| **Pumped Storage** | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| **Hydro** | 22% | 22% | 21% | 23% | 19% | 18% | 18% |
| **Wind** | 3% | 3% | 3% | 3% | 3% | 3% | 3% |
| **Solar** | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| **Other** | 2% | 2% | 2% | 2% | 2% | 2% | 2% |

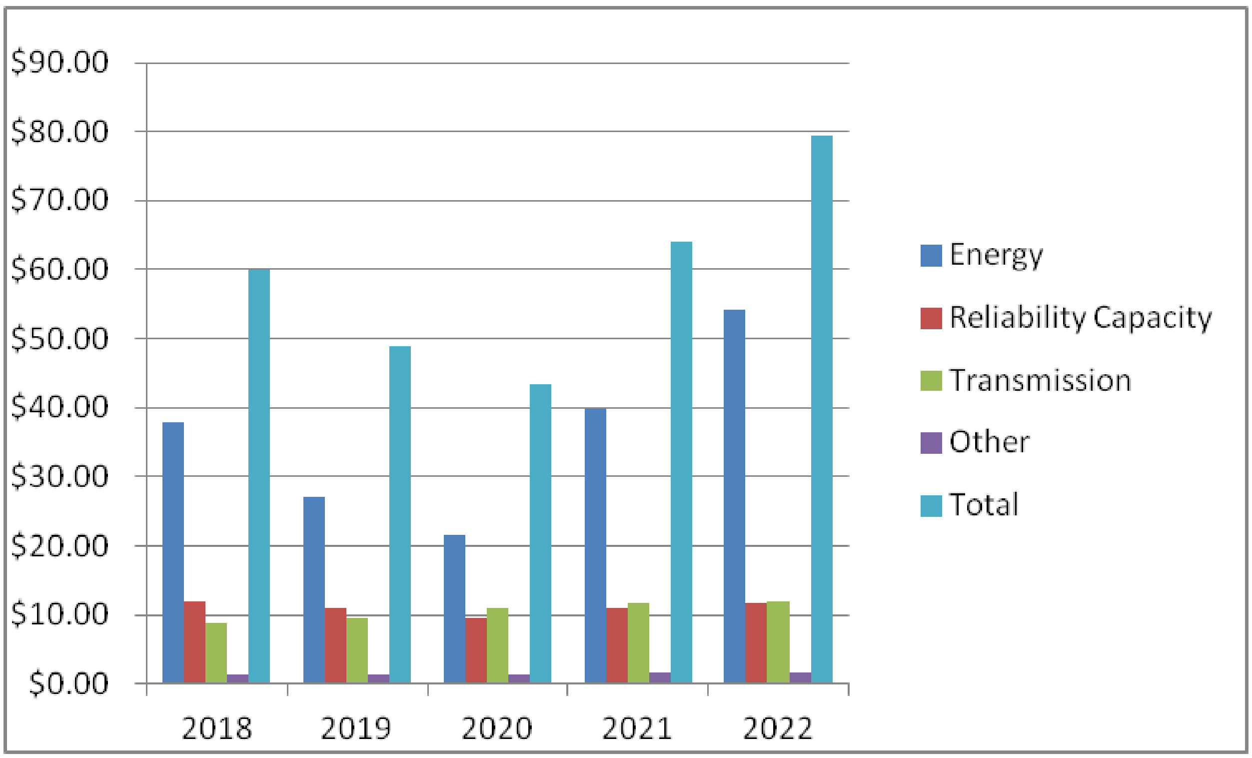
Source: NYISO Gold Book, Load and Capacity Data Report

**Table 11. PJM Interconnection Wholesale Cost**

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Energy** | $37.83 | $27.15 | $21.65 | $39.79 | $54.16 |
| **Reliability Capacity** | $11.89 | $11.05 | $9.45 | $11.04 | $11.71 |
| **Transmission** | $8.84 | $9.52 | $11.03 | $11.72 | $11.98 |
| **Other** | $1.44 | $1.26 | $1.28 | $1.52 | $1.52 |
| **Total** | $60.00 | $48.98 | $43.41 | $64.07 | $79.37 |

Source: PJM Interconnection 2022 Markets Report

**Graph 4. PJM Interconnection Wholesale Cost**



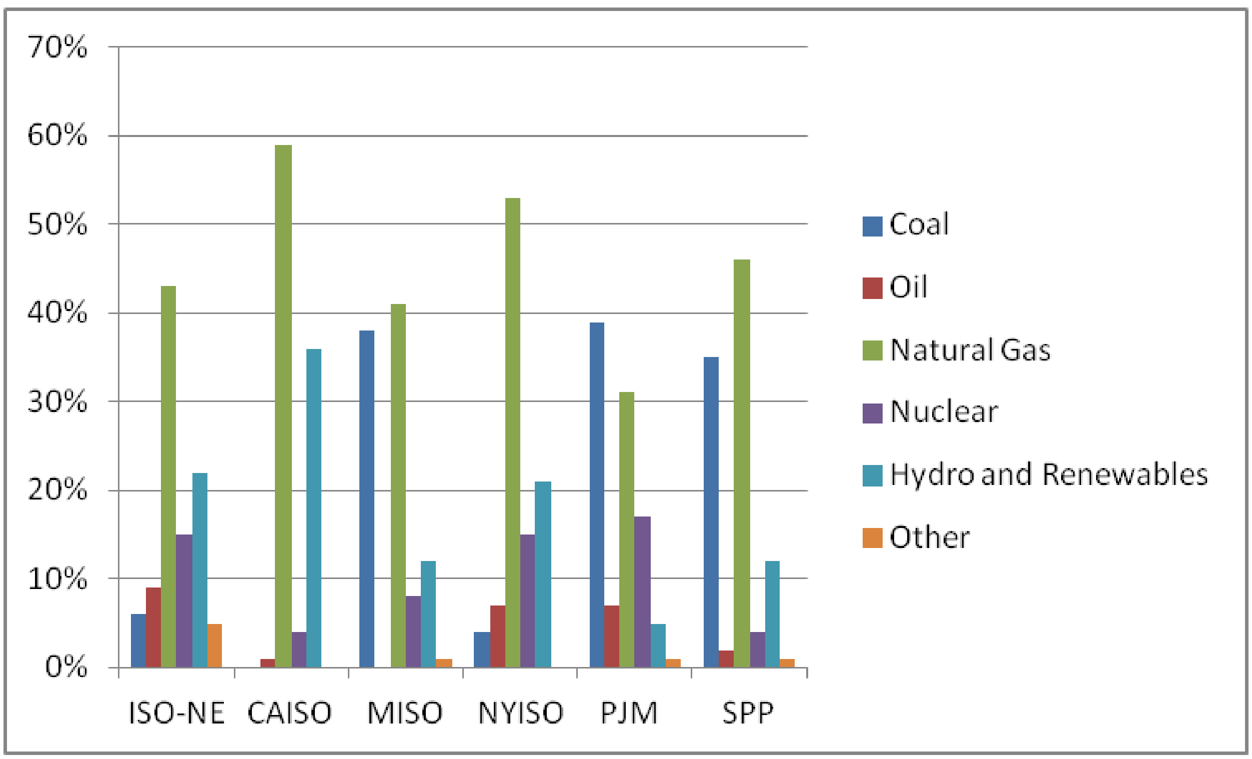

Source: PJM Interconnection 2022 Markets Report

**Table 12. 2014 Fuel Diversity, Capacity Markets**

| | ISO-NE | CAISO | MISO | NYISO | PJM | SPP |
|---|---|---|---|---|---|---|
| **Coal** | 6% | 0% | 38% | 4% | 39% | 35% |
| **Oil** | 9% | 1% | 0% | 7% | 7% | 2% |
| **Natural Gas** | 43% | 59% | 41% | 53% | 31% | 46% |
| **Nuclear** | 15% | 4% | 8% | 15% | 17% | 4% |
| **Hydro and Renewables** | 22% | 36% | 12% | 21% | 5% | 12% |
| **Other** | 5% | 0% | 1% | 0% | 1% | 1% |

Source: 2015 ISO/RTO Metrics Report

**Graph 5. Fuel Diversity, Capacity Markets**



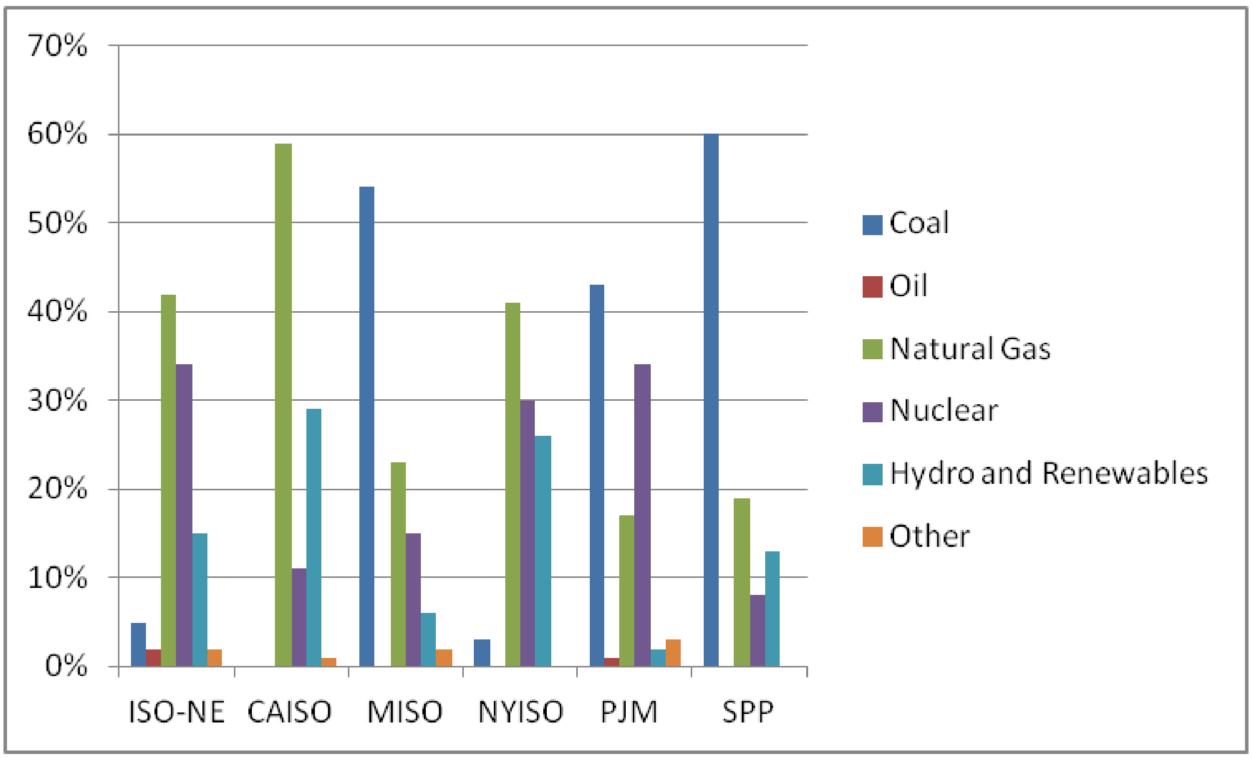

Source: 2015 ISO/RTO Metrics Report

**Table 13. 2014 Fuel Diversity, Energy-Only Markets**

| | ISO-NE | CAISO | MISO | NYISO | PJM | SPP |
|---|---|---|---|---|---|---|
| **Coal** | 5% | 0% | 54% | 3% | 43% | 60% |
| **Oil** | 2% | 0% | 0% | 0% | 1% | 0% |
| **Natural Gas** | 42% | 59% | 23% | 41% | 17% | 19% |
| **Nuclear** | 34% | 11% | 15% | 30% | 34% | 8% |
| **Hydro and Renewables** | 15% | 29% | 6% | 26% | 2% | 13% |
| **Other** | 2% | 1% | 2% | 0% | 3% | 0% |

Source: 2015 ISO/RTO Metrics Report

**Graph 6. Fuel Diversity, Energy-Only Markets**




Source: 2015 ISO/RTO Metrics Report

## Table 14: ISO-NE Capacity Auction Results

| | | Demand in Megawatts (MW) | | | Supply (MW) | | Reserve Margin (percentage) | |
|---|---|---|---|---|---|---|---|---|
| Auction Number | Capacity Delivery Year | Expected Peak Demand | Region-wide Resource Adequacy Requirement | Capacity Commitments Procured in Capacity Auctions | Capacity Commitments Procured Outside the Capacity Auction | Total Capacity Commitments Procured | Calculated with Resource Adequacy Requirement | Calculated with Total Capacity Commitments Procured |
| **1** | 2010/2011 | 29,035 | 31,480 | 32,085 | 1,308 | 33,392 | 8 | 15 |
| **2** | 2011/2012 | 29,405 | 31,232 | 34,971 | 851 | 35,822 | 6 | 22 |
| **3** | 2012/2013 | 29,020 | 30,709 | 34,582 | 854 | 35,436 | 6 | 22 |
| **4** | 2013/2014 | 28,570 | 30,862 | 35,108 | 856 | 35,964 | 8 | 26 |
| **5** | 2014/2015 | 29,025 | 31,900 | 34,595 | 891 | 35,486 | 10 | 22 |
| **6** | 2015/2016 | 29,380 | 32,221 | 33,928 | 973 | 34,902 | 10 | 19 |
| **7** | 2016/2017 | 29,400 | 31,777 | 33,829 | 985 | 34,815 | 8 | 18 |
| **8** | 2017/2018 | 29,790 | 32,618 | 31,478 | 998 | 32,475 | 9 | 9 |
| **9** | 2018/2019 | 30,005 | 32,823 | 32,405 | 890 | 33,295 | 9 | 11 |
| **10** | 2019/2020 | 29,861 | 32,808 | 33,220 | 911 | 34,130 | 10 | 14 |
| **11** | 2020/2021 | 29,601 | 32,722 | 33,470 | 896 | 34,366 | 11 | 16 |

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in ISO New England’s initial capacity auction for capacity delivery years 2010/2011 through 2020/2021.

## Table 15: MID ISO Capacity Auction Results

| | | Demand in Megawatts (MW) | | | | Supply (MW) | Reserve Margin (percent) | |
|---|---|---|---|---|---|---|---|---|
| Auction Number | Capacity Delivery Year | Expected Peak Demand | Region-wide Resource Adequacy Requirement | Capacity Commitments Procured in Capacity Auctions | Capacity Commitments Procured Outside the Capacity Auction | Total Capacity Commitments Procured | Calculated with Resource Adequacy Requirement | Calculated with Total Capacity Commitments Procured |
| **1** | 2013/2014 | 91.539 | 97,214 | 62,255 | 34,959 | 97,214 | 6 | 6 |
| **2** | 2014/2015 | 127,597 | 136,912 | 89,890 | 47,022 | 136,912 | 7 | 7 |
| **3** | 2015/2016 | 127,319 | 136,359 | 88,130 | 48,229 | 136,359 | 7 | 7 |
| **4** | 2016/2017 | 125,913 | 135,483 | 99,488 | 35,995 | 135,483 | 8 | 8 |
| **5** | 2017/2018 | 125,003 | 134,753 | 85,290 | 49,463 | 134,753 | 8 | 8 |

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in Midcontinent ISO's initial capacity auction for capacity delivery years 2013/2014 through 2017/2018.

## Table 16: NYISO Capacity Auction Results

| | Demand in Megawatts (MW) | | Supply (MW) | Reserve Margins (percent) | |
|---|---|---|---|---|---|
| Capacity Delivery Month | Expected Peak Demand | Region-wide Resource Adequacy Requirement | Total Capacity Commitments Procured In and Outside the Auctions | Calculated with Resource Adequacy Requirement | Calculated with Total Capacity Commitments Procured |
| **Aug-06** | 33,295 | 37,154 | 39,829 | 12 | 20 |
| **Aug-07** | 33,447 | 37,228 | 39,691 | 11 | 19 |
| **Aug-08** | 33,809 | 36,633 | 39,663 | 8 | 17 |
| **Aug-09** | 33,930 | 36,362 | 39,219 | 7 | 16 |
| **Aug-10** | 33,025 | 35,045 | 38,609 | 6 | 17 |
| **Aug-11** | 32,712 | 34,684 | 38,827 | 6 | 19 |
| **Aug-12** | 33,295 | 35,076 | 38,477 | 5 | 16 |
| **Aug-13** | 33,279 | 35,467 | 37,338 | 7 | 12 |
| **Aug-14** | 33,666 | 35,812 | 37,547 | 6 | 12 |
| **Aug-15** | 33,567 | 35,920 | 38,665 | 7 | 15 |
| **Aug-16** | 33,359 | 35,430 | 38,166 | 6 | 14 |

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in NYISO's initial capacity auction for the capacity delivery month of August for 2006 through 2016.

## Table 17: PJM Capacity Auction Results

| Auction Number | Capacity Delivery Year | Expected Peak Demand | Region-wide Resource Adequacy Requirement | Capacity Commitments Procured in Capacity Auctions | Capacity Commitments Procured Outside the Capacity Auction | Total Capacity Commitments Procured | Calculated with Resource Adequacy Requirement | Calculated with Total Capacity Commitments Procured |
|---|---|---|---|---|---|---|---|---|
| **1** | 2007/2008 | 137,421 | 148,277 | 129,409 | 24,133 | 153,542 | 8 | 12 |
| **2** | 2008/2009 | 139,806 | 150,935 | 129,598 | 24,404 | 154,001 | 8 | 10 |
| **3** | 2009/2010 | 142,177 | 153,480 | 132,232 | 24,694 | 156,926 | 8 | 10 |
| **4** | 2010/2011 | 144,592 | 156,637 | 132,190 | 25,596 | 157,786 | 8 | 9 |
| **5** | 2011/2012 | 142,390 | 154,251 | 132,222 | 25,186 | 157,408 | 8 | 11 |
| **6** | 2012/2013 | 144,857 | 157,489 | 136,144 | 23,756 | 159,900 | 9 | 10 |
| **7** | 2013/2014 | 160,634 | 173,549 | 152,743 | 23,560 | 176,304 | 8 | 10 |
| **8** | 2014/2015 | 164,758 | 178,087 | 149,975 | 29,763 | 179,738 | 8 | 9 |
| **9** | 2015/2016 | 163,168 | 177,184 | 164,561 | 14,407 | 178,968 | 9 | 10 |
| **10** | 2016/2017 | 165,412 | 180,332 | 169,160 | 14,205 | 183,364 | 9 | 11 |
| **11** | 2017/2018 | 164,479 | 179,545 | 167,004 | 14,538 | 181,542 | 9 | 10 |
| **12** | 2018/2019 | 161,418 | 174,897 | 166,837 | 14,289 | 181,126 | 8 | 12 |
| **13** | 2019/2020 | 157,189 | 171,037 | 167,306 | 13,944 | 181,250 | 9 | 15 |
| **14** | 2020/2021 | 153,915 | 167,644 | 165,109 | 13,289 | 178,398 | 9 | 16 |

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in PJM Interconnection’s initial capacity auction for capacity delivery year 2007/2008 through 2020/2021.

## Table 18: 4 RTOs with Capacity Markets

| RTO | Year | Energy Market Costs | Capacity Market Costs | Ancillary Services Market Costs | Total RTO Market Costs | Total RTO Market Costs (in dollars per megawatt-hour) |
|---|---|---|---|---|---|---|
| | 2011 | 7,223 | 1,451 | 42 | 8,715 | 64 |
| | 2012 | 5,500 | 1,252 | 60 | 6,812 | 51 |
| ISO New England | 2013 | 8,349 | 1,083 | 158 | 9,590 | 71 |
| | 2014 | 9,297 | 1,081 | 339 | 10,717 | 82 |
| | 2015 | 5,988 | 1,124 | 212 | 7,325 | 56 |
| | 2016 | 4,130 | 1,160 | 146 | 5,437 | 42 |
| | 2014 | 27,433 | 320 | 54 | 27,808 | 42 |
| Midcontinent ISO | 2015 | 18,086 | 536 | 42 | 18,664 | 29 |
| | 2016 | 17,680 | 1,120 | 53 | 18,853 | 29 |
| | 2009 | 7,916 | 1,463 | 173 | 9,551 | 60 |
| | 2010 | 9,875 | 1,714 | 176 | 11,764 | 72 |
| | 2011 | 8,937 | 848 | 147 | 9,932 | 61 |
| New York ISO | 2012 | 6,894 | 1,583 | 134 | 8,611 | 53 |
| | 2013 | 8,941 | 2,965 | 152 | 12,057 | 74 |
| | 2014 | 9,611 | 3,403 | 147 | 13,161 | 82 |
| | 2015 | 6,298 | 2,595 | 139 | 9,033 | 56 |
| | 2016 | 4,834 | 2,039 | 191 | 7,065 | 44 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | 2008 | 60,658 | 7,638 | 921 | 69,218 | 91 |
| | 2009 | 30,872 | 9,808 | 669 | 41,349 | 58 |
| | 2010 | 39,637 | 10,680 | 705 | 51,021 | 68 |
| | 2011 | 38,511 | 8,198 | 734 | 47,443 | 61 |
| **PJM Interconnection** | 2012 | 30,612 | 5,508 | 646 | 36,766 | 45 |
| | 2013 | 33,670 | 6,463 | 1,147 | 41,280 | 49 |
| | 2014 | 45,569 | 7,987 | 911 | 54,467 | 65 |
| | 2015 | 30,194 | 9,727 | 648 | 40,569 | 49 |
| | 2016 | 24,300 | 9,400 | 570 | 34,270 | 41 |

Source: GAO-18-131, Electricity Markets. Total annual costs in regional transmission organizations (RTO) with capacity markets, in millions of dollars, adjusted for inflation, for available years.

## Table 19: 6 RTOs, Wholesale Power Costs by Charge Type

| RTO/ISO | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| **CAISO** | | | | | |
| **Energy** | $50.83 | $34.61 | $30.84 | $38.09 | $46.46 |
| **Transmission** | $8.03 | $9.87 | $10.82 | $9.85 | $11.91 |
| **Capacity** | - | - | - | - | - |
| **Operating Reserves** | $0.30 | $0.27 | $0.51 | $0.69 | $0.85 |
| **Ancillary** | $0.00 | $0.00 | $0.00 | - | - |
| **RTO and Regulatory Fee** | $0.40 | $0.42 | $0.42 | $0.42 | $0.43 |
| **Other** | $0.54 | $0.50 | $0.40 | $0.52 | $1.41 |
| **ISONE** | | | | | |
| **Energy** | $51.87 | $30.94 | $35.43 | $45.76 | $42.23 |
| **Transmission** | $14.18 | $15.95 | $16.78 | $18.11 | $17.87 |
| **Capacity** | $8.56 | $9.17 | $9.40 | $25.07 | $32.49 |
| **Operating Reserves** | $1.87 | $0.75 | $0.80 | $0.86 | $0.82 |
| **Ancillary** | $0.32 | $0.32 | $0.30 | $0.29 | $0.31 |
| **RTO and Regulatory Fee** | $1.30 | $1.37 | $1.50 | $1.58 | $1.57 |
| **Other** | $0.43 | $0.45 | $0.45 | $0.34 | $0.12 |
| **MISO** | | | | | |
| **Energy** | $36.91 | $25.02 | $24.34 | $26.70 | $29.15 |
| **Transmission** | $2.65 | $2.93 | $3.45 | $3.74 | $3.55 |
| **Capacity** | $0.00 | $0.00 | $0.01 | $0.00 | $0.00 |
| **Operating Reserves** | $0.08 | $0.06 | $0.08 | $0.10 | $0.11 |
| **Ancillary** | $0.30 | $0.33 | $0.35 | $0.34 | $0.35 |
| **RTO and Regulatory Fee** | $0.20 | $0.21 | $0.21 | $0.24 | $0.32 |

| | | | | | |
|---|---|---|---|---|---|
| **Other** | $0.56 | $0.26 | $0.25 | $0.32 | $0.32 |
| **NYISO** | | | | | |
| **Energy** | $33.92 | $22.48 | $18.31 | $19.05 | $25.19 |
| **Transmission** | $0.66 | $0.64 | $0.83 | $0.79 | $0.85 |
| **Capacity** | - | - | - | - | - |
| **Operating Reserves** | $0.58 | $0.50 | $0.85 | $0.76 | $0.81 |
| **Ancillary** | $0.44 | $0.46 | $0.45 | $0.47 | $0.55 |
| **RTO and Regulatory Fee** | $0.71 | $0.72 | $0.91 | $0.98 | $0.96 |
| **Other** | $0.14 | $0.07 | $0.15 | $0.28 | $0.20 |
| **PJM** | | | | | |
| **Energy** | $53.14 | $36.16 | $29.23 | $30.99 | $38.24 |
| **Transmission** | $5.72 | $6.90 | $7.12 | $8.62 | $8.57 |
| **Capacity** | $8.91 | $11.14 | $8.99 | $8.75 | $11.89 |
| **Operating Reserves** | $0.59 | $0.36 | $0.24 | $0.24 | $0.31 |
| **Ancillary** | $0.51 | $0.51 | $0.53 | $0.59 | $0.57 |
| **RTO and Regulatory Fee** | $0.26 | $0.27 | $0.21 | $0.32 | $0.32 |
| **Other** | $1.15 | $0.38 | $0.16 | $0.11 | $0.21 |
| **SPP** | | | | | |
| **Energy** | $3.47 | $2.59 | $4.02 | $4.29 | $4.24 |
| **Transmission** | $5.68 | $6.34 | $7.49 | $8.16 | $8.05 |
| **Capacity** | - | - | - | - | - |
| **Operating Reserves** | $0.39 | $0.27 | $0.28 | $0.29 | $0.29 |
| **Ancillary** | $0.15 | $0.17 | $0.21 | $0.22 | $0.21 |
| **RTO and Regulatory Fee** | $0.63 | $0.69 | $0.61 | $0.69 | $0.67 |
| **Other** | $0.43 | $0.33 | $0.35 | $0.33 | $0.36 |

Source: GAO-18-131, Electricity Markets.

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