Capacity Markets

1 Introduction

A fundamental requirement of electric power systems is the maintenance of reliability. Reliability of the bulk electric power system is thought of in terms of two attributes: adequacy and operating reliability. These two terms are defined as follows [1]:

> **Adequacy** is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
>
> **Operating reliability** is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

In this document, we are concerned with adequacy, particularly the ability to maintain it within the planning process. *The single most influential way to maintain adequacy is to ensure the area's installed generating capacity will almost always exceed the area's peak requirement for each year in a given planning horizon*. There are two major qualifications to this last statement:

- Generator failures: The "almost always" part of this last statement recognizes that generation may fail, and so no matter how much generation is built, it is impossible to ensure the area's installed capacity will definitely exceed the area's peak requirement for each year in a given planning horizon (there is always the possibility, albeit very small, that enough generation may fail simultaneously to cause remaining generation to be unable to meet the demand).

- Non-generator means of ensuring adequacy: Adding installed generation capacity is not the only way to improve adequacy. There may be situations where the total generation is in fact sufficient, but the transmission between that generation and the load is insufficient to carry all of the generation that can be produced. Although building generation close to the load center may be an option, it might be an expensive one. In such a case, adding transmission may be the most cost-effective means of achieving adequacy. Alternatively, one may consider purchasing capacity from neighboring utilities, demand-side means (e.g., conservation programs and/or load control during peak periods), and/or storage.

Maintaining adequacy has always been a primary objective of the electric power industry. However, the process used to maintain adequacy previous to the advent of centralized bid-in electricity markets (CBM), and the process still used today in sectors of the country operating under the traditional regulated/vertically integrated markets (TRM), is necessarily different than the way adequacy is maintained in areas today operating under CBM.

In TRM, for any given service area, there is a single entity having responsibility, actually an obligation, to maintain adequacy for the customers of that region. The single entity is the vertically integrated utility. The vertically integrated utility accepts this obligation in exchange for the opportunity to earn a fair return on their investments through energy rates charged to customers. There are four observations to make about this "exchange":

1. Compact: This "exchange" is an implicit agreement between the electric utility and the customers it serves. It has been known as the "regulatory compact." The following paragraph characterizes it well [2]:

    > "It is occasionally argued that regulation constitutes an agreement between a utility and the government: the utility accepts an obligation to serve in return for the government's promise to set rates that will

compensate it fully for the costs it incurs to meet that obligation. This agreement is sometimes called the regulatory compact. Although this phrase is often heard, there is in fact no binding agreement between a utility and the government. Regulation is an exercise of the police power of the state, over an industry that is "affected with the public interest." Its need arises primarily from the monopoly characteristics of the industry, and its general objective is to ensure the provision of safe, adequate, and reliable service at prices (or revenues) that are sufficient, but no more than sufficient, to compensate the regulated firm for the costs (including returns on investment) that it incurs to fulfill its obligation to serve. The legal obligations of regulators and utilities have evolved through a long series of court decisions, several of which are discussed in this guide."

2. Monopoly: The "exchange" usually provides that the vertically integrated utility would be the only organization having the regulatory compact within a given service area, thus, the regulatory compact ensured the vertically integrated utility would operate as a monopoly.
3. Regulator: It would be awkward for the utility to actually make an agreement with all of the customers it serves. Thus, the customers it serves are represented by the state regulator, generally called the "utility board," the "public service commission," or the "public utilities commission." The function of the state regulator is unique in that it has sole authority to regulate the rates the electric utility charges the people of the state. (This differs from the North American Reliability Corporation, NERC; although NERC monitors and polices reliability, it has no authority over rates. This also differs from the Federal Energy Regulatory Commission, FERC, which has authority only over energy exchange that occurs between organizations in different states.)
4. Energy rates: For most customers, it is through the energy rates that revenues are provided to the utility to maintain adequacy (uniquely large customers may also pay a specific charge related to their peak demand). However, the maintenance of adequacy is much more of a capacity issue rather than an energy issue.

The difference between capacity and energy is that it is capacity that determines whether demand can be met at a singular point in time; energy is the integration of that demand (or the generation that supplies it), over a time interval. Thus, because energy rates are used to pay for capacity needs, there needs to be an "adder" to the short-term cost of energy to pay for the longer-term cost of capacity. Regulators are well aware of this need and understand they must be willing to allow the electric utility to reflect this adder in their energy rates.

When some regions in the US introduced CBM, the regulatory compact had to be revisited. The reason for this was that because CBM necessarily relied on having many competitive market participants, the vertically integrated utility could no longer be granted monopolistic status; neither could a rate of return be guaranteed, at least not for the parts of its organization which participated in the competitive energy market. In CBM, because the regulator no longer provides these two guarantees to the utility, the utility could no longer be expected to accept the obligation to ensure the reliability of the service area. This left open the very important question: who would be responsible for ensuring the reliability of the service area?

There have been three responses to this question:

1. <u>The regional transmission organization (RTO)</u>: In 1999, FERC Order 2000 brought about the concept of RTOs [3]. An RTO is an organization, independent of all generation or transmission owners and load-serving entities, that facilitates electricity transmission on a regional basis with responsibilities for grid reliability, planning, and transmission operation. Although the RTO's primary focus was transmission (and not generation), it was also responsible for grid reliability; in addition, it is not possible to perform transmission planning without knowing something about generation. Thus, through the RTO, an organization was created that would at least pay attention to

reliability. RTOs were well-positioned to maintain operational reliability via monitoring the grid and enforcing operating limits. However, RTOs were limited in maintaining long-term adequacy, since they could not build and own capacity themselves (a requirement necessary to maintain the market independence of the RTO).

2. The real-time and day-ahead markets: At the heart of the CBM were the real-time and day-ahead markets where market participants provided offers to sell energy (and later also to sell ancillary services, i.e., regulation and contingency reserves). Because revenues received by energy suppliers was dictated by the market clearing price, and because the market clearing price would by definition be equal to (for the marginal units) or higher than (for all other units) the offers to sell energy made by the market participants, there would be a difference between what market participants were paid and what they were willing to be paid (their costs), and this difference, integrated over time, would be sufficient to fund development of additional generation capacity. An important feature of this thinking is that the price of energy would become particularly high during periods of peak demand, and extremely high during the rare moments when generation is just sufficient (or insufficient) to meet demand. This is illustrated in Figure 1 (inspired by a figure in [4]), where the baseload units are making a great deal of money when the price is established by the emergency peakers. These short-duration bursts of revenue are especially useful to incent the suppliers to build additional capacity.

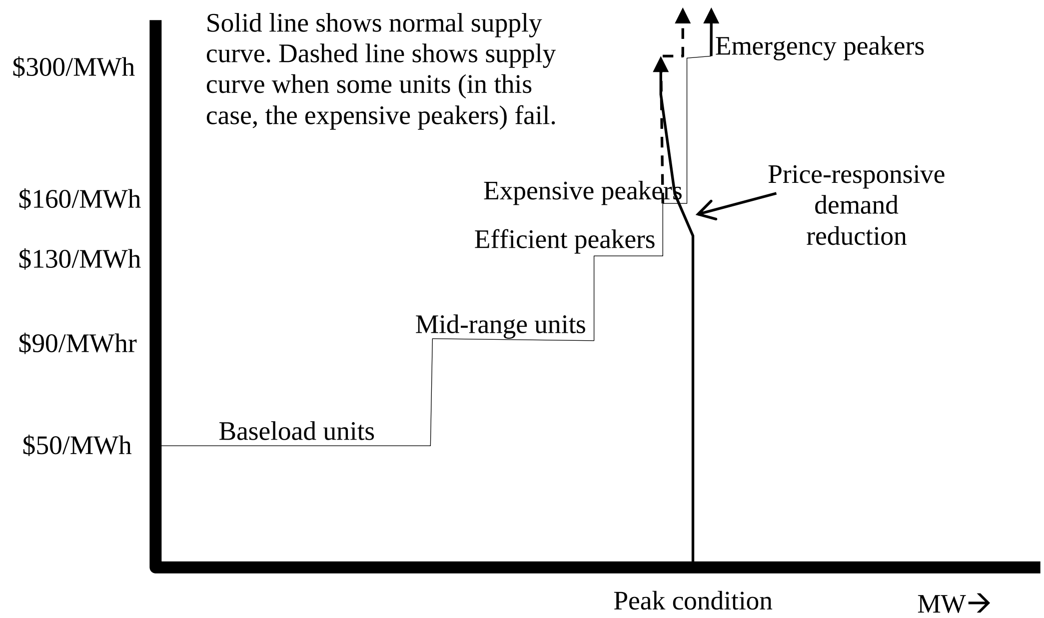


Figure 1: Illustration of energy price under peak condition with all units available and peak condition when some units fail

There are three additional issues that need to be described, in reference to Figure 1.

a. True vs. offered: Figure 1 is based on the suppliers offering their true marginal costs. This is theoretically what market participants do when the capacity of the suppliers significantly exceeds the demand. However, when operating conditions reach a point where capacity is just sufficient (or insufficient) for supplying demand, suppliers will know this and will increase their offers in order to push the clearing price up based on the realization that if the market needs all the supply it can get, it will not be possible to offer too high a price, a behavior that is consistent with the following thinking on the part of the supplier during peak periods: “Even if I offer far above the next highest offer, I will be selected (and will become the marginal unit, i.e., the price-setting unit).” Thus, the price can soar to very high levels during such a condition. This is how a market operates when the commodity is scarce. There exists a large literature on the topic of scarcity pricing which argues that such price increases are not bad in and of themselves and in fact provide the very signal that suppliers need to increase their capacity.

b. Price caps: Most electricity markets provide price caps to limit the energy price that can be reached during scarcity conditions. For example, PJM implements a "shortage pricing" mechanism when reserves are short, imposing a price cap of $2700/MWhr for energy [5]. (Additional information on shortage price mechanisms used by ISO markets may be found in [6].) Although this price cap protects customers against volatile, high prices, they may require load shedding if emergency resources are unwilling to supply at that price. It has been argued that such price caps inappropriately skew the need for capacity investment by limiting the additional revenues that can be obtained during scarcity conditions and therefore should not be allowed. However, others argue that the basic problem cannot be addressed by lifting the price cap because the price of blackouts is not known and cannot be known, and therefore market agents cannot use this knowledge to calibrate their generation offers during periods of blackout risk.

c. Blackouts: The extreme form of an event caused by a lack of adequacy is a blackout whereby a large number of customers are interrupted for a significant duration. The cost of such sustained load interruptions has been referred to as the value of lost load (VOLL), and estimates vary greatly with region and with type of customer, as indicated in Figure 2 (note that the units are $/kWh, to be multiplied by 1000 to get $/MWh).

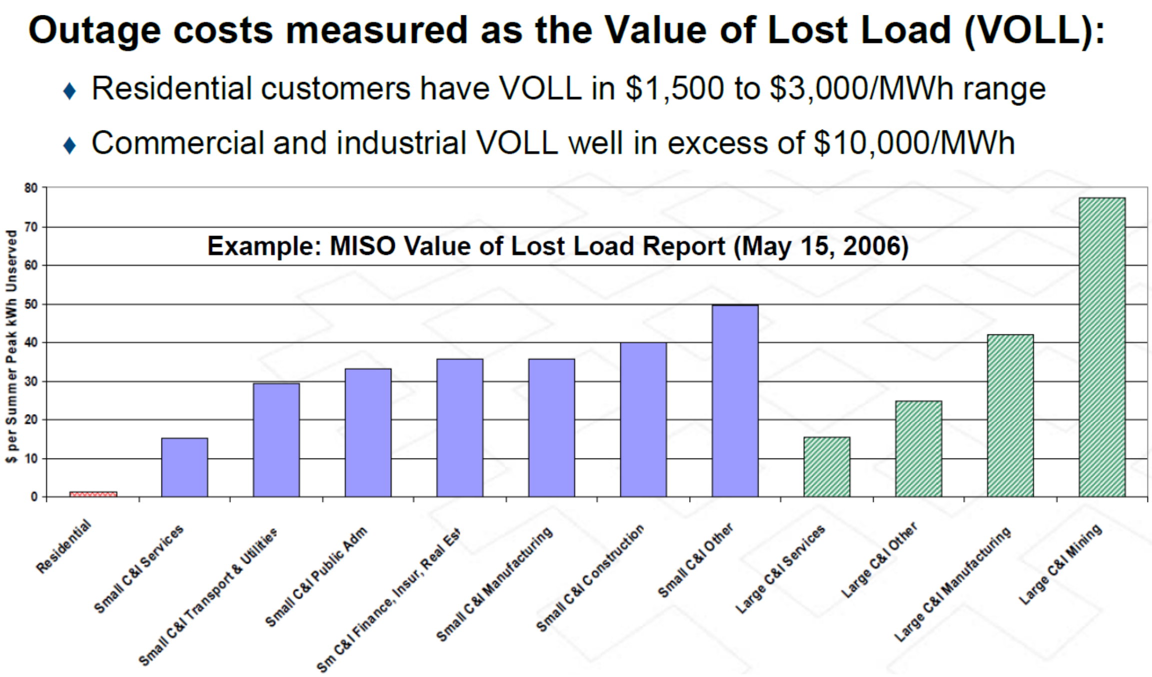


Figure 2: Value of Lost Load

It should be understood that there is a great deal of uncertainty associated with the plots of Figure 2. Still, the figure establishes that the VOLL is significantly higher than the price caps being imposed on most energy markets today. And so it may follow that price caps on the order of $2700/MWhr really do distort the market, and lifting those price caps would provide the desired market signal to incentivize capacity investment.

However, reference [4] argues that blackouts cannot be priced simply because, by definition, the commodity (energy) cannot be bought and sold during a blackout and thus it is not possible to establish a scarcity price during a blackout. That is, "electricity markets cannot optimize blackouts," and "the price that is being paid to generators during blackouts must be set by administrative rules" [4].

This reasoning has led to the concept of the "missing money," which refers to the fact that the energy markets do not provide revenue sufficient to induce capacity investment, a concept that is consistent with experience of several years of real-time and day-ahead market operation, where it was observed that construction of new generation capacity was not keeping pace with generation retirements and demand growth, so that reserve margins were declining. Historical installed reserve margins (IRMs) since 1999 are indicated in Table 1 for PJM [7] and in Figure 3 for NYISO.

Table 1: PJM Installed Reserve Margins

Approved IRM by Delivery Year

Delivery Year	IRM	Updated IRM
1999/2000	20.0%	
2000/2001	19.5%	
2001/2002	19.0%	
2002/2003	19.0%	
2003/2004	17.0%	
2004/2005	16.0%	
2005/2006	15.0%	
2006/2007	15.0%	
2007/2008	15.0%	
2008/2009	15.0%	
2009/2010	15.0%	
2010/2011	15.5%	
2011/2012	15.5%	
2012/2013	15.6%	
2013/2014	15.4%	15.9%
2014/2015	15.4%	15.9%
2015/2016	15.4%	15.3%
2016/2017	15.6%	

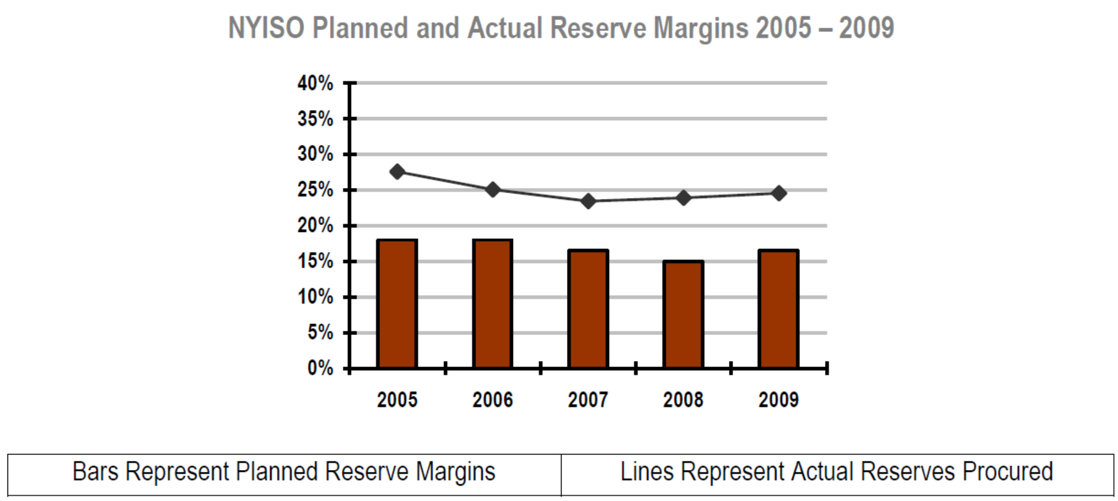


Figure 3: NYISO Reserve Margins

This leads us to the third response to the question: who would be responsible for ensuring the reliability of the service area?

3. Capacity markets: Capacity markets are separate bid-in markets for capacity only, completely independent of the energy markets. In the US, they have been established by three different ISOs: PJM, ISONE, and NYISO (probably because they all had some level of experience with similar mechanisms when they operated under a TRM paradigm) and more recently, also MISO. In section 2, we describe the first capacity markets implemented by these organizations and extend that discussion to include their later evolution.

2 Initial development of capacity markets

The description below is heavily adapted from [8].

The first capacity market designs were referred to as ICAP markets. In these designs, a "capacity ticket" for one unit of installed capacity could be sold by each generation owner up to is total installed capacity. Each load-serving entity (LSE) had to acquire ICAP up to its forecast demand plus the region's specified reserve margin. A price cap prevented capacity prices from getting too high. These units were bought and sold on two-sided auctions, although they could also be traded bilaterally.

The initial ICAP markets ran on very short time horizons, e.g., 1 month, so the capacity supply and demand were essentially fixed during the time interval (it was not possible to actually build anything during that time). The outcome was considered to be "bipolar," that is, if there were a supply surplus, the price was zero (no bids to buy), and if there were a supply deficit, the price rose to the cap (offers were made only at the cap price), as indicated in Figure 4a below.

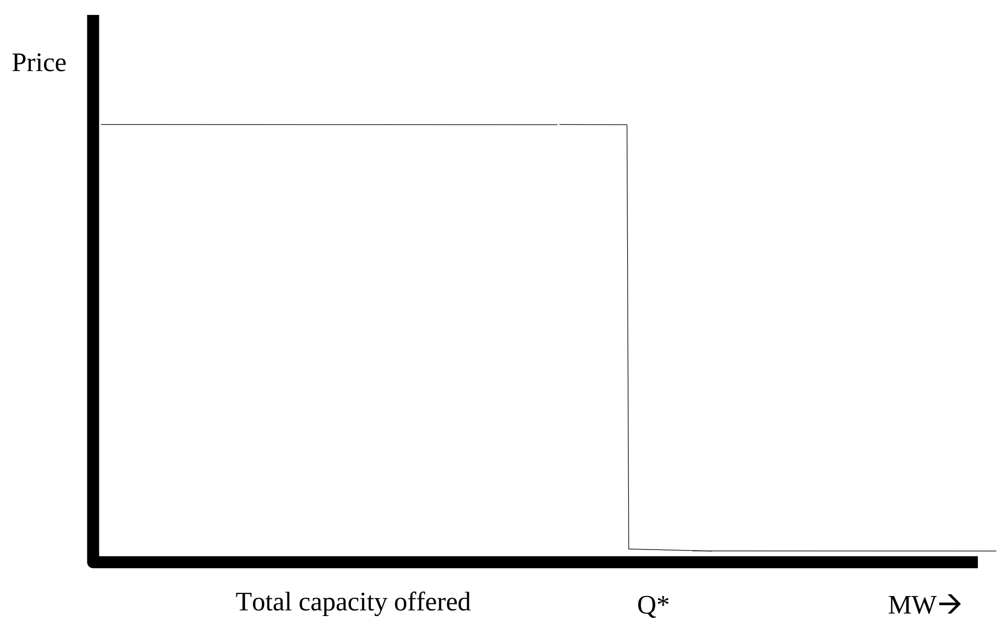


Figure 4a: Bipolar pricing

2.1 Inclusion of unit reliability

PJM improved this approach by replacing installed capacity, ICAP, with UCAP=ICAP×(1-EFOR$_D$). Here, UCAP represents the "unforced capacity," and EFOR$_D$ represents the "Effective Forced

Outage Rate under Demand.” (The index is related to but not the same as EFOR.) The $EFOR_D$ is given by [9]:

$$\mathrm{EFOR}_D = \frac{\begin{matrix}\text{forced} \\ \text{outage hours}\end{matrix} + \begin{matrix}\text{equivalent forced} \\ \text{derated hours}\end{matrix}}{\begin{matrix}\text{forced} \\ \text{outage hours}\end{matrix} + \begin{matrix}\text{service} \\ \text{hours}\end{matrix}}$$

$$EFOR_D = \frac{FOH + EFDH}{FOH + SH}$$

Here, the numerator is the total equivalent forced outage hours, and the denominator is the total equivalent hours that the unit is in demand. In these equations, it is important that FOH and EFDH are only computed from time periods where the unit is in demand.

So use of $EFOR_D$ was an attempt to factor in the influence of a unit’s reliability.

2.2 Use of demand curve

The problem described above where the prices were essentially bipolar was addressed by substituting the participation of the LSE’s with a demand curve, referred to formally as a variable resource requirement (VRR).

The demand curve approach provided that:
(a) Capacity is purchased by the ISO (and passed to the LSEs);
(b) The price at Q*, when capacity is as desired (to achieve the desired reserve margin), is the “cost of new entry” (CONE) which is set at the cost for a peaking plant (after subtracting net energy and ancillary service revenues).
(c) The relationship between the purchase price and the quantity offered is a pre-determined relationship such that a higher price is paid when the total quantity is below the desired capacity Q* (accounting for reserves), and the price decreases as the total quantity exceeds Q*, as illustrated in Figure 5b.
(d) The price is capped.

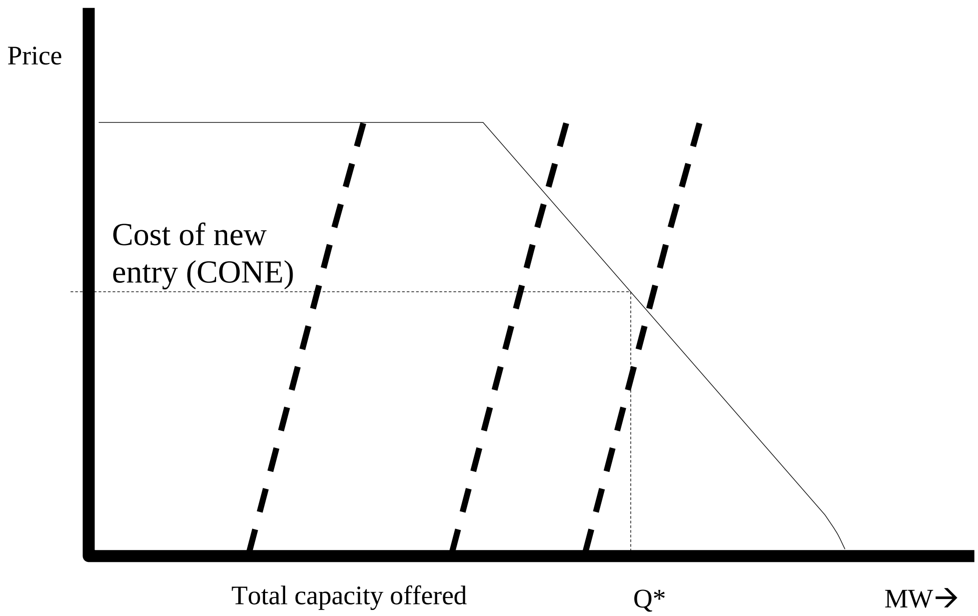


Figure 5b: Demand curve

2.3 Locational ICAP

In the NYISO design, the ICAP included a locational aspect and so was referred to as LICAP, with three zones: New York City, Long Island, and the "Rest of State." Each zone had its own demand curve. More detail is provided in the appendix.

2.4 Forward capacity markets

Two ISOs, PJM and ISONE, believed that their ICAP would be more effective, generating more capacity at lower prices, if the ICAP extended forward in time its contracting period beyond a month, giving rise to the so-called forward capacity markets. These are referred to as the Forward Capacity Market (FCM) in ISONE and the Reliability Pricing Model (RPM) in PJM. Both have three-year contracting periods.

The effect of the extended contracting period is to flatten the supply curve, as illustrated in Figure 6. Additional detail is provided in the appendix for PJM and ISONE.

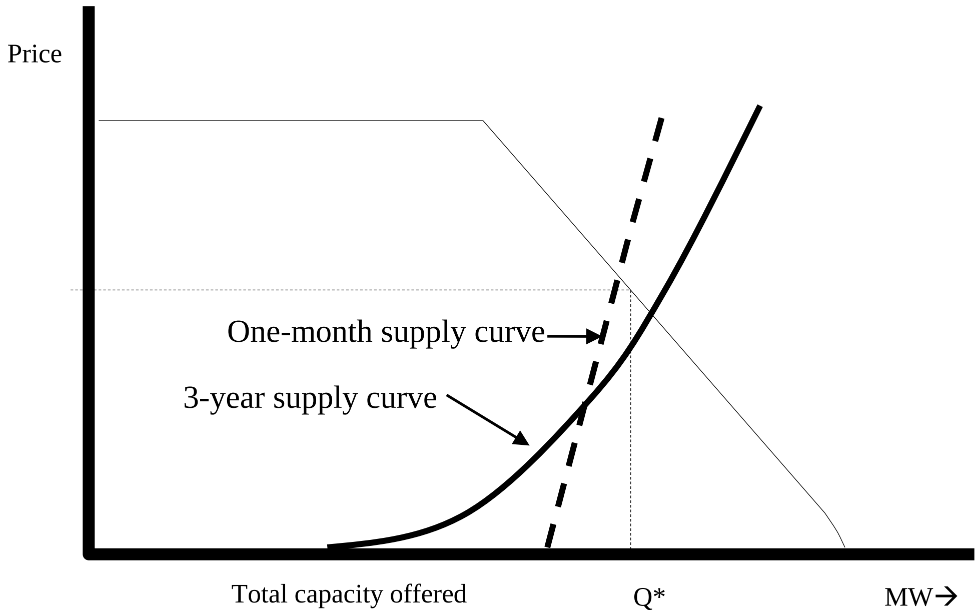


Figure 6: Supply curves for 1 month and 3 year capacity market designs

2.5 Capacity markets in other ISOs

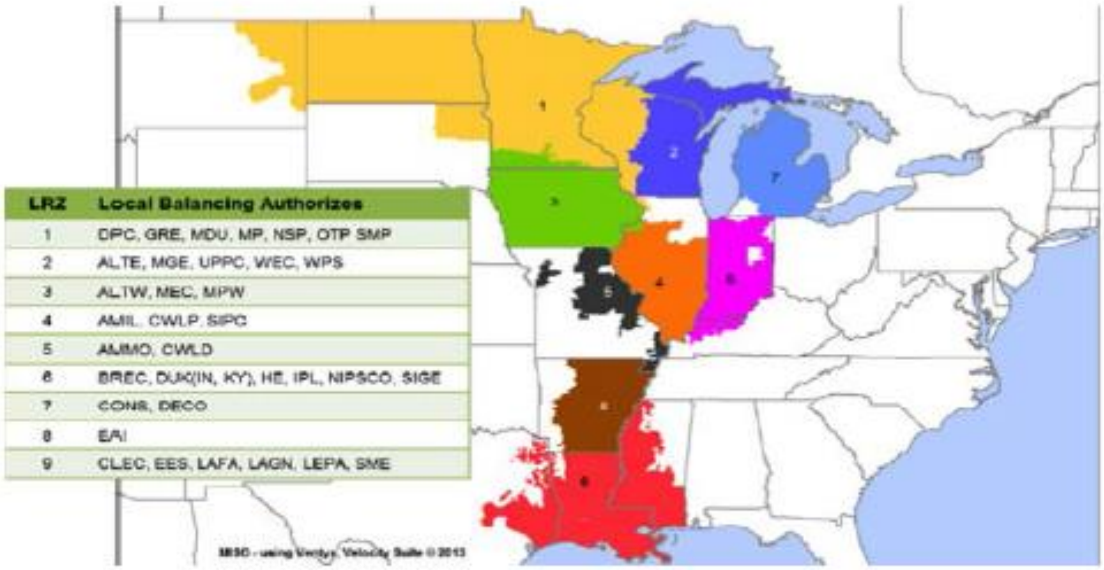
Although CAISO and ERCOT do not have capacity markets, there are activities in each which suggest that they are moving in this direction, as summarized in the appendix.

3 Summary of today's capacity markets

Reference [10] provides a good summary of capacity markets, duplicated below.

	PJM	MISO	NYISO	ISO-NE
Procurement Framework	Reliability Pricing Model (**RPM**)	Resource Adequacy Requirement (**RAR**)	Installed Capacity Market (**ICAP**)	Forward Capacity Market (**FCM**)
Year Implemented	2007/2008	2013/2014	2006/2007	2010/2011
Most Recent Volume Cleared*	167,003.7 MW (Cleared in BRA for 17/18 DY**)	136,912 MW (Cleared in PRA for 14/15 DY**)	3290 MW / 2619.4 MW (Cleared in Summer 14 / Winter 13-14 Strip Auctions)	33,712 MW (Cleared in FCA for 17/18 CCP**)
Most Recent Cleared Prices	**$ / MW-day** • RTO: $120 • MAAC: $120 • EMAAC: $120 • SWMAAC: $120 • PSEG: $215 (Cleared in BRA for 17/18 DY**)	**$ / MW-day** • LRZ 1: $3.29 • LRZ 2-7: $16.75 • LRZ 8-9: $16.44 (Cleared in PRA for 14/15 DY**)	**$ / kW-month** • LI: $6.39 / $4 • NYC: $16.24 / $7.54 • NYCA: $5.15 / $2.58 • G-J: $9.96 / - Summer / Winter Strip Auction (Cleared in Summer 14 / Winter 13-14 Strip Auctions)	**$ / kW-month** • CT: $7.02 / $15 • ME: $7.02 / $15 • Boston: $15 / $15 • ROS: $7.02 / $15 Existing / New Resources (Cleared in FCA for 17/18 CCP**)
Notes	* Volumes Cleared refer to unforced capacity (UCAP) or capacity otherwise qualified as representing the amount of installed capacity that is actually available at any given time. ** DY (Delivery Year) & CPP (Capacity Commitment Period) refers to June 1 – May 31 of the next year.			

Observe in the previous table that each capacity market has zones, e.g., in the MISO capacity market, the zones are shown as below.



4 A capacity market model

Reference [11] provides a high-level model of the PJM capacity market, which I have provided below. The acronym “LDA” stands for “locational deliverability area.”

Minimize ResourceOfferCost - LDA_DemandCurveRevenue

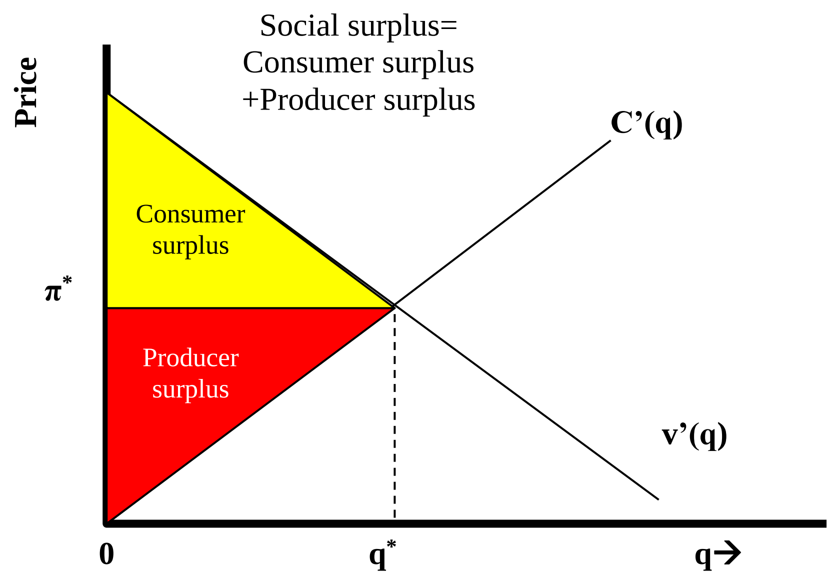
Subject to several constraints, among which are, for each LDA:

1. LDA power balance:
   LDA_Capacity_Award+LDA_Import
   >=LDA_DemandCurveAward
2. LDA capacity award calculation
   LDA_Capacity_Award
   =sum of capacity of each resource in LDA
3. Import limit constraint:
   LDA_Import<=LDA_Import_Limit

Some additional comments:

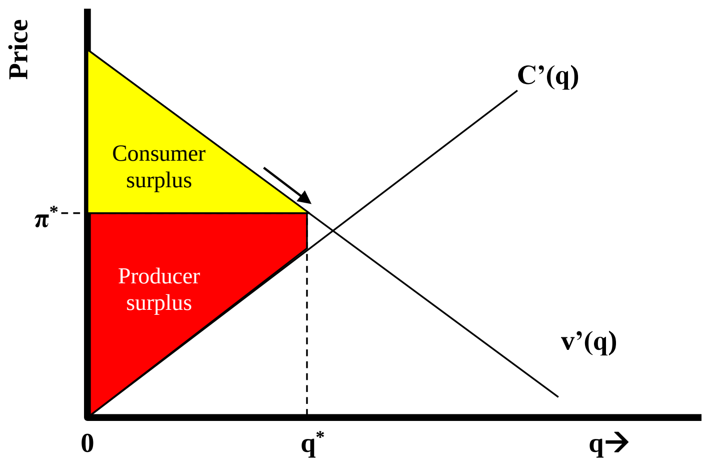
1. The objective is to minimize the difference between the cost of the commodity (in this case, capacity) and the value prescribed to it. What are we really doing here?

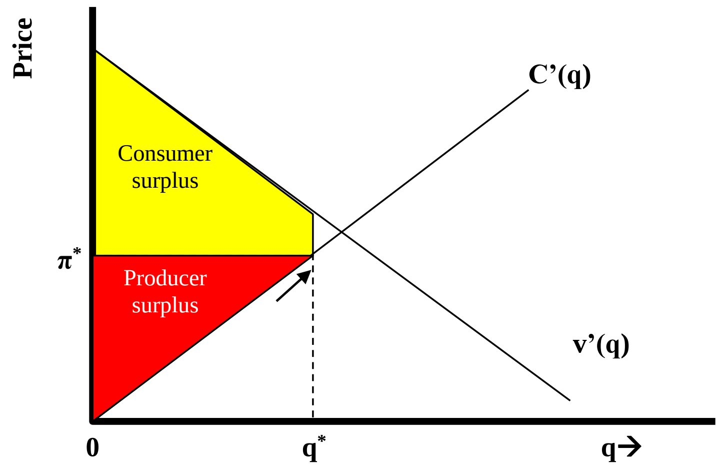
   Definition: The sum of the consumer surplus and the producer surplus is called the *social surplus*. It is a measure of the total benefit seen by an economy and it is what we want to maximize. It is illustrated below.



   Why does the point (q*,pi*) maximize social surplus?

- If willingness to pay for an additional unit of capacity is higher than its cost of producing it, we increase social surplus by producing one more unit.





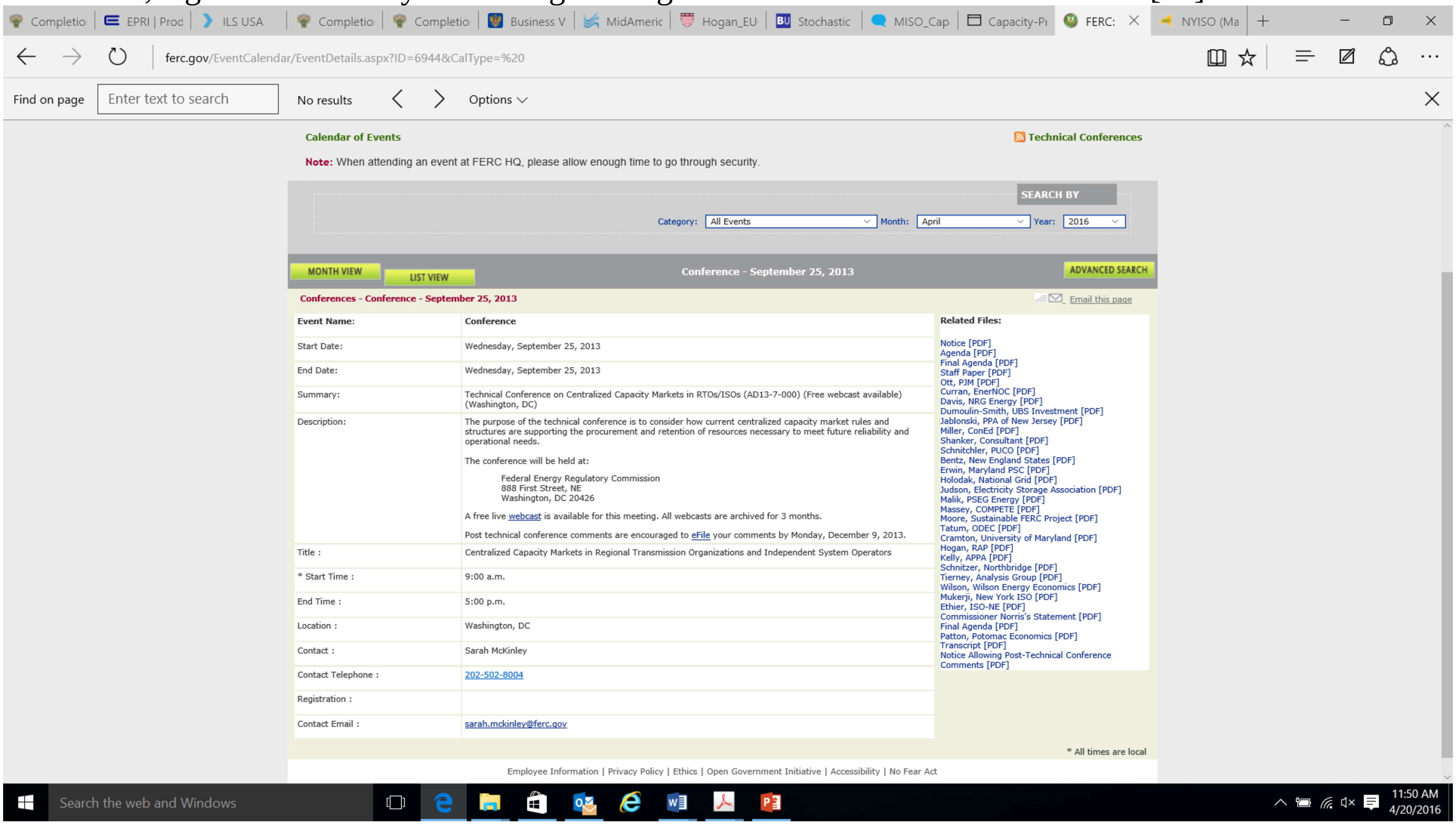
- If willingness to pay for an additional unit of energy is lower than its cost of production, then we increase social surplus by producing one unit less.
- It is only when willingness to pay for an additional unit of energy equals the cost of producing an additional unit can we be maximizing the social surplus.

2. The market clearing price (MCP) is the shadow price (Lagrange multiplier) of each LDA power balance constraint.

5 Additional points

- We have not done a complete job in these notes communicating the intricacies and processes of capacity markets. Reference [12] and others would be a good place to start in understanding these additional issues.
- Market power is an issue in capacity markets; designs must account for this.
- The capacity markets have separated capacity procurement from operations. Thus, capacity markets are not GEP, and they are certainly not TEP or CEP.
- It would seem that capacity markets should be more like a GEP, with reliability evaluation. Furthermore, given transmission can also provide capacity, it would seem that capacity markets should be more like a CEP.
- So, …Why are capacity markets separated from operations, and from transmission?

- This topic has been in-flux. A FERC technical conference on this topic was held in September 2013; a great deal of very interesting reading can be found at the related website [13].



Here is an interesting article, from http://midwestenergynews.com/2016/01/07/illinois-ag-wants-refunds-for-ratepayers-from-miso-auction/.

6 Illinois AG wants refunds for ratepayers from MISO auction

6.1.1.1.1 Written By EnergyWire01/07/2016

By Jeffrey Tomich

Federal energy regulators ordered the grid operator for a large swath of the central United States to alter rules that govern its annual capacity auction in response to complaints over soaring prices in southern Illinois.

The Federal Energy Regulatory Commission issued the order Dec. 31 declaring elements of the rules governing the spring auction "unjust and unreasonable." FERC specifically ordered the Midcontinent Independent System Operator to change two key formulas in its tariff that governs bidding by power plant owners.

The order applies to future auctions and is expected to result in lower prices than would have been produced under existing auction rules. Meanwhile, FERC is continuing its investigation into claims that last year's auction clearing prices in southern Illinois were manipulated.

FERC declared any future refunds issued in response to complaints retroactive to May 28, the day the first ones were filed.

The Dec. 31 order is the latest action in a complex and controversial issue involving the price of capacity in southern Illinois. Capacity payments ensure that power plants are available at times of peak demand. Prices are embedded in consumer electric rates.

The flare-up in Illinois began in April when prices in MISO's grid in the southern half of the state surged ninefold to $150 per megawatt-day while clearing prices across the rest of MISO were $3.75 (*EnergyWire*, April 17, 2015). The increase means the average residential customer in Ameren Illinois' service area will pay an extra $131 a year.

The increases sparked a political backlash and complaints to FERC by Illinois Attorney General Lisa Madigan, Public Citizen and others. FERC in October ordered its Office of Enforcement to conduct a formal investigation (*EnergyWire*, Oct. 5, 2015).

Madigan applauded FERC's decision to require changes in MISO's auction rules. She also urged regulators to deliver relief from last year's price jump.

"FERC has acknowledged downstate electric customers deserve relief from an inflated and absurd pricing process," Madigan said in a statement. But the commission "still needs to order refunds to consumers for the outrageously high prices."

Tyson Slocum, director of Public Citizen's Energy Program, said it's logical to think that if FERC decided elements of current auction rules to be unjust that it should find the same of the most recent results. If so, consumer refunds could total in tens of millions of dollars, he said.

"It seems reasonable to conclude," Slocum said. "But that's not a given."

MISO, which is studying new rules for the capacity market in southern Illinois -- the only area within the grid operator's 15-state footprint with a competitive retail electricity market -- said it's continuing to review last week's order (*EnergyWire*, Dec. 11, 2015). The grid operator must file the rule changes with FERC within 30 and 90 days, respectively.

"As we review the order, we will work with stakeholders to better understand the changes directed by the commission and how they would be implemented for the upcoming auction," MISO spokesman Andy Schonert said in an emailed statement.

FERC's order requires MISO to recalculate a "reference" price published ahead of the auction. The price, which was based on the price of capacity in neighboring PJM Interconnection LLC, acts as a benchmark for power plant owners, informing them how much they can bid without inviting scrutiny by MISO's market monitor.

The commission, which rejected parts of the complaint, also ordered MISO to adjust how it calculates the amount of power that can be imported into specific "zones," such as southern Illinois (Zone 4). Allowing for more power to be imported increases the available supply and helps reduce prices.

And from http://www.utilitydive.com/news/miso-exelon-dynegy-propose-capacity-market-reforms-in-southern-illinois/414519/

MISO: Exelon, Dynegy propose capacity market reforms in southern Illinois

By Robert Walton | February 25, 2016 print

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6.1.2 Dive Brief:

- Dynegy and Exelon have proposed a series of market reforms to the Midcontinent Independent System Operator (MISO), calling for longer planning cycles rather than a 12-month capacity auction which they say can distort price signals.
- Dynegy is calling for a series of four one-year auctions running through 2021, and Exelon proposed a similar method using rules from neighboring PJM Interconnection, according to EnergyWire.
- MISO, last fall, said that capacity market reforms may be required to drive future investment and maintain reliable supply. The generators submitted their proposals to a MISO task force addressing market issues in a portion of Illinois.

6.1.3 Dive Insight:

Last year, a MISO capacity auction in Zone 4, mostly made up by Southern Illinois, cleared $150/MW-day compared to $16.75/MW-day during the same period last year.

That led to investigations and claims generators may have been manipulating the market. In response, MISO kicked off a task force to address the issues and consider market reforms, which it now appears could include a restructuring of how the region plans for its power needs.

"We need to make sure the market design is sufficient to either ensure that exist resources will consistently be available into the future or that new resources would replace them were those existing resources to go away," MISO spokesman Jeff Bladen told EnergyWire.

According to Exelon, utilizing an auction mechanism in southern Illinois that is similar to the process in PJM markets would help ensure "parity between northern and southern Illinois," the generator said in its filing.

Dynegy, which came under investigation following the price spikes, said a series of four auctions would provide a better price signal. Illinois Attorney General Lisa Madigan last year asked federal regulators to halt the subsequent rate increase associated with the auction in question, and to investigate the utility.

Dynegy defended its actions, claiming it "offered all of its megawatts into the MISO auction with no physical or economic withholding in accordance with MISO tariffs and as approved by the Independent Market Monitor."

EnergyWire notes MISO is gearing up for another, similar meeting next month, where a wider group will propose capacity market changes.

Appendix

NYISO: In NYISO's Installed-CAPacity (ICAP) market, capacity procurement is based on demand curve established by the regulator using the forecasted peak load plus a margin in order to suffice reliability requirements (Loss of Load Expectation (LOLE)) [14]. Unlike PJM and ISO-NE, the NYISO capacity mechanism is short term. The capacity is procured through ICAP auctions, self-supply and bilateral arrangements. New York has capacity requirements for three zones: New York City, Long Island and New York-Rest of State. The NYISO conducts auctions namely the capability period auction (covering six months), the monthly auction and the spot market auction. The resource requirements do not change in the monthly auctions and the ICAP spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSE's load forecasts. Higher (lower) ICAP market clearing price indicates lower (higher) capacity procurement, and hence the price is expected to drive investments in new generators. The capacity market expenses are distributed amongst LSEs according to the proportion of their load.

ISO-NE: In the annual forward capacity auctions (FCA) market of ISO-NE, both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied [15]. The FCA market consists of Descending-Clock and market-clearing auctions to clear the capacities, including both existing and new entrants each subject to specific rulings, for meeting the Installed Capacity Requirement (ICR). Apart from this, the FCM model also takes local capacity requirements as input for ensuring sufficient capacity for local regions subject to constrained transmission. The three-year lead time encourages participation by new resources and allows the market to adapt to resources leaving the market. If the first round of auction does not attract minimum estimated capacity for ensuring adequacy, then the auction is cancelled and ISO-NE establishes bilateral contracts to procure the remaining capacity. Resources whose capacity clears the FCA acquire capacity supply obligations (CSOs). Like the NYISO and PJM, the FCA process models transmission constraints to identify the import- or export-constrained load zones.

PJM: The PJM Reliability Pricing Model (RPM) [16] is similar to NYISO's ICAP market, in terms of estimating the required capacity in terms of a capacity demand curve and going through a RPM auction to procure required capacity, and allowing RPM clearing price to attract newer investments. It is different from ICAP market and similar to NE-ISO's FCM in terms of forward clearing time of three years. However, if the auction does not attract sufficient capacity to meet the minimum capacity requirement, the auction is not cancelled (unlike NE-ISO), and the resulting high price of capacity is expected to spur newer investments.

CAISO: Although CAISO does not operate a formal capacity market, the state's Public Utility Commission has imposed a mandatory resource adequacy requirement. It mandates each Load Serving Entity (LSE) to procure 115 percent of their aggregate system load on a monthly basis as long as a different reserve margin is not mandated by the LSE's local regulatory authority. It also requires deliverability criteria each LSE must meet, as well as system and local capacity requirements. The CAISO provides technical assessments to support these requirements, as well as running short-run capacity procurement mechanisms in case of shortfalls. Presently, the PUC and CAISO are cooperating on defining possible longer run (multiyear) resource procurement rules, including provisions for flexible capacity.

MISO: Although MISO does not have a long term capacity mechanism, it does impose a monthly capacity requirement on all LSEs on the basis of load forecast plus reserves. MISO requires the LSEs to specify the physical capacity, including demand resources that they have allocated specifically to meet their load forecast. They can acquire this capacity either through bilateral purchase or self-supply. Additionally, MISO provides an opportunity for the load that has not arranged all of its capacity to procure its needs from uncommitted resources through conducting monthly auctions.

ERCOT: Currently, the LSEs are expected to procure the required capacity to meet the peak load, but there is no formal market mechanism. However, Texas is also actively planning a capacity market [17] for the future.

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