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DEEP WP 017

Electricity Capacity Markets at a Crossroads

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April, 2017

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Capacity Markets at a Crossroads

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April 2017

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Contents

Executive Summary

Almost twenty years after the initial restructuring of power markets in much of the United States, investments in generation and other supply resources are executed under three different resource adequacy (RA) paradigms. Much of the country still executes investments through a process of regulatory planning by utilities overseen by local regulatory authorities. These resources are compensated either under cost-based regulatory principles or through long-term contracts between utilities and non-utility generation.

The energy only paradigm, prominent internationally, continues to be the foundation for valuing resources in the ERCOT market. Supply resources earn revenues through the sale of energy and ancillary services on daily and hourly markets. During periods of scarcity, prices are allowed to rise thousands of dollars above the operating costs of resources in order to allow for the recovery of capital and other fixed costs.

Outside of ERCOT, supply resources in other U.S. markets operated by regional transmission organizations can earn revenues for the provision of capacity, a product defined by the expected *potential* to supply energy. Some regions assign RA requirements to load-serving entities (LSEs), who have the responsibility to either self supply or procure capacity sufficient to cover their required reserve margins. Other regions operate centralized capacity markets, in which the system operator effectively acquires the capacity and allocates the costs to LSEs. The common thread for all of these markets is that there is an explicit or implicit value placed on capacity that creates a additional revenue stream for resources that is distinct from the sales of energy and ancillary services.

These three paradigms frequently overlap. Regulated entities are sometimes subject to RA requirements or capacity markets. Many elements of the energy-only paradigm, particularly high scarcity prices, are being adopted in most ISO markets. The Midwest Independent System Operator (MISO), which places RA requirements on its members, also runs an auction based capacity market that provides LSEs with an optional venue through which to meet their RA obligations.

All of these paradigms have proven capable of supporting investment of generation and other resources. New capacity has been added through each of these channels over the last 15 years. Policy questions about resource adequacy are therefore not a matter of whether a particular paradigm can support *any* investment, but rather about the relative efficiency of investment and the performance of the resources that have been procured. Importantly, regardless of the RA paradigm that underpins investment, the vast majority of investment in *any* region is primarily supported by some combination of long-term bilateral contracts, vertical integration, as well as regulatory cost-recovery.

These questions are becoming more pressing with the emergence of several trends that are challenging traditional approaches to planning for, and securing, resource adequacy. These trends include the following.

1. **Low average energy prices** are challenging the financial viability of a large number of incumbent baseload generation resources. This has raised questions as to whether RA policies are adequately valuing the contributions of these resources relative to the resources that are displacing them.

Despite ongoing changes to allow technically higher maximum prices in periods of scarcity, these changes have been more than offset by lower natural gas prices and increased entry of renewable generation. However, policy makers should not over-react to the fact that some incumbent baseload generation units and technologies are under increasing financial pressure. In many cases these units would have difficulty in any market environment given the trends with natural gas prices and renewable energy. The key policy question is whether there are specific attributes that are not being captured by existing RA frameworks. While an argument could be made that the greenhouse gas characteristics of nuclear energy are undervalued in many states, particularly relative to renewable energy, such gaps due to state and federal environmental policies, rather than RA design flaws. An argument has also been made that markets do not adequately reflect the benefits of a diverse fuel mix, however, risks of natural gas prices are not external to deregulated suppliers who do have an incentive to hedge those risks.

2. **Alternative resources**—such as renewable generation and demand response—are rapidly increasing their market shares in both energy and capacity markets. This has increased the importance of imperfect metrics that compare and incentivize the relative reliability contribution and the performance of diverse resources.

Roughly half of new capacity added to ISO markets in the last five years has been from renewable resources with intermittent production. Demand response resources have also earned a substantial market share in capacity markets in the last five years. Each type of resource represents new and distinct challenges for measuring their reliability benefits, at least in a time frame of months or years in advance. A key policy question is the degree to rely upon performance incentives and short term market rewards to provide adequate value to resources with the ability to perform flexibly and in the periods of highest need. Demand response resources create the additional challenge of establishing an accurate (and manipulation resistant) baseline against which reductions in consumption are measured and rewarded.

The influx of diverse resources places more need to accurately measure their contributions, which is most easily accomplished when one knows exactly the market conditions under which those resources are producing. This implies that markets, even those with capacity payment frameworks, should further emphasize the incentives provided to resources for the provision of energy and ancillary services, particularly during periods of scarcity. The definition and interpretation of scarcity may need to be expanded to include aspects of ramping and other short-run dynamic services. In addition, the rewards for services should be symmetric. Policymakers should closely monitor the design and structure of DR payments and performance.

3. The extension of uniform RA market policies to states with **increasingly diverse regulatory preferences** is creating tension between the oversight of RA markets and the policy preferences of individual states.

RA policies are increasingly expanding into regions operating under traditional regulation. Many of the original justifications for RA markets, such as compensating for missing money from market revenues, and preventing the free riding of competitive retailers, do not apply to these regions. In the regulatory arena there is a tension between the fact that RA policies can better inform local regulators but may also be viewed as impinging on their jurisdictional authority. System operators should explore ways in which regulated control areas, or eventually individual customers can make individual choices about their reliability and resource preferences in ways that would not negatively impact the reliability of other users of the network.

One arena in which the conflicts between wholesale market oversight (including RA oversight) and state regulatory goals has been the area of state subsidies for generation capacity. Conflicts have arisen between states that are supporting specific projects or technologies, and market mitigation principles designed to prevent uneconomic investment that depresses capacity prices. While current market power mitigation measures now preclude some of this capacity from influencing capacity markets, those same measures can create a dynamic where too much entry is promoted.

At the same time, states may find alternative methods for accomplishing their goals while avoiding those same mitigation measures. In order to reconcile state goals with regards to the environment and technology, states and the Federal government may need to more strongly policy tools, such as cap-and-trade, that promote state goals without distorting market prices for power or capacity.

4. The adoption of newer **smart grid technologies** provides the potential to apply more flexibly reliability and RA standards to both states and consumers, but the process for establishing reliability and planning standards must be made more flexible if more diverse preferences are to be accommodated.

Integrated ISO markets have operated in a way that shares equally the responsibility for, and consequences of resource inadequacy. This has made resource adequacy a “public good” that has provided justification for RA policies in many markets. Emerging “smart-grid” technology holds the potential to isolate consequences for resource shortfalls to the providers responsible for those shortfalls. These technologies can allow for more diversity in reliability preferences, and in assumptions about the capability of specific resources to support reliability.

Traditional metrics for reliability planning, such as the “one-in-ten-year” rule are, by some measures, out of step with economic analysis of the benefits of these levels. Standards continue to be considered the jurisdiction largely of engineers, with little consideration to the economic costs of benefits of setting standards at different levels. Organizations such as NERC that set and enforce reliability standards should consider the impact of new technologies on both planning and operational standards in a way that better accommodates economically efficient reductions or curtailments in load.

A common theme to all these challenges is that the changing of technology and policy priorities has increased the difficulty in reaching broad consensus over what a unified set of reliability requirements and metrics should be. Legitimate differences in opinion over the reliability value of demand response, intermittent renewable energy and the effectiveness of energy efficiency measures have created conflict amongst local regulatory authorities and between those authorities and regional transmission organizations. As resources become more diverse, the challenge of forecasting their value for reliability months and years in advance greatly increases. This could necessitate an increased reliance on short-term performance measures, of which energy prices are the most sophisticated. It also increases the value to planners of being able to isolate negative reliability consequences (physical and/or financial) to load-serving entities that are responsible for resource shortfalls.

1 Resource Adequacy Paradigms

- Historically, investment in electricity generation has been made by monopoly utilities receiving a regulated rate of return on their prudently incurred costs. Payments were based upon costs rather than the market value of the generation.
- Under electricity restructuring, payments earned by investors in generation capacity are based upon the market price of the electricity produced by that generation.
- Under the *energy-only* paradigm, all payments are based upon the value of the energy and ancillary services sold by the generation unit. Although short term markets form the basis for the value of a unit, many generation investments are backed by bilateral contracts with load-serving entities.
- Under a *capacity payment* paradigm, generation units earn revenues based upon an explicit or implicit value of the qualifying capacity of the resource in addition to revenues earned through the sale of energy and ancillary services. The value of capacity is set either through centralized capacity markets or through resource adequacy requirements that mandate load-serving entities acquire sufficient capacity to satisfy planning requirements.
- Substantial generation investment has occurred under all three RA paradigms over the last 15 years.

The US electricity sector uses three models to incentivize the provision of adequate generation resources. Traditionally this has been accomplished through the utility "cost of service" model. Utilities would invest in capacity deemed useful by state regulators (*e.g.*, the Public Utilities Commission). Approved investments would be allowed to earn a guaranteed rate of return.

With the advent of electricity restructuring, some US wholesale markets were established without explicit mechanisms to ensure resource adequacy. Instead, they were structured on the premise that the ability to earn substantial amounts of revenue during periods of high prices in the wholesale energy and ancillary services markets would be sufficient to incentivize firms to develop the required resources. Markets following this approach came to be known as energy-only markets.

The California electricity crisis, which was marked by high energy prices and rolling blackouts, changed many perceptions of on how to restructure electricity markets. On the one hand, the reliability issues experienced in California increased calls for more coordinated oversight of investment. This was despite the fact that the installed capacity in California going into the summer of 2000 comfortably met traditional planning margins (Bushnell 2005). On the other hand, concerns over market power, made prominent by the California experience, also reinforced resistance to raising caps on offers and prices in short term energy and ancillary services markets.

During this period, eastern ISOs in New York, New England and PJM provided various forms of remuneration to producers for their installed capacity (ICAP). These systems had evolved from reserve sharing arrangements within their respective power pools that had predated regulatory restructuring. While the designs of these capacity markets have also been criticized, the fact that eastern markets had avoided the fate of California helped to reinforce a perception that providing resources remuneration for capacity, in addition to payment for the supply of energy and ancillary services, was a desirable, and perhaps even necessary element of restructured markets. While the designs of such mechanisms have changed significantly during the last decade, payments for capacity are an important feature of many restructured US markets.

Currently, all three of these channels for incentivizing and financing generation investment—regulation, energy only markets, and capacity markets—co-exist in the United States. In this section we review the intellectual foundations and concerns with each of the approaches.

1.1 Traditional Rate-of-Return Regulation

Historically the bulk of US electricity generation infrastructure was constructed by regulated Investor-Owned Utilities (IOUs) and financed under rate-of-return regulation. While the details of regulation have always varied significantly from state to state, the general approach is for a planning process to identify a *determination of need* for new investment, based upon assumptions over future demand growth and supply conditions. Once a need for capacity was identified, a utility may propose investments to satisfy that need to be reviewed and approved by their regulator. Upon approval, the utility would invest the necessary capital (raised through a combination of debt and equity) to construct the plant. Absent disallowances by the regulator due to negligence or controllable cost over-runs, the utility would recover its investment cost plus an *allowed rate of return* on its investment upon completion of the facility.

This channel for resource adequacy has been very effective in adding new capacity. Of the 1140 gigawatts (GW) of capacity operating today, only one third was built by Independent Power Producers (IPPs).[2] Figure 1 plots the amount of new capacity that came on line in a given year. The capacity is broken down among IOUs, IPPs, and other owners.[3] The figure shows a few interesting trends. First, in the 1980s, IOUs invested in much more new capacity than the IPPs. By 2000, this had reversed though both types continue to invest. Second, we see a slowdown in new investment in the late 1990s that is then followed by a rapid increase in new capacity after 2000, particularly by IPPs.

[2] The data are from the Energy Information Administration form 860.
[3] Other includes federally-, state- and municipally-owned utilities, cooperatives, industrial, and commercial.

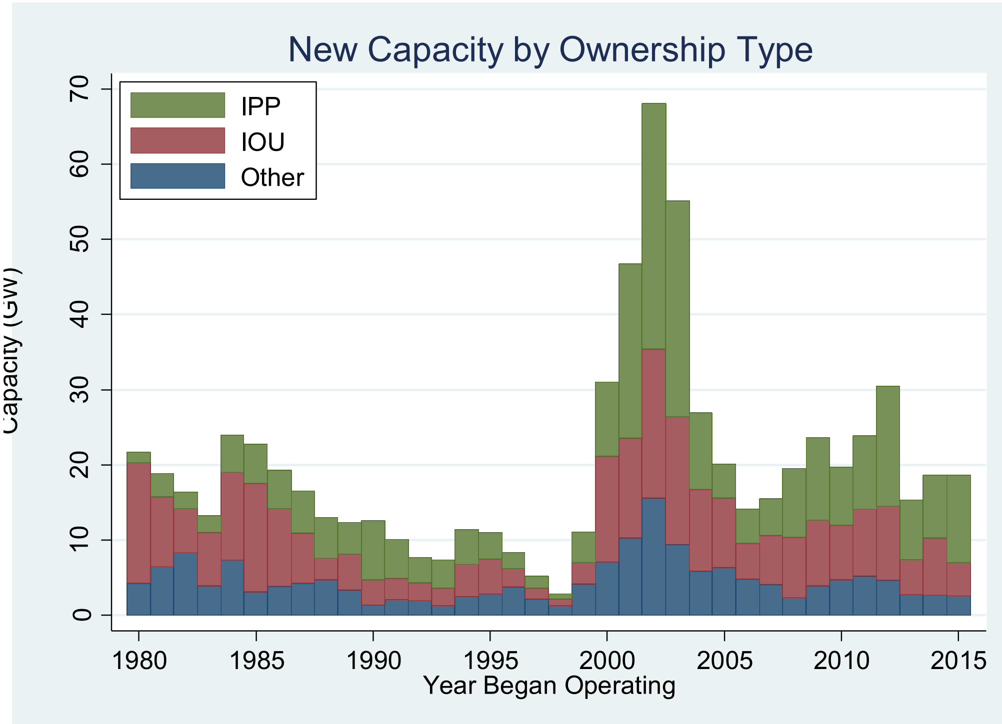

Figure 1: New Capacity by Ownership Type

A long literature, going back to the 1950s, discusses the potential distortions created by rate-of-return regulation. A prominent hypothesis by Averch and Johnson (1962) relates a firm's choice of input mix (*e.g.,* capital, fuel, and labor) to the relationship between the firm's true cost of capital and the rate of return on capital allowed by the regulator. The "Averch-Johnson effect" is the bias in favor of "gold-plated" inflated capital investment and excessive capacity margins. While the empirical evidence on the extent and scope of this effect is unclear (Joskow and Noll 1981), the standard practice of allowing the guaranteed recovery of all prudently incurred investment costs, at the very least, likely skewed the perception of risk. Joskow (1997) notes: "Traditional regulatory principles, based on the prudent investment standard and recovery of investment costs, implicitly allocates most of the market risks associated with investments in generating capacity to consumers rather than producers."

One area in which the distortion of risk was argued to be significant was the focus of utility investments on nuclear generation stations during the 1970s and 1980s. Diablo Canyon, for example, was expected to cost under a dollar a watt in today's dollars and to be built with eight years of when construction started in 1966 (Gilbert 1991). However, due to numerous cost over runs, regulatory changes, and poor management, the project took more than an additional decade to finish with the final costs over five times the initial projection. Davis (2012) reviews the US economic history of nuclear power highlighting the high costs. Today there are several reactors being built, and all are under rate-of-return regulation.

Another potential distortion from regulation is the timing of funding. Traditionally utilities have not been awarded ratepayer funding for their investments until the investment was completed and entered into service as a *used and useful* asset. The lag between capital expenditures and allowed recovery of those costs became a significant issue during the 1970s and 1980s when several nuclear investments experienced long delays and massive cost overruns. The fact that a utility may access funds only upon completion of a project can distort the perception of sunk costs, leading rational regulated entities to pursue completion of projects even if the going forward costs exceed going forward value, as project completion would also allow recovery of capital costs sunk into that project up to that date.

Rate-of-return regulation has provided the US with an extremely stable level of resource adequacy and reliable performance. Thus from a reliability standpoint this approach has proven successful. It is largely from the economic standpoint that rate-of-return regulation has been criticized. In general the "cost-plus" nature of rate-of-return regulation provides very weak incentives for firms to minimize their costs. Through the Averch-Johnson effect utilities may have an incentive to invest in both excessive and capital-intensive generation capacity. Others have argued that the monopoly character of regulated markets can produce less efficient generation operations than more contestable markets. One of the motivations for electricity restructuring was to provide market incentives for investment decisions. Joskow (1997) noted that "the most important opportunities for cost savings are associated with long-run investments in generating capacity."

1.2 Energy-Only Markets

In unregulated markets, where firms are not allowed to recover their operating and investment costs through rate of return regulation, revenues are usually earned from the sale of goods and services. In electricity markets, this means the sale of either energy or ancillary services. The term *energy-only* markets has come to represent this paradigm, where there is no additional compensation made for the availability of the capacity to produce goods, only for the provision of the goods themselves.

In perfectly competitive markets, prices will be set at the marginal cost of production. The recovery of capital costs must come from periods where prices rise above short-run MC. In such conditions investors either implicitly or explicitly determine the market value of capacity through the concept of *scarcity pricing* (Borenstein 2000). Peak-load pricing is an example of scarcity pricing that occurs in markets that are capital intensive, have limited economic storage and where demand fluctuates, like markets for hotels and electricity. As demand shifts, prices adjust to clear the market and avoid shortages. The result is relatively volatile short-term prices (even in perfectly competitive markets) as small shocks to demand can translate to large price swings with inelastic supply (when the supply curve is very steep). When capacity binds and prices are set by the demand curve, prices will rise above the average variable costs of all operating plants. This allows for a contribution towards the recovery of fixed costs (see Figure 2).

This concept is called scarcity pricing because the quantity demanded would exceed the quantity supplied if price just equaled the average variable cost of the most expensive generating unit. The component of the price necessary to reduce demand to the point where it can be met by available capacity is often called the *scarcity rent.* In a competitive market that satisfies several other conditions, firms will build new capacity as long as the cumulative scarcity rents exceed the cost of capacity. Free-entry would drive the scarcity rents to equal (on average) the cost of new capacity over time.

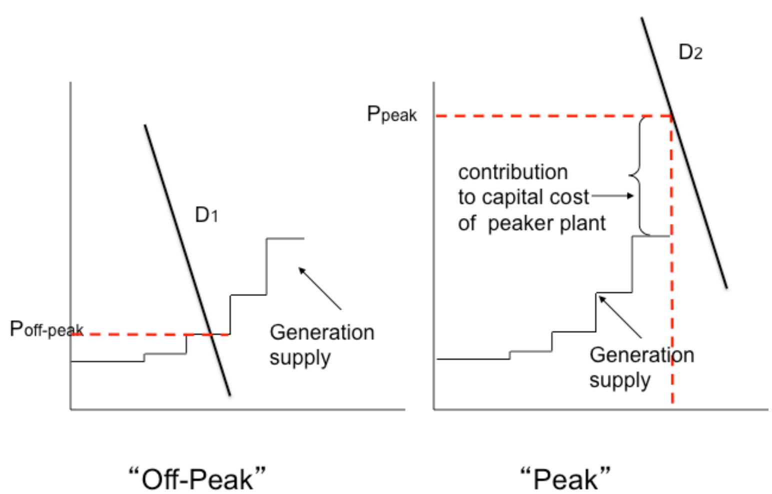

Figure 2: Scarcity Pricing Example

In the electricity concept, two factors create a fundamental challenge to the implementation of the scarcity pricing paradigm: the lack of price-responsive short-term demand and reliability standards designed to prevent scarcity. In classic economic figures demonstrating the operation of markets, including energy-only markets, demand is depicted as downward sloping, meaning that as prices increase consumers consume less. Such active participation by consumers in short-term power markets has been notoriously absent, although there is some prospect that the recent advances in home automation and smart metering can make major inroads into this shortcoming. Given the lack of downward sloping demand, prices are periodically set by *penalty parameters* that implicitly set prices when constraints, such as those enforcing ramping, transmission congestion, and energy balance limits bind. These parameters play the role of a price cap, but in a more complex setting in which one of several constraints could produce "scarcity." If these parameters are set too low, they can limit prices below levels necessary to recover investment costs. This price cap issue is one of the most visible potential causes of the *missing money problem.* This term has been used to describe the set of complications in power markets that can depress revenues below that necessary to support sustainable investment in generation capacity.

The second problem is more fundamental. If operators, for reliability purposes, never allow markets to experience scarcity, then how can prices rise to the levels necessary to finance investment? In the words of Cramton and Stoft (2006), "the missing money problem is not that the market pays too little, but that it pays too little when we have the required level of adequacy."

To address these challenges, restructured electricity markets have made changes to update their pricing mechanisms in ways that can, in theory, provide adequate revenues without resorting to load shedding to generate high prices. Over the last 10 years, several attributes of scarcity pricing have been added to most Independent System Operator (ISO) markets in the US.[4] While the specifics vary, all involve a combination of potentially higher prices that can be triggered by deficiencies in operating reserves rather than load shedding.

The potentially higher prices are set by the penalty parameters described above. The key design element is the condition under which those penalties would be applied. Under revised forms of scarcity pricing, prices for both energy and ancillary services begin to rise above the offer prices of generation units when operating reserves begin to drop below certain target levels (see red dashed line below). In this way scarcity is defined by lower reserve margins rather than an absolute shortage of energy.

[4] Throughout this document, we will use the term ISO to refer to both ISOs and Regional Transmission Organizations (RTOs).

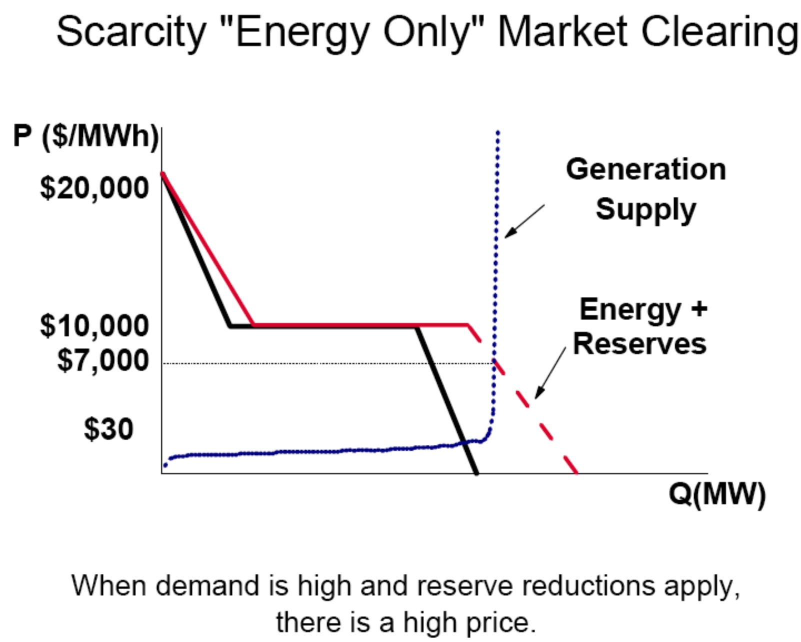

Figure 3: Scarcity Pricing and Reserve Deficiency (Hogan 2005)

The scarcity pricing approach described in Hogan (2005) and elsewhere accommodates the fact that a substantial share of consumption would not be price responsive. The horizontal segment of the black (energy) and red (energy + reserves) demand curves captures this fact. One critical parameter in scarcity pricing is therefore the height (or price point) of these segments at which prices would often be set in times of scarcity. This is the penalty value at which prices are set if reserves are insufficient to clear on section where demand is downward sloping. Hogan proposes this level be set at the *Value of Lost Load* (VOLL) in order to capture the average willingness to pay for electricity service amongst those customers not actively bidding demand into the market.

There has been, and continues to be, much focus on regulatory limits to *offer prices*, also known as "bid caps," which are set at $1000/MWh in most US markets, as a source of the missing money problem. However, it is important to recognize that these bid caps need not create any missing money if scarcity pricing is properly implemented. Therefore the key parameters are the penalty values that can set prices *above* the offer bids of any generator, rather than the bid caps that limit those offers to still quite high levels. These parameters do allow prices to rise above $1000/MWh but not to the $10,000/MWh heights envisioned by Hogan.[5]

It is also important to acknowledge that administrative parameters are playing a key role in driving incentives for investment and operations in energy-only markets. The notion that the energy-only approach was a "pure" market approach that is less subject to regulatory discretion was roundly criticized by Cramton and Stoft (2006). They observed

[5] FERC (2014) summarizes scarcity pricing practices amongst ISOs.

that "the energy-only approach relies on an administratively determined energy + reserve demand curve to control scarcity revenues, investment, and capacity level. It is no less centrally planned than the ICAP approach." They dismiss the notion that this is a market approach, noting that "an energy-only approach can use the `market' to solve every part of the resource adequacy problem except for one: adequacy."

While it is true that, in the absence of sufficient price-responsive demand or other demand-response resources, administrative penalty parameters must play a role in setting prices, this does not by itself make energy-only markets less desirable than other approaches. Indeed, all US markets utilize some form of scarcity pricing and rely significantly upon penalty parameters, whether as a substitute for or as a complement to other resource adequacy components.

1.2.1 Scarcity Pricing and Performance Incentives

One reason why even those electricity markets that provide significant RA revenues, such as PJM, also utilize scarcity pricing is that the prices that firms earn for providing electricity (namely, the energy market and ancillary services prices) provide an extremely strong incentive for the performance of generation capacity. Even Cramton and Stoft acknowledge that scarcity pricing, if it were feasible, sets "the economic gold-standard for performance and investment-quality incentives."

As we will discuss below, performance incentives pose one of the biggest challenges for RA structures, particularly in the face of an increasingly diverse mix of resource types. Providing missing money alone does not ensure the adequacy or reliable supply, only the adequacy of generation capacity with the *potential* to provide reliable supply. But reliability is not enhanced if the "adequate" capacity is not operating when it is needed.

This challenge is articulated by Harvey, Hogan et al. (2013) in their review of the New York capacity market. They note that:

> *The use of a capacity market to make up the "missing money" needed to support the capacity required to meet capacity requirements has the unintended consequence of creating a series of missing incentives relative to an energy-only market as that maintained in ERCOT. The New York ISO attempts to replace these missing incentives with a series of administrative rules and requirements, some of which work better than others.*

1.2.2 Market Power and Hedging

The focus of the scarcity pricing argument is that suppliers who supply, and consumers who consume, during periods of scarcity should face the economic cost of that scarcity. Perfectly competitive suppliers would earn large rents from producing during such periods, and therefore would focus their efforts on ensuring their capacity was truly able to perform during such events. The other side of this coin arises when suppliers are not perfectly competitive. Just as the prospect of high prices should increase supply from small firms, it could encourage the withholding of supply by large firms seeking to create, rather than respond to, a scarcity event.

For some observers, market power is an intractable problem in electricity markets that makes necessary lower price caps (*e.g.*, penalty values), and therefore some form of supplementary RA payment that would make up for the missing money created by the price caps. The Cramton and Stoft (2006) capacity market design is motivated by the goal that "the missing money must be restored without reintroducing the market power problems currently controlled by price suppression."

Firms may exercise market power using either or a combination of two mechanisms. The first is to offer generation into an energy market at a high offer price (a price mechanism). The second is to offer less than the full quantity that a firm has available, for example by claiming a forced outage (a quantity mechanism). All organized US electricity markets have some degree of market power mitigation that is designed to limit at least local market power by suppliers. However, these mitigation procedures limit offer prices of units, rather than compel them to operate. Therefore current market power mitigation practices are insufficient to eliminate market power, particularly during periods of near scarcity.

While the market power problem is acknowledged as a serious potential risk for energy-only markets, traditional capacity markets are not universally embraced as the solution. One issue is that RA markets mandate a relatively inelastic demand for a new product ("capacity") that can also be subject to market power by both buyers and sellers, particularly if RA is required at a local level. Another issue is that some RA market designs do little to mitigate the short-term market power of sellers. Indeed, early capacity markets did little to address this problem. As Cramton and Stoft note: "Standard ICAP designs fail to provide market-based incentives and hedge load. (Failure to hedge load, also indicates a failure to hedge capacity and reduce spot market power.)"

This passage points to the alternative solution promoted by some to RA requirements, the application to Load-Serving Entities (LSEs) of mandates for *financial hedging* rather than physical resources. Academic research has supported the conclusion that even structurally deficient power markets can operate reasonably competitively when the bulk of power transacted has been hedged, through physical or financial contracts, in advance.[6] Long-term contracts also provide the stable source of commitment sufficient for financing new generation investment. This has led some to ask whether the resource adequacy problem was more accurately cast as a financial contracting problem. Bushnell (2005) observes:

> *To the extent that the financial solvency of LSEs in general, and regulated utilities in particular, is the motivation for resource obligations, the focus on capacity alone does not satisfactorily address the motivation. In fact a standard for energy procurement, whether in the form of firm contracts, options, or swaps, is necessary to address the concerns about inadequate hedging by utilities. But if a*

[6] See, for example, Wolak (2000) and Bushnell, Mansur, and Saravia (2008).

standard requiring energy purchases is in place, is a process for remunerating physical capacity necessary?

Oren (2005) argues that RA policy should be viewed as a form of mandatory hedging. "Rather than considering the intervention as a reaction to the failure of the energy spot prices to properly reflect scarcity rents, one may regard the regulatory intervention as a proactive measure in the form of a mandatory hedge or insurance that will assure that prices stay within a socially acceptable range" (Oren 2005). He proposed a framework in which LSEs would be required to procure call options that would protect them against extreme price spikes. Such options, when provided by generators, would provide further incentive for those firms to supply during high price periods.

As discussed below, system planners and engineers have been uncomfortable with what they perceive as a reliance on purely financial, rather than physical, resource plans. There has been a strong preference for the "steel in the ground" that can ensure reliable service when necessary. However, financial instruments are still necessary for both financing investment and for providing the appropriate performance incentives. As Hogan (2005) notes, "In the end the ICAP approach carries with it much of the baggage of the financial contract without the simplicity."

While more advanced scarcity pricing concepts have now been implemented in most US ISO markets. Only the ERCOT market has explicitly embraced the energy-only paradigm as sufficient for providing signals for investment. The Southwest Power Pool is in the process of exploring whether and how to coordinate the planning of its member systems. All of the other markets have adopted some form of resource adequacy requirement or capacity market. In the following section, we explore the reasons why most systems have adopted this approach.

1.3 Capacity Markets and Resource Adequacy Requirements

In this document, we group together a diverse set of policies that share one important component, a distinct focus on resource *capacity* in addition to payments for energy and ancillary services. As we describe below, some of these policies take the form of mandates or standards for capacity that are the responsibility of an individual LSE. Others take the form of centralized capacity markets that are overseen by ISOs. In all cases, there is an implicit or explicit value placed on the ability of a resource to demonstrate qualified capacity in a time frame well in advance of a daily wholesale market. In this section, we trace the motivations for and historical evolution of these mechanisms. Section 2 then surveys the range of RA policies currently in effect today.

From the very early stages of market operations, researchers have noted several aspects of power markets that challenged the adequacy of the scarcity pricing paradigm for new investment (Hogan 2005, Oren 2005, Cramton and Stoft 2006, Joskow 2006). Fundamental sources of concern with the energy-only approach have been the combination of demand that is unresponsive to prices and of pricing "penalty values" that become computationally necessary to determine prices in the absence of elastic demand. If current penalty values prove to be too low, or invoked too infrequently, additional compensation in the form of RA or capacity payments can be necessary in a market regime. This allows firms to recover their long-run costs in a region that is resourced to the satisfaction of reliability planners.

In addition, Joskow (2006) documents the common practice of system operators to take "out-of-market" actions in the spirit of maintaining reliability that had a side effect of suppressing market prices. For example, from 1999 to 2002, the New England market declared an operating reserve deficiency in 46 hours but prices only reached the price cap in six of those hours. There have also been aspects of power markets where physical network characteristics require a balance of supply and demand with more frequency, and possibly geographic granularity, than that for which prices have been calculated (*e.g.,* "the missing markets problem"). While the widespread adoption of locational marginal pricing (LMP) has largely eliminated deficiencies in reflecting transmission scarcity in energy prices, most ancillary services markets are operated with much less spatial granularity.

Joskow (2006) and Cramton and Stoft (2006) evaluate the sufficiency of market prices for energy and ancillary services to support the long-run average cost of generation. They find that the implied revenues from these markets fall short of the levels necessary to support new investment. Market monitors in ISOs have also adopted a somewhat standardized measure tracking the potential revenues of a hypothetical marginal generator (FERC 2011). These measures consistently find that energy and ancillary service market revenues, on an annual basis, fail to meet the monitor's estimates of the long-run cost of new generation.

However, several caveats provide caution against treating these findings as definitive evidence that energy and ancillary services prices will always be incapable of supporting investment. First, many of these calculations are being made in the context of markets that already have some form of capacity or resource adequacy mechanism. Second, it is extremely difficult to define the appropriate time horizon necessary for cost-recovery of assets that last multiple decades. The fact that a plant has not fully covered its capital cost over an annual or even half-decade period is not necessarily a sign of market failure. Last, the industry has been continuously buffeted by significant changes to design, regulation, and policy; the most recent being a surge in support for renewable generation that has largely dominated investment since 2006. These shocks make it unlikely that the data on investment result from anything approaching a stable long-run equilibrium.

In the face of continued evidence that short-term energy markets were not producing sufficient revenues for generation to recover their capital cost, pressure grew during the mid-2000s to expand or adopt policies that would supplement the revenues of generation and other resources. Several eastern ISO markets had featured forms of capacity payments since the 1990s, but their design and implementation of these first generation capacity instruments has been criticized as inadequate at both funding generation and providing correct incentives for performance (Cramton 2003, Harvey 2005).

All eastern ISOs shared a general approach to capacity during this period. Each load-serving entity was responsible for acquiring or providing a share of a capacity need determined by the ISO. In theory, these requirements forced Load-Serving Entities to provide suppliers the revenues necessary for the maintenance of (or investment in) capacity. These payments would be expected in a competitive setting to equilibrate at the revenue shortfall necessary to keep the marginal source of capacity in the market. This logic is illustrated in Figure 4 from Harvey (2005). Generation units V, R and J are earning energy and AS revenues that fall short of their ongoing fixed costs. In an energy only paradigm, at least one unit would be expected to exit. This dynamic would repeat until the exit of units raised prices enough to support the ongoing fixed costs of all remaining generation.

Under the ICAP formulation, LSEs would be expected to compensate generation for their capacity to a level that allows sufficient capacity to remain in the market to meet their ICAP obligations. This is illustrated by the negative net revenues of Unit J, the marginal source of capacity in Harvey's example. Under an efficient transparent market, one would expect the market clearing price of capacity to reflect this revenue shortfall of the marginal source of generation. However, markets such as California, which feature similar RA obligations, wide spreads in prices paid for capacity have been observed.

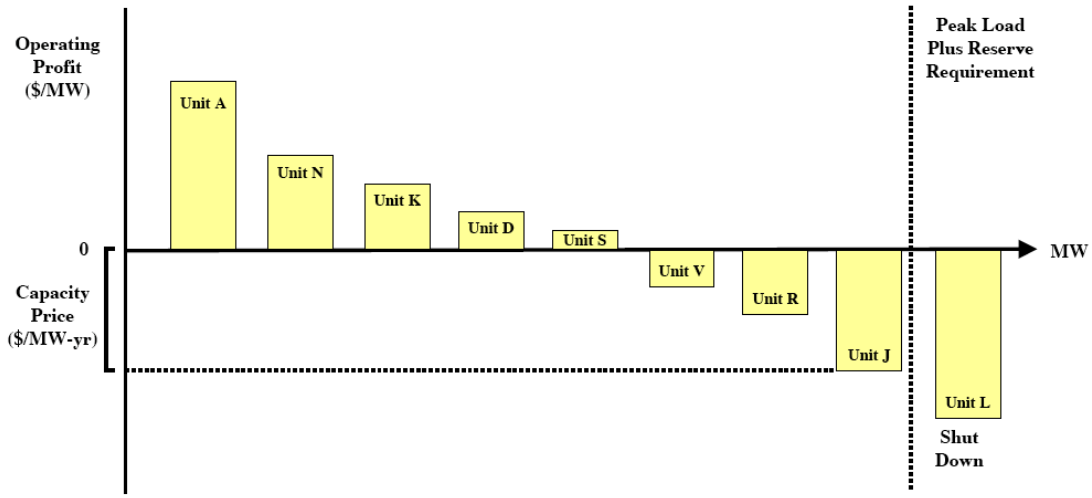

Figure 4: Unit Ranked in Order of Decreasing Operating Profit per MW

While early ICAP mechanisms provided payment to generators, on average, for revenues missing from energy and ancillary services markets that year, several aspects of these policies created concerns that they might be at once both costly for consumers *and* insufficiently rigorous to support reliable supply. Among the shortcomings listed by Harvey are:

- The need for administrative rules to determine the value of location, treatment of imports, and operational responsibilities of capacity.
- The perpetuation of continuously low energy prices that discourage participation of demand response and other alternative resources.
- The potential for market power in the ICAP market, particularly when ICAP requirements are defined in a relatively small local area.

Possibly the most telling criticism of the ICAP markets was that failed in their primary purpose, increasing reliability. In the words of Cramton (2003):

> *The products are designed in such a way that they do little to promote reliability – the objective of the markets. Reliability comes from having sufficient operable resources that are sufficiently flexible to handle contingencies as they arise. ICap and OpCap have nothing to do with the responsiveness of resources, and little to do with a resource's ability to produce energy consistently and at reasonable prices.*

The ICAP approach was traditionally focused on maintaining sufficient margins of installed capacity above peak summer demands. However, as Harvey (2003) notes, "while one often thinks of the summer peak as the time of maximum stress on the transmission and generation system, several reliability crises have arisen in recent years during the winter months."

The key shortcoming of many early RA paradigms has been a disconnect between payments for maintaining capacity and requirements or incentives for that capacity to operate in times of greatest need. This problem is illustrated by experiences in the ISO-NE market during the winter of 2003-04, where a cold snap lead to high demand in both gas and electricity markets. Several gas-fired generators that had received ICAP payments were nonetheless not operating as energy prices were insufficient to recover fuel costs and the ICAP payments did not require availability under those conditions. Steel was in the ground, but not producing electricity when it was needed. As Harvey (2005) notes:

> *The crux of an ICAP system is that energy market revenues under shortage conditions are limited by price caps and marginal capacity is kept available by the ICAP payment. If the ICAP payment does not depend on having firm gas supply, the incremental energy market revenues may not be sufficient to cover the cost of contracting for firm gas supply and generators may not do so.*

One last area of concern with the eastern ICAP approach was the short-term nature of commitments and the volatility of payments. Some aspects of ICAP markets were cleared on a monthly or even daily basis, leading to many periods with near zero prices and other periods where capacity prices approached either \$250/MW-day or \$13,000 a MW-month. The volatility in prices was influenced by the ability of LSEs to pay deficiency charges only for individual days in which they were short of capacity. The volatility of these prices, and therefore of the income streams received by generators, contributed to criticisms that revenues in these markets were hardly less volatile than in an energy only paradigm.

The suite of concerns over early iterations of capacity markets led to a substantial amount of research and regulatory activity directed at "reform" of the approaches through which RA was required and rewarded. Some markets, such as Texas, placed further emphasis on scarcity pricing and in effect doubled down on the energy-only paradigm. The New York, PJM and New England markets adopted changes directed at providing capacity with larger, more locational, and more stable compensation, while adding penalties for non-performance in various forms. In addition the procurement of capacity was extended farther (3 years) into the future in PJM and New England. In the following section, we review the key attributes and differences between the regional approaches to RA that are in effect today.

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2 Overview of Current RA Policies in US Markets

- We summarize the key parameters of the major energy-only, RA requirements, and centralized capacity markets.
- Markets share many similar characteristics, but differ on specific attributes such as the incentives/penalties for non-performance and the measurement of qualifying capacity values.
- Capacity prices are more transparent in centralized capacity markets.
- Prices in all markets have experienced large differences over time depending upon whether new capacity is procured through the markets.

Current US ISO resource adequacy policies contain similar requirements and goals but differ considerably in implementation and breadth. The range of RA paradigms is illustrated in Figure 5. Resource adequacy structures can be organized into three groups: (1) traditionally "planned" markets operating fully under regulation (2) energy-only markets which rely on energy prices to signal investment, and (3) regions where a separate explicit distinct platform and revenue stream for capacity is established either implicitly or explicitly. These capacity payments can be required either through established bilateral RA requirements (BRAR) that can be met with capacity procured in a variety of ways, or through centralized capacity markets (CCM) that discover a single capacity price applied to resources in a locational area.

In practice, the boundaries between these categories are not as sharp as implied by Figure 5. As discussed below, many participants in regions with RA requirements or centralized capacity markets remain regulated. And RA needs in planning regions are often met through procurement of generation from unregulated independent power producers. Further, while requirements in BRAR regions are often met through self-supply and bilateral arrangements, some also feature voluntary centralized capacity auctions. In the following sections we describe how the capacity approaches have been implemented.

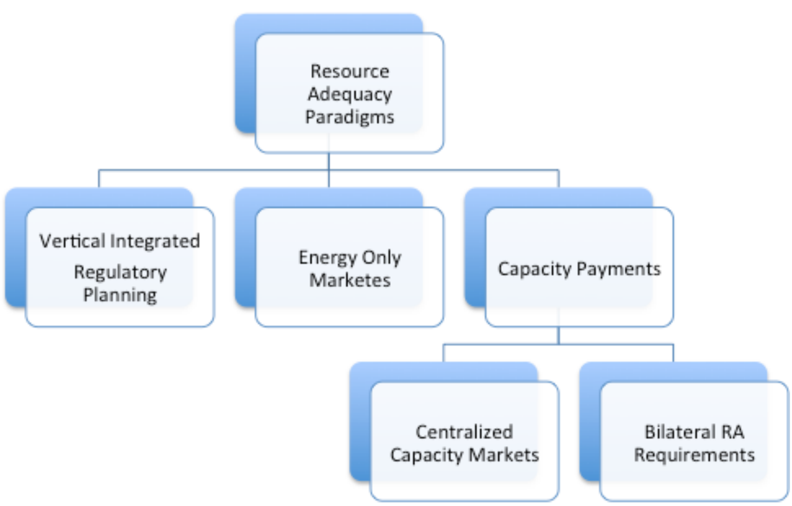

Figure 5: Resource Adequacy Paradigms

2.1 Energy-Only Markets

Energy-only markets rely on energy prices and scarcity pricing mechanisms to provide sufficient signals and revenues for capacity to be available when and where it is needed. While entities administering energy-only markets must allow energy prices to be sufficiently high to drive investment, they must also be conscious of ratepayers' willingness to pay and the need to mitigate potential supply-side market power. The Electric Reliability Council of Texas (ERCOT) currently administers an energy-only market with a system-wide offer cap and pricing mechanisms to ensure conditions are adequately reflected in prices. As of June 1, 2015, the system-wide offer cap in ERCOT is $9,000/MWh which is derived from a Value of Lost Load (VOLL) estimate (Surendran et al. 2016). ERCOT also has a provisional revenue threshold that, if exceeded, would cause the system-wide offer cap to be reduced. If the Peaker Net Margin reaches a cumulative threshold, the system-wide offer cap is will be reduced to the higher of $2,000/MWh or 50 times the daily natural gas price index (Potomac Economics 2016a).

ERCOT also has two pricing mechanisms designed to better reflect scarcity conditions in the energy market. In June 2014 ERCOT introduced the Operating Reserve Demand Curve (ORDC) to provide effective shortage pricing when operating reserve levels are low. The 'operating reserve adder' derived from the ORDC is added to the real-time energy price and paid to reserves in real-time. The ORDC is constructed by multiplying the loss of load probability at varying levels of operating reserves by the value of lost load. The payments for reserve capacity will increase as the quantity of reserves decreases. If the available reserve capacity drops below 2,000 MW, payments will reach the VOLL or $9,000 per MWh (Surendran et al. 2016). The Reliability Deployment Adder was implemented in June 2015 to allow energy prices to reflect the costs of reliability actions taken by ERCOT, such as RUC commitments and deployed load capacity. Prices will generally fall when these actions are taken, so the adder is determined by recalculating prices with RUC commitments and deployed load capacity removed (in a separate SCED run). If this price is higher, the difference is the reliability adder (Potomac Economics 2016a).

2.2 RA Requirements Met Through Self-Supply or Bilateral Contracts

The California ISO (CAISO) and Southwest Power Pool (SPP) establish capacity requirements for the Load-Serving Entities (LSEs) in their region that can be met by self-supply or bilaterally procured resources. Capacity prices in these areas are less transparent than in areas with centralized capacity markets, due to the lack of a standardized auction or clearing-house for capacity. Local regulatory authorities may set limits on prices paid for capacity and the regional organizations may set penalties for LSEs that are short.

Currently SPP Criteria section 2.1.9 sets the minimum required capacity margin (currently at 12%). Each Load Responsible Entity (LRE) must meet its reserve requirement using the SPP established criteria and testing procedures for counting resources. The Capacity Margin Task Force, an organizational group commissioned by SPP and composed of staff and member representatives, has proposed a planning reserve margin assurance mechanism that would penalize LREs who are deficient in meeting their reserve margin requirement by compensating parties with excess capacity. The deficiency payment be based on the Cost of New Entry (CONE)[7] and a multiplier of which would vary based on the region-wide reserve margin level in order to provide increasing incentives as reliability decreases in the region.[8]

The CAISO currently establishes more prescriptive RA requirements based on location and resource characteristics. CAISO defers to local regulatory authorities to establish system RA requirements and a planning reserve margin. In addition to the system requirements set by local authorities, the CAISO establishes local and flexible resource adequacy requirements. The flexible RA requirements are designed to ensure the CAISO system has the ability to meet sustained periods of upward ramp. Resources must have specific characteristics and take on unique must-offer obligations to qualify for flexible RA capacity. LSEs are required to submit RA plans to the CAISO listing the capacity committed to serve the various requirements annually and monthly. The CAISO also has authority to procure backstop capacity if RA requirements are not met. This is referred to as the Capacity Procurement Mechanism and involves a competitive offer process with a soft-offer cap of $6.31/kW-month (CAISO Department of Market Monitoring 2016).

[7] The CONE is calculated by estimating the total cost of a new resource and the levelized annual cost for the resource. The total cost estimate includes siting and construction costs, permitting and a competitive return on capital. A net-CONE estimate is also regularly calculated. It subtracts any forecasted net-revenues from energy and reserve markets from the CONE (ISO-NE Staff, p.5).

[8] Capacity Margin Task Force, Planning Reserve Assurance Policy, March 2016. See https://www.spp.org/organizational-groups/board-of-directorsmembers-committee/markets-and-operations-policy-committee/capacity-margin-task-force/

2.3 Centralized Capacity Markets

Centralized capacity markets create a single platform and revenue stream for capacity in a region. Currently the Midcontinent ISO (MISO), the ISO New England (ISO-NE), the New York ISO (NYISO) and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) administer centralized capacity markets. These entities typically have a RA requirement but may construct a sloped demand curve for use in the auctions. Sloped demand curves reflect the fact that the optimal level of reliability changes with the price of reliability, help mitigate market power, and reduce price volatility (ISO-NE 2015, PJM 2016). The methodologies for developing the demand curves differ among entities but generally involve the RA requirement and estimates of CONE. Figure 6 shows the NYC 2014-16 Winter Demand Curve. The highlighted points are priced at variations of the levelized cost to build a new peaking unit. The grey dotted line is the capacity requirement (NYISO 2016).

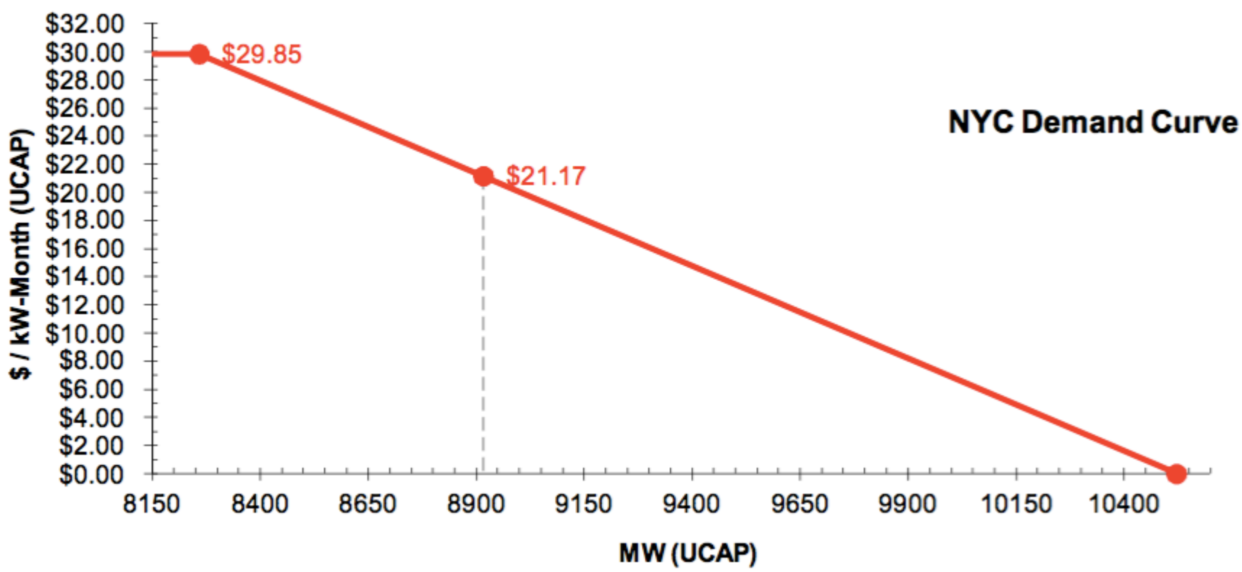

Figure 6: NYISO 2015-16 Demand Curve for NYC Area[9]

The various centralized capacity markets procure capacity in different timeframes. ISO-NE and PJM hold the first auction three years in advance of the delivery year and additional auctions as the delivery year approaches. MISO holds auctions immediately prior to the delivery year and NYISO holds auctions for periods of six months (30 days in advance). More forward capacity auctions allow for greater entry as long as enough time exists for new investments to be made contingent on auction results (Brattle 2015).

[9] Translation of Winter 2015-2016 Demand Curves can be found at: http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2015/Winter%202015-2016/Documents/Demand%20Curve%20Winter%202014-2014%20-%20combined.pdf

Most centralized capacity market structures include market power mitigation measures focused on offer floors and caps as well as the evaluation of planned retirements or exits. For example, PJM enforces a minimum offer price set at the net asset class CONE price in order to limit net-buyers' ability to suppress prices (PJM 2016). The ISO-NE's internal market monitor has a cost review process for resources seeking to permanently or temporarily exit the capacity market designed to mitigate physical withholding (ISO-NE Internal Market Monitor 2016).

Not all centralized capacity markets are mandatory. MISO's RA structure is similar to CAISO's and SPP's in that the established RA requirement can be met in a variety of ways. Its voluntary Planning Resource Auction (PRA) serves as an optional platform to procure capacity. LSE's in PJM may also opt out of the Reliability Pricing Model (RPM) capacity market and participate in the Fixed Resource Requirement Alternative which requires Capacity Plan for their load meet reliability requirements. There has been discussion regarding the benefits of mandatory capacity markets in states with traditionally regulated utilities as there is concern that state-approved resources may not clear, potentially undermining state policy objectives (Brattle 2015). Table 1 shows recent outcomes in each of these centralized capacity markets.

Table 1: **Recent Capacity Market Outcomes**

	Requirement (MW)	**Capacity Cleared (MW)**	**Prices**	**Delivery Year**
MISO	136,359	Auction: 88,130 FRAP[10]: 48,229	Z1-3,5&6: **$3.48**/MW-day Z8&9: **$3.29**/MW-day Z4: **$150**/MW-day	2015-16
ISO-NE	33,456	36,309	**$3.43**/kW-mo	2015-16
NYISO	39,273		NYCA: **$2.39**/kW-mo NYC: **$10.68**/kW-mo LI: **$3.68**/kW-mo G-J Locality: **$6.17**/kW-mo	Average of 2015 Summer and 2015/16 Winter Periods
PJM	162,777[11]	Base Auction: 164,561	**$160**/MW-day (weighted average)	2015-16

Sources: Potomac Economics (2016b), Monitoring Analytics (2016), ISO-NE Internal Market Monitor (2016), and Potomac Economics (2016c).

[10] Capacity shown in Fixed Resource Adequacy Plan (FRAP) that does not enter the capacity auctions.
[11] Requirement does not include capacity shown in Fixed Resource Requirement (FRR) option.

2.4 Common Components of RA Structures

2.4.1 Planning Reserve Margins

The North American Electric Reliability Corporation (NERC) regularly publishes reliability and adequacy assessments for the bulk power systems in North America. NERC uses reserve margins as a measure of resource adequacy in its analysis. [12] The reserve margin concept is central to the resource adequacy structures examined here. In fact, all of the entities set RA requirements (or 'targets' in ERCOT) using forecasts of peak demand and a planning reserve margin. NERC has acknowledged the 'one event in ten years' reliability metric as the most common criteria for setting resource adequacy requirements. This standard effectively requires an electric system to maintain sufficient resources to meet system peak load in all but 1 event in 10 years (NERC 2016). There are large differences in how the one-in-ten standard is interpreted across entities though. For example, entities may define a reliability event in a number of ways or even use a 'one day in ten years' standard which could lead to significantly different reserve margins (Brattle Group and Astripe Consulting 2013). This standard is commonly used in Loss of Load Expectation (LOLE) studies to determine reserve margins.[13] CAISO is the only entity that does not use a LOLE study and instead uses a standard 15% margin.

2.4.2 Resource Obligations

Resources with capacity that clears in a capacity market or is committed to meet an RA requirement have obligations to be available and perform in Day-Ahead and Real-Time energy markets. CAISO, MISO, NYISO, ISO-NE, and PJM have explicit requirements for resources to schedule into the energy market (most commonly just the Day-Ahead Market). MISO has an additional requirement to offer in the first post-Day Ahead Resource Adequacy Commitment Process (MISO 2015). CAISO specifically requires flexible resource adequacy resources to economically bid into Day-Ahead, RUC and Real-Time markets if capable (CAISO Department of Market Monitoring 2016).

2.4.3 Performance Incentives

Performance incentives are an important element in resource adequacy frameworks as they aim to ensure resources provide the level of reliability expected from them. Entities use varying forms of performance incentives. Some are more stringent than others. The most stringent would be that of energy-only markets where resources not available during times of scarcity will not receive the necessary revenues resulting from high energy-prices. PJM and ISO-NE also have strong performance incentives. PJM is transitioning to a Capacity Performance product which will be subject to a non-performance assessment. Each resource will be assessed based on their expected performance and actual performance during emergency event hours. The non-performance charge is based on a CONE estimate or RPM revenues (PJM 2016). ISO-NE will be implementing new performance incentives in June 2018. Under the Pay for Performance

[12] The Reserve Margin is generally shown as the difference between installed capacity and system peak load as a percentage of system peak load.
[13] Loss of Load Expectation (LOLE) is the expected number of days capacity will be insufficient to serve load in a given timeframe.

rules participants will be compensated in two settlements: base capacity payments and performance payments. The performance payments can be positive or negative according to their performance during reserve deficiencies (ISO-NE Internal Market Monitor 2016).

The CAISO has a Resource Adequacy Incentive Mechanism that assesses resource availability based how well a resource met its must-offer obligation to bid or schedule into the required markets. The CAISO could also assess performance in when determining the Net Qualifying Capacity for a resource but the CAISO has not yet specified performance criteria (CAISO 2016). MISO conducts a monitoring check by assessing resources offers and outages in each hour of the day and applies a tolerance threshold for deviations from the must offer requirements. However, MISO will only notify participants if they pass or fail the monitoring check (MISO 2015).

2.4.4 Unconventional Resources

Unconventional resources such as demand response, wind, solar, energy storage and energy efficiency have brought challenges to resource adequacy frameworks. Demand response (DR) and energy efficiency (EE) resources can be difficult to measure and evaluate. Entities have created unique and sometimes complicated rules and processes in order to allow these resources to participate in capacity markets (see Table 2). Intermittent resources' production is variable, lowering their ability to contribute to reliability requirements. Most of the entities examined here discount nameplate capacity from intermittent resources when determining their contribution to the reserve margin. The discount is calculated in a variety of ways such as by assessing average historical production during peak hours or using an Effective Load Carrying Capability (ELCC) methodology.[14]

2.5 Summary

This section provides a detailed description how each ISO electricity market in the US addresses resource adequacy. While there are many more details, Table 3 summarizes these RA requirements and characteristics. In the next section we examine the current challenges that these markets face.

[14] The ELCC methodology is a measure of the extent that a resource can reduce the LOLE or contribute to system reliability. The value is based on the ability of the resource to serve incremental load while considering the random variability of system events and generation outages.

Table 2: Unconventional Resource Capacity and Counting Methodologies

ISO	Demand Response Capacity	Intermittent Resource Capacity	Intermittent Resource Capacity Discount
ERCOT		Wind 18% of total capacity in 2015.	Capacity contribution factor for wind resources ranges 12-55% based on season and location. Determined by ELCC study.[15]
CAISO		Wind & solar had 4,297 MW or 8.5% of total RA capacity in 2015 (averaged over top 210 hours).	Minimum amount of generation produced in at least 70% of the peak demand hours studied.
MISO	6,413 MW expected for Summer 2016.	Wind was 2% of unforced capacity in 2015.	Use historical performance in hours 15-17 for most resources and ELCC for wind capacity credit (at 14.7% in 2015-16).
ISO-NE	2,871 MW or roughly 8% of qualified capacity for 2019-20 delivery year.	949-1,144 MW or roughly 2.5% of qualified capacity for 2019-20 delivery year.	Availability determined using 5-year median output during reliability hours.
NYISO	3.7% of UCAP Requirement for Summer 2015.	Wind 4% of total capacity. 1% other renewables.	Average production during hours 14-18 in summer and 16-20 in winter. Wind factor currently at 10%
PJM	12,149.5 MW of DR and EE cleared in RPM for Summer 2015.	Wind 0.5% of installed capacity. 0.1% Solar	Historical operating data during hours 3-6pm or class average capacity factor.
SPP		Wind 14.86% of total capacity in 2015.	Use historical generation shapes.

Sources: MISO (2015), NYISO (2016), (ISO-NE Internal Market Monitor 2016), (Monitoring Analytics 2016), PJM (2014), Potomac Economics (2016b), CAISO (2016), CAISO Department of Market Monitoring (2016).

[15] ERCOT conducts a LOLE study and resource contributions to reliability for informational purposes. ERCOT does not have a resource adequacy requirement.

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Table 3: Summary of ISO Resource Adequacy

ISO	Procurement Structure	RA Requirement	Timeline	Price Formation	Market Power Mitigation	Resource Obligations	Performance Incentives
ERCOT	**Energy-only market** that primarily relies on scarcity pricing mechanisms.	No requirement. 'Target' reserve margin is 13.75%	n/a	Operating Reserve Demand Curve adder and Reliability Deployment Adder. Use LOLE[16] and value of lost load.	System offer cap set to $9,000/MWh. Mechanism in place to reduce offer cap if costs become excessive.	n/a	n/a
CAISO	**Bilateral RA Requirement:** met through **bilateral contracts and self-supply**.	System requirements set by LRAs (most at 15% reserve margin). Local and flexible requirements determined by ISO.	Yearly and monthly requirements.	Largely unknown. Backstop capacity procured by ISO via auction, paid as bid.	n/a Backstop procurement auction subject to soft-offer cap.	Must-offer obligations vary by capacity type but involve scheduling and bidding in Day-Ahead and Real-Time markets.	**Average.** Incentive mechanism assesses adherence to must-offer obligation. No established performance criteria.
SPP	**Bilateral RA Requirement:** Procurement is through bilateral contracts and self-supplied.	Planning reserve margin set at 12%.	Peak summer season.	Unknown.	n/a	None.	None.
MISO	**Bilateral RA Requirement:** LSEs may use bilateral contracts, *or* procure through a voluntary centralized ***Planning Resource Auction (PRA)***	System-wide and zonal requirements set with LOLE study. The 2015 required reserve margin set to 14.7%	Auction held immediately prior to delivery year. Proposal for 3-yr forward auction for competitive retail states.	Currently demand curve is vertical at RA requirement. Proposal for sloped demand curve for competitive retail states.	Participants may self-schedule or submit $0 offers in PRA. Offer cap set at 2.7*zonal CONE.[17]	Must offer in Day-Ahead Energy and Reserve markets and first post Day-Ahead RAC process every hour.	**Weak.** MISO monitors must offer obligation but no formal incentive structure. Forced outages will reduce capacity counted.
ISO-NE	**Centralized capacity market:** called the *Forward Capacity Auctions (FCA)* Centralized capacity Market	System and local requirements set with LOLE study.	3-years in advance with additional auctions held annually and monthly.	Sloped demand curve, uses LOLE and CONE.	Minimum competitive offer prices. Requests to exit reviewed by market monitor.	Must offer into energy market and schedule maintenance with ISO	**Strong.** New pay-for-performance design integrates performance into capacity payment.
NYISO	**Centralized capacity market:** called the *Installed Capacity Auctions.*	System and local requirements set with LOLE study. Current reserve margin is roughly 17%.	Auctions held immediately prior to and during 6 month capability period.	Sloped demand curve, uses capacity requirement and CONE.	Market power tests determine when to impose offer floors and caps	Must schedule or bid in Day-Ahead market.	**Weak.** No performance mechanism but forced outages reduce capacity counted.
PJM	**Centralized capacity market:** called the *Reliability Pricing Model (PRM)*	System and local requirements set with LOLE study.	Base auction 3-years in advance. Incremental auctions held up to delivery year.	Slopped Demand Curve, based on requirement, net-CONE & demand reservation prices.	Minimum offer price set at net asset class CONE.	Must offer into Day-Ahead market.	**Strong.** New Capacity Performance product focuses on emergency events.

[16] Loss of Load Expectation (LOLE) is the number of days capacity is expected to be insufficient to meet load.
[17] Cost of New Entry (CONE) is an estimate of total costs for a new resource.

3 Current Challenges for Resource Adequacy Policies

- Low average energy prices are challenging the financial viability of a large number of incumbent baseload generation resources. This has raised questions as to whether RA policies are adequately valuing the contributions of these resources relative to the resources that are displacing them.
- Alternative resources—such as renewable generation and demand response—are rapidly increasing their market shares in both energy and capacity markets. This has increased the importance of imperfect metrics that compare and incentivize the relative reliability contribution and the performance of diverse resources.
- The extension of uniform RA market policies to states with increasingly diverse regulatory preferences is creating tension between the oversight of RA markets and the policy preferences of individual states.
- The adoption of newer smart grid technologies provides the potential to apply more flexibly reliability and RA standards to both states and consumers, but the process for establishing reliability and planning standards must be made more flexible if more diverse preferences are to be accommodated.

In discussing some of the key challenges confronting resource adequacy (RA) policy today, there is a common theme that runs through many of these issues. It is a theme that has been at the core of RA policy debates since the onset of restructured electricity markets: the degree to which the planning, financing, and operations of power plants should be incentivized by short term energy and ancillary services markets, and the extent to which additional RA policies are necessary to support generation and alternative resources.

Resource adequacy policies have always had to balance a goal of providing additional revenues to generation resources while also ensuring those payments in turn translated into the performance of those resources during the periods in which they were most needed. There is tension between these goals: performance incentives backed by penalties create risk for suppliers by threatening to claw back RA revenues. This reintroduces some of the uncertainty in revenues that RA policies were, to some extent, designed to mitigate. At one end of the spectrum are energy only markets, where all revenues must be earned through the daily provision of energy or ancillary services. At the other extreme, capacity payments with no performance obligations provide a stable revenue base for resources, but can lead to “steel in the ground” that sits idle during periods of need due to a lack of gas procurement, adequate maintenance, or a lack of wind or sun. We have discussed above experiences in New England and PJM that have led those markets to adopt more stringent performance incentives.

Recent and ongoing RA initiatives have been spurred in part a mismatch between 2000’s era RA policies and the resources that are increasingly being added to markets around the US. The diversity of resources being added to the US grid, including renewable energy, storage, demand response, as well as conventional fossil generation, has forced a re-evaluation of what types of performance is reasonable to expect from a RA resource, and what penalties and incentives are justified in pursuit of this performance.

In theory, properly designed market-based wholesale energy and ancillary services markets calculate exactly the value being provided by resources at the time the provide it. Practical limitations have called into question the ability of these markets to capture all values, however, particularly during periods of capacity, ramping, or transmission scarcity. Ongoing concerns over supplier market power in short-term energy and ancillary services markets have begat mitigation policies that can at times also limit scarcity rents. On the other hand, it is increasingly difficult to project, years in advance, the value to a system provided by a combustion turbine relative to a wind turbine, in turn relative to a battery capable of providing 30 minutes of supply. Even if such projections were practical, the existing metrics for valuing resources are insufficient for capturing the full diversity of performance that can be provided.

In the following sections we discuss four general trends that have challenged the assumptions behind the design and implementation of today's RA policies. These trends are *low average energy prices*, the increasing penetration of *alternative resources*, the application of RA policies to areas with *diverse regulatory preferences*, and the need to reconcile *traditional reliability standards with new smart-grid technology.*

3.1 Low Average Energy Prices

- Average energy prices were substantially lower in 2010-15 than in 2005-2010.
- Despite ongoing changes to allow technically higher maximum prices in periods of scarcity, these changes have been more than offset by lower natural gas prices and increased entry of renewable generation.
- The tenuous financial position of specific baseload technologies or plants does not necessarily imply that energy markets and RA policy are not working as intended, but may rather imply those plants are a bad fit for current and future resource mixes.
- The key policy question is whether RA policies adequately value the characteristics of threatened incumbent technologies relative to the technologies that are replacing them.

In many discussions of RA policies during the early 2000s, capacity payments were often described as a transitional tool. Cramton and Stoft (2006) offer the most comprehensive vision of this transition. They argue that capacity markets can "fade away" because "as demand response improves, spot prices will spend more time at levels above $100, which will increase scarcity revenues." Increased scarcity revenues would lead to lower capacity prices in competitive capacity markets, until, if enough resources are interested in entering the market simply for energy revenues, the capacity price falls to zero.

Such a transition may be slowly underway, however any changes to the frequency and levels of scarcity prices have been overwhelmed by other trends in the industry to produce relatively lower, rather than higher energy and ancillary service revenues.
Table 4 reports the annual average energy prices for each ISO.[18] We see that all most all markets have observed a significant decline in average prices from 2005 to 2015. In addition,

Table 5 shows a similar trend for the maximum hourly price across years for each market.

Table 4: Mean Energy Prices by Market and Year

Year	CAISO	ERCOT	ISONE	MISO	NYISO	PJM	SPP
2005			77.57	50.19	76.46	57.97	
2006			60.33	42.07	60.26	48.7	
2007			67.34	46.9	66.77	56.12	47.61
2008			80.49	48.03	78.15	66.25	52.19
2009	32.87		41.79	26.56	40.09	37.06	27.6
2010	35.31	29.89	49.23	31.76	47.89	44.71	31.95

[18] The data are ISO system-wide average hourly prices from SNL Energy. SNL has both day ahead and real time prices for most ISOs. For these markets we average these market prices for each hour. We have mostly day ahead prices for CAISO and mostly real time for SPP. We report the annual averages for each market.

2011	30.16	43.55	46.54	31.78	45.25	42.69	29.39
2012	28.58	26.13	36.06	27.23	35.5	32.95	22.51
2013	41.11	31.31	56.2	30.93	46.04	36.84	25.98
2014	46.07	37.34	63.98	38.66	54.43	48.69	34.06
2015	31.55	24.82	41.47	26.47	34.62	33.8	23.33

Table 5: Maximum Hourly Average Prices by Market and Year

Year	CAISO	ERCOT	ISONE	MISO	NYISO	PJM	SPP
2005			493.42	197.4	749.29	219.66	
2006			615.72	307.07	595.42	510.11	
2007			216.04	339.08	640	437.24	261.8
2008			309.93	281.61	498.83	337.79	542.86
2009	474.83		174.68	158.93	221	157.79	483.71
2010	109.74	312.59	308.99	210.7	384.71	233.67	401.51
2011	90.77	2750.85	391.35	287.29	624.79	459.84	308.86
2012	164.36	1258.93	256.89	573.65	520.7	235.7	208.91
2013	172.35	1195.08	782.51	486.81	545.31	317.15	222.58
2014	167.17	2265.44	754.42	938.58	727.5	1127.9	809.27
2015	117.69	1204.12	541.2	262.17	307.13	353.75	601.59

These prices are primarily driven by declines in natural gas prices, but the expansion of low marginal-cost renewable energy sources has impacted prices, notably in Texas and California, and can be expected to place further downward pressure on prices as the renewable energy share increases. Figure 7 shows the amount of renewable capacity that began operating each year from 2000 to 2015. Capacity is broken up by market type: Eastern Capacity Markets (PJM, ISO-NE, and NYISO); Transitional or RA Requirement (CAISO, MISO, and SPP); Energy Only (ERCOT); and Regulation (all other areas).

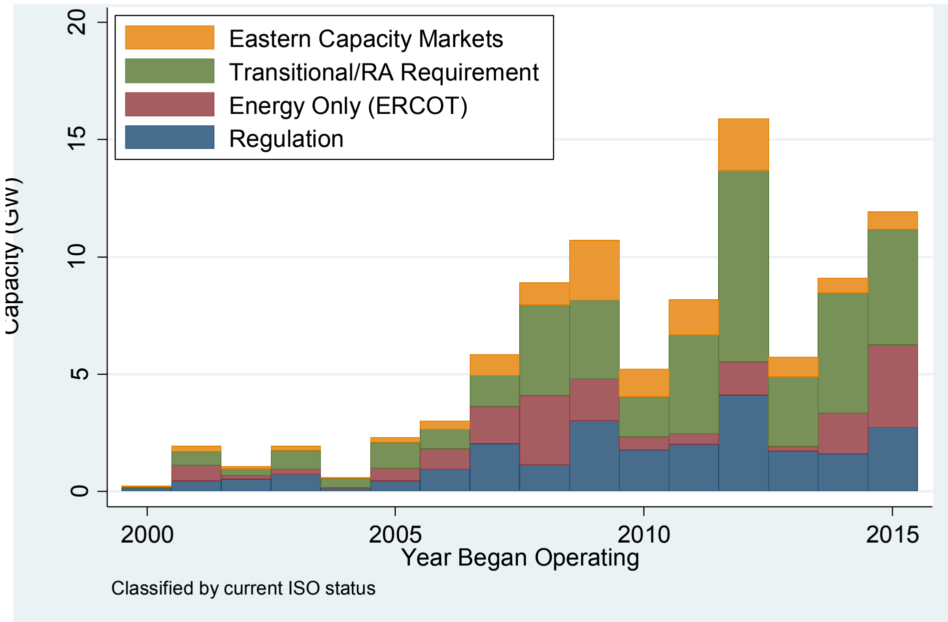

Figure 7: New Renewable Capacity by Market Type

In comparison, Figure 8 shows the investment in non-renewable capacity in these markets over this time period. Across all markets, investment in new fossil generation has slowed while renewables have grown. Over the past five years, the overall level of investment in renewables has been similar to that in more traditional areas (note that the figures have different scales).

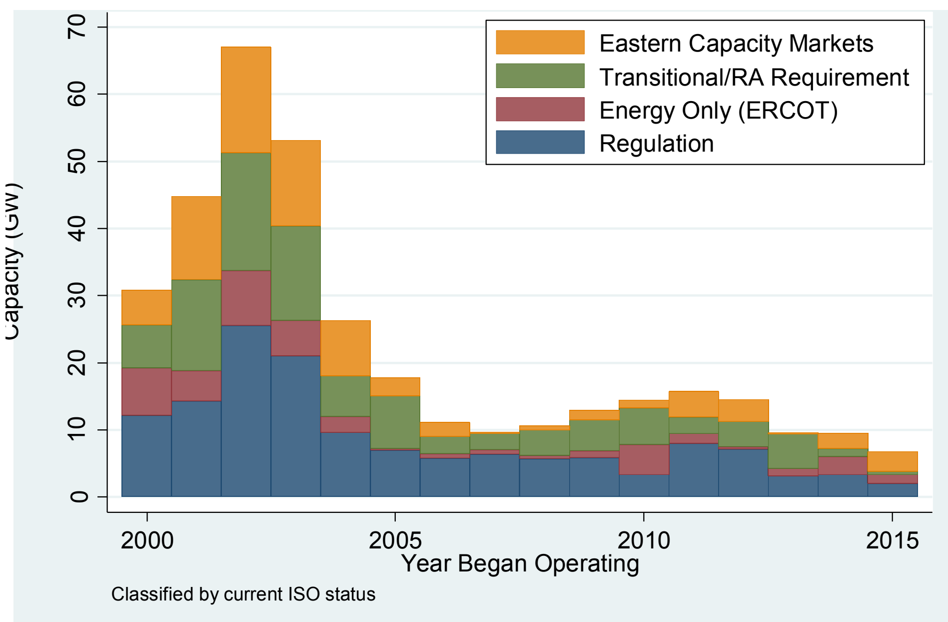

Figure 8: New Non-Renewable Capacity by Market Type.

This shift in generation mix has and likely will continue to threaten the financial position of some legacy generation technologies. Nuclear generation is most notably on the endangered list. Davis and Hausman (2016) discuss how costs of operating these plants have increased while peak prices have fallen. Several nuclear power plants have shut down in recent years due to low expected profits. For example, shortly after having its license renewed, Vermont Yankee shut down due to concerns of low energy and capacity prices.[19] Energy revenues alone in recent years are not sufficient to cover these costs. Most nuclear facilities are operating either under traditional regulation, or in markets that feature some form of resource adequacy payments. Even with capacity payments, it appears that revenues may be insufficient to cover the operating costs of several nuclear generation stations.

The key policy question is whether the financial threat to existing nuclear and coal generation represents a failure of RA policy, or simply reflects efficient price signals driven by a combination of over-supply and an inefficient technology mix. From a resource adequacy perspective, the issue is not whether market revenues are sufficient for nuclear capacity to survive, but whether those revenues are sufficient to maintain *some form* of capacity that is capable of supporting a reliable electric system.

The policy issue can therefore be reframed as whether the current RA structures adequately capture the value provided by the resources that are in the process of displacing legacy baseload generation. To the extent that retiring baseload coal and nuclear generation is being replaced by combined-cycle natural gas plants, the operational characteristics of new and departing generation are similar and there is no reason to think the policies are not working as designed.

The main area of controversy is the extent to which baseload plants are being displaced by intermittent (or variable energy) renewable generation, and to a lesser extent, demand response (DR). Newell, Oates et al. (2015) note that over 18 GW of new natural gas power plant capacity has been arranged through the last six PJM capacity auctions. However, the last two of these auctions have also resulted in the procurement of over 11 GW of demand response. We discuss the issues surrounding variable energy resources in the next section.

If we assume that current trends toward increased renewable electricity generation will continue, this will likely induce a long-run realignment of prices and generation technologies. A significant share of zero marginal cost, variable supply implies much more volatility in energy and ancillary services prices. Table 6 shows the standard deviation of the hourly market prices as in Table 4. While some markets like ISO-NE and NYISO seem to be showing greater volatility over time, others (including ERCOT, MISO and SPP) see the opposite trend.

[19] Entergy to Close, Decommission Vermont Yankee, Entergy press release, August 27, 2013; http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=2769.

Table 6: Standard Deviation of Prices by Market and Year

Year	CAISO	ERCOT	ISONE	MISO	NYISO	PJM	SPP
2005			27.76	31.61	32.72	31.51	
2006			22.64	24.15	27.83	26.61	
2007			20.61	26.71	28.7	27.24	23.75
2008			29.1	29.45	31.74	32.96	33.28
2009	14.09		16.72	12.82	18.13	14.46	17.36
2010	10.26	15.38	20.17	15.19	21.97	21.06	17.49
2011	12.45	117.28	20.95	15.12	23.4	22.95	15.25
2012	10.81	34.15	18.12	14.35	19.28	15.34	9.01
2013	9.29	22.64	46.48	11.98	29.77	16.75	10.85
2014	11.76	42.47	65.21	21.6	55.42	52.49	29.7
2015	8.45	27.82	36.51	9.6	28.23	23.51	16.36

Under regulation, the capital costs of traditional generation can be covered through regulated retail rates set at levels above the average short-run marginal cost of providing energy, or "system lambda." Doing so, however, creates an increasing gap between retail rates that cover the full average cost of supply, and would be wholesale prices in a restructured market. When such gaps grow large, there is increased pressure for policy change.

In restructured markets that are supported by capacity or resource adequacy policies, absent an adjustment to energy prices, suppliers will draw an increasing share of revenues from capacity (RA) payments. As discussed above, this places even more importance on the design parameters of capacity markets. A well-designed capacity market would accurately measure the contribution of a disparate set of resources, as well as provide the proper incentives for the reliable operation of capacity.

In order for energy markets to reach the long-run competitive equilibrium, extended periods of low prices need to be offset by less-frequent periods of extremely high prices. Markets will need to assess whether current bid-caps, and more importantly pricing "penalty" values will need to be raised, or if there needs to be an expansion in the conditions in which penalty prices apply.

3.1.1 Energy Prices and RA Time Horizon

Low *current* energy prices have reinforced questions about the proper time horizon over which RA policies should apply, as some planners believe that inadequate current compensation could exacerbate resource shortfalls five to ten years into the future. Whether to commit to a resource farther into the future has long been a contentious element of RA policy debates, one that is sometimes linked to the activity of retail choice in a region. Bilateral RA obligations, such as those imposed in CAISO, MISO, and soon in SPP, are more difficult to apply years into the future if LSEs face the prospect of non-trivial load migration.

There are serious questions as to how accurately planners can forecast *system* load three or five years into the future.[20] In addition, there is great concern that such forecasts cannot be accurate even at the LSE level. Therefore, the desire to commit capacity payments to resources farther than one year in the future has been held out as a strong argument for a centralized capacity market (Pfeifenberger, Spees et al. 2012), in which the ISO is effectively the counter party purchasing capacity for all its users. Having a single party purchase all expected capacity needs reduces the forecasting problem to one of aggregate demand, regardless of LSE market shares. However, this does not ensure that the proper amount of total capacity is acquired. Harvey, Hogan et al. (2013) argue that "this has been particularly apparent in the PJM capacity market which contracted forward for capacity based on load growth forecasts that proved materially inaccurate following the financial crisis, with the cost of keeping the excess capacity in service, or of buying back the capacity obligation at a lower price in an incremental auction, borne by PJM power consumers."

Some of the sharpest debates in RA policy continue to be related to how far in the future formal RA procurement needs to be. Spees, Newell et al. (2015) argue that retail choice creates a form of market failure in procurement, "LSEs serving retail choice customers do not have captive load and cannot know what their load obligations will be in the future; they cannot be expected to procure future supplies or develop resource plans on behalf of an as-yet undetermined customer base." Skeptics note that other capital intensive industries, such as telecommunications, support capital investment without capacity payments despite analogous risks of customer migration. Bushnell (2005) argues that "Even if a retailer is long, it can still resell its contracted energy on the wholesale market. Many information industries with far higher ''churn rates'' of customer migration have managed to finance capital expansion."

Another argument in favor of forward capacity procurement is that it better coordinates planning and investment in generation amongst unrelated (and often competing) entities, and also helps to inform investments by regulated entities, particularly in the transmission network. Spees, Newell et al. (2015) argue that the single-year time horizon for RA in MISO "limits MISO's ability to determine if system-wide and locational resource adequacy needs are likely to be met. It also creates transmission planning challenges if MISO has insufficient information to determine what transmission upgrades will be necessary to accommodate retirements and support new resources." Harvey, Hogan et al. (2013) note that one possible use of a forward capacity market is "to identify in a forward timeframe in which replacement capacity or transmission upgrades can be put in service, potential retirements of specific facilities whose operation is needed to maintain local reliability." However they also argue that generic forward capacity markets are a bad fit for this need. They note that "contracting for an aggregate amount of capacity in this auction does not ensure that specific resources will remain in operation to meet local reliability requirements." This is because most forward capacity markets only establish forward *financial* commitments. The specific capacity source can be reconfigured between the time of the commitment and the delivery of the capacity.

One last argument focuses on the fact that it is unrealistic to expect new generation capacity to

[20] Newell, et al. (2015) document how the annual forecasts for PJM over the last decade has been consistently overstating load growth. For example, the 2011 vintage forecast of 2017 peak demand was over 10 GW higher than the 2015 vintage forecast for the same year.

be constructed in one-year or less. This argument overlooks the point that the capacity payment itself may not be necessary or sufficient to finance new generation investment. These payments are not the only game in town. As Harvey, Hogan et al. (2013) note, an annual capacity requirement "does not *prevent* load-serving entities from contracting forward for capacity." Knowledge of a pending capacity obligation (or opportunity for revenue) can be intended to spur contracting outside of the RA framework. Cramton and Stoft (2006) point out that the issue is confidence in the level (and existence) of a payment, rather than its specific timing, noting that "Short-term capacity markets could pay hourly and would work fine, provided investors *believe* the payments will continue."

The procurement of capacity multiple years in advance involves a theoretical trade-off between coordination amongst investors - who may have imperfect information about the market and each-other – and the concentration of decision making into a single entity whose forecasting errors can impact the entire market. In some ways these reflect the trade-offs debated upon deregulation of electricity supply, where regulatory procurement could be highly efficient in theory but at times fell short in practice. Decentralized decisions made through the market place can be more volatile and less coordinated, but are often an efficient method for discovering the aggregate beliefs and preferences of a large number of participants.

The question of the *length* of commitment through capacity markets comes down to a determination of whether capacity payments can and should be capable of financing resources, by themselves, or whether these markets are intended to provide incentives to spur bilateral contracting and regulatory procurement outside of the capacity market.

In both cases, more careful research, or even anecdotal review of the effectiveness of ISO targets, and the activity in bilateral contracting would help inform the question of the optimal forward time-frame and commitment time of RA markets.

3.2 Integration of Alternative Resources

- Roughly half of new capacity added to ISO markets in the last five years has been from renewable resources with intermittent production.
- Demand response resources have earned a substantial market share in capacity markets in the last five years.
- These trends have placed further importance on the ex-ante measurement of capacity, and the performance incentives applied to these resources.
- A key policy question is the degree to rely upon performance incentives and short term market rewards to provide adequate value to resources with the ability to perform flexibly and in the periods of highest need.

This section examines how RA requirements may be affected by the integration of alternative resources including renewables, energy storage, and demand response. The shift to these alternative resources impacts power markets in three important ways: their impact on average energy prices; their impact on capacity market prices; and the extent to which their intermittency and energy limitations create new reliability needs that are not satisfactorily addressed by conventional RA and ancillary service policies. Each of these concerns have been observed in restructured electricity markets. In California, for example, the penetration of utility-scale solar has helped contribute to low, or even negative, energy prices during the middle of the day. In addition to influencing energy prices, alternative resources (primarily renewable generation) have earned an increasing share of capacity or RA payments.[21]

The magnitude of these changes is illustrated in Figure 9. While the overwhelming share of new capacity added in ISO regions during the early 2000s was fired by natural gas, since 2010 roughly half of all new capacity has been powered by renewable sources. If this trend continues as expected, the implication is that not only will conventional resources find it increasingly difficult to recover costs from short-term markets, they will find more competition and lower prices in the RA markets also. While renewable resources have played a very large role in resource adequacy in California and MISO, to date, as described in Section 2, demand response has been the most prominent alternative resource in much of the east.

[21] Intermittent renewables are also referred to as Variable Energy Resources (VERS).

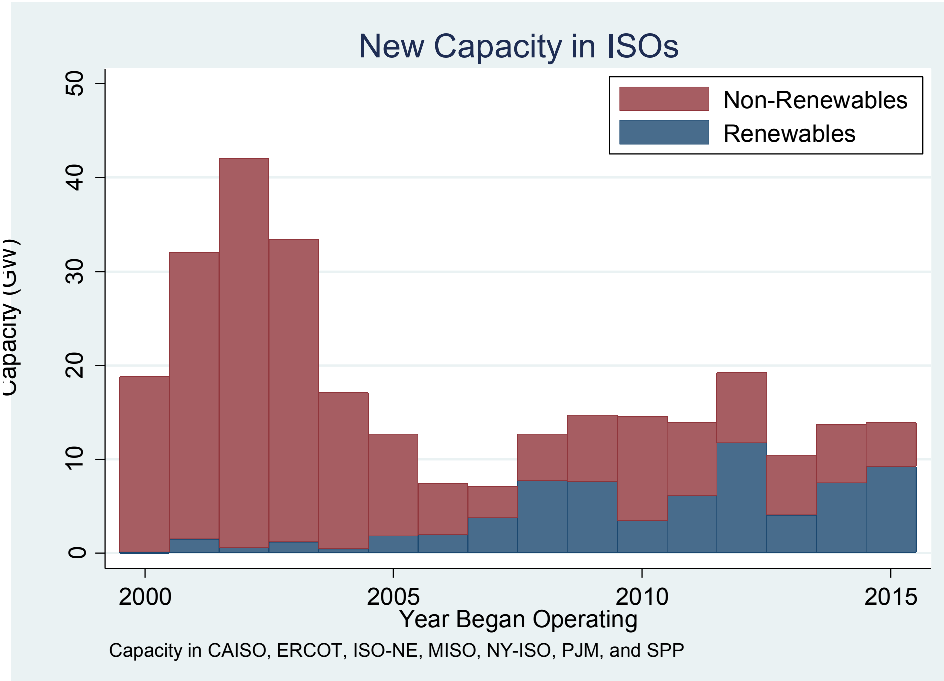

Figure 9: Decomposition of New Capacity

One key policy question, therefore, is whether alternative resources can and should provide a comparable form of "capacity" as conventional resources. Such questions get to the heart of what has been a central issue with RA policy from the start: what exactly constitutes "capacity" under such policies?

ISOs have struggled even to define the attributes that constitute the boundaries between conventional and alternative resources. Among the key elements that have been debated and periodically revised are the following:

- Should qualifying capacity be limited to resources that can be made available on demand, or evaluated based upon a probabilistic expectation of performance?
- How location specific should capacity procurement be?
- What performance characteristics should be required?
- What are the performance obligations of participating capacity?
- Should those obligations be applied uniformly or adapted to specific resources such as energy-limited storage, and variable energy resources?

These questions highlight the distinction between an energy-only setting and those with compensation for capacity. Performance in an energy-only setting is simply the sale of energy or ancillary services in a daily market. If a unit is operating and selling into the market, it earns revenue. If it is not, then it earns no revenue. Under a capacity payment paradigm, qualified units earn revenue in advance and can keep those earnings even if the unit is not available under a long set of possible exemptions. When resources were of like type and operated by firms with similar incentives, common assumptions about availability did not distort procurement. However, with a new range of more diverse resources, ISOs are again revisiting their ex-ante assumptions about performance and the incentives provided to resources committed through RA markets.

3.2.1 Incentives and Mandates for Performance

A capacity market would have no value if resources were not expected to be able to produce energy when the market was tight. Here we examine how capacity markets are being modified to consider incentives and mandates to achieve performance. In their review of the NYISO capacity market, Harvey and Hogan note the following:

> "The larger the total revenues collected through the capacity market rather than the energy or ancillary service market, the greater the concern with the many inherent approximations that appear in the necessary simplifications of the complex problem of constructing forward estimates of resource requirements and defining administrative requirements to provide appropriate performance and investment incentives for capacity suppliers." (Harvey, Hogan et al. 2013)

The simplifications and assumptions made in the procurement of capacity were more tolerable when the types of capacity being procured were relatively similar. The assumptions did not bias procurement towards one type or resource or another. These stresses have become more significant with the increase use of unconventional resources to meet capacity needs. This has left the designers of RA policies with two choices: (1) further refine and categorize the types of capacity to be required; or (2) increase reliance on short-term energy and ancillary services revenues to provide signals about the characteristics and performance abilities of new capacity.

ISOs are taking a diverse approach to this choice. Harvey, Hogan et al. (2013) strongly support an emphasis on short-term market rewards, arguing that "attempting to use capacity market rules to elicit capacity resources with the optimal mix of characteristics to meet load over the operating day has the potential to become more and more difficult as the diversity of the resource mix increases and has the potential to end badly, resulting in both lower reliability and higher consumer cost." In New England, ISO-NE has also shown a preference for strong performance incentives that would be uniformly applied to all resources. The ISO argues that performance incentives are the key to inducing flexible resources necessary to complement intermittent supply: "Changes to the FCM that improve incentives for resource flexibility and availability will provide better incentives for investment in resources that can balance intermittent power supply" (ISO-NE 2012).

Conversely, in California the CAISO, in conjunction with California state agencies, has been incrementally working towards a setting with multiple, nested, capacity requirements. In addition to a standard RA requirement that is applied to all participating Load-Serving Entities, the California Public Utilities Commission adopted a "flexible" Capacity Procurement requirement in 2014. The requirement for the first time explicitly distinguishes types of capacity by operational characteristics. Other RA requirements and capacity markets differentiate resources by location, and reduces their qualifying capacity through availability metrics, but do not place explicit limitations based upon an ability to respond on demand to operational orders.

The California proceeding highlights many of the difficulties inherent in specifying not just a quantity of capacity, but also a range of operational requirements in a RA context. If fast ramping capability is a key need, must such capability be available for a full hour or smaller intervals? Must resources be available all the time, during peak needs, or during shoulder ramping periods? The difficulties have been magnified by the need to compare dramatically different resources types, including energy-limited storage, conventional generation, and demand response. In addition ensuring capability, California has also experienced problems enticing flexible resources to perform. A non-trivial amount of conventional capacity in the California market bids in such a way that operators must treat it as an inflexible unit. The flexible RA proceeding has therefore been about inducing *existing* flexible resources to act flexible as well as securing the investment of new flexible resources.

In PJM and New England, the policy direction has been toward encouraging flexible participation through the prospect of extreme penalties if units do not perform and additional rewards if they do perform. However, these payments, while significant, are limited to hours in which scarcity, in terms of deficient energy or ancillary service provision, have been identified by the operator. While this approach can focus resource efforts on a relatively low number of scarcity hours, it is less clear if it is suited to, for example, a routine daily need for ramp. To the extent ramping or other constraints lead to volatile prices, but not official "scarcity" conditions, these mechanisms may still fall short of providing adequate incentives and revenues for high frequency flexible resources

3.2.2 Demand Response

Questions about the value of renewable generation center on the intermittency and timing of their supply. By contrast, questions relating to demand response revolve more around the measurement of, and compensation for, their contributions.

Concerns over the measurement of DR performance depend upon how the product is designed. Some concerns arise from the challenge of measuring the baseline consumption from which reductions are supposed to be measured. Some DR products use historical consumption of either the specific DR provider or a similar comparison group to establish a baseline of performance. Energy savings are then measured by comparing actual consumption to the baseline. Two issues can arise. First, firms or customers could strategically increase their baselines, as evidenced by a pilot program in Anaheim, CA (Wolak 2006). Second, firms can strategically enroll or offer their "reductions" only during periods when they know their consumption would be lower than the baseline anyway. One prominent example of this phenomenon was California's 20-20 program, which rewarded consumers who reduced their consumption by 20% relative to the prior year with a 20% rate reduction. Ito has demonstrated (Ito 2015) that the response seen in this program was not significantly different than observed in a typical year due to the natural churn of customer usage.

The payment to be made for demand response has been a controversial topic that has been linked to FERC order 745 and the subsequent legal battles over its implementation (King, Crawford et al. 2015). Order 745 established a payment level for DR that many economists have argued is both inflated and discriminatory relative to other forms of equivalent service (Hogan 2016). For example, storage that is "in front" of a retail meter would earn wholesale prices, while identical storage behind a retail meter would be eligible for DR payments (Bushnell, Harvey et al. 2011).

Going forward, with the uncertainty over order 745 resolved, key research and policy questions will involve establishing the quality of DR performance, relative to other resources, and assessing whether payment formulas are resulting in an inefficiently large focus on DR relative to other resource types.

3.3 Adaptation of RA Markets to Diverse Regulatory Settings

- RA policies are increasingly expanding into regions operating under traditional regulation.
- Many of the original justifications for RA markets do not apply to these regions.
- RA policies can better inform local regulators but may also be viewed as impinging on their jurisdictional authority.
- Conflicts have arisen between states that are supporting specific projects or technologies, and market mitigation principles designed to prevent uneconomic investment that depresses capacity prices.
- States and the Federal government may need to more strongly emphasize policy tools, such as cap-and-trade, that promote state goals without distorting market prices for power or capacity.

In traditional, vertically integrated markets, concerns over resource adequacy remain internal to the firm and its regulator, and are dealt with largely through the process of regulatory planning. Many of the intellectual motivations for RA policies, such as compensation for money missing from market revenues, hedging, and the coordination of multiple retailers within a system, do not apply to systems operating under traditional regulatory principles.

However, regional RA policies are increasingly being adapted and applied to regions that remain largely unchanged by electricity restructuring. Many members of the MISO and SPP systems meet this description, and utilities in several western states are considering joining an expanded California ISO.

Figure 10 shows the 48 states and Washington DC. The map shows which states have retail choice by outlining the state in blue. In addition, the figure depicts which states have bilateral RA requirements in orange or centralized capacity markets in red. While some ISOs cover only part of some states, we code the RA status of a state based the majority status.

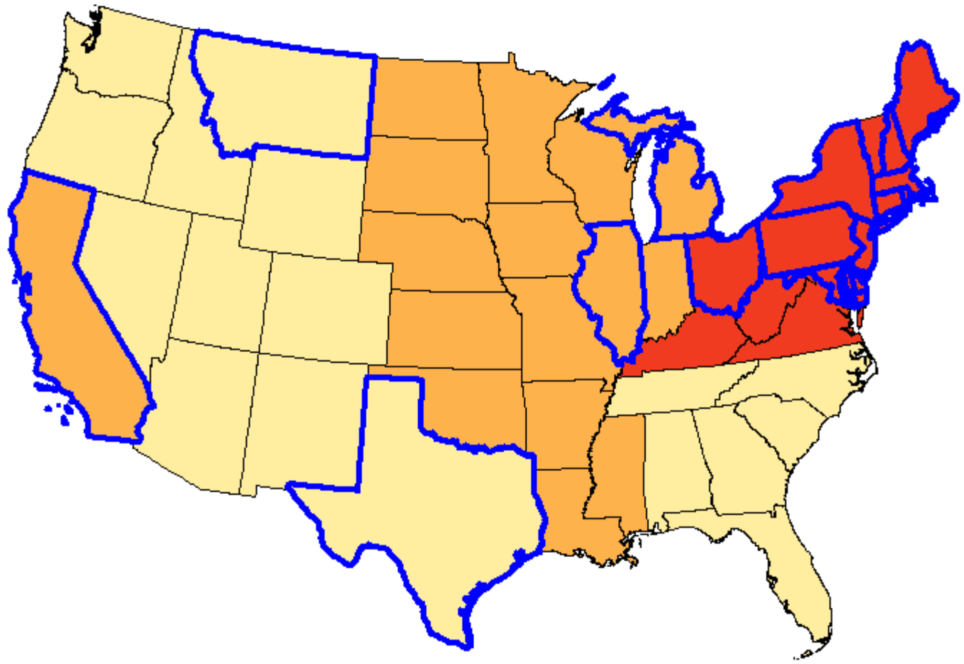

Figure 10: Map of States in the Lower 48 that have Retail Choice (Blue Outline) and States that have Bilateral RA Requirements (Orange) or Centralized Capacity Markets (Red).

The idea of applying RA policies to regulated utilities is not new. As (Harvey 2005) describes, it arose from the formation of regional power pools.

> *"The need for resource adequacy mechanisms, such as installed reserve requirements, the precursor of ICAP systems, initially arose in the Northeast from the implementation of economic dispatch which eliminated the link between an entity's generation and load….This operating environment led to rules providing for shared responsibility for load shedding within the impacted region of the pools, rather than attempting to assign responsibility to the generation-short distribution company."*

This passage highlights the conclusion that the adoption of market-based dispatch equates to an abandonment of the ability to isolate load-shedding to the individual utilities responsible for a shortage event. This makes reliability a public good shared between utilities where it formerly had not been. We will discuss this conclusion further in the following section. However, it is also important to note that this shared responsibility for reliable dispatch stems from a need for an *operating margin,* one that is provided daily or in real time.

The translation of this shared short-term reserve requirement into a longer-term RA requirement or market, while perhaps intuitive, is not absolutely necessary. The expectation and knowledge of an ongoing responsibility to meet shared needs for reserves (and of large penalties for those who fail to do so) should solve the incentive problem.

The extension to an RA requirement or market constitutes an additional step of coordinated planning and oversight of *how* individual utilities and firms plan on meeting their ongoing shared obligations. Much of the ongoing tension between local regulatory authorities and regional bodies such as ISOs stem from differences in forecasts, assumptions, and philosophy over the level of resources that will actually be needed to assure reliability, and the type of resources capable of filling those needs. The fear of losing some jurisdictional authority over aspects of these choices has reinforced the reluctance of some states to join regional ISOs.

Of course, regional coordination is not necessarily a bad thing. As Spees, Newell et al. (2015) point out, RA markets can be used as a tool to make regulation more effective. "Regulated utilities lack the level of information and forward price transparency that would facilitate the most cost-effective investment decisions. Regulated utilities also have incomplete information on other LSEs' supply plans that may affect their own reliability."

An added challenge arises in markets where regulated states share responsibilities with those that have adopted elements of regulatory restructuring. As a region comprising states (Illinois) that feature retail choice and those that do not, MISO has had to most directly confront these competing priorities. Again, Spees, Newell et al. (2015) argue that RA markets can better inform investment choices, or else "shortages in retail choice states will also have cost impacts on regulated state customers, as the tighter reserve margin will drive up wholesale energy prices, for example by increasing the frequency and severity of scarcity pricing events.

However, within the confines of traditionally regulated utilities, RA policies may or may not be seen as *better* regulation, so much as a *different* approach to regulation. This is particularly true for forward capacity procurement. As Harvey, Hogan et al. (2013) note, "it needs to be kept in mind that forward contracting for capacity shifts risk from capacity suppliers to consumers…. An intrinsic feature of an ISO coordinated forward capacity market is that capacity is procured based on an administratively determined load forecast, rather than a market based evaluation."

3.3.1 State Policy Priorities and Market Power Mitigation in RA settings

The area in which the diversity of State policies and regulatory approaches have produced the most visibility and conflict has been the views adopted by some markets, and by FERC, that State policies represent unacceptable interference with market outcomes. The crux of the dispute is whether sources of generation that have been subsidized or indirectly supported by states or state policy are depressing RA prices in an anti-competitive manner. This issue is sometimes referred to as *buyer side market power.*

As part of their oversight role to ensure markets produce just and reasonable prices, centralized capacity markets in PJM, ISO-NE, and NYISO have in place *minimum offer price rules.* The rules were intended to prevent large LSEs to exploit their market position by financing (or contracting for) uneconomic extra capacity. Such a strategy could be profitable for a LSE if it depressed the price of capacity and the LSE was a net buyer of sufficiently large amounts of capacity.

Such policies are rather blunt methods for dealing with a structural market power problem that can lead to inefficient outcomes. FERC (2013) notes that the policy intervention triggered by the inefficient entry of capacity can perversely result in the construction of even more capacity. Furthermore, FERC states that:

> *If that resource does not clear the market, it will not receive a capacity payment, and, in some cases, it may not be counted toward satisfying the load-serving entity's capacity obligation, requiring that the load-serving entity procure and (pay for) additional capacity resources to meet its capacity obligation.*

Such strategies are not limited to centralized capacity markets. Regulatory procurement rules in California has resulted in a bias toward new capacity with the result that prices for incumbent capacity have been extremely low for many years (Pfeifenberger, Spees et al. 2012). The problem fundamentally is one of buyer concentration, rather than the specific market environment in which those buyers operate.

The ISO-NE did propose an alternative two-part mitigation approach that would have set mitigated (*e.g.*, higher) prices for incumbent generation, but allowed the unmitigated (*e.g.*, lower) prices to impact new capacity. The logic behind this approach was that it eliminated the theoretical market benefits to "dumping" extra capacity on the market, since it would not lower the bulk of capacity payments that go to incumbents. At the same time ISO-NE's two-part approach would have avoided the perverse outcome of acquiring even more capacity through the market in response to inefficient entry of uneconomic capacity. The FERC rejected this approach and instead ordered ISO-NE to adopt measures consistent with that of PJM (Miller, Butterklee et al. 2012).

Minimum offer regulations have been particularly controversial when they overlap with state specific policy goals. Both New Jersey and Maryland pursued initiatives to support local generation with special procurement backed by ratepayers, and argued it was necessary given the inadequate geographic differentiation of the PJM capacity market at the time. Up to that time, state mandated projects had been exempt from minimum price mitigation, but a protest by non-utility generation spurred revisions the PJM's rules that partially eliminated this exemption.

In the lawsuit that followed these changes, New Jersey Petitioners argued that "by eliminating the state-mandated exemption, FERC effectively attempts to substitute its own power supply preferences for those of the states and LSEs in violation of § 201 of the FPA, which provides that states retain authority over "facilities used for the generation of electric energy." The US Third Circuit Court of Appeals found otherwise, stating that the rule did not impose resource preferences on the state, as long as the resource cleared the market:

*Such a requirement ensures that the new resource is economical—*i.e.*, that it is needed by the market—and ensures that its sponsor cannot exercise market power by introducing a new resource into the auction at a price that does not reflect its costs and that has the effect of lowering the auction clearing price.*

Left unsaid at this stage of the dispute was the role of state *environmental* preferences relative to the market. In particular, state subsidies or mandates for renewable generation would appear to the exact same effect upon capacity prices as did the Maryland and New Jersey Procurement. Clearly parts of FERC see renewable subsidies as a separate issue:

[Commissioners Wellinghoff and LaFluer] urged New England to consider an exemption for renewables as in PJM: "While it is true that all [out-of-market] capacity, regardless of intent, will have the same effect on the market-clearing price, it is also true that some [out-market] capacity is not intended to suppress the market-clearing price, but to further legitimate public policy goals, such as the progressively escalating renewable portfolio standards present in each of the six New England states." (Miller, Butterklee et al. 2012)

At the moment, therefore, the policy in most markets is to apply minimum offer price mitigation to *some* state supported resources but not all of them. The policy of the FERC is to *allow* but not require markets to exempt specific projects or resource types. The major markets (PJM, NYISO, and ISO-NE) allow for exemptions of renewables.
In April of 2016, the Supreme Court effectively upheld the FERC's stance on minimum offer prices in capacity markets (SCotUS 2016).

The current state of policy continues to expose compromises that do not fully satisfy unregulated market participants or proponents of state priorities. Miller, Butterklee et al. (2012) argue in favor of more bright line safe harbors for state subsidies:

The better principle going forward is that the FERC should seek to avoid interference with state public policy goals. And the best way to accomplish this is to create clear exemptions up front to avoid disputes and litigation on a case-by-case basis. Additional exemptions could include generators needed for reliability and also a safe harbor for any state that decides to have a non-discriminatory RFP issued, e.g.*, based on environmental performance of the generator.*

On the other hand, broad exemptions to buyer side mitigation could open up wide loopholes that could be exploited by creative state policy makers and LSEs. As the set of alternative resources becomes more diverse, the idea that FERC can know an acceptable subsidy when they see it may become less credible. Many economists would argue that the best way to balance the competing concerns of favoring classes of generation while avoiding a domino effect of market distortions would be to apply a uniform environmental policy to *all* resources. A carbon tax or cap-and-trade programs for SO_2 and CO_2 meet this description. Subsidies for desirable technologies will always have the effect of artificially depressing market prices, and Federal policy will still need to grapple with how to balance those competing forces.

3.4 Reconciliation of Emerging Technologies, Economic Efficiency, and Reliability Standards

- Integrated ISO markets have operated in a way that shares equally the responsibility for, and consequences of resource inadequacy.
- This has made resource adequacy a "public good" that has provided justification for RA policies in many markets.
- Emerging "smart-grid" technology holds the potential to isolate consequences for resource shortfalls to the providers responsible for those shortfalls.
- These technologies can allow for more diversity in reliability preferences, and in assumptions about the capability of specific resources to support reliability.
- Organizations such as NERC that set and enforce reliability standards should consider the impact of new technologies on both planning and operational standards in a way that better accommodates economically efficient reductions or curtailments in load.

A bedrock assumption behind RA standards and policies is that customer preferences for generation level reliability are uniform and that they are very high. It is almost certain that preferences are not identical and quite likely that some, if not many, customers would have a willingness to pay for RA below that which has been imposed upon them by these structures. The ubiquitous "one in ten" standard for reliability events has multiple interpretations, but analysts have tried to map it to a more standardized measure, such as the Value of Loss Load. Cramton and Stoft (2006) using $80,000 a KW-yr as the cost of capacity, translate the one in ten to a Value of Lost Load of over $250,000/MWh. This is well in excess of some estimates of VOLL, but allowing for the risk of cascading outages may complicate this translation.

As described above, the basis for such standards, similar to the basis for RA policy, is to prevent negative spillovers, or the "free-riding" of one system on the resources of their neighbors. Power systems have long operated as if, in the words of Spees, Newell et al. (2015) "reliability is a "common good" that helps or hurts all customers equally. Any involuntary load shedding events caused by a shortage will be applied indiscriminately to customers regardless of whether their representative LSEs met their resource adequacy requirements." In other words, a resource shortfall results in random outages. This is predicated upon the notion that it is impossible to identify and implement the reliability preferences of individuals or communities.

The advancement of technology provides an opportunity to revisit these assumptions. The American Recovery and Reinvestment Act of 2009 provided $4.5 billion for "smart grid" technologies and much of that has been leveraged with matching funds from states and utilities (Joskow 2012). The deployment of retail smart meters accelerated massively over the last half-decade. Combined with advances in sensors and monitoring at the higher voltage level, ISOs are close to having the technology to distinguish the supply contributions of individual control areas and perhaps individual retailers.

These developments imply that it may be possible to retreat from the axiomatic belief that reliability is a public good. Certainly within short operational time frames, shared responsibility for operating reserves will be necessary for the foreseeable future. However, over longer planning horizons it may be possible to identify control areas or individual Load-Serving Entities who have failed to provide adequate resources and to isolate involuntary load curtailments to only the customers of the responsible LSEs.

Ironically, most of the country operated their interconnected control areas in such a fashion before the onset of regional ISOs. Each individual utility was responsible for balancing its load through internal resources and voluntary exchanges with neighboring regions. The temptation to free-ride on a neighbors supply, always technically possible for interconnected control areas, was tempered by NERC oversight and the prospect of serious *ex-post* penalties for “leaning” on a neighbor’s system.

With emerging technology and creative market design, it can be possible to allow individual firms to approach their resource needs according to their individual assumptions and beliefs, rather than through a standardized set of metrics and rules. Disagreements between local regulators and ISOs about the likely effect of energy efficiency programs, intermittent supply, or demand response can be put to the test by allowing local regulators to make their choices, but also live with the consequences.

At a smaller scale, in markets with retail choice, individual customers may be able to align with retailers according to their reliability preferences as well as other attributes. A retailer that carries a smaller planning margin may be able to charge lower prices, but would no longer be able to share that risk with involuntary partner organizations. Its customers would be subject to the resource decisions taking by their retailer, and would ideally be well informed about the implications of their choices.

Much of the technical capability for such activity exists already. Advanced metering technology is widely deployed and ISOs and utilities have had the capability to selectively interrupting individual customers for over two decades. One challenge is being able to diagnose the causes and fault for resource shortfalls quickly enough.

Currently, almost all of the innovation in this area has been limited to the participation of load through demand response products. These products themselves are gaining an increasing share in many capacity markets. However the business model and operational characteristics are still constrained to operating within a conventional RA paradigm.

In order for there to be more diversity in the approaches to reliability and resource adequacy, reliability organizations such as NERC must play an active role. In some cases, the activities described above would violate existing NERC standards. This implies that there needs to be more careful examination about what the definition of “reliability” should be, and what environments are best suited to rigid standards, and which can be conducive to more flexible choices.

Much of the hoped for innovation from electricity restructuring has been concentrated at the wholesale level. There has been much progress in the efficiency, design, and operation of power plants and of high-voltage systems. However, much less has changed at the consumer level, despite the wave of technologies that have become available. It could be the case that the application of "one-size-fits-all" resource adequacy policy has contributed to the lack of innovation in retail services by reducing the scope for such innovation.

If such opportunities continue to be denied within the context of an integrated electric system, pressure for rolling out services "behind the meter" may grow. There are enormous benefits from ever larger pooling of the consumption and resources of electric systems, but without more flexible regulatory approaches to reliability, systems may instead become more Balkanized into micro-grids that are capable of providing the diversity of reliability that has been slow to materialize at the wholesale level.

4 Conclusions

This document examines the issue of resource adequacy (RA) in the US electricity generation sector. Three paradigms have been used to address RA adequacy: traditional regulation; energy-only markets; and markets with RA policies. This document provides a detailed description of how each electricity market considers RA issues. In addition, we have examined the current challenges for resource adequacy.

We reach the following conclusions. First, low average energy prices are challenging the financial viability of a large number of incumbent baseload generation resources. This has raised questions as to whether RA policies are adequately valuing the contributions of these resources relative to the resources that are displacing them. Second, alternative resources—such as renewable generation and demand response—are rapidly increasing their market shares in both energy and capacity markets. This has increased the importance of imperfect metrics that compare and incentivize the relative reliability contribution and the performance of diverse resources. Third, the extension of uniform RA market policies to states with increasingly diverse regulatory preferences is creating tension between the oversight of RA markets and the policy preferences of individual states. Forth, the adoption of newer smart grid technologies provides the potential to apply more flexibly reliability and RA standards to both states and consumers, but the process for establishing reliability and planning standards must be made more flexible if more diverse preferences are to be accommodated.

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