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Program on Technology Innovation: Alternative Approaches to Generation Adequacy Assurance

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PRODUCT DESCRIPTION

Reliability of electricity supply—"keeping the lights on"—has been the principal motivation for many technical and economic constraints imposed on market designs. While short-term operational reliability is provided by means of protection devices, operating standards, and procedures that include security-constrained dispatch and procurement of ancillary services, long-term generation adequacy requires investment in upgrading and expansion of generation capacity. In restructured electricity markets, such expansion critically depends on economic incentives to existing and new generators that will induce sufficient investment. This report reviews the various mechanisms that have been proposed and implemented in the United States and around the world to rectify the prevailing adequacy problem by stabilizing generators' income and creating incentives for investment in generation capacity.

Results & Findings

Following are key areas examined in this report:

- The development of capacity markets in the United States and direct capacity payments adopted throughout the world
- Practical implementation of energy-only approaches that have no explicit capacity remuneration and highlights of the backstop mechanisms used to ensure cost recovery for suppliers and attract investment if new capacity is needed
- Approaches to generation adequacy that require direct intervention by the regulator or system operator, involving competitive tendering or negotiated contracts for new capacity and strategic reserves that the system operator procures on a long-term basis
- The prevailing generation adequacy measures adopted in the European Union, with emphasis on the national diversity in chosen approaches

Challenges & Objective(s)

The objective of the report is to examine alternative approaches to ensuring generation adequacy. The key challenges lie in assessing the relative effectiveness of the diverse approaches to resource adequacy and in providing a qualitative cost-benefit evaluation of these approaches.

Applications, Values & Use

This report provides a qualitative comparison of the alternative resource adequacy mechanisms, evaluates how they meet certain criteria, and examines how they may fit in various market environments. Such information will enable load serving entities and independent system operators to examine the suitability of various approaches to individual energy company circumstances.

EPRI Perspective

Technological innovation—leading to improvements in the efficiency and cost of relatively small power plants—has prompted market reforms that allow load serving entities to take advantage of the wider mix of resources available to meet their future needs. Added to that is the promise of further technological innovation in metering control, generation, and transmission technologies. The complexity of choices can reflect the diversity of consumer tastes and preferences as well as the willingness of electricity producers and consumers to accept more risk in exchange for proper rewards.

Approach

The author first performed an in-depth literature search then relied upon professional expertise and industry interviews to address the following topics:

- The energy-only market and the efficient investment paradigm
- Impediments to energy-only markets and the "missing money problem"
- Contrasting approaches to resource adequacy
- Evolution of installed capacity markets in the United States
- Capacity payment mechanisms
- Variants of energy-only markets
- Competitive tendering and strategic reserves
- Generation adequacy mechanisms in the European Union
- Qualitative evaluation of alternative resource adequacy

Keywords

Generation
Resource Adequacy
Capacity
Independent System Operator
Reliability
European Union

ACRONYMS

CAISO	California Independent System Operator
CC	Combined-Cycle
CCM	Capacity Credit Market
CEC	California Energy Commission
CONE	Cost of New Entry
CPT	Cumulative Price Threshold
CPUC	California Public Utilities Commission
CRAM	Centralized Resource Adequacy Market
CT	Combustion Turbine
EAP	Energy Action Plan
EILS	Emergency Interruptible Load Service
ELCON	Electricity Consumers Resource Council
ERCOT	Electric Reliability Council of Texas
EU	European Union
FERC	U.S. Federal Energy Regulatory Commission
FCM	Forward Capacity Market
GW	Gigawatt
IAEE	International Association for Energy Economics
ICAP	Installed Capacity
IEEE PES	Institute of Electrical & Electronics Engineers Power Engineering Society
IPEX	Italian Electricity Market
IRP	Integrated Resource Plan
ISO	Independent System Operator
IOU	Investor-Owned Utility
IAEE	International Association for Energy Economics
kW	Kilowatt

LaaRs	Loads acting as Resources
LCR	Local Capacity Requirement
LDC	Load Duration Curve
LECG	Law and Economics Consulting Group, LLC
LICAP	Locational Installed Capacity
LOLP	Loss-of-Load Probability
LSE	Load Serving Entity
MC	Marginal Cost
MCP	Market Clearing Price
MCSM	Modified Competitive Solution Method
MISO	Midwest Independent Transmission System Operator
MCPE	Market Clearing Price for Energy
MCSM	Modified Competitive Solution Method
MW	Megawatt
MWh	Megawatt-Hour
NEISO	New England Independent System Operator
NEMA	Northeast Massachusetts/Boston
NERC	North American Electric Reliability Council
NETA	New Trading Arrangement
Nord Pool	The Nordic Power Exchange
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
O&M	Operation and Maintenance
OOM	Out-of-Market
PASA	Projected Assessments of System Adequacy
PER	Peak Energy Rents
PJM	Pennsylvania-New Jersey-Maryland
PSMC	Power System Management and Control
PUCT	Public Utility Commission of Texas
RAR	Resource Adequacy Requirement
RFP	Request for Proposal
RMR	Reliability Must Run

RPM	Reliability Pricing Model
RUC	Reliability Unit Commitment
SPP	Southwest Power Pool
TC	Target Capacity
TERA	Teknechron Energy Risk Advisors
TSO	Transmission System Operator
USAEE	United States Association for Energy Economics
UCAP	Unforced Capacity
VOLL	Value of Lost Load
VRR	Variable Resource Requirement

EXECUTIVE SUMMARY

The reliability of electricity supply has been one of the overriding concerns in the restructuring of the electric power industry. The slogan “keeping the lights on” has been the principal motivation for many technical and economic constraints imposed on market designs. The term supply reliability encompasses, however, a mix of system attributes that have diverse economic and technical implications under alternative market structures.

In an ideal competitive energy market, generators always offer supply at marginal cost. However, inframarginal profits (from scarcity rents resulting from clearing prices set by peaking units and demand-side bids) produce adequate income to cover generators’ fixed costs. This provides sufficient incentive for investment when needed. In such an ideal market, generators bear all the investment risks and load bears the price risk, while financial instruments and long-term contracts between sellers and buyers enable them to manage their risk exposures. Unfortunately market imperfections—including technological barriers to demand response, local market power, and price mitigation measures—result in depressed energy prices and “missing money,” which prevent generators from recovering their fixed costs. Such revenue shortfalls discourage investors from expanding generation capacity needed to meet socially desirable reliability levels. Various mechanisms have been proposed and implemented in the United States and around the world to rectify this problem by stabilizing generators’ income and creating incentives for investment in generation capacity.

For all practical purposes, most restructured electricity markets abandoned the notion of letting the market determine the socially desirable level of generation capacity in favor of a central planning criterion for reserves based on technical and social considerations. The various approaches to ensuring generation adequacy vary, however, with respect to how explicit is the regulator in prescribing the level of generation capacity, as opposed to providing financial incentives and relying on market forces to provide the desired level. These approaches fall into three general categories: 1) Mechanisms based on capacity remuneration through direct capacity payment or capacity markets, 2) Energy-only markets with various degrees of price spike suppression and backstops, and 3) Centralized procurement of generation resources by the system operator or designated agent charge by the regulator.

This report

- Reviews the development of capacity markets in the United States and variants of direct capacity payments adopted throughout the world.
- Discusses practical implementation of energy-only approaches that have no explicit capacity remuneration.

- Highlights the backstop mechanisms used to ensure cost recovery for suppliers and attract investment if new capacity is needed.
- Provides an overview of approaches that require direct intervention by the regulator or system operator. Such approaches involve competitive tendering or negotiated contracts for new capacity and strategic reserves that the system operator procures on a long-term basis.
- Takes a look at the prevailing generation adequacy measures adopted in the European Union, highlighting the national diversity in chosen approaches.
- Provides a qualitative assessment in Table 10-1 that examines the necessary conditions for implementing the various adequacy schemes introduced in the United States and around the world, and compares these schemes with respect to a list of criteria.

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1
INTRODUCTION

The reliability of electricity supply has been one of the overriding concerns in the restructuring of the electric power industry. The slogan "keeping the lights on" has been the principal motivation for many technical and economic constraints imposed on market designs. The term supply reliability encompasses, however, a mix of system attributes that have diverse economic and technical implications under alternative market structures. The North American Electric Reliability Council (NERC) defines *reliability* as: "… the degree to which the performance of the elements of the technical system results in power being delivered to consumers within accepted standards and in the amount desired."[1] Imbedded within this definition is the requirement for *supply adequacy*, which is defined as "the ability of the system to meet the aggregate power and energy requirement of all consumers at all times." The supply adequacy requirement is derived from the notion of the "obligation to serve," which has been part of the regulated vertically integrated utility legacy.

The notion of supply adequacy attempts to characterize the system's ability to meet demand on a long time scale in view of the inherent fluctuation and uncertainty in demand and supply, the non-storability of power, and the long lead-time for capacity expansion. Generation adequacy has been measured traditionally in terms of the amount of planning and operable reserves in the system and the corresponding loss of load probability (LOLP) that served as criteria for planning and investment decisions. Thus, adequacy is distinct from *operational reliability*, which identifies short-term operational aspects of the system that are characterized through contingency analysis and dynamic stability assessments. Adequacy is provided by means of protection devices as well as operating standards and procedures that include security-constrained dispatch and procurement of ancillary services such as voltage support, regulation capacity, spinning reserves, and black-start capability. From a technical perspective, however, operational reliability and adequacy are closely related, since a system with abundant reserve capacity provides more flexibility in handling unforeseen disturbances. It is important to recognize that a system with limited planning reserves may experience shortages, but it can still be operated reliably, while a system with ample reserves can be operated unreliably and experience blackouts.

Prior to the introduction of wholesale and retail electricity markets, regulators required utilities to maintain a target reserve margin, ranging somewhere between 15% and 25%, to ensure a desired level of reliability and resource adequacy. Regulators ensured that integrated utilities would serve retail loads and meet prevailing reliability standards at just and reasonable prices. This approach required a mix of resources designed to serve the fluctuating demand at least cost. New capacity expansion plans were based on forecasted load growth and reserve margin requirements

[1] E. Hirst, *et al*., March 1999.

in order to reliably meet future needs. Regulators set the price of electricity service so as to provide the utility with an opportunity for cost recovery and reasonable return on its investment. In some jurisdictions, up to the mid-1990s, utilities could build new generating facilities only if the new additions were approved in their Integrated Resource Plans (IRPs). These plans required utilities to review alternatives to constructing generating facilities, including purchases from non-utility qualifying facilities, demand-side management, and renewable resources.[2]

Sending timely and accurate price signals to the majority of customers was not a key priority. In maintaining a healthy reserve margin, regulators used concerns over reliability and cost as justification for their policy of special tariffs for interruptible loads, which were primarily targeted at large commercial and industrial customers. The regulatory approach was appropriate in an era when regulators were primarily concerned with controlling monopoly utility profits, technological innovation was slow, and economies of scale in generation and transmission justified viewing the electric power industry as a natural monopoly. However, technological innovation—leading to improvements in the efficiency and cost of relatively small power plants—has prompted market reforms that allow load serving entities (LSEs) to take advantage of the wider mix of resources available to meet their future needs. Added to that is the promise of further technological innovation in metering control, generation, and transmission technologies. The complexity of choices, including price options, now feasible at reasonable cost, can reflect the diversity of consumer tastes and preferences as well as the willingness of electricity producers and consumers to accept more risk in exchange for proper rewards.

Most of the restructured electricity systems worldwide recognize the need for centrally controlled ancillary services, typically procured by the system operator through an auction market or through long-term contracts with generators. In many cases, market participants are allowed to self-provide certain ancillary services, but the quantities are prescribed by the system operator, who is also the provider-of-last-resort for these services. In exceptional cases such as the Australian system, generators are not remunerated for providing reserves but are induced to provide “free reserves,” with the opportunity to collect very high scarcity rents when these reserves are deployed to produce energy.

With respect to long-term reserves, however, there is considerable diversity in reliance on market-based approaches, and the debate over which is the correct way of ensuring generation adequacy is still raging. The expanded choices in wholesale and retail markets open the door for free riding by LSEs when it comes to risk management and public goods such as service reliability. The situation is potentially more complicated in most of the deregulated retail electricity markets, where regulators may not require that competitive retailers procure resources

[2] For instance, the Public Utility Commission of Texas, as well as many other state regulators, required regulated utilities to rely on competitive solicitation to procure additional resources to meet their increasing growth in demand for electricity. Competitive solicitations would include conventional generation resources, new technologies such as renewable resources, and demand-side management programs. This approach is still common in Europe under the name “tendering” and has been recently adopted in California as an interim “long-term adequacy” mechanism for attracting new generation capacity.

that provide deliverable energy to their loads in a multiyear time frame.[3] The glut of generation in some of these newly restructured markets may have also reinforced the practice of relying on spot market procurements and avoiding the burden of long-term contracts in serving loads that might switch suppliers in the future.

Regulators within this paradigm need to maintain a prudent reserve margin that meets the reliability needs of newly restructured markets, while not imposing unnecessary expenses on customers that also may unnecessarily interfere with customer choice. At present, most regulators do not enforce a reliability requirement on LSEs similar to what the integrated utilities in the old regulated world had to meet.

The following section will survey the economic principles that underlie market-based resource adequacy, impediments to implementing the theoretical paradigm, and consequences to such impediments. The section will also review solution-based approaches implemented or proposed in the United States and Europe and provide a qualitative cost-benefit evaluation of such approaches within the scope of different technical constraints and political economies.

[3] When retail markets are still relatively young, competitive retailers are uncertain about their market shares and might be at a competitive disadvantage if they procure firm resources two or three years into the future, while their competitors might not do so and while they have the financial incentive to purchase loads from retailers with the lowest prices.

2
ENERGY-ONLY MARKET AND THE EFFICIENT INVESTMENT PARADIGM

From the perspective of classical economic theory, the "gold standard" for the provision of adequate generation capacity in a competitive electricity market is through reliance on energy prices and scarcity rents. In other words, as is common for most commodities, producers are paid market prices for the energy they sell and recover their fixed costs for capacity, startup costs, and no-load costs from their inframarginal profits and scarcity rents. Such profits are accrued by the seller whenever the market-clearing price for energy exceeds the marginal cost of production. (When generators can also sell ancillary services such as operating reserves, the income from those sales also contributes to the inframarginal profits.) The basic principles of such a market are as follows:

- Energy is priced at marginal cost with demand side setting the price during scarcity hours.
- Competitive forces drive generation capacity, technology mix, and prices toward a long-term equilibrium, where the total amount and technology mix of generation capacity is optimized with respect to supply and demand preferences for reliability and cost.
- Fixed costs of generation capacity at long run equilibrium are exactly covered by inframarginal costs and scarcity rents.
- Forward markets and hedging instruments enable parties to manage their risk exposure.

Figure 2-1 below illustrates the profits for inframarginal units during hours of the day when the marginal price is set by more expansive units as well as the scarcity rents that accrue to all the operating units when the marginal price is set by the unserved load.

In theory, sellers will break even, when the total amount of generation capacity and the capacity mix are optimal (meaning minimization of total cost of energy, capacity, and lost load), and all energy produced is remunerated according to marginal cost pricing. Such pricing must include scarcity rents, with prices set to the value of lost load (VOLL) or determined by demand response, during shortage periods. These scarcity rents and inframarginal profits, illustrated in Figure 2-1, will exactly cover the sellers' fixed costs. This result, which will be demonstrated below, provides the theoretical support for marginal cost pricing in a multi-technology production mix.

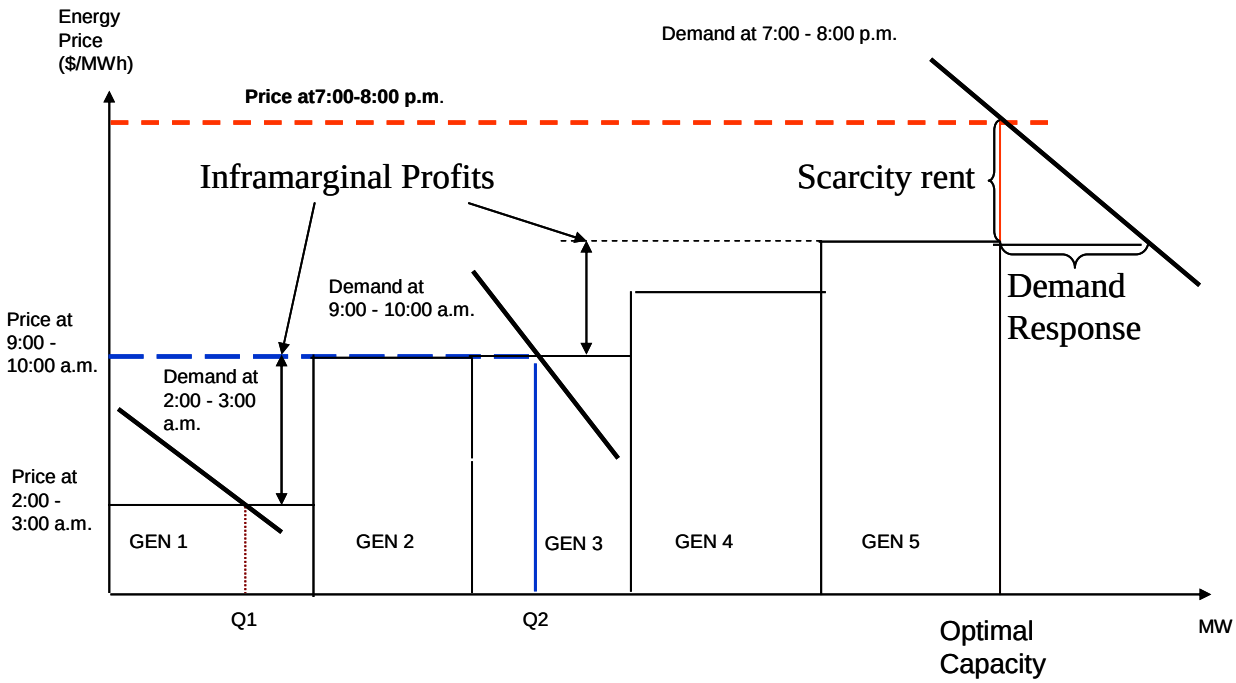


Figure 2-1
Illustration of Inframarginal Profits and Scarcity Rents Under Marginal Cost Pricing

Figure 2-2 below illustrates on the left panels, the classical approach to determining the optimal capacity mix to serve a variable load represented by a load duration curve (LDC). Each generation technology is characterized by an amortized fixed cost per megawatt (MW) and a variable (energy) cost per megawatt-hour (MWh). The load duration curve can be interpreted as a stack of load slices of different duration. Each load slice can be assigned to a technology that minimizes the combined fixed and variable costs for serving its duration.[4] Projecting the duration boundaries, up to the LDC, enables utilities to determine the optimal capacity for each technology as well as the duration range within which each technology is at the margin under merit order dispatch.

The total cost of each generation unit—when the generation portfolio is optimally planned and dispatched—can be recovered by charging each load slice the fixed and variable costs corresponding to its assigned technology and paying it to the corresponding generator. In these circumstances, the 1-MW load slice marked in the upper left panel of Figure 2-2 costs

F3+C3*(T0+T1+T2+T3), which can be paid directly to a generator of type GN3 serving it.[5]

[4] This approach assumes that generation capacity is infinitely divisible and ignores startup costs associated with multiple starts during the period represented by the load duration curve.

[5] This approach underlies what has been known as the Wright Tariff used in the United States in the early years of the industry.

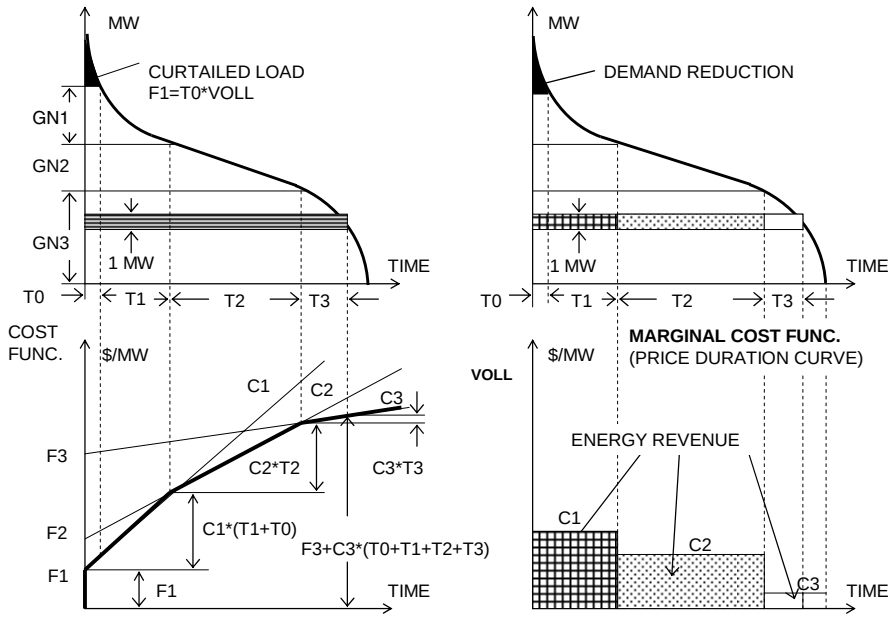


Figure 2-2
Capacity Planning and Cost Recovery

Alternatively, the cost of serving that load slice can be recovered through a marginal cost charge for each MWh produced (i.e., the variable cost of the unit on the margin) supplemented by a capacity payment equal to F1. This will produce a total payment of F1+C1*(T0+T1)+C2*T2+C3*T3, which is shown in Figure 2-2 to be equal to F3+C3*(T0+T1+T2+T3). It should be noted that under optimal capacity planning F1=T0*VOLL. As illustrated in Figure 2-3, the capacity payment F1 can alternatively be recovered as a scarcity price on energy set to VOLL for the duration T0, during which some load is not served either through demand response or involuntary curtailment. Such an approach is preferable to a capacity payment since it produces incentives for demand response. In the event that demand response is technologically not feasible, a scarcity price of VOLL combined with any form of load shedding may be regarded as an appropriate proxy to demand response. The above analysis also demonstrates that either capacity payments or scarcity rents for energy should be paid to all generation units uniformly and not just to the peaking units, as is often suggested.

The above analysis shows that when generation capacity and technology mix are at their optimum, marginal cost pricing—with energy prices set to VOLL during load shedding periods—will lead to full cost recovery by generators. However, with changing fuel costs and uncertain load growth, neither the total capacity nor the capacity mix is likely to be at the optimal levels. Thus, some technologies will experience excess profits while others will sustain losses. Such profit and loss scenarios are the correct economic signals that will drive the industry toward the desired equilibrium through new entry of the profitable technologies and retirement of the unprofitable technologies. Figure 2-4 provides a simple example that illustrates the process of exit and entry.

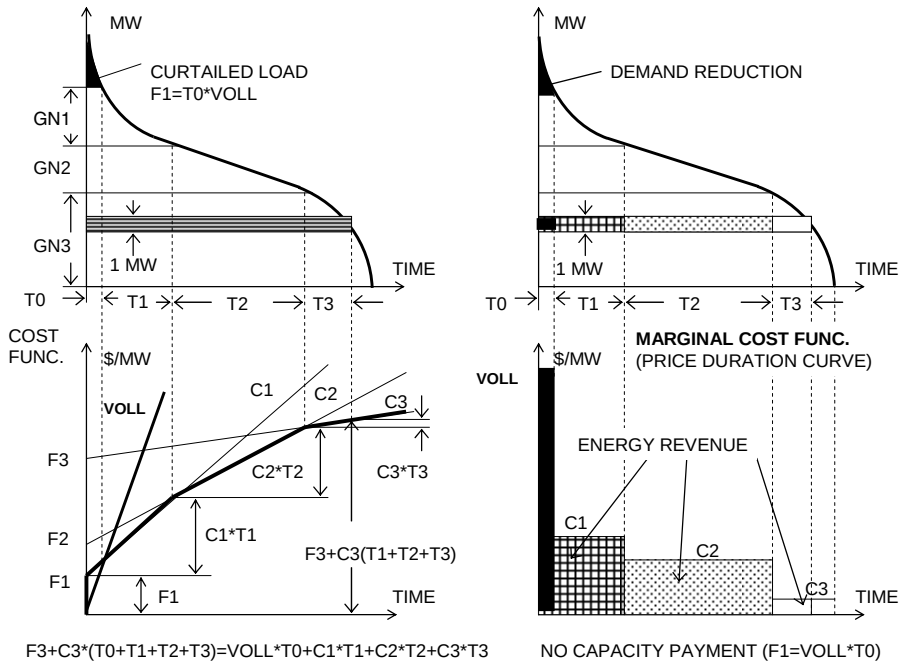


Figure 2-3
Fixed Cost Recovery Through Scarcity Pricing During Load Curtailment

Figure 2-4 illustrates a supply function for a system with two types of generation units, which are denoted in the table below as G1 and G2. The following table summarizes relevant data for the supply system:

Generator type	No of units	Unit capacity	Fixed cost	Marginal cost
G1	50	80 MW	$926,400/Month	$15/MWh
G2	100	60 MW	$288,000/Month	$25/MWh

The demand is characterized by two demand functions for peak and off-peak hours (P=Price, Q=Quantity)

Off-Peak:	420 Hours/Month	P=30-Q/1000
Peak:	300 Hours/Month	P=50-Q/1000

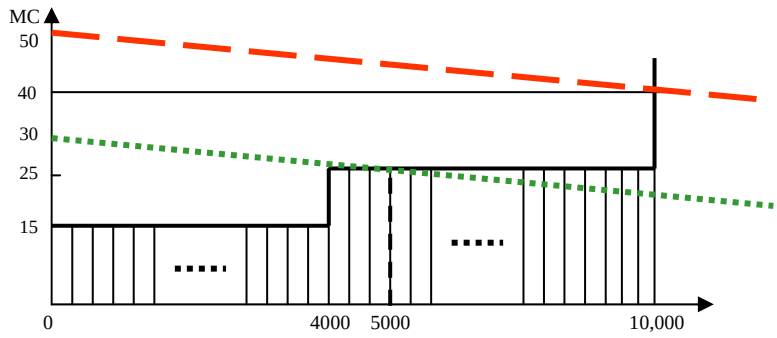


Figure 2-4
Short-Run Equilibrium

In the short run equilibrium, the price during off-peak hours is $25/MWh with demand at 5000 MW, while during peak hours, the total supply of 10,000 MW is exhausted at a scarcity price of $40/MWh. The corresponding net income for G1 and G2 generators is as follows:

G1: 80*[(40-15)*300+(25-15)*420)] - 926,400 = $9600/Month (excess profit)

G2: 60*(40-25)*300 - 288,000 = ($18,000/Month) (deficit)

Under such circumstances, one would expect entry by G1 generators and retirements of G2 generators that are losing money. This process will reach a long-run equilibrium with 2000 MW of new G1 capacity and exit of 3000 MW of G2 capacity. Figure 2-5 illustrates the new capacity mix and resulting long-run equilibrium.

Peak Price: $41/MWh

Off-Peak Price: $24/MWh

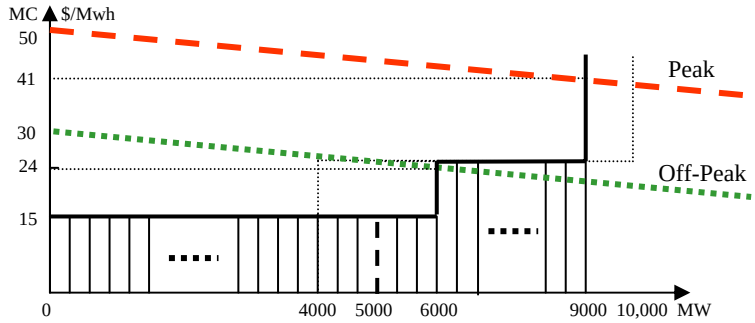


Figure 2-5
Long-Run Equilibrium

The new equilibrium will have an off-peak scarcity price of $24/MWh, with corresponding demand of 6000 MW, and a peak scarcity price of $41/MW, with all 9000 MW of capacity being used. The resulting net income for both generator types is summarized below.

G1: 80*[(41-15)*300+(24-15)*420] – 926,400 = 0 (Break-even)

G2: 60*(41-25)*420 – 288,000 = 0 (Break even)

Thus, the capacity mix has reached a long-run equilibrium where all generators break even and any additional capacity will lose money.

In reality, a long-run equilibrium, as described above, is achieved, if at all, through a series of "boom and bust" cycles of capacity expansion. A capacity shortage drives energy prices up, resulting in excess profits that attract new investment in capacity, which in turn drives energy prices down. Likewise, excess capacity results in low energy prices that reduce inframarginal profits to the point that some generators are not able to cover their fixed capacity costs. That results in early retirement of older or less efficient units and a reduction in capacity, which in turn raises energy prices. A similar process takes place when the generation mix is suboptimal, resulting in adjustments in the generation mix through retirements of some plants and construction of new ones.

There are several unique characteristics of electricity markets that differentiate them from other commodity markets and induce higher volatility of spot energy prices. These include the 1) "instant perishability" and non-storability of the product, 2) steep "hockey stick" shape of the supply function (which is a direct consequence of the optimal technology mix and the load-duration profile), and 3) high level of uncertainty about demand and available supplies. Such uncertainty is induced by weather that affects demand and availability of inexpensive hydro resources as well as by outages of plants and transmission facilities. Price volatility alone, however, should not impede the efficiency of energy markets as a mechanism for inducing adequate investment in generation. On the contrary, high price volatility will, in theory, motivate risk-averse buyers and sellers to enter into long-term forward contracts that will hedge their risk exposure. Such contracts enable investment in new generation when needed. High spot prices and anticipated shortages increase forward prices and stimulate entry. In such an ideal setup, suppliers and buyers are free to select the level of risk they want to assume, and they will use financial hedges and contractual arrangements that allocate risk efficiently.

The natural inclination of market designers with an economic background is to favor energy-only markets. Such markets have been established in Australia, New Zealand, Alberta, Canada, Texas (by the Electric Reliability Council of Texas—ERCOT), and California prior to the 2000-2001 crisis. This approach functions adequately in systems with abundant reserve capacity—such as ERCOT—and in systems where extremely high spot prices reflecting temporary scarcity are tolerated—as in Australia where spot prices can and have risen occasionally to $8000/MWh. Recently, the Texas Public Utility Commission has adopted a rule institutionalizing an energy-only approach, and the Midwest Independent System Operator (ISO) has filed a proposal based on an energy-only approach. These areas will be discussed in further detail later.

3
IMPEDIMENTS TO ENERGY-ONLY MARKETS AND THE "MISSING MONEY PROBLEM"

A realistic assessment of energy-only markets must recognize that achieving the long-run equilibrium, where capacity is optimal and sellers break even, depends on several premises whose validity in the context of electricity markets is debatable. This market failure is partially due to the inherent nature of generation capacity expansion and electricity production as well as to regulatory intervention in electricity markets motivated by political and social considerations. One critical element in achieving such equilibrium is the scarcity rent that must be reflected in energy prices when capacity shortages develop. When demand is inelastic and the commodity is non-storable, as is the case for electricity, such scarcity rents can result in extremely high price spikes, which most regulators and legislators consider unacceptable. It is difficult to distinguish legitimate scarcity rents due to shortages from price gouging due to abuses of market power and market manipulation through physical and economic withholding of capacity. The California energy crisis brought such concerns to the forefront of electricity market regulation worldwide. Not surprisingly, only a few systems around the world have opted for energy-only markets, relying on the economic forces described above to ensure adequate investment in generation capacity. Even these markets have deviated from the economic ideal by imposing "damage control" price caps. Although the unusually high $8000/MWh price cap in Australia is rarely binding, it is a primary motive for hedging by market participants.

Another implicit assumption in the economic paradigm underlying energy-only markets is the presumed existence of demand responses through exercise of customer choices. Unfortunately, this assumption is often invalid due to several factors involving technology, politics, and tradition. From a technical perspective, enabling customer choice of generation adequacy requires deployment of metering, control, and communication technologies that allow differential curtailment of loads when prices exceed preselected levels, or that enable direct customer responses to real-time prices. While the rapid decline in the cost of information technologies is promising, the economic justification for direct customer load control for low-end consumption levels is still debatable. Furthermore, empowering customers to make their own tradeoffs between service availability and cost requires that customers be exposed to real-time prices. Customers should have a default fixed-price service in the same way that homeowners can obtain fixed mortgage rates, but such options should be assessed a fair market risk premium. Unfortunately, electricity tariffs are riddled with politically motivated cross-subsidies that distort direct assignments of costs. Furthermore, most public utility commissions are reluctant to embrace real-time pricing.

Finally, there is a deeply ingrained tradition in the power industry to view generation adequacy as a public good. As a result, system operators continue to operate their systems under the traditional "obligation to serve" paradigm. For example, while rotating outages are considered

acceptable when reserve levels drop below a certain level (stage 3 alert), high prices (e.g., $1950/MWh in California during the autumn of 2000) are not considered acceptable reasons for rotating outages. Treating generation adequacy as a private good requires a paradigm shift in system operation from an "obligation to serve" to an "obligation to serve at a price." Such a shift, however, is highly controversial.

Most wholesale electricity markets, particularly the ones in the United States, have some form of price or offer caps and other forms of market mitigation measures to address price spikes or potential market failure resulting from excessive concentration of generation ownership and inelastic demand for electricity (Table 3-1). Based on the price caps of $1000 or less allowed in various wholesale markets in North America, a number of market participants and economists believe that market designs with existing price mitigation measures do not allow sufficiently high energy prices to provide adequate investment cost recovery to generators in order to induce timely construction of new resources or retention of existing resources.[6] According to Cramton and Stoft (2006), ISO New England reports a $2 billion annual cost recovery deficit for generators in its jurisdiction. Furthermore, they estimate that at the optimal capacity level, peaking units would recover only 25% of their capacity cost. A recent white paper on the Alberta electricity market made a similar observation.[7] These arguments are based on the notion that scarcity pricing requires that high prices reflect the tightness of supply in electricity markets. Proponents of scarcity pricing argue that prices should be allowed to reflect the value of lost load (VOLL) that could result in shortage situations. VOLL could be in the thousands of dollars, well above any existing offer cap currently in place in most restructured electricity markets. For example, Hogan (2006) estimates VOLL at $10,000 per MWh.

Table 3-1
Price or Offer Caps in Various Electricity Markets

Market	Price or Offer Cap
Alberta	$C 1000
Australia	$AUS 10,000
California ISO (CAISO)	$400
ERCOT (2006)	$1000
ERCOT (2007)	$1500
ERCOT (2008)	$2250
ERCOT (2009)	$3000
France	No Cap
ISO-New England	$1000
Italy	No Cap
Japan	No Cap
Midwest ISO	$1000
New York ISO (NYISO)	$1000

[6] P.L. Joskow, 2005.

[7] Alberta Department of Energy, 2005.

Table 3-1 (continued)
Price or Offer Caps in Various Electricity Markets

Market	Price or Offer Cap
Netherlands	No Cap
New Zealand	No Cap
Nord Pool	No Cap
Pennsylvania-New Jersey-Maryland (PJM)	$1000
Ontario	$C 2000
Philippines	62,000 Pesos
Singapore	$SGD 4500
South America (Argentina, Brazil, Chile, and Colombia)	No Cap
South Korea	No Cap
Southwest Power Pool (SPP)	$1000
Spain	No Cap
United Kingdom	No Cap

Notes:

1. The Canadian markets (Alberta and Ontario) offer caps are in Canadian dollars. A Canadian dollar, as of October 28, 2007, is worth about $0.96 U.S. dollar at current exchange rates.
2. An Australian dollar as of October 28, 2007, is worth $US 1.09to $US 01.00 at current exchange rate. The Australian market does limit the amount of money a resource can capture on a weekly basis, after which the $AUS 10,000 offer cap drops to $AUS 100.
3. The ERCOT market also has a low offer cap of $500 or 50 times Houston Ship Channel gas price index from the previous day, whichever is higher.
4. The wholesale electricity market in France does not have any price cap. However, it has regulated retail electricity prices that are kept fairly low by the government. As wholesale market prices rise, it becomes very difficult for alternative suppliers to compete with the incumbents.
5. The New Zealand market has no cap, but the highest price allowed in settlement has been $NZ 10,000. At the time of this writing, NZ regulators are reviewing the need for a formal cap.
6. The Nordic Power Exchange (Nord Pool ASA) has no price cap in the financial forward electricity market; however, there is a system limitation to the bids (currently $EUR 2000) in the physical day-ahead auction. This limit is not viewed as a regulatory price cap, as it can be changed from day to day. Furthermore, Nord Pool has cross-border transmission capacity constraints between the Nord Pool countries and on the interface to Germany, with market splitting when these cross-border interfaces are congested.
7. Each 11 Pesos equals $US 1.00 at current exchange rates.
8. As of October 28, 2007, 1 $SGD is worth between about $US 0.68 to $US 0.69 at current exchange rates.
9. At the time of this writing, the Midwest Independent Transmission System Operator (MISO) has filed a plan with the U.S. Federal Energy Regulatory Commission (FERC) that keeps the $1000 offer cap but would raise real-time prices as high as $3500 when MISO is using reserves to clear the energy market.

Unfortunately, mitigation designed to protect the public against market power abuse will also often suppress legitimate scarcity rents and inframarginal profits. In a competitive unrestricted market, scarcity rent is the difference between the value to consumers of the most valuable MWh that cannot be supplied due to limited generation capacity (i.e., the marginal demand-side offer accepted) and the marginal cost of the most expensive MWh not served. By definition, scarcity implies that marginal prices are set by the unserved load (demand offers) rather than supply-side offers that reflect marginal cost of supply. In the presence of market power, however, suppliers may attempt to capture rents under shortage or near shortage conditions by physically withholding capacity to induce shortages, possibly in combination with a strategy of economic withholding, i.e., offering needed capacity at very high prices. While the resulting market clearing price (MCP) in such cases may reflect scarcity, it is extremely difficult to differentiate legitimate scarcity rents from economic withholding markups after the price spike event occurs. Such considerations have prompted adoption of mitigation protocols by many ISOs, which often suppress legitimate scarcity rents that are necessary for generation cost recovery. Another important source of price suppression, which has been highlighted by Hogan (2005, 2006), results from deployment of operating reserves without properly accounting for the scarcity conditions implied by such action. Figure 3-1 illustrates how the use of operating reserve shifts the energy supply function to the right, resulting in lower energy prices.

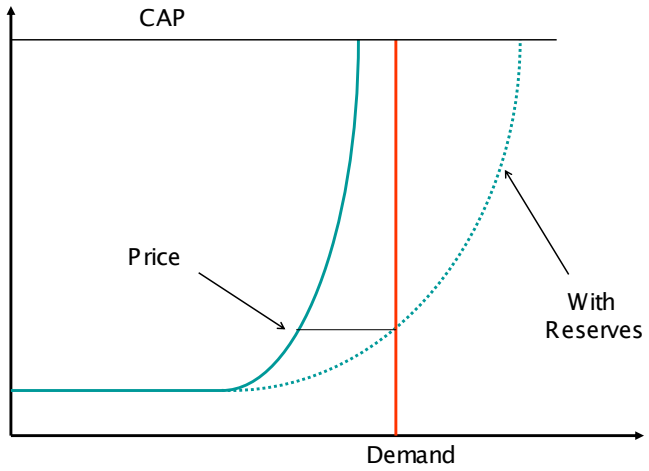
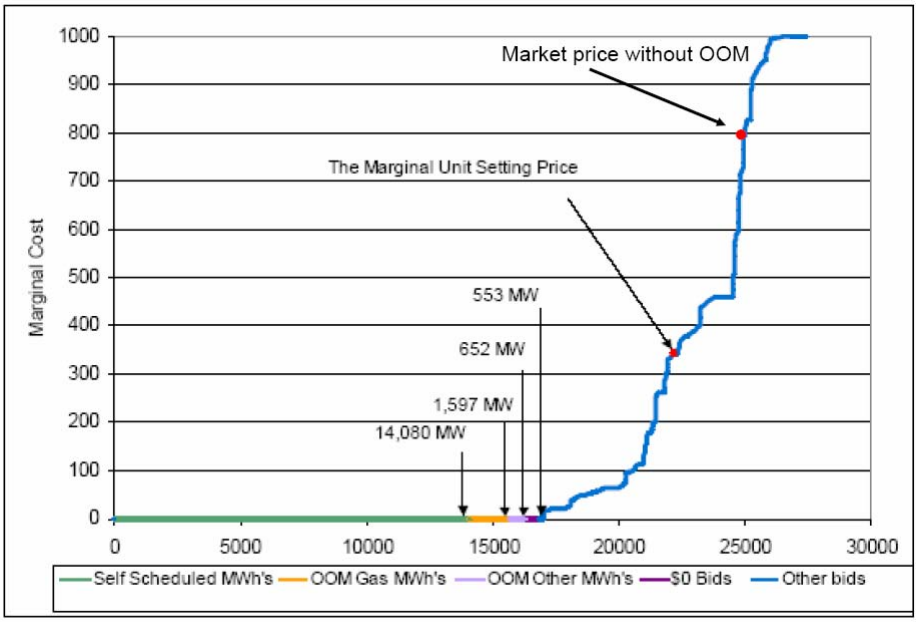


Figure 3-1
Suppression of Energy Prices Due to Deployment of Operating Reserves

Other forms of market interference motivated by reliability concerns, such as out-of-market (OOM) procurement of resources (e.g., reliability must run or RMR), deployment of operating reserves to avoid involuntary curtailments, and reliability unit commitment (RUC), will have the effect of suppressing spot energy prices. Figure 3-2 illustrates how committing generation units at minimum load for reliability reasons pushes the supply function to the right, causing energy price suppression. The combination of price caps, market mitigation, reserves deployment, and OOM actions by the system operator all contribute to the suppression of energy prices and scarcity rents. This phenomenon has become known as the "missing money problem," referring to revenue deficiency for generators to the point that they cannot recover their fixed costs.



Source: ISO NE

Figure 3-2
Suppression of Energy Prices Through Out-of-Market Commitment of Generation Units

While in principle a liquid forward market could provide adequate forward support for resource adequacy, most existing restructured electricity markets show limited amounts of market-based long-term contracting. Evidently, the protection provided to LSEs by the capped spot prices reduces, from their risk management perspective, the optimal quantity of forward contracts in their portfolios and caps the price they are willing to pay for such contracts. Indeed, with capped spot prices, LSEs would prefer to cover only a portion of their quantity risk with forward contracts and rely on the spot market to cover the difference between their peak load and their contracted amount. Consequently, generators that provide planning reserves may operate in only a few peak demand hours, with high energy prices during the year, which are typically insufficient to cover their fixed costs due to the capped spot prices. Furthermore, suppressed spot energy prices will be reflected in low contract prices as well. A higher offer cap would transfer more risk to LSEs and would provide incentives for them to cover a larger portion of the quantity risk through bilateral contracts and reduce their reliance on the spot market.

4
CONTRASTING APPROACHES TO RESOURCE ADEQUACY ASSURANCE

The debate over whether capacity mechanisms separate from energy markets are needed in restructured electricity markets has been going on for nearly a decade. Numerous papers have been written on the subject and arguments for and against such mechanisms have been documented, for instance, by Jaffe and Felder (1996); Graves, Hanser, and Earl (1998); Bowering and Gramlich (2000); Hobbs, Inon, and Stoft (2001); Abbott (2001); Besser, Farr, and Tierney (2002); De Vries and Hakvoort (2002), (2003a), (2003b). The Ph.D. thesis by De Vries (2004) provides an excellent comprehensive discussion and analysis of literature in this area. The proponents of capacity mechanisms argue that given the technical, political, and social realities of electricity markets, energy markets need to be supplemented by some "capacity mechanism" that will ensure generation adequacy. The primary objective of such mechanisms is to create sufficient incentives for efficient levels of investment. In most cases, however, this goal is interpreted as inducing investment in generation that will meet prescribed reliability criteria based on technical rather than economic considerations. Stabilization of generators' income streams is also often viewed as a means toward achieving the efficient investment objective. The debate is hardly resolved at this point, especially given the lack of evidence that capacity mechanisms have accomplished their stated goals and the perception that such mechanisms are merely a wealth transfer device from consumers to generators. Currently, there are three prevailing approaches to assuring generation adequacy discussed below.

Adequacy Mechanisms Based on Capacity Products

Direct capacity remuneration through a *capacity product mechanism* is a "top down" or accounting-based approach, driven by the question of whether generators are making sufficient income from energy and ancillary service sales to recover their fixed costs. This perspective, adopted in a number of markets in the United States and abroad, addresses directly the "missing money" problem discussed above and elaborated on by Cramton and Stoft (2005 and 2006), with minimal changes to the energy market. The top down approach has solved the missing money problem, resulting from artificial suppression of energy spot prices, by supplementing generators' income through "capacity payments." Another resolution is through the introduction of an artificial short-term capacity product for which the demand is set administratively and the cost allocated to the load. The income from such a product is intended to make up the missing money, thus ensuring the financial integrity of generators and attracting new investment if needed.

Installed Capacity Markets

Since the initial establishment of capacity markets in the U.S. northeastern power pools, they have been the subject of continuous debate and have undergone several refinements motivated by their unsatisfactory performance in terms of producing needed investment in generation. Section 5 of this report provides a detailed account of the evolution of these markets, however, it is worth noting at this point that a recurring theme in this evolution has been the attempt to rectify obvious flaws associated with the short-term definition of the capacity products. The latest forward capacity market (FCM) mechanism adopted by Independent System Operator – New England ISO-NE and the Reliability Pricing Model (RPM) proposed at PJM extend the lead-time and duration time of the product. These reforms go a long way toward encouraging participation by new entrants. At the same time, however, the reforms have moved closer to the traditional centralized resource planning paradigm by being prescriptive with regard to location and even fuel mix of new generation resources. The call option features embedded in the FCM and RPM designs also improve the economic basis of the nonperformance penalties and the market reciprocity, whereby generators receiving capacity payments must forego peak energy rents (PERs). However, these mechanisms have been very controversial in the markets where they are being implemented. Critics have argued that these capacity mechanisms overly compensate existing inefficient generation, rely on prices that are administratively determined, place too much investment risk on LSEs, and stifle innovation and bilateral contracting for end-use customers.[8] Furthermore, these mechanisms still have the general shortcomings of capacity markets, which tend to suppress incentives for demand response and self-provision while displacing private risk management activities.

Capacity Payments

A simplistic view of capacity payments is to consider generation capacity as a distinct product required to support the reliable supply of the energy commodity, which is priced independently. The time interval over which the capacity product is defined, and the terms that define availability and eligibility for capacity payments, differ across implementations. The simple rationale for capacity payments is that such payments create explicit incentives for investments in generation capacity by paying scarcity rents directly. The higher the capacity payment the more capacity it will attract. As capacity increases, the probability that not all loads can be served, or loss-of-load probability (LOLP), decreases. The optimal capacity level is such that the expected marginal VOLL due to a 1-MW reduction in generation capacity (LOLP×VOLL) equals the marginal cost of 1 MW of peaking capacity (typically provided by a combustion turbine). According to this rationale, marginal cost pricing of capacity will result in a capacity payment of LOLP×VOLL. In a simple world with no uncertainty and no lumpiness of investment, as long as the capacity payment exceeds the marginal cost of peaking generation capacity, investors will find it attractive to build more capacity. Thus, in equilibrium, LOLP×VOLL equals marginal cost of peaking capacity, which is the condition for the optimal

[8] Electricity Consumers Resource Council (ELCON), 2006, provides comments on PJM, ISO-NE, and NYISO capacity mechanisms from the perspective of industrial customers. PennFuture, 2006, provides comments focused on PJM's RPM from the perspective of environmentalists.

capacity level. It has been argued by capacity-payment proponents, therefore, that a capacity payment of LOLP×VOLL will lead to an optimal capacity level.

A more sophisticated justification for capacity payments originates from the theory of socially optimal peak load pricing in a regulated monopoly dating back to Boiteaux (1960). Under that theory, social welfare is maximized when energy is priced at marginal cost. However, as shown earlier, for such pricing to recover all the generation cost, it must be supplemented by a fixed payment per MW that equals to the amortized marginal cost of the peaking capacity. Hence, capacity payments are viewed as a second best approach to socially optimal peak load pricing, and such added capacity payments needed to cover generation cost are recovered as demand charges from consumption during peak periods.

Capacity payments are popular in several South American countries such as Argentina, Chile, Peru, and Colombia; in European countries such as Spain and Italy; and in South Korea where generators receive direct payments for capacity from the system operator, which are uplifted to customers on a prorated basis. Capacity payments are sometimes differentiated according to generation technologies (e.g., South Korea had, until January 1, 2007, a two-tier capacity payment for baseload capacity and peaking capacity) and may be commingled with stranded cost recovery (e.g., Spain's system). Often such payments are coupled with a cost-based offer requirement in the energy market (e.g., South Korea and Peru).

In Argentina and Peru, only capacity selected to produce energy or provide reserves will receive capacity payments. In Argentina, this practice has resulted in energy offers below marginal cost. Such "underbidding" is prohibited in Peru, where the regulator determines the marginal cost of each generation technology except for suppliers with natural gas plants, who can declare their marginal cost annually. In South Korea, there was a two-tier system for baseload and peaking generators. All generators were required to submit regulated marginal cost-based offers for energy. Generators were classified into the two tiers, which received different capacity payments, and their energy offers were cleared separately for baseload and peaking load, resulting in two different market clearing prices for the generators. The load was charged an average price that recovers the energy and capacity payments to the generators. As of January 1, 2007, the two tiers were merged into a single tier price mechanism with reference capacity payment of 7.17 Won per kWh. The reference capacity payment is determined by the capital cost of a gas turbine and the assumed availability factor. The capacity payment is linked to the *ex post* reserve margin relative to the annual peak load, as follows. If the reserve margin is between 12% and 20% above the realized annual peak load, all the capacity is remunerated based on the reference capacity payment. If the reserve margin falls below 12%, then the total reference capacity payment corresponding to a 12% reserve margin is prorated over the existing capacity (so that the payment per kilowatt-hour is higher than the reference payment). Likewise if the reserve margin exceeds 20%, then the total reference capacity payment corresponding to a 20% margin is prorated over the existing capacity (so that the payment per kilowatt-hour is lower than the reference payment).

Usually capacity payments are fixed for extended duration and sometimes adjusted annually to reflect scarcity or abundance of capacity. However, before the New Trading Arrangement (NETA) was introduced in the United Kingdom, the restructured UK market had capacity

payments that varied hourly according to the declared availability by generators and the corresponding LOLP calculation. These payments led to rampant gaming and manipulation of declared availability by generators. Such capacity payments were eliminated under NETA. However, Bidwell and Hanney (2004) argue that, as a consequence of the low energy prices under NETA, investment in new generation capacity in the United Kingdom has virtually stopped since 2001, and generation adequacy is threatened.

In general, capacity payment mechanisms are an effective means to stabilize the income of incumbent generators, but there is no clear evidence that such payments encourage investment in new generation. Generators receiving capacity payments have no obligation to use that income for new investment or for facility improvement. Furthermore, since capacity payments have the effect of suppressing marginal cost and the resulting energy spot prices charged to consumers who cannot opt out of paying the capacity charges, such mechanisms undermine potential demand response. In Chile—one of the first countries to liberalize their electricity industry and to institutionalize a capacity payment program—recognition that this scheme has not produced the desired outcomes in terms of providing incentives for investment has led to recent reassessment of their resource adequacy policy and new proposals along the line of call option obligations.[9]

Energy-Only Markets

The energy-only approach—adopted in Texas (by ERCOT) as well as Australia, New Zealand, and Alberta—relies on energy remuneration and scarcity pricing to guide investment and focuses on removing the impediments described earlier that cause the missing money problem. The remedial steps needed to enable an energy-only approach include the removal or relaxation of offer caps, scarcity pricing to reflect OOM actions, reserves deployment, and development of demand response. Market power mitigation and customer protection is accomplished through risk management practices such as hedging and long-term contracting. Often one or more, transitional backstop mechanisms such as mandatory load hedging, cumulative caps on fixed cost recovery, and emergency interruptible loads are used to ensure a smooth transition to an energy-only approach.

The energy-only market approach takes the view that resource adequacy assurance is a challenge of managing risk in a competitive commodities market. Hence, earnings from unmitigated spot market transactions and long-term bilateral contracts that provide a risk-sharing mechanism between consumers and producers should stabilize generator income streams and induce the proper level of investment. Thus, resource adequacy can be ensured by eliminating spot market distortions and by facilitating bilateral contracting and risk management.

To the extent that

- unmitigated energy markets are infeasible,
- markets for risk are not fully functional, or

[9] Barroso, Rudnick, and Hammons, 2006.

- contracting practices fail to provide adequate incentives for generation investment,

then various forms of transitional backstop can be implemented. Such backstops may include hedging obligations. Centralized procurement mechanisms for these hedges can be instituted to promote resource adequacy. However, since such mechanisms rely on energy as the underlying commodity, they can only succeed if artificial barriers to efficient energy spot prices that can reflect scarcity are eliminated. In other words, customer protection through price mitigation measures must be greatly restricted and replaced, if necessary, with mandatory hedging requirements that will complement voluntary risk management and contracting practices. Unmitigated energy prices will ensure that the capacity payments to generators through voluntary contracts and mandatory hedges resolve the missing money problem.

Variants of the latter approach have been implemented in several restructured wholesale electricity markets, with no capacity payments but a high offer cap, with limited mitigation of resource-specific offers (i.e., an energy-only resource adequacy mechanism). The experience suggests that high offer caps can indeed provide a strong incentive for generation resources to supply electricity service, and for market-based demand response to be available. There is evidence that high offer caps have resulted in increased voluntary bilateral contracting between buyers and sellers and demand response, which has resulted in lower average spot market prices. Apparently, LSEs—faced with the prospect of paying thousands of dollars per megawatt-hour on spot market procurement during shortage periods—have been compelled to maintain forward supply contracts in order to avoid such outcomes. For instance, a number of retailers in the Australian market hedge their positions with option contracts on peaking generation that require the peakers to make energy offers in the real-time market on behalf of the retailer.[10]

Central Resource Procurement: Competitive Tendering and Strategic Reserves Contracts

The most direct approach, which is closest to the traditional regulated utility paradigm, is based on *tendering* for new resources when needed. This approach—regarded as a "market friendly" extension of traditional investment planning in a monopolistic context—has been employed in several European countries, including France, Germany, and Portugal, and in California. Under this paradigm, the regulator determines the need for new generation capacity based on load forecasts and technical consideration and designates an agent, typically a dominant LSE to contract through a request for proposal (RFP) or a "call for tender" for construction of new generation. Such calls for tender typically involve multiyear power purchase agreements and often include constraints on location of the plants and use of certain technologies.

Strategic reserves procurement by the system operator is akin to tendering but focuses on ensuring availability of existing supply and demand-side resources. Strategic reserves contracts typically impose restrictions on the participation of a contracted generator or load resource in the market and give the system operator dispatch discretion that he can use to maintain system reliability and avoid involuntary curtailments. Hence, such a contract serves a dual role in

[10] Peter Adams, personal communication (2005).

promoting resource adequacy. By using market resources, spot energy prices are increased, thus helping with fixed cost recovery for generators. In some cases, the system operator may use as strategic reserves resources that are uneconomical but critical to system reliability or can improve security of supply and reduce involuntary load curtailment. The key issue in deploying such resources is to minimize market distortion. This can be done, for example, by limiting such deployment to scarcity conditions and reflecting such scarcity in the spot prices.

5
EVOLUTION OF INSTALLED CAPACITY MARKETS IN THE UNITED STATES

Installed-capacity, or operating-capacity obligations, have been the mechanisms for assuring generation adequacy in the northeastern ISOs in the United States, including Pennsylvania, Maryland, and New Jersey (PJM); New England (ISO-NE); and New York (NYISO). This approach originates in the mechanisms that existed in the cooperative power pools that previously operated in these areas. These required each utility member of a pool to provide sufficient installed capacity to cover its peak load. In real-time operations, each pool redispatched energy generation among its members so as to minimize the total operating cost, and distributed the savings among its members according to an agreed-upon formula. However, to prevent utilities from free riding on each other's capacity, a utility whose peak load exceeded its installed capacity was assessed a penalty proportional to the shortfall, and the funds were re-distributed to those utilities with excess capacity. The capacity obligations were based on a *pro rata* share (in turn, based on peak loads) of the total capacity requirement, which was determined according to engineering calculations and technical reliability standards. In the New England pool, for instance, the penalty during the period 1988-1989 was $75/kW per year, and the reference point for the annual capacity obligation was based on a weighted average of monthly peaks and the annual peak. Utilities in the New England pool were also allowed to turn over to the pool curtailable service contracts with their customers, which counted toward their capacity obligations.

After the restructuring of the northeastern pools, which have transformed themselves into ISOs, capacity obligations have been assigned to the LSEs. Due to the expectation that retail competition would result in massive switching of customers among load-serving entities, it appeared reasonable to shorten the term of the capacity obligations. Furthermore, the administrative penalty, or reward for shortages and excesses, was replaced by a market-based approach. This approach allowed LSEs to trade capacity obligations among themselves, and with the generators who supply the capacity, at market prices determined by supply and demand. Under this paradigm, installed capacity (ICAP) has become a separate product for which the demand is induced by the regulatory requirement imposed on the LSEs. The pricing of ICAP is set by the ICAP market, which brings together LSEs who need to meet their capacity obligation with generators who are able to satisfy the demand for ICAP by committing their installed capacity.

The main problem with the short-term installed-capacity markets in PJM, ISO-NE, and NYISO is that the supply and demand functions for the traded products are virtually vertical. On the demand side, the LSEs must meet an imposed obligation for installed capacity, with little flexibility to meet that obligation. On the supply side, the stock of "iron in the ground" is fixed

on the time scale of the ICAP product (typically a month). The only price elasticity in the ICAP market comes from possible demand-side participation, when curtailable supply contracts can substitute for ICAP. Consequently, the ICAP market prices tend to either be close to zero, when total available capacity exceeds the total demand for ICAP, or very high when there is a capacity shortage.

Attempts to improve the performance of ICAP markets have focused on three aspects:

- The time step of the ICAP obligation and the traded ICAP products
- Performance obligations associated with ICAP and non-performance penalties
- Price elasticity of ICAP demand

The time step has been the most contentious aspect of ICAP and the main source of the "bipolar" price behavior in ICAP markets. From the generators' viewpoint, a one-month installed capacity obligation does not provide sufficient certainty of cash flows to attract capital for new investment when ICAP prices go up due to scarcity. Furthermore, the short look-ahead period of the ICAP obligations in the initial designs of the U.S. northeastern electricity markets left no room for participation in the ICAP markets by new planned capacity due to the length of time that it takes for such capacity to be built. Consequently, the ICAP markets have been limited to existing capacity, and the result of that was the bipolar price behavior described above. Furthermore, because of the short duration of ICAP products, ICAP markets were also susceptible to exercise of market power due to non-contestability by new entrants. At the same time, the suppressed energy prices have not been able to provide correct price signals and sufficient revenue to incentivize new entry. These deficiencies have been widely recognized and over the last several years, significant efforts have been devoted to improving the capacity markets in the United States, as described below.

Another important aspect of ICAP that differentiates the various markets is the performance obligation of the ICAP seller and the penalty for non-performance. Availability to generate power at a price that does not exceed the price cap is the most obvious performance requirement. One might interpret this as a financial call option on energy at a strike price that equals the price cap in the real-time market—typically $1000/MWh in the northeastern ISOs. With a typical call option, when the option is exercised, the seller of the option is liable for the difference between the spot price and the strike price. When the spot price is capped, however, a call option with a strike price set at the cap has no financial liability. Thus, to ensure compliance, some penalty must be imposed on capacity that is not available to produce energy. Defining the terms of compliance and setting the penalty for non-performance have been contentious topics in the design of ICAP markets, especially when generators that sell capacity in one market have opportunities to sell energy in other markets. To address this issue, some markets impose a "must offer" requirement on capacity committed to fulfill LSEs' ICAP obligations. However, "delisting" rules typically allow generators to buy their way out of the must-offer requirement. Thus, defining compliance standards for ICAP and fine-tuning noncompliance penalties are continuing challenges in implementing a capacity obligation approach to generation adequacy assurance in the three U.S. northeastern ISOs and in other systems considering such a mechanism.

The following subsection describes the early ICAP markets and their minor refinements, followed by a discussion of recent steps taken in some markets to introduce new and improved capacity mechanisms.

Early ICAP Markets and Their Refinements

The original PJM ICAP market

The PJM installed capacity market was the first of its type to become operational in 1999. Capacity owners were under obligation to offer their capacity to the market for a given price ($/MW). There was no distinction between old and new capacity, and capacity owners would be penalized if they could not meet certain performance standards. The ICAP payments did not take into account the value of the location of the resource or the unit operational characteristics. This approach proved inadequate for assuring resource adequacy, as the U.S. Federal Energy Regulatory Commission (FERC) noted in its 2004 Staff Report, stating that: "Much of the country has no obvious market mechanism to signal the need for new building in advance of shortages. The success of capacity markets in addressing the issue is not yet proven".[11] The PJM early ICAP market suffered from the typical deficiencies detailed above.

Bipolar nature of ICAP clearing prices: The first incarnation of an ICAP market was based on a daily product. The short product duration and short look-ahead period of the ICAP obligations in the early design of the PJM market left no room for participation in the ICAP market by new planned capacity due to the length of time that it takes for such capacity to be built. Consequently, the ICAP markets have been limited to existing capacity, and the result of that was bipolar pricing mentioned earlier: the value of the ICAP product was either zero (during times when the reserve margin was healthy) or the deficiency penalty (during times when the reserve margin was thin).[12] The high price volatility and eventual collapse of the initial daily ICAP market at PJM, seen in Figure 5-1, led to the development of a more sustainable monthly capacity market and to a proposal for a seasonal capacity obligation.[13] Figure 5-2 illustrates the effect of increased product duration on price stability. Similar moves toward capacity products with longer durations have been implemented at ISO-NE and NYISO. [14]

[11] FERC Docket No. MO05-4-000, page 65.

[12] While the value of the product would be infinity if the market price were unconstrained, in reality the price of the monthly ICAP product cleared at the cap set by PJM.

[13] FERC Docket No. EL01-63-001.

[14] The PJM ICAP market currently operates with multiple maturities: 12 months, six months, and one month, as well as a daily market. The NYISO operates markets for capacity obligations of six months, multiple months up to six months, and one month.

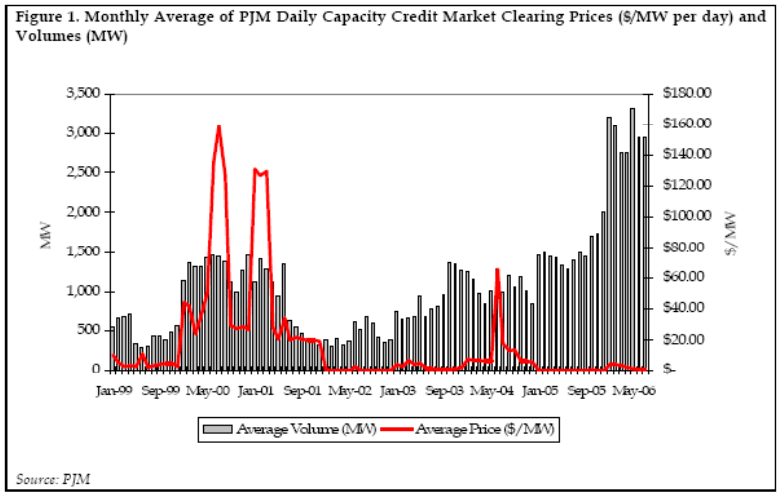


Figure 5-1
Monthly Average of PJM Daily Capacity Credit Market Clearing Prices ($/MW/Day) and Volumes (MW)

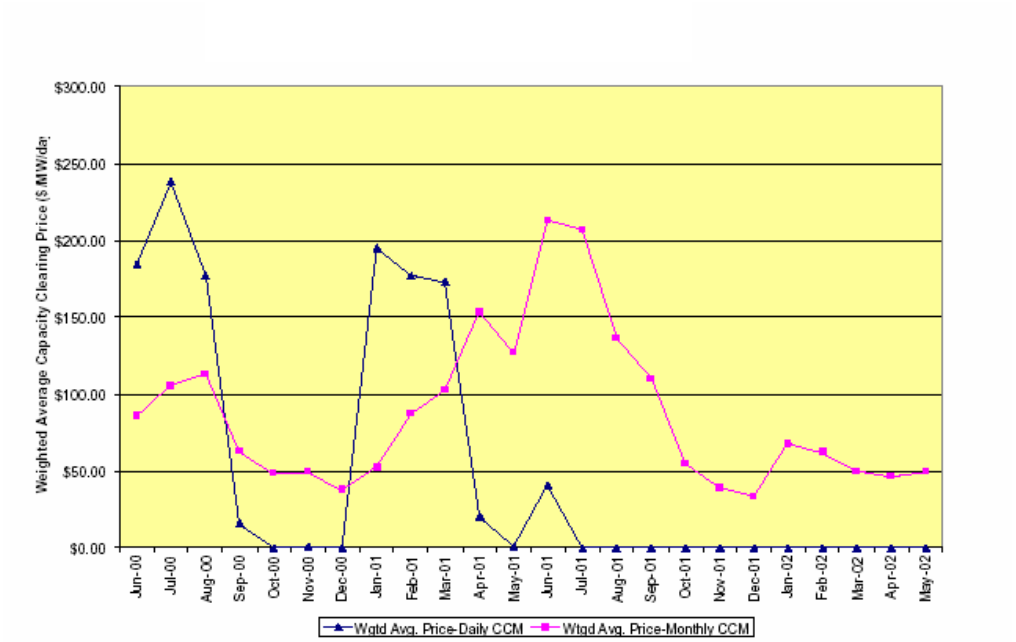


Figure 5-2
ICAP Market (Daily and Monthly Capacity Credit Market) Price Trends at PJM

Deliverability problems of ICAP products: Inability to build transmission quickly enough to accommodate new generation investment—and concentration of new capacity in locations remote from load pockets where generation capacity was needed—results in deliverability problems in meeting expected electricity demand. For example, in ISO-NE, new quick response units were built in Maine near the gas sources, but energy from these resources could not be delivered to Connecticut load centers because of transmission constraints.

"Leaky" performance standards: Generators that have sold ICAP to a local LSE at PJM are subject to recall of energy sold for export out of PJM. However, as pointed out by Bowering and Gramlich (2000), there is a loophole in the PJM system that under certain circumstances allows generators to "delist" their capacity at PJM and declare that it is no longer a capacity resource. Delisting means that a unit is formally removed from status in PJM as a capacity resource and is therefore not subject to recall—thus, it can export energy on a firm basis. Delisting can occur with two days notice, but in practice a minimum one-hour notice is allowed. Delisted generation capacity cannot be used to meet an LSE's capacity obligation, so it may be charged penalties for shortfalls in its committed capacity. An LSE that is short on capacity when the PJM system has adequate resources is charged a penalty equal to 1/365 of the annual value of capacity, and that penalty is doubled during a PJM capacity shortage. Bowering and Gramlich estimate the normal penalty at about $160/MW per day during normal conditions and $320/MW per day during a capacity shortage at PJM. Assuming that the penalty is covered by the delisted generator, it is rational for a generator to delist its capacity if, for instance, the spread in energy prices between PJM and external markets exceeds $20/MWh for a 16-hour forward period during PJM shortage conditions, and $10/MWh for a 16-hour forward period when PJM has adequate resources. According to Bowering and Gramlich, such spreads are common and they conclude that, "The financial consequences of the failure of capacity resources to deliver energy to PJM are generally much lower than the financial consequences of failing to deliver energy to external buyers."

Lack of contestability by new generation: As indicated earlier, the short-term nature of the capacity product made it impossible for new generation capacity to participate in the ICAP market so that incumbent generation with steel in the ground could exercise market power in shortage situations. The reforms extending the duration of the ICAP obligation did not go far enough in terms of creating capacity obligations that could enable responses by new planned investment when ICAP prices increased due to capacity shortages.

Centralized Resource Adequacy Market (CRAM)

The deficiencies in existing ICAP markets and seams problems arising from incompatibilities in these markets prompted the commissioning of a study to develop a proposal for a single integrated capacity market for the ISO-NE, NYISO, and PJM. The NERA (2003) report recognized the need for a long-term forward-looking capacity obligation to ensure adequate investments in generation and proposed a centralized resource adequacy market (CRAM) for these three markets. The report proposed that LSEs be subject to a capacity obligation to ensure that sufficient capacity is in place with sufficient lead time for planning and construction, as suggested by FERC in its Notice of Proposed Rule Making that proposed a standard market design. The ISOs would act as central buyers of capacity and make forward commitments to buy capacity. These commitments would be supported financially by uplifted charges to all LSEs during the capacity supply period. According to the CRAM proposal,

"The ISO would determine the resource need in advance of the planning period, would hold a central procurement through an auction, would pay the auction price to all resources provided during the period and would recover the cost from load during the planning period. The difficulties arising from uncertainty with respect to load obligations several years in the future would be eliminated and all LSEs would face a common charge for resource adequacy that

would be passed on to consumers and would be competitively neutral at the retail level. Consumers will receive the benefits of adequacy and pay the cost of adequacy."[15]

A key aspect of the proposed scheme was that

"The planning horizon must be sufficiently long to enable the CRAM to be a deciding factor in the decision to construct. … Only when the pool of competitors is expected to include entrants can market power concerns be adequately addressed. Practically, this means that a three-year planning horizon is the minimum."[16]

The proposal recommended that the commitment period should be from one to three years, with preference for longer durations in order to reduce generators' uncertainty about revenues—which is expected to result in lower risk premiums in their costs of capital. The proposal suggested that all required capacity be procured or under contract at all times, arguing that sequential auctions for progressive procurement would be unreliable for determining prices. The CRAM proposal was shelved due to disagreements among interested parties in the three northeastern ISOs; however, some elements of the CRAM proposal have resurfaced recently and influenced capacity market designs adopted by ISO-NE and PJM.

ISO-NE's Proposed Locational ICAP Market (LICAP)

The New England ICAP market has experienced bipolar pricing of its capacity deficiency auction like other ICAP markets. Prices were fluctuating between zero and the capacity deficiency penalty, but prices eventually collapsed due to systemwide excess capacity, as shown in Figure 5-3. After February 2004, ICAP prices essentially dropped to zero.

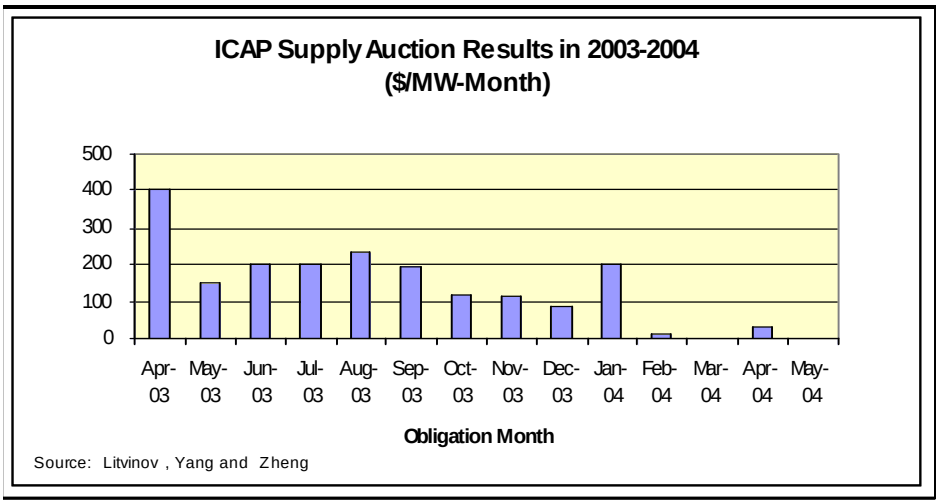


Figure 5-3
Prices in the ISO-NE ICAP Market

[15] NERA Economic Consulting, 2003.

[16] *Ibid*.

Litvinov, Yang, and Zheng (2004) reported that ICAP prices have been insufficient to support existing generation and new investment. Furthermore, because the capacity market in New England does not account for transmission constraints, systemwide excess capacity in the ISO-NE territory has masked local deficiency of capacity in congested areas such as Boston. Out of the total generating capacity in New England, which amounts to 32,615 MW, 41% is financially distressed due to revenue shortfalls, and the owners are in various stages of bankruptcy. Figure 5-4 illustrates the average net revenue shortage for combined-cycle (CC) and combustion turbine (CT) units under alternative estimates of the carrying costs for these units. The carrying cost includes cost of capital, plant O&M cost, and other economic parameters such as tax, inflation, and risk adjustments.

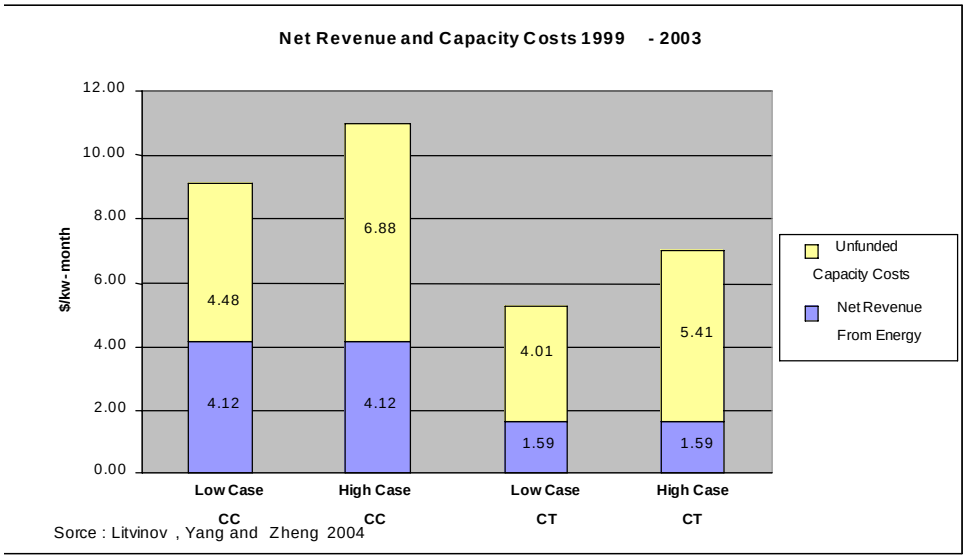


Figure 5-4
Average Net Revenue Shortage of Combined-Cycle and Combustion Turbine Generators in the ISO-NE

The estimates of required fixed cost recovery, shown in Figure 5-4, motivated, in part, the ISO-NE's proposed solution of creating locational ICAP markets for four distinct areas: Maine, Northeast Massachusetts/Boston (NEMA), Connecticut, and the rest of the ISO footprint. Coordinated ICAP auctions account for three directional capacity transfer constraints: Maine exports, NEMA imports, and Connecticut imports. Financial capacity transfer rights (similar to flowgate rights) would be issued to provide instruments for hedging LICAP price differences.

A demand curve for LICAP was to be used in the ISO-NE spot LICAP auction. According to Cramton and Stoft (2005), the demand curve was intended to provide a rough approximation to a capped annual energy revenue stream, including scarcity rents that would naturally decline as reserve capacity increases and scarcity rents go down. The proposed LICAP demand curve, illustrated in Figure 5-5, was anchored at a nominal level of target capacity with a corresponding price that equals the amortized expected capacity carrying cost of a peaking unit. From that reference point, currently set to 106% of the minimum LICAP requirement, the curve extends linearly in both directions. The demand curve intersects the $0/kW per month level at some preset capacity value above the target level. Currently, that point is set to 118% of the minimum requirement. The demand curve rises as quantity drops below the target level and is capped at

twice the expected carrying cost of a peaking unit when capacity is at or below the minimum LICAP requirement.

The LICAP clearing price was to be adjusted *ex post* on an annual basis by subtracting the inframarginal energy revenues per megawatt per year realized by a CT used as a benchmark. The adjusted clearing price was intended to settle LICAP shortfalls or excesses among LSEs, and to determine payments to generators and dispatchable load resources. Payments were to be prorated based on availability during a predetermined set of days when generation capacity is scarce. The locational feature of LICAP and the prorating of payments based on availability on certain days were intended to add intrinsic value to an otherwise artificial product whose demand is derived from an administrative requirement. Likewise, although artificially determined, the downward sloping demand function was to have provided an effective means of eliminating the binary nature of ICAP prices that result from a vertical demand function. The downward sloping demand function also eliminates much of the incentive to withhold capacity. Eventually, the LICAP proposal was scrapped due to strong opposition from different advocacy groups, a strong lobby in the U.S. Congress, and governors in five out of six states in the ISO-NE jurisdiction.

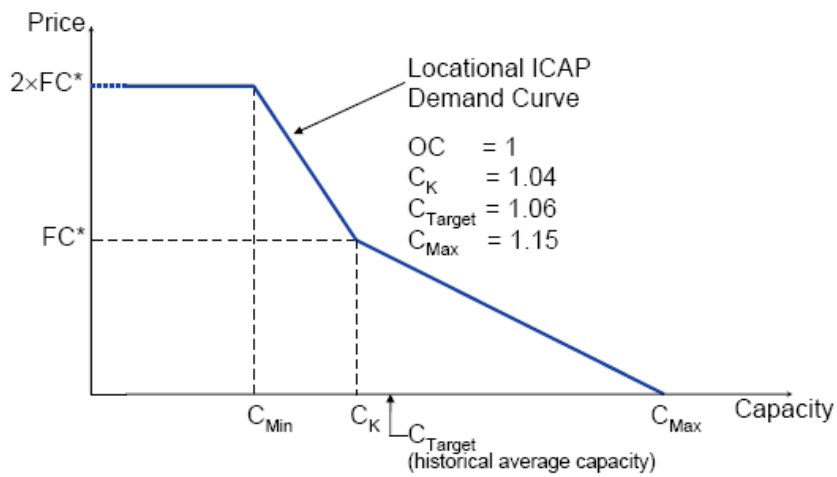


Figure 5-5
Proposed LICAP Demand Function in ISO-NE

New and Improved Capacity Mechanisms

Given some of the shortcomings mentioned above regarding the earlier ICAP markets in the northeastern United States, market operators and stakeholders along with scholars identified new approaches to improve the operation of capacity mechanisms. In fact, new and improved versions of previous capacity markets were introduced in all three ISOs (PJM, NYISO, and ISO-NE), and FERC eventually approved their implementation. The improved mechanisms are briefly described in the following subsections.

PJM's Reliability Pricing Model (RPM)

To improve its capacity mechanism, PJM recently reached a stakeholders' consensus in finalizing its Reliability Pricing Model (RPM) with a variable resource requirement (i.e., sloped demand function), which was filed with FERC on August 31, 2005. The RPM is based on an integrated resource planning model that looks four years into the future to determine generation resource needs in terms of location and fuel mix. Under the originally proposed scheme, the necessary generation capacity to maintain adequate reliability is procured through a central auction on a four-year forward basis, which enables participation by existing generators and new investors. The RPM encompasses existing and planned transmission, generation, and demand-side response, while incorporating locational pricing in its forward auction.

The RPM auction features an administratively determined downward sloping demand curve that allows the procured quantity to vary with price. This scheme is also known as variable resource requirement (VRR). The use of an administrative demand function has been rationalized on the ground that it reduces volatility of the capacity payment to generators and thus encourages more investment in generation capacity, resulting in increased social welfare.[17] However, this argument is debatable since the administrative demand function is based on the assumption that generation firms are risk averse, while society as a whole and consumers in particular are assumed to be risk neutral. Furthermore, the analysis presumes that most of the risk is endogenous, so that reducing uncertainty for generators also reduces uncertainty for consumers, which is the case when external risk is minimal. The analysis results might be different if the main source of investment uncertainty were due to load forecast errors and uncertain fundamentals, so that the question becomes one of whether such uncertainty should be born by investors or consumers. The intent of the RPM was compatibility with areas having retail choice as well as areas with traditional regulation.

Following initial approval by FERC[18] on April 20, 2006, the parties entered into four months of settlement discussion (ordered by a FERC administrative law judge) that resulted in only slight modification to the original proposal. Specifically, the contracting lead time was reduced from four to three years, and the demand function was shifted down so that it is capped at 1.5 times the cost of new entry (CONE), which is estimated at about $65,000/MW/yr. The curve drops linearly from 1.5 x CONE at 98% of target capacity to 0.2 x CONE at 105% and then vertically down to zero, as shown in Figure 5-6. The RPM establishes locational capacity requirements, allows for demand response and transmission participation, has explicit market mitigation rules, and allows opt-out alternatives for LSEs who do not want to participate. Features, which were in the initial proposal, such as seasonal pricing of capacity, operational price adders, and load following requirements for a portion of the capacity obligation, were eliminated, while several other minor features have been added. The capacity is reduced by a six-year backward looking moving average of expected energy profits corresponding to a generic peaking unit. This adjustment is referred to as a peak energy rent (PER) deduction. The PER deduction is based on the notion that capacity payments are intended to restore the "missing money" to the generators'

[17] See testimony by Ben Hobbs in FERC Docket No EL05-148-000 and ER05-1410-000.

[18] FERC Docket No EL05-148-000 and ER05-1410-000.

income stream and no more. However, the PER is capped at the capacity payment so that generators receiving such payments incur no downside risk. Capping the PER deduction and basing it on long-term average energy profits, is the result of a compromise with generation firms, who see capacity payments as an independent, "bankable" income stream that can provide collateral for investment financing only if it is stable.

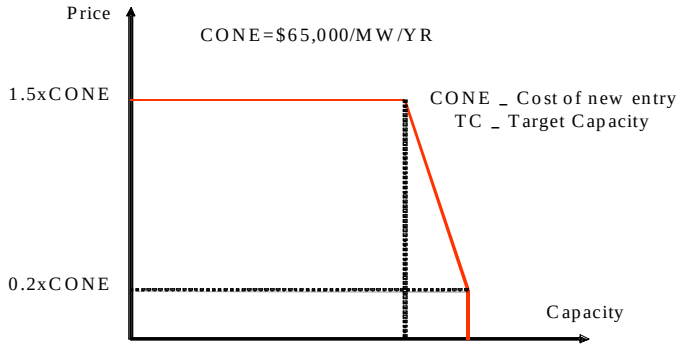


Figure 5-6
VRR Demand Curve in the PJM RPM

NYISO's Demand Curve Model

In attempting to reduce the volatility of ICAP prices that had been at the NYISO and other ISOs, the NYISO was the first to introduce a variable resource requirement (VRR), also known as an ICAP demand curve, in the New York capacity market.[19] The Demand Curve Model was developed through the stakeholder process and went into effect in May 2003. Prior to introducing the VRR, the NYISO ran a semiannual auction for six-month capacity products, a monthly capacity auction for monthly capacity products for the remainder of the six-month capability period, and a centralized deficiency auction prior to each month.

Each LSE had to provide contracts to demonstrate to the NYISO that it was covering its capacity requirement for the ensuing month. Any shortfalls were covered through the centralized deficiency auction in which the NYISO bid for all the deficient capacity at a price equal to the deficiency penalty imposed on LSEs for each MW-month of capacity deficiency. LSEs exceeding their capacity obligation could offer their excess in the auction. The deficiency auction

[19] New York Department of Public Service, January 31, 2003.

New York Department of Public Service, March 6, 2003.

New York Independent System Operator Inc. (NYISO), May 27, 2004.

New York Independent System Operator Inc. (NYISO), 2004.

FERC Electric Service Tariff Article 5.

represented a "vertical demand function" where the ISO demanded a fixed quantity of capacity, and resource providers and LSEs with spare capacity offered supply schedules against it. The experience has been that prices in that auction were either at the deficiency price or close to zero.

Under the VRR arrangement, the six-month strips are auctioned off, while monthly ICAP auctions continue to operate as double auctions in which LSEs and resource providers can adjust their seasonal strips. The daily spot deficiency auction, however, has been replaced with the VRR, which represents a downward sloping demand curve capped at the deficiency penalty. The downward sloping segment of the demand function is linear and is determined by two points. The first "reference point" is defined by the minimum capacity requirement and a price that equals some percentage of the estimated CT cost. The second point is set at the level of capacity at which the capacity value is nil. The parameters of the demand curve vary by location, specifically differentiating New York City (NYC) and Long Island (LI) from the rest of the state, and are subject to adjustment. For example, the capacity level at which the capacity value is nil was set at 118% of the minimum capacity requirement for NYC and LI, while for the rest of the state it was set to 112%. The capacity metric used in the demand curves is Unforced Capacity (UCAP), which is rated based on historical performance of the unit and adjusted accordingly. Imports qualify as capacity only if backed by transmission contracts. The initial demand curves were specified in NYISO Tariff 2004—Article 5, Section 5.14.1(b). The demand curves for summer of 2007 are illustrated in Figure 5-7 below.[20]

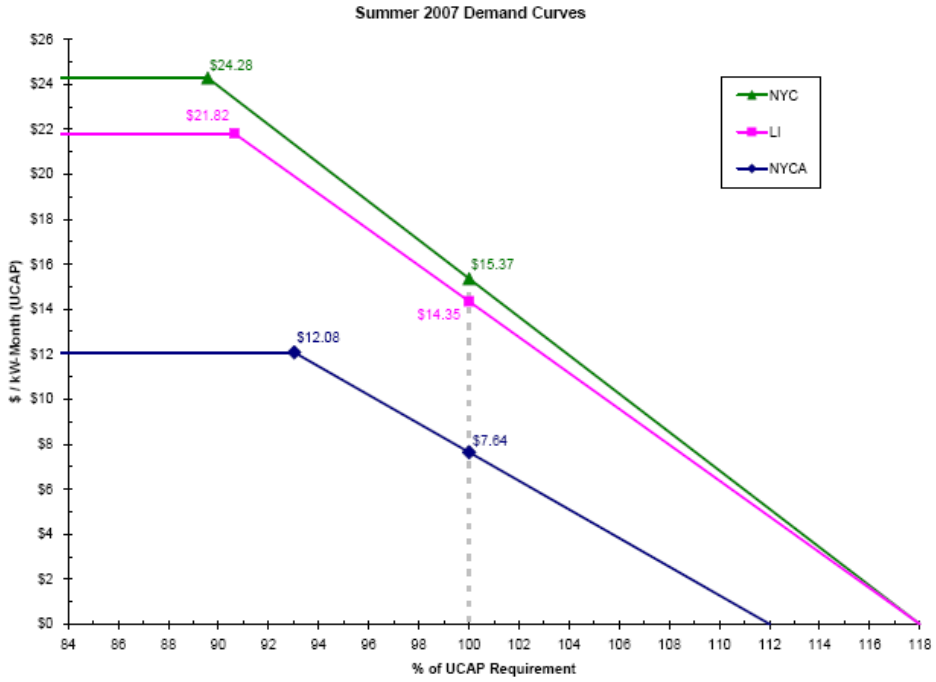


Figure 5-7
NYISO Summer 2007 Locational Demand Curves for UCAP

[20] New York Independent System Operator, Inc. *ICAP/UCAP Translation of Demand Curve*.

The demand curves corresponding to capability years 2008/2009, 2009/2010, and 2010/2011 are specified in a recent report dated August 31, 2007.[21]

In the NYISO report to FERC,[22] it is stated that the ICAP demand curve has achieved the goal of stabilizing ICAP spot prices in the deficiency auction, as illustrated in Figure 5-8. Furthermore, purchased quantities in the deficiency auction have increased, while clearing prices have decreased. The deficiency auction has also provided a price floor for the six-month and monthly capacity markets. The VRR seems to function well and mitigates incentives for withholding capacity by rewarding available capacity in excess of the minimum requirement and by recognizing that such extra capacity has value in enhancing reliability and moderating energy and ancillary service prices.

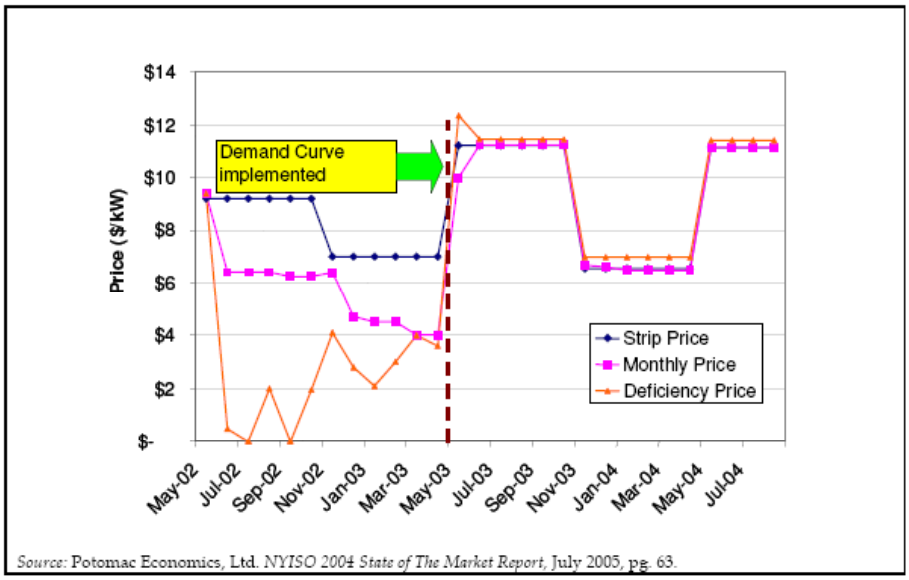


Figure 5-8
Stabilizing Effect of VRR on the NYISO ICAP Market

However, there is no evidence that the demand function approach has achieved its primary objective of attracting new generation resources. As a result, the New York Public Service Commission (NYPSC) has been exploring approaches such as imposing load hedging obligations on LSEs and resource procurement options. In a recent press release dated April 18. 2007,[23] the NYPSC stated that the existing wholesale electricity market structure has not led to much merchant-driven supply nor shown much promise for new merchant-driven entry, both of which are needed in order to meet reliability needs.

[21] New York Independent System Operator, Inc. *Proposed NYISO Installed Capacity Demand Curves.*

[22] FERC Docket No. ER03-647-000.

[23]New York Public Service Commission.

ISO-NE's Forward Capacity Market (FCM)

In light of the opposition to the LICAP proposal, ISO-NE went through a consensus building process with stakeholders and state regulatory authorities to finalize a settlement agreement to address its capacity market. In April 2006, a FERC Administrative Law Judge approved this settlement agreement, which outlined a forward capacity market for ISO-NE that will replace the previous LICAP design. The new design is based on a three-year forward capacity market (FCM), where the capacity product emulates several key features of physical call options, and procurement is achieved through a descending clock auction with a vertical demand curve, as shown in Figure 5-9.

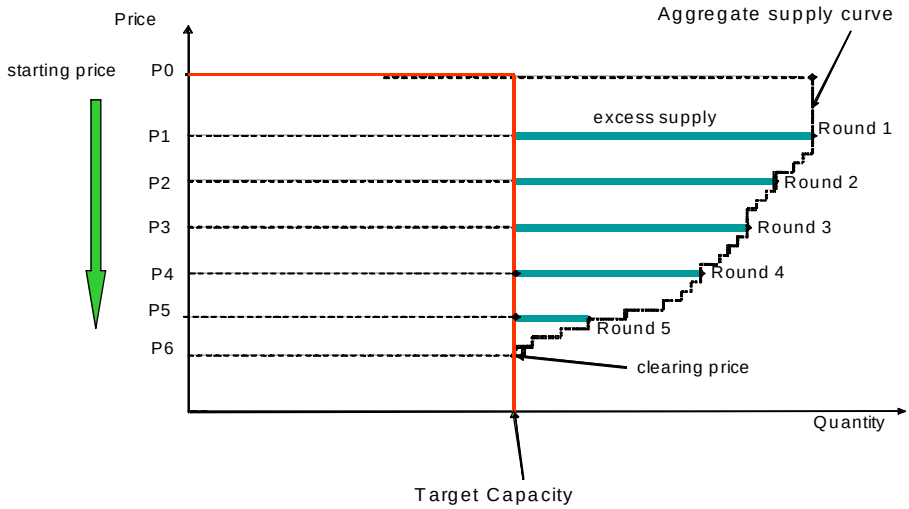


Figure 5-9
The FCM Descending Clock Auction

The FCM has integrated several key features that are similar to the call options approach described by Oren (2005b) and some elements of the CRAM approach discussed earlier in this section. Capacity is procured three years forward for the duration of one year for incumbent generators and up to five years for new generation through an annual competitive descending clock auction. The procurement is zonal, based on local reliability needs, load forecasts, and forecasted transmission availability, and the capacity payment could vary by location. The procured capacity contracts must be backed by qualified existing or planned physical generation resources or by demand-side resources.

The procured capacity contracts entail an obligation to offer energy in the spot energy market at a strike price that reflects the marginal energy cost of a generic peaking gas turbine unit. The strike price is enforced by deducting from the capacity payments the PER, which represent a rebate of excess revenues (above the strike price) of a generic peaking unit computed on a monthly basis. The strike price is specified in terms of a strike heat rate set to 22,000 and a fuel cost index, so that the strike price can track fuel cost. However, unlike the case of a call option, the PER calculation is not based on *ex-post* energy prices but rather on a 12-month backward

looking moving average of energy prices. Furthermore, the PER deduction is capped so that a generator would not have to give back more than two months worth of capacity payment. If, for instance, energy prices rise to abnormal levels due to, say, a very hot summer, generators that received capacity payments will only forgo two months worth of capacity payments, but will keep the balance of the payment they received in the energy market. The "backward smoothing" and capping of the PER weakens the market power mitigation effect of the call option feature. However, proponents have argued that taking away more of the capacity payment through PER adjustments would weaken generators' performance incentives. The capacity payments for multiyear contracts obtained by new generators are based on the auction price of the first year and indexed for inflation in subsequent years. Payments for the capacity and cost recovery from the load occur at the time of performance (starting three years after the procurement).

Periodic and seasonal reconfiguration double auctions enable parties to adjust their positions by committing additional capacity or withdrawing (delisting) committed capacity. Such delisting can take place up to four months prior to start of the commitment period. The seasonal reconfiguration auction also allows changes in procured capacity so as to reflect changes in load forecasts and for trading of obligations among market participants. The traded tender in the reconfiguration auction is full-year commitment, unlike the traditional ICAP markets such as NYISO, where the traded tender has been monthly or even shorter-term capacity obligations. Nonperformance is subject to penalties in the form of reduced capacity payments. In that respect, the FCM contract further differs from call options since the nonperformance penalties are not based on actual liquidation damages reflecting the difference between the spot energy cost and the strike price. The FCM contract is designed to prevent nonperformance penalties in excess of the net capacity payment (after PER adjustment) received by the nonperforming resource, which would be possible under market-based penalties, reflecting actual liquidation damages.

The descending clock auction is started at twice the amortized annual CONE, and the price is expected to be set by new entrants above CONE. However, new generation may be procured through bilateral contracts and bid into the auction as a price taker at zero price.[24] When new generation capacity is offered at zero price, it pushes the remainder of the FCM supply function to the right, which will depress the auction clearing price. In the extreme, if all the needed new generation is procured through bilateral contracts and offered into the FCM auction at zero price, the auction clearing price may dip below CONE, which may result in missing money for incumbent generation, a problem that FCM tries to remedy. To avert such an outcome that could be caused by exercise of monopsony power, an alternative pricing rule has been adopted that set a floor on the FCM auction price at 0.9*CONE.

Finally, since the FCM contracts will start to produce revenues no sooner than 2010, a transition mechanism employing straight capacity payments will be implemented to ensure continuity of capacity-based income to incumbent resources. The transitional capacity payment starting December 1, 2006, ranges from $3.05 to $4.10/kW-mo.

[24] In fact, the Connecticut Public Service Commission has authorized utilities in the state of Connecticut to issue an RFP for bilateral contracts with new generation capacity, requiring generators to bid their contracted capacity at zero price in the FCM auction.

6
CAPACITY PAYMENT MECHANISMS

Variable Capacity Payments

Previous United Kingdom System

As described earlier, capacity payments provide direct remuneration to generators for installed or active capacity. The determination of active capacity is often based on simulation models that assess the probability that a generation unit in the merit order will be needed, given the load forecast for a certain time horizon. The capacity payment can be fixed annually or can be varied according to LOLP calculation. In the United Kingdom, before NETA, the capacity payments to available generators were changed hourly based on available capacity and the implied LOLP. Arguably, fixed cost recovery through capacity payments would induce generators to offer energy at their true marginal cost. However, in some systems with capacity payments (e.g., Peru and South Korea), marginal-cost offers are mandated.

Brazilian System

A somewhat different implementation of an hourly capacity payment mechanism has been introduced in Brazil, where the generation portfolio deployed by the system operator to meet load and required reserves includes a fictitious generator that accounts for capacity deficiency ("non-supplied load plant"). The marginal cost function of this fictitious generator is based on an engineering calculation that assesses the economic impact of the reduced reliability as a function of capacity shortage, which is reflected by the dispatch level of the fictitious generator. Hence, when available capacity is low, the fictitious generator sets the market clearing price, which effectively provides an "adder" to the energy price that includes a scarcity rent or the hourly value of reliability reflected by the current LOLP. A similar approach has been employed in Brazil to reflect hydrological shortages during drought periods by imposing mandatory rationing, which is similarly represented in the dispatch as a proxy generator whose marginal cost curve takes into account the social cost of curtailment as a function of the curtailment level.

Recently, the Brazilian regulator has adopted a new approach to generation adequacy assurance based on call options obligations imposed on distribution companies and procured through a centralized auction. The details of the design are described by Bezerra *et al*. (2006).

Fixed Capacity Payment Mechanisms

Fixed capacity payment mechanisms (typically adjusted annually) are currently used in Spain as well as in several South American countries, including Argentina, Chile, Peru, and Colombia.[25] More recently, the concept has been implemented in Italy.

Spanish System

In the Spanish system, capacity payments are commingled with stranded investment remuneration. As observed by Fraser and Passo (2003),

"In Spain the methodology behind the capacity price is not known and seems to be influenced by political decisions. The capacity price is set on a yearly basis, and does not appear to be determined by investment costs, since it has been lowered without explanation by administrative decisions in spite of narrowing capacity margins, and the investment has not kept up with demand growth. Uncertainty, about future levels means that the incentive is not trusted by investors, although it has provided sufficient incentives to keep old existing plants open, which has helped to maintain reliability in the face of substantial demand growth."

The funds for capacity payments in the Spanish system, like the stranded cost recovery funds, are collected as an uplift and distributed among the generation companies based on their technology mix and the dispatch pattern. This allocation mechanism affects a significant portion of generators' revenues and influences the way generation companies dispatch their units, which distorts the short-term objective of efficient economic dispatch.

Chilean and Peruvian Systems

The capacity payment mechanisms implemented in Chile and Peru are similar and are based on the Chilean model that employs simulation to determine the annual LOLP estimates on the basis of "effective capacity" and hydrological forecasts. The capacity payments are calculated as LOLP×VOLL, with VOLL set by the regulator, and the payments are awarded to generators in proportion to their "effective capacities." In Peru, the procedure for calculation and remuneration of capacity payments has been codified into the law so that any changes, even in the mathematical formulas, must be voted on in Congress. Initially, all generation capacity in the Peruvian system received capacity payments. The scheme was overly successful in attracting new investment in generation and resulted in substantial excess capacity. The development of natural gas resources in the jungle region further increased the displacement of old generators with more efficient gas units. In Peru, only owners of generation capacity can enter into bilateral contracts (even if their capacity is never dispatched), so there is a market for old units that should have been retired. As a result, the rule has been modified so that only units that are in the merit order for dispatch are awarded capacity payments for their effective capacities (which may be substantially greater than the economically dispatched capacities). To prevent generators from

[25] In Colombia, the capacity payment is being replaced by a new mechanisms based on call options on firm energy.

undercutting their offered prices for energy so as to get in the merit order and thereby collect capacity payments (as has been the case in Argentina), the Peruvian system mandates that generators' offered prices must be cost-based (no more and no less). The only exception to this rule pertains to new gas plants that are allowed to declare their marginal costs on an annual basis. This exception attempts to recognize the fact that many of the gas contracts have a take-or-pay provision and therefore their true marginal cost cannot be determined objectively. In theory, new generation capacity should displace old capacity only if the energy-cost saving with the new capacity exceeds the amortized investment cost. However, the inability of incumbent generators in Peru to offer their energy below marginal cost, and the way that capacity payments are awarded, creates an opportunity for new natural gas plants to declare their marginal costs slightly below that of the incumbents and thereby capture capacity payments. This possibility can lead to inefficient investment and excess capacity construction (as has been the case), which ultimately translates into higher retail prices.

Argentine System

In Argentina, according to the Putnam, Hayes & Bartlett, Inc. (1997) report, the wholesale electricity market includes two different related capacity payments. One is an hourly capacity payment paid to capacity that is generating or has been committed as reserve on the day ahead dispatch. The second is a payment for long-term thermal backup capacity for extremely dry hydro years, which is evaluated annually before the start of the winter season. These payments were instituted after the Argentine system experienced two years of severe rationing resulting from a combination of insufficient investment, technical problems with nuclear and hydro plants, and two dry years in succession. In 1992, through a presidential decree, a private company, CAMMESEA, was created and assigned responsibility, as defined in the law for load dispatch, coordination of grid operation, and commercial administration of the market. The capacity payments are based on generation (resulting from dispatch) and reserves on peak hours of working days. Different rules concerning capacity payments apply to thermal and hydro plants, and the capacity prices are set at the discretion of the energy secretariat. Since capacity payments are based on dispatch, and a plant displaced in the dispatch loses both energy revenue and the capacity remuneration, there is an incentive for generators to understate their marginal energy cost. This leads to distortions in the efficient use of generation capacity and creates incentives for inefficient over-investment that can lead to collapse of energy prices and to boom-and-bust investment cycles. The overall experience in the Argentine system has been that the original objectives of the capacity payments have been accomplished, but in excess. Even in the worst hydro conditions and in the rare contingencies that occurred, there was sufficient reserve to meet loads, while retail prices remained high.

Colombian System

The market in Colombia was restructured in 1994 through legislation that established a competitive market. A dispatch center is responsible for centralized dispatch and coordination of system operation, whereas the Sistema de Intercambio Comerciales, or SIC, is in charge of the commercial administration of the market. The Colombian electricity system had excess hydro capacity but very little thermal capacity, which exposed it to hydro shortages that occur

approximately every five years. Because of abundant hydro power, prices of electricity have been low for long time stretches, which made it impossible to attract investments in thermal generation that predictably would be idle most of the time. The Colombian regulator instituted capacity payments, with the objectives of 1) distributing the capacity income among generators according to their expected contribution in covering supply under hydrological shortage conditions and 2) attracting investment in thermal capacity. Under this scheme, generators are paid based on their expected participation in load covering in the dry season of a dry hydro year, even if the plant does not generate, as long as it is available. The methodology for determining the remunerated capacity of each unit is based on an optimal production simulation model applied to stress scenarios. The regulator sets the specific price for capacity based on the fixed cost of an efficient generation technology. In 1997, for instance, the capacity price was $5.25/kW per month, based on the amortized cost of an open-cycle gas turbine.

The Colombian regulator CREG has recently adopted an alternative approach to capacity payment based on firm energy options. Under this scheme, distribution companies will be required to buy firm energy options from generators through a descending clock auction. The options will have a strike price determined by the regulator. The details of the mechanism are described by Cramton and Stoft (2007).

Italian System

The Italian electricity market (IPEX) began operation on March 31, 2004, as a noncompulsory exchange (i.e., bilateral contracts are allowed). Day-ahead and real-time balancing markets for energy are run by the market operator, while markets for system services (including congestion relief, reserves, and real-time markets) are run by the Italian transmission system operator, GRTN. The widening gap between demand and local generation, as well as increased reliance on imports, have drawn the attention of Italian legislators to the problem of generation adequacy. According to Fraser and Passo (2003), while the official estimate of net installed capacity in Italy was 76,950 MW in 2002, realistic industry estimates place the national capacity at 48,950 MW. Adding the 6300 MW import capacity brings available capacity up to 55,250 MW, which must meet the peak demand that is currently about 52,000 MW. To address this adequacy problem. Italian legislators introduced a new law that establishes a capacity payment scheme that explicitly remunerates generation capacity. The Minister of Productive Activities, who introduced the discussion of the draft law in June 2003, stated that: “I believe that the explicit remuneration of capacity will provide the system with adequate capacity, including the reserve margin, and will avoid leaving the signaling of capacity scarcity only to market prices.” Subsequently, on December 19, 2003, the Italian government issued Decree No. 379, providing guidelines to the regulator and the transmission system operator to establish a capacity payment scheme. A temporary administrative mechanism began in April 2004, and is still in force, although a permanent mechanism was to have replaced it by 2005. The temporary capacity payment scheme identifies eligible units for capacity payments. Such units must be dispatchable in the day-ahead markets and must declare their availability in a set of “critical days.” Those units engaging in physical bilateral contracts, receiving other incentives (e.g., renewable energy sources), or being affected by production uncertainty (intermittent sources such as wind and run-of-river hydro) are not eligible. Eligible units receive a basic payment and a supplemental payment that is offered only when IPEX’s average weighted energy price is below the regulated

price, up to a maximum of 20% of the regulated price. The funds for capacity payments are collected through an uplift of 0.5 Euro/MWh. The permanent capacity payment scheme is under development.

South Korean System

South Korea, like Peru, has a cost-based power pool where generators are required to offer their energy at marginal cost and receive capacity remuneration to cover their fixed cost. Until January 2007, the unique feature of the South Korean market was the separation of the generation fleet into two distinct markets based on whether they are classified as baseload units or peaking units. Each group of generators receives different capacity payments and was required to submit their cost-based energy offers into the designated market. As of January 1, 2007, the two-tier capacity market has been merged into one, with a capacity payment structure determined *ex post* based on the reserve margin relative to the realized peak load. The payment is made as a price adder on a per kWh basis, with a reference level that is calculated based on the capital cost of a gas turbine and estimated utilization of such units. The payment is kept at the reference level for reserve margins in the range of 12% to 20% above the realized annual peak load. Outside that range, the payment is prorated over the existing capacity so that the total payment below 12% reserves is the same as the reference-price-based payment at 12% reserves, while total payment above 20% reserves is the same as the reference-price-based payment at 20% reserves.

7
VARIANTS OF ENERGY-ONLY MARKETS

While the general principles of energy-only markets and the underlying economic rationale are straightforward, as described earlier, actual implementations vary in response to the political and economic conditions prevailing in different jurisdictions. This section discusses three U.S. markets that do not have explicit capacity remuneration and hence can be considered as energy only. These markets, however, are quite different in terms of how closely they follow the energy-only paradigm and the extent of backstop and transitional measures used to ensure resource adequacy. The section then describes an approach that employs call option obligations, which is consistent with the energy-only paradigm while addressing the objectives of a capacity-based mechanism.

The ERCOT Energy-Only Market

In Texas, following the passage of legislation in 1999 that deregulated retail competition in 2002, and as ERCOT prepared to operate as a single control area[26], the Public Utility Commission of Texas (PUCT) approved the wholesale market rules with a $1000 offer cap. ERCOT saw a rush on investment in baseload combined-cycle capacity, without the support of a capacity mechanism. While the reserve margin in ERCOT was sufficient in the years immediately after retail deregulation, concerns were raised that the wholesale market neither sent the appropriate market signals that valued the location (and deliverability) of that investment nor provided sufficient market signals to value the operational characteristics of generation and load resource (e.g., flexibility of real-time dispatch, minimum loading of generation units, and startup times). In addition, almost all of the new dispatchable generation was designed to operate as baseload with little or no new peaking generation entering the market.

In deliberations on the appropriate resource adequacy mechanism to choose for ERCOT, competitive retailers and industrial consumers strongly objected to the use of a capacity market approach. A retailer group suggested even higher offer caps than the PUCT accepted, reflecting their strong dislike of a capacity payment approach to resource adequacy. At least one of the PUCT commissioners expressed reluctance to institute a potential subsidy to generation, in the form of capacity payments, which once present, would be difficult to remove.[27]

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[26] ERCOT began operating as a single control area on July 31, 2001, when pilot retail competition began in ERCOT. Prior to that date, ERCOT consisted of 10 individual control areas operated by each major integrated electric utility in ERCOT.

[27] Public Utility Commission of Texas, Project No. 24255.

In 2006, the PUCT, which regulates both the wholesale and retail markets of ERCOT, adopted a combination of market power and resource adequacy rules that explicitly rejected capacity payments in favor of raising the systemwide offer cap to ensure resource adequacy.[28] In its resource adequacy rule, the PUCT stated that it adapted the Australian energy-only resource adequacy mechanism to the ERCOT market.[29] In this proceeding, the Commission adopted Substantive Rules 25.504 (Market Power) and 25.505 (Resource Adequacy). The combination made ERCOT an energy-only market, in contrast to a capacity-and-energy approach used in electricity markets in the Eastern Interconnect of the United States.

In the ERCOT resource adequacy mechanism, the offer cap is to be raised from the $1000 level that prevailed when the rule was adopted in August 2006 to $3000 in 2009. In addition, the Commission ended a systemwide market mitigation measure, the Modified Competitive Solution Method (MCSM)[30], which changed market clearing prices *ex post* under certain market conditions that suggested economic or physical withholding might have occurred. The PUCT also expressed its intention to rely on increased market-based demand response to meet its resource adequacy goals.[31] Increased market-based demand response would also weaken the potential for market power abuse during times when scarcity pricing was expected.

An important aspect of the ERCOT energy-only market is the absence of a must-offer obligation of any kind and the reliance on hockey stick offers to set scarcity rents. Unlike the MISO system that will be discussed below, ERCOT has no scarcity pricing mechanisms for operating reserves, although a scarcity adder reflecting emergency deployment of reserves is being developed. In addition, a temporary backstop program for procurement of emergency interruptible load service (EILS) has been adopted.[32] The EILS procurement by ERCOT is intended to guard against rotating blackout events and will be deployed only when involuntary curtailment of load is imminent. The procurement is limited to 1000 MW, and the total procurement cost has been capped by the Commission at $17 million for 2007. Utilities wishing to participate in the program will submit capacity offers in a pay-as-bid auction. When the EILS is called, the load does not receive any further remuneration for the unused energy other than the avoided cost or imbalance settlement, based on the prevailing market clearing price for energy (MCPE).

As part of this rulemaking project, the Commission developed a formal definition of market power, reduced mitigation on smaller market participants, and gave larger market participants the opportunity to apply for the Commission's approval of voluntary mitigation plans. The rule will raise the offer cap in ERCOT-procured markets to allow generation and load resources the

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[28] Public Utility Commission of Texas, Project No. 31972, page 6. A more detailed discussion of the development of this rule can be found in Schubert *et al*., 2006.

[29] *Ibid.*, page 42.

[30] Hurlbut, *et al*., 2004.

[31] Public Utility Commission of Texas, Project No. 31972, pages 68-69.

[32] Public Utility Commission of Texas, Project No. 33457.

opportunity to recover their fixed costs, improve incentives for bilateral contracting, and increase the transparency of ERCOT-procured ancillary service and energy markets.

Scarcity Pricing and Market Power Abuse

Because price spikes could be substantially higher under an energy-only mechanism with medium to high offer caps, regulators would have an even greater need to distinguish between scarcity pricing and market power abuse. Therefore, there is a need to supplement this *ex ante* framework with substantial market monitoring resources and greater transparency to proactively address potential market power abuses.

Various markets applying the energy-only approach to resource adequacy have used the following approaches to address potential market power abuses:

- ***Transparency of offers into ISO-procured energy and ancillary services markets***

The increased disclosure will enhance market transparency, providing incentives for market participants to make offers into ISO-procured energy and ancillary services markets that are consistent with the properly functioning competitive market and not the result of market power abuse or other market manipulation. The implementation schedule for disclosure is also being tied to the schedule for increases to the offer cap, thereby further emphasizing the PUCT's decision that these two issues are interrelated.[33]

The interrelationship the PUCT cites is consistent with disclosure policies in electricity markets in the United States and other foreign markets. In FERC jurisdictional markets, for instance, resource-specific information submitted into an ISO-procured market is released six months after the information was gathered, which is consistent with heavily mitigated individual resource offers and a low offer cap.[34] Quick disclosure of resource-specific information appears to provide limited benefit under these circumstances, because market participants are protected ex *ante* from potential price spikes, know the limited range in which the offers are made, and rely on mechanisms run by an ISO to trigger scarcity pricing in the markets.

By contrast, an energy-only resource adequacy mechanism with lighter price mitigation and high systemwide offer caps is believed to work best when the ISO discloses resource-specific offers or unit output quickly. This approach is based on the experience of the Australian market and the belief that companies that have the potential of abusing their market power will be reluctant to expose themselves to public criticism resulting from actions they take in the market to raise prices. This combination of lighter mitigation and quicker disclosure is seen in established electricity markets outside of the United States. For example, 1) the Australian electricity market discloses resource-specific offers with the names of the generators making the offers within 24

[33] Public Utility Commission of Texas, Project No. 31972, pages 27-28.

[34] Recently, a number of these ISOs have decided to implement scarcity-pricing mechanisms that prescribe specific situations when prices can rise to the offer cap.

hours; 2) the New Zealand electricity market discloses the same information within 14 days and may shorten the disclosure window in the near future; and 3) the Alberta electricity market displays the output of each generator, by name, on its website in real time.

- ***Structural components to address market power***

The Texas Legislature has put in statute a limitation on ownership of no more than 20% of installed capacity in the ERCOT market. In addition, the deregulation of the Texas market required integrated utilities that would offer customer choice to unbundle services into separate retail, wires, and generation companies, with strict code of conduct rules limiting their interactions.

- ***Market monitoring focused on key players***

In ERCOT, the PUCT instituted a provision in its market power rule, stating that market participants that owned or controlled less than 5% of total installed generation capacity would be deemed not to have systemwide market power (informally known as "small fish swim free" provision). As a result, the market monitor can focus more time and energy on the actions of a handful of large market players, who would be considered most likely to be pivotal suppliers during non-peak system conditions and have the potential of exerting unilateral market power.

- ***Voluntary mitigation plans***

In ERCOT, market participants with portfolios larger than 5% of the installed capacity have the opportunity to earn scarcity rents on their units. If they are uncertain whether the offers from those units would be considered an exercise of market power, they have the opportunity to apply for a voluntary mitigation plan with the PUCT. The PUCT would review the plan, and if approved, would provide the market participant with an absolute defense against charges of market power abuse as long as it adhered to the voluntary mitigation plan.

- ***Keeping market participants informed on short-term overall supply and demand***

Market participants are provided short-term forecasts to assist them with their unit commitment decisions (quick-start generation and demand resources). In the Australian market, for instance, the market operator emphasizes the importance of projected assessments of system adequacy (PASA) in informing market participants of unit availability and load forecasts.

Demand Participation

One of the current problems in restructured electricity markets is the highly inelastic demand for electricity among all but the largest consumers. Inelastic demand requires substantial *generation* reserve margin. When the generation reserve margin falls, an electricity market is vulnerable not only to high prices (e.g., scarcity pricing) but also to abuse of market power, because differentiating between scarcity pricing and market power abuse is difficult to prove after the fact. Increasing market-based demand response increases competition with generation at near peak demand or at peak demand, reducing the need for or scope of *ex ante* mitigation of potential

systemwide market power abuse while allowing for scarcity pricing. For this reason, aggressive development of demand response is a key component of the Texas energy only market. Four key elements of that effort include the following:

- ***Interval metering for large loads***

From the opening of the ERCOT wholesale market in July 2001 until 2005, large industrial customers with peak loads of 1 MW or more have been required to use real-time interval meters rather than load profiles to settle energy imbalances at ERCOT. This threshold is now 700 kW in ERCOT. Exposure to real-time prices has encouraged peak-shaving and price-responsive demand in ERCOT.

- ***Loads Acting as Resources (LaaRs)***

For a number of years, ERCOT has allowed loads to participate in the spinning and non-spinning reserve markets as Loads acting as Resources (LaaRs). Up to half of ERCOT's spinning reserve requirement of 2300 MW is being met by LaaRs.

- ***Advanced interval meters for small loads***

Smaller loads are usually settled on profiles that are not conducive to real-time, critical peak, or time-of-use pricing. A number of markets, including ERCOT, are considering installing advanced meters for residential and small commercial customers that would provide retailers with interval load data (such as hourly usage) and end users with pricing information. Such information could allow retailers to offer a variety of programs that could give all loads the opportunity to respond to high prices in the spot market or price patterns reflected in time-of-use rates.

- ***Centralized day-ahead market***

One of the most important market design elements that will increase peak-shaving and price-sensitive loads is a financially binding, centralized, day-ahead market—a feature of every current or future nodal market design in the United States. With a centralized, day-ahead market, customers with large loads can make multi-hour block offers in the day-ahead market to curtail loads (or resell their power and not appear in the following day's real-time market).

Limiting Excessive Wealth Transfers

As mentioned above, it is very difficult to distinguish between market power abuse and legitimate scarcity pricing needed to send adequate price signals. Furthermore, the time lag between the market price signal and the entry of new generation complicates market mitigation that, if unchecked, could lead to significant transfers of wealth to generators. Therefore, the newly restructured wholesale electricity markets should have some limit on the earnings associated with very high offer caps to ensure scarcity pricing without price gouging. For instance, the Australian approach also includes a backstop feature called the cumulative price threshold (CPT), which caps the cumulative fixed-cost recovery over a one-week period. When

the limit is reached, the resource's $AUS 10,000 offer cap drops to $AUS 50-$AUS 100/MWh for no more than one week. The threshold that triggers the drop in the price cap has not been reached more than once in a year.[35]

By contrast, the ERCOT wholesale market has lower offer cap, but limits the amount a resource can capture on an annual basis to $175,000 per MW (slightly over twice the estimated annual fixed cost of a gas unit). When that limit is reached, a much lower offer cap applies for the remainder of the calendar year.[36] Having such a cumulative cap in these markets with relatively high offer caps, however, could create a bright line, which enables pivotal suppliers to collect the allowed rents while staying within the allowed limits. Any market mitigation approach would need to address the problem of pivotal suppliers in the markets through market monitoring.

The Proposed Energy-Only Market at the Midwest ISO (MISO)

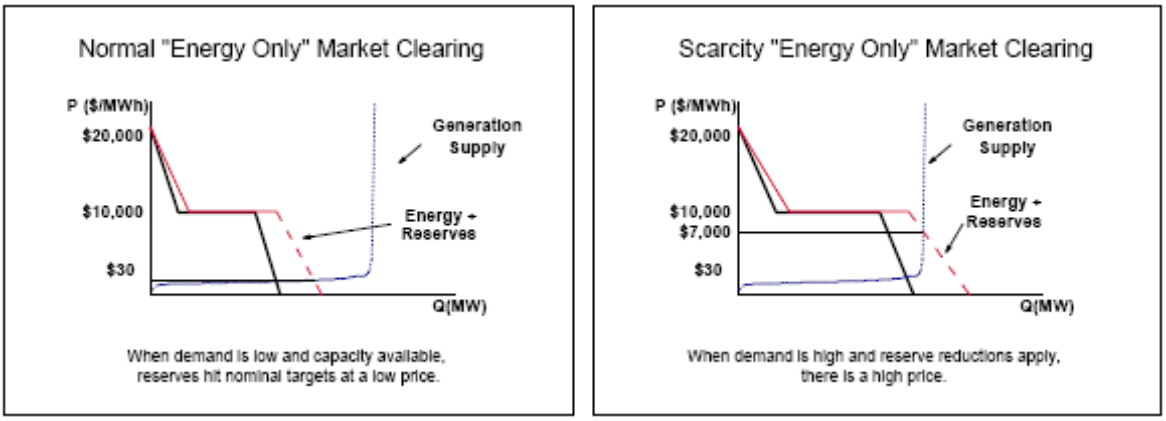
In February 2007, MISO filed with FERC a resource adequacy proposal that relies on energy-only remuneration and contracting obligations imposed on load serving entities. The proposal retains the $1000 per MWh energy offer caps during non-scarcity conditions (i.e., when reserves are not deployed for energy production). However, an administrative demand curve for reserves will be used to set reserve prices during scarcity conditions, when operational reserves are deployed. These reserve prices will also be added to the energy clearing prices during such scarcity periods. The demand curve for reserves, which will be used in the day-ahead and real-time markets, will allow scarcity pricing to rise as high as $3500 per MWh, which is MISO's estimate of VOLL. Real-time co-optimization of energy and reserves will be implemented to improve resource utilization during scarcity conditions.

The administrative demand curve for reserves, which is part of the MISO proposal, follows closely the methodology proposed by Hogan (2005, 2006) and illustrated in Figure 7-1. According to this scheme when operating reserves fall short due to emergency deployment of operating reserves or procurement shortfall, the operating reserves price rises along the dashed demand function. The reserve price reaches VOLL (which in the figure is set to $10,000 per MWh) when the reserve falls below a minimum level (determined by the system operator) at which point the load must be shed.[37] The operating reserve scarcity price is paid to all spinning reserves and is added to the balancing energy price to reflect opportunity cost (since any MW-producing energy source has the opportunity to offer spinning reserves instead).

[35] Communication with Peter Adams, Manager, Surveillance and Enforcement, Markets Branch, Australian Energy Regulator, February 1, 2005.

[36] The lower offer cap in ERCOT market is $500/MWh or 50 times Houston Ship Channel Natural Gas Price Index, whichever is larger.

[37] At MISO, the VOLL is set to $3500 instead of the $10,000 in the figure.



Source: Hogan (2005)

Figure 7-1
Scarcity Pricing Through Pricing of Operating Reserves

The state commissions within MISO would be expected to enforce a contracting requirement for all loads, both traditional cost-of service load and competitive retail loads, to ensure resource adequacy. The desirability of a "must-offer" availability requirement in day-ahead markets for contracted resources in MISO will be reviewed in the future.

The California Resource Adequacy Program

The devastating consequences of the California energy crisis highlighted several fundamental flaws in the California electricity market design and several policies adopted by the California Public Utilities Commission (CPUC) in deregulating the California electricity market. Many commentators have identified the lack of long-term contracting between the unbundled generation and distribution sectors and the over reliance on spot market transactions as major causes for the market meltdown and as an impediment to system reliability. To remedy these shortcomings, the California ISO (CAISO) and the CPUC initiated a market redesign initiative in 2002, and the CPUC, following up on this initiative, committed to creating a resource adequacy program for the state. The objective of this program was to support the system reliability objectives of the CAISO while improving economic efficiency and assuring reasonable prices for California consumers. The low offer cap of $400/MWh in the CAISO energy market and the absence of any capacity payments made bilateral contracting obligations an essential backstop mechanism, which would reduce the CAISO's heavy reliance on RMR contracts to meet local reliability needs.

The Resource Adequacy Requirement (RAR) Program accomplishes these goals by mandating long-term contracting and procurement of generation capacity by the CPUC jurisdictional load-serving entities. By coordinating these contracting requirements with the CAISO local reliability criteria, the CPUC hopes to reduce CAISO reliance on costly reliability must run (RMR) contracts that are expansive and hinder economic efficiency in the market. At the same time, the contracts protect customers against price excursions during shortage conditions (as seen during the California energy crisis) and encourage investment in new generation. This section discusses the short-term RAR, which is aimed at ensuring availability of existing resources for the next

year to meet ISO local reliability requirements while protecting customers against price excursions. Contracting for new generation to address long-term resource adequacy needs is handled through a tendering process that will be discussed later.

The foundation for the RAR Program was established by the CPUC in orders D.04-01-050 and subsequently in order D.04-01-035, issued in the spring of 2004. In September 2005, the California Legislature enacted Assembly Bill 380, which required the CPUC, in consultation with the CAISO, to establish RARs for all the LSEs under CPUC jurisdiction.

The initial CPUC Resource Adequacy Order D.04-01-050 and D.04-10-035 issued in 2004 established the LSE obligation framework, set forth qualifying capacity rules, and authorized a wide range of resource types. In a subsequent order in D.05-10-035 issued in 2005, the CPUC clarified the notion of monthly capacity versus peak load, established required elements for standardized contracts, and clarified the availability obligation to the CAISO of contracted generators. In 2006, the CPUC issued another order, D.06-07-031, that resolved a number of regulatory uncertainties, including treatment of forced outages vs. scheduled outages, title clearing, credit worthiness, and the role of intermediaries. The order also modified the required elements of tradable, standardized capacity contracts and authorized trading via bulletin boards or exchanges. The short-term RAR imposed on the LSEs are based on load forecasts developed by the California Energy Commission (CEC) and on local reliability needs determined by the CAISO. Contract portfolios of the LSEs are subject to compliance verification by the CPUC. In August 2006, the CPUC launched a proceeding aimed at determining whether there is a need for a centralized capacity market that will supplement or replace the current contract-based resource adequacy approach.

The primary purpose of the short-term RAR is to address the local RAR by ensuring that sufficient local generation capacity is contracted and available to the CAISO to meet its local reliability need in load pockets and to reduce dependency on RMR contracts. The program is adjusted and applied annually as follows:

- The CAISO performs a local capacity requirement (LCR) study a year ahead of the CPUC program adjustments.
- Key LCR study inputs include load forecasts by the CEC, transmission system configuration, generation expansion plans, import capability, the status of all “must take” units, maintenance of path flows, and NERC performance level criteria. Load pocket modeling is based on transmission constraints and import effectiveness.
- The CAISO’s LCR for each load pocket will include non-generation resources such as operational responses, short-term equipment upgrades rating reevaluation, and demand response.
- The CAISO provides several LCR levels based on reliability levels (N-1, N-2, etc.). Use of probabilistic criteria for LCR studies is being planned.
- The CPUC Energy Division translates the LCR results to the CPUC-jurisdictional LSE local RAR and calculates, along with the CEC, the local RAR for each LSE. The calculation is based on the requirement that each LSE covers 115%-117% of their peak load share in each

local reliability area (some aggregation of local reliability areas was done to improve market liquidity).

- The CPUC Energy Division monitors compliance of the LSE resource portfolios for the coming year with the RAR, and these are subsequently reviewed by the CAISO, which has authority to procure backstop RMR resources needed to complement the RAR resources.
- The CAISO's backstop procurement role addresses both reliability needs and market power mitigation by exempting the LSE from the RAR procurement if no capacity offers below $40/kw/year are available.

In August 2006, the CPUC launched a proceeding, which will extend throughout 2007, aimed at determining whether there is a need for a centralized capacity market that will supplement or replace the current contract-based resource adequacy approach, which has several shortcomings. One of the problems with the current program is the overwhelming burden of compliance verification due to the diversity of contracts. Furthermore, the dual role of the contracts addressing both price hedging and local reliability needs is problematic, since from a financial perspective it makes little sense to contract forward for more than 100% of forecasted annual load. Optimal hedging of variable load would normally cover only a fraction of the peak load with forward fixed-price contracts, while the remainder is served through spot market procurements. Covering 100% of the peak load with forward contracts is suboptimal, since under such a strategy the LSE is over hedged when demand is low. The LSE, as a result, would have to sell its excess energy in the balancing market at a potential loss, since low demand in the face of oversupply is typically correlated with low spot prices.

Call Options Obligations

Contracting obligations in the context of energy-only markets are intended to greatly reduce the potential for a boom-bust cycle by effectively imposing mandatory price insurance as a way to protect customers against high spot prices instead of artificially suppressing these prices. For such contracts to be properly priced and address the "missing money" problem, unhedged spot prices for energy and operating reserves must be allowed to fully reflect scarcity conditions. The purpose of mandatory call options is to restore the price protection offered to customers through price caps and to ensure resource availability at these prices, with minimal interference in the private risk management markets. This result can be achieved by setting the strike price for the mandatory call options sufficiently high (i.e., $1000 per MWh, such as the prevailing price cap in many markets). Under such a scheme, any LSE has to cover its peak load and appropriate planning reserve requirements with the standardized backstop call options, any forward contract, or call options of comparable duration and equal or lower strike price. The call options give the holder the right, but not the obligation, to obtain a fixed amount of energy at the strike price, which can come from a generation resource or a curtailable load resource.[38] Holding options

[38] An ISO might find it prudent to require LSEs to procure some curtailable load resources with call options that have a strike price greater than $1000 per MWh in order to maintain system reliability during extreme weather events or random emergency conditions. Such an approach would allow the ISO to avoid mandatory load shedding by having loads that consume electricity during emergency conditions available to pay other loads to curtail. The higher strike prices would reduce the up-front cost of procuring such voluntary load shedding. Such contracts could be procured annually rather than for three years to increase the potential range of load participation.

allow LSEs to buy cheaper energy from the spot market when available, reducing the cost to consumer, as compared to a forward contract that entails a “must take” obligation at the contract price. The LSE benefits from holding call options, which offer customers the same protection as a price cap without locking them into a fixed price.

Further price protection can be obtained through traditional private contracting. However, the call options strike price must be sufficiently high to allow headroom and provide incentives for price risk management. Call options can be obtained from generation resources with verifiable physical capacity to cover the contract or from interruptible customers, who sell a call option that commits them to curtail load when the spot price reaches the strike price. The opportunity to sell call options effectively gives customers an opt-out mechanism, since the revenue from selling the call option will offset their share of the call option obligation cost to which they are subject. Resources that are not bound by call option contracts are allowed to offer their energy to the spot market at prices that exceed the strike price, while generators and interruptible customers that have sold call options are obliged to offer the corresponding energy into the spot market at the strike price or below. In a case where a load obligated by a call option is not curtailed when the price reaches the strike, then the LSE is liable for non-performance and must pay the difference between the uncapped spot price and the strike price. Such liability automatically implements a non-performance penalty scheme based on market economics that keeps the customers unharmed.

Proposals for various forms of contracting obligations, in the form of physically covered call options, are described by Oren (2000, 2005a, and 2005b) and by Vázquez *et al*. (2002). Mandatory load hedging, although with no physical cover requirement, has also been proposed recently by Hogan (2005, 2006) in the context of an energy-only market proposal. A recent implementation of a call option approach, with a central procurement auction in Brazil, is described by Bezerra *et al*. (2006), and a similar approach has been proposed in Colombia by Cramton and Stoft (2007).

De Vries 2004, who reviews the alternative capacity mechanisms with respect to generation adequacy in Europe, concludes that reliability contracts of the types described by Oren (2000) and Vazquez *et al*. (2002) represent the most promising and robust way to prevent regional shortages. These contracts can be implemented either through a centralized procurement scheme or as bilateral contracts subject to a regulatory obligation. The latter approach is compatible with a decentralized system and is the most straightforward way to achieve reliability since it creates direct contractual connections between LSEs and the generation companies for the entire demand plus reserve margin. The main downside is that their effectiveness may be limited by vertical integration of generators with retail companies, which can result in self-dealing.

Centralized vs. Decentralized Procurement

Backstop call option obligations can be met through bilateral contracting with generators or interruptible customers. However, in order to achieve the resource adequacy objective and to provide incentives for new investment in generation capacity, it is necessary to define the call options with at least a three-year forward lead time and a duration of one to several years. The need for such a lead time has been recognized in other mechanisms mentioned earlier, such as

the PJM RPM, CRAM, and the ISO-NE FCM, as a way to allow new entrants with no "iron in the ground" to participate in the market and offer call options against capacity that they intend to build. Such a forward-looking approach is essential to mitigate market power of the incumbent generators in the call option market. The problem with forward-looking commitments is that load forecasts change, the load migrates among LSEs, and small representatives may not have adequate credit to cover such long-term obligations.

These difficulties may be addressed by creating a centralized market of last resort for call options. Such a market, which will complement the traditional over-the-counter bilateral contract market, can be managed by the ISO, which will act as counterparty and assume all the credit risk. The ISO will centrally procure the backstop call options on behalf of the system load through an auction mechanism. Payment to the options sellers will be made at performance time, and the cost will be recovered from the load through their LSE on a prorated basis. Hence, load migration problems and load forecast errors are dealt with based on realized load.

Self-provision in such a centralized market can be handled in two ways. One is to allow LSEs to submit proof of contracts they hold in lieu of their call option obligations. The better approach, however, is to have holders of qualifying contracts sell call options into the centralized auction covered by the contracts. The proceeds they will receive from such sold options will offset the charges for their obligation.

A centralized market for call options achieves the objectives of capacity markets without introducing an artificial capacity product. Instead, the call options market supports an energy-only approach and can be phased out if sufficient bilateral procurement and self-provision takes place to the point that the centralized market of last resort becomes obsolete.

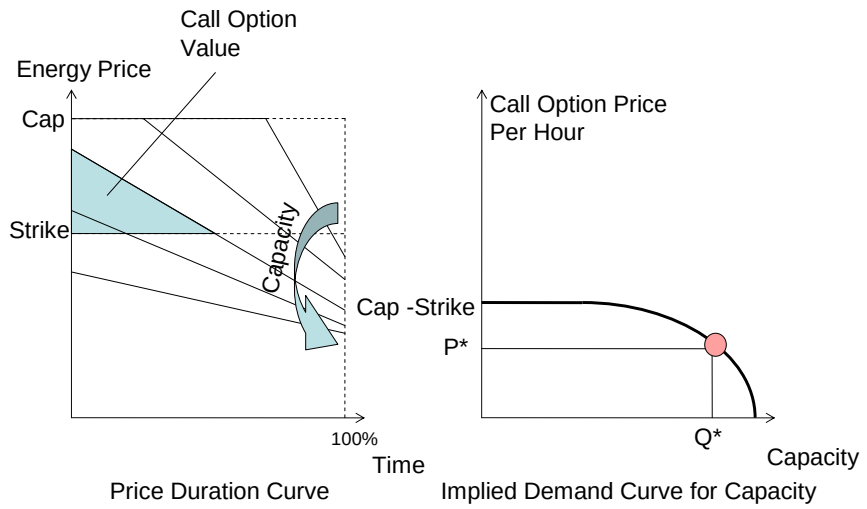
To demonstrate the equivalence of a call options approach to capacity markets, Figure 7-2 illustrates the relationship between the value of a call option with a fixed strike price and total system generation capacity. The left panel illustrates a family of capped price-duration curves for energy, which become less steep and eventually may not even hit the price cap as capacity increases. The value of a call option is represented by the shaded area under the price-duration curve and above the strike price. This value is bounded above by the difference between the price cap and the strike price times the number of hours, and declines to zero at a capacity level at which the energy price will never exceed the strike price. Assuming that the price-duration curve reflects the value of lost load, as it should, then the optimal capacity level for the system is the level at which the call option's value—plus the net profit from energy sales by a peaking unit capped by the strike price—is equal to the amortized fixed cost of a CT.

Plotting the option value as function of total capacity produces a downward sloping curve that resembles the demand function for capacity employed in northeastern U.S. capacity markets. This indicates that a market for call options, accompanied by an unmitigated spot energy market, can produce the result that a capacity market with an administrative demand function tries to emulate. The difference is, however, that the call option value function is market based and results from the opportunity cost for generators to sell their energy in the spot market. Consequently, there is no need to procure capacity in excess of the target capacity based on technical considerations. The effect of the downward sloping demand beyond that target level

can be achieved by allowing excess capacity to take the risk and reap the potential benefits of selling energy in the spot energy market at full spot market prices.

Deliverability Issues

To ensure that the resource adequacy objective is achieved, i.e., sold call options translate into physical capacity, the call option must have physical cover. This means that a seller of a call option must identify physical generation capacity or firm interruptible load or make a commitment to build the capacity within a certain time frame. The question that arises is how to guarantee that the capacity will be built where it is needed so that the energy it produces is deliverable.



At optimal capacity Q* the call option price
P* = Average Hourly {CT fixed cost – CT energy profit with price capped at Strike}

Figure 7-2
Implied Demand Curve for Capacity Based on Call Option Value

The approach that has been adopted in the northeastern ISOs is to define locational capacity markets that reflect transmission constraints. As a result, capacity prices in such systems will vary based on location. The call option approach enables such locational differentiation naturally in a locational marginal pricing (LMP) based system. This is because the financial liability associated with a call option and the opportunity cost of committing to the strike price are determined by the difference between the LMP and the strike price, so that the call option premium will vary by location.

There is still, however, an outstanding question of how granular the call option obligation and the corresponding physical cover should be. The physical cover associated with the call options can have the same granularity as the financial obligation or courser. For example, the call option obligation can be zonal, implying that nonperformance penalties will be based on the difference between the average zonal spot price and the strike price, while the physical cover can be

anywhere in the system. In such a case, the generator selling the call option can cover its financial risk with capacity anywhere in the system as well as short-term transmission congestion rights between the location of the capacity and the location corresponding to the call option sold.

8
COMPETITIVE TENDERING AND STRATEGIC RESERVES

Tendering for New Generation Capacity

Competitive tendering and long-term procurement of resources by the system operator represent market-friendly extensions of the resource planning and operational paradigms employed by vertically integrated monopolistic utilities in regulated environments to ensure resource adequacy and operational reliability. Variants of such mechanisms are common in the European Union (EU), but competitive tendering has also been adopted in the United States by state commissions attempting to ensure needed investment in new generation capacity. In the EU, France, Germany, and Portugal have opted for competitive tendering as the mechanism through which needs for new capacity (based on traditional resource planning methodology) are going to be met. In France, however, no such tender has been issued to date. Given the planned construction of a new nuclear power plant and possible life extension of existing nuclear plants, it is unlikely that a call for tender will be issued in France in the near future. In California, for instance, the CPUC has authorized investor-owned utilities to procure new generation as a transitional mechanism for ensuring long-term resource adequacy. The Connecticut Public Service Commission has authorized an RFP for procurement of new generation, which will be then offered into the ISO New England FCM auction at zero prices. In doing so, Connecticut is able to exercise monopsony power, hoping to reduce electricity cost to its consumers by depressing the FCM auction price that determines payment to incumbent generation capacity.

A definite advantage of tendering is that it guarantees investment in new capacity that will meet reliability requirements based on technical integrated resource planning methods. Direct negotiation with new generators or competitive tendering can constrain the location and technology of the new capacity so as to meet local reliability and technology mix targets (e.g., renewable portfolio). Neither capacity payments nor short-term capacity markets have proven effective in inducing new investment that meets target criteria. Both are largely viewed as payoff to incumbents. While energy-only markets, with or without backstop mechanisms, are supposed to incentivize new generation investment, there is only limited experience to support such assertions. The reformed capacity markets reviewed above in New England and PJM were designed to ensure new entry, while leveling the play field between incumbent and new generation. The locational feature of these markets will hopefully direct new investment to the locations where it is needed. However, as described above, competitive tendering surfaces in such settings as a means for exercise of monopsony power so as to reduce payments to incumbent resources.

On the other hand, one can legitimately argue that competitive tendering based on centralized resource planning, prolongs the regulatory regime that the industry is attempting to leave behind and interferes with progress toward a competitive energy market. Allowing competitive forces in energy markets to drive investment has been the primary driving force behind electricity market reforms around the world. The Green Paper, published by the Commission of the European Communities (2006) states, "Europe has not yet developed fully competitive internal energy markets. Only when such markets exist will EU citizens and businesses enjoy all the benefits of security of supply and lower prices."

The California Long-Term Resource Adequacy Requirement Program

The California long-term RAR Program is aimed at ensuring that sufficient generation capacity is built in the right locations to meet future local reliability requirements. In a 2004 long-term procurement Decision D. 04-04-003, the CPUC directed all LSEs to follow the state mandated "loading order" contained in the California's Joint Agency Energy Action Plan (EAP) by prioritizing energy efficiency, demand-side resources, and the Renewable Portfolio Standards goal in their procurement plan. Recently, the second phase of the long-term procurement program was addressed in a July 21, 2006, CPUC decision. The program recognizes that the short-term RAR program may not be able to provide sufficient generation investment incentives unless at least part of the short-term RAR is met with long-term contracts with new generation capacity. The provisions adopted in this decision are on a limited and transitional basis, do not apply to utility-owned generation, and are limited to new and repowered generation.

The decision designates investor-owned utilities (IOUs) as the entity responsible for procuring new generation for the system through bilateral negotiation or competitive tendering. However, it divides the management of energy and capacity components of resources procured under this program. It determines that the IOUs are not responsible for management of the energy component of new generation and requires that the value of that energy component be revealed through an auction mechanism for long-term tolling rights to the energy. The capacity cost, determined as the total contract cost net of the energy value revealed through the auction, will be allocated to all LSEs within the IOU service territory. The cost allocation methodology adopted in this decision is set for up to 10 years, but LSEs that can prove to be resource adequate "over a sufficiently long time" can opt out of the cost allocation provisions.

Procurement of Strategic Reserves

Under the procurement of strategic reserve mechanism, the system operator enters into long-term contracts with generators that effectively limit their spot market activity in exchange for some agreed upon remuneration. Such an arrangement is similar to national strategic petroleum reserves that remove oil supplies from the market and retain them in storage with the intention of releasing them when needed to mitigate market distress. Procurement of strategic generation reserves can promote generation adequacy in several ways. First, reducing supply in the short run increases prices and enhances investment incentives so that part of the strategically reserved capacity will be replaced by new investment. Second, in the case of true scarcity, dispatching the reserved capacity can eliminate or reduce the need for load curtailment, so that the system

operator can better meet the "obligation to serve" dictum (whether this is efficient is, of course, debatable). The later goal can also be served by interruptible load serving as strategic reserves. Such an approach has been recently adopted in ERCOT under the Emergency Interruptible Load Service (EILS) Program, which is intended to provide a short-term backstop in case of unforeseen shortages. In some cases, strategic reserves are also employed to prevent early retirement or mothballing of resources that are noncompetitive but are needed for reliability reasons.

The effectiveness of this mechanism depends on the implementation parameters. These include the triggers for dispatch of strategic reserves, the way strategic reserves are compensated, and the prices paid for energy produced by strategic capacity reserves. Dispatch triggers can be based on technical considerations, such as operating reserve margins, or on energy prices that signal short-term scarcity. The extent to which deployment of strategic reserves distorts market signals for investment depends mainly on the price paid for energy produced by strategic reserves. For instance, if energy from strategic reserves is priced at VOLL or at the prevailing cap on offers, then no distortion of prices should occur and the only effect of dispatching the reserves is to avoid curtailment of loads. On the other hand, if energy from strategic reserves is paid a price lower than the offer cap, and their dispatch is triggered when the energy price reaches that level, then the offer price of the reserves creates a flat segment in the supply function and effectively sets a reduced offer cap until all of the reserve capacity is dispatched.

In the United States, the general attitude in ISO markets is hostile toward any kind of intervention by the ISO that may affect market prices. Consequently, any long-term procurement of resources by the ISO is subject to intense scrutiny. Justification for any procurement beyond day ahead by the ISO must be based on reliability considerations and is subject to challenge by FERC. Such an attitude also prevails in ERCOT, which is not subject to FERC jurisdiction. By contrast in Europe and, in particular, in Nord Pool, the system operator is viewed as "market maker" which is expected to use flexible resources procured on a long-term basis to "smooth out" prices and mitigate reliability events.

The remuneration of strategic reserves, the terms under which they are dispatched, and their ability to capture additional energy payments when deployed determine the incentives of generators to sell strategic reserves and the extent to which procurement of strategic reserves can mitigate market power. So, for example, while pricing strategic-reserve energy at the offer cap may be desirable because such an action does not distort energy prices, this approach will not mitigate generators' incentive to withhold capacity in order to raise prices.

The structure of strategic-reserve contracts may be restricted by rules governing the actions of the system operator. In the United States, where system operators are typically restricted from playing an active role in the energy market, the terms under which strategic reserves can be deployed must comply with these restrictions. In European countries, the system operator is given more discretion in how to utilize such reserves.

Strategic reserve contracts may take different forms. The reliability-must-run (RMR) contracts in Texas are de facto an implementation of strategic reserves, limited to plants that their owners want to mothball. These plants, however, are needed for reliability reasons (based on the ISO's

determination on technical grounds). In these circumstances, a plant enters into an RMR contract that guarantees cost recovery (plus a regulated profit margin) in order to remain operational, but the plant is prohibited from participating in any energy or ancillary service market and is subject to dispatch as a price taker by ERCOT (the Texas ISO). ERCOT protocols dictate that these plants can be dispatched only as a last resort when the markets fail to provide the needed resources to meet system reliability requirements. Other U.S. systems such as California do not prohibit units with RMR contracts from participating in the energy and ancillary services markets, so they cannot be regarded as truly strategic reserves.

Another approach to implementation of a strategic reserve mechanism is a forward reserve market similar to that implemented by ISO New England and described in FERC Docket No. ER03-1318-002 (2004). Under a generic forward reserve scheme, generators are paid an "opportunity cost payment" for not offering energy below a prescribed "threshold price" plus a premium that would compensate the generators for penalties associated with performance risk. Such a contract keeps the generation capacity off the market, assuming that the threshold price is above their marginal cost, and can therefore be viewed as a strategic reserve. The threshold price may also set an automatic price trigger for dispatching energy when the spot energy price exceeds the threshold price if the contract would require standing offers at the threshold price. (This is not the case in New England, where contracted units can submit offers above the threshold price and will only be dispatched if the market clearing price is at or above the offer price.) If the threshold price is substantially above the marginal cost of the contracted units, one may interpret such contracts as a form of legitimized "economic withholding," which enables the system to maintain a reserve margin needed for reliability purposes without depressing energy prices so as to discourage new investment.

Ideally, a strategic reserve should be offered to produce energy at the price cap so as not to interfere with the energy market and be deployed only as a substitute to involuntary load curtailment during scarcity. That would suggest that the threshold price for the forward reserve contracts should be set at the price cap. Unfortunately, such an approach allows inefficient dispatch when low-cost units under contract are kept off the market while other less efficient units are dispatched. The New England forward reserve market attempts to avoid such dispatch inefficiency by setting the threshold price to approximate the marginal cost of a peaking gas turbine unit. While this dilutes the role of the forward reserve contracts as strategic reserves, it avoids the potential efficiency losses as long as the units selected for forward reserves are of the targeted technology. Furthermore, since the lost opportunity cost of the targeted units is zero, the price of the forward reserve contracts is driven primarily by the penalties associated with performance risk. In the ISO New England implementation, forward reserve contracts are not eligible for an operating reserve scarcity rent that is paid to operable capacity whenever a shortage of operating reserves occurs.

According to De Vries (2004), the European Electricity Directive (Article 7, Directive 2003/54/EC) allows member states to conduct a "tendering procedure" for new generation capacity when existing generation resources appear insufficient. Depending upon the details of the implementation, such as the conditions imposed on availability of contracted units, the tendering procedure may resemble the creation of a strategic reserve or a capacity payment.

The practice of procurement and discretionary deployment of strategic reserves by the system operator has been used in Nord Pool since 2001-2002 and has been more recently adopted in the United Kingdom (under NETA) and in the Netherlands. In parts of Sweden and Norway, the system operator enters into a mid-term contract with producers, paying them to keep some capacity in reserve. In Sweden, approximately 2 GW (out of a 27-GW peak load) are under such contracts and are activated by the system operator, as needed, at preset energy prices. In addition, since 2001-2002, the system operator in Norway procures reserve capacity from generators and load resources (offering demand reduction) through a monthly auction in an optional market. The distinction between reserve capacity procurement and strategic reserves procurement by the system operator is quite subtle. Strategic reserves are fully controlled by the system operator and their energy is sold at a predetermined price. However, resources retained through the reserve capacity auction can sell energy in the balancing market at the prevailing spot price, but are prevented from offering their retained capacity in the day-ahead market. Approximately, 2 GW (compared to a 23-GW peak load) of reserve capacity is procured by the Norwegian system operator in the monthly reserve capacity market. Both the strategic reserves cost and reserved capacity cost are uplifted by the system operator to the load through the transmission tariff.

Nilssen and Walther (2001) describe the seasonal (3-4 months) operating reserve contracts in Norway. These contracts may be viewed as providing a short-term strategic reserve, since they also reduce capacity offered into the energy market and subject the reserve capacity to the system operator's dispatch decision. However, the primary objective of that mechanism is to stimulate demand response and create an operating reserve cushion rather than to incentivize new capacity investment. At the other extreme, in Finland and in Sweden, the system operator actually owns and operates directly some peaking units, but such activity is controlled by the regulator, who determines the volume of energy that can be produced by the system-operator-owned resources.

9
GENERATION ADEQUACY MECHANISMS IN THE EUROPEAN UNION

This section summarizes the situation in the European Union with regard to supply adequacy for electric power. Sections 4, 6 and 8 discussed the various approaches to generation adequacy in the EU, contrasting the various resource adequacy mechanisms. Provided here is a summary of the situation in the EU with some additional comments. Much of the material in this section is based on a presentation by Trotignon (2006), including Figure 9-1, below, which illustrates the various resource adequacy mechanisms currently employed in Europe. With the exception of Spain and Italy, where capacity is directly remunerated through capacity payments, competitive tendering and variants of strategic reserves procurement are the mechanisms of choice in most European countries.

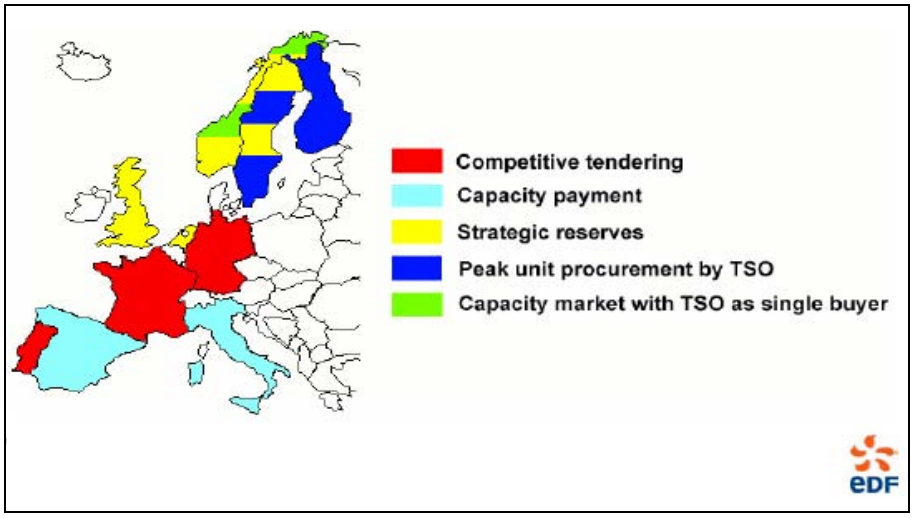


Figure 9-1
Resource Adequacy Mechanisms in Europe

According to the Green Paper, published by the Commission of the European Communities (2006), there is a need for one trillion euros over the next 20 years to meet energy demand and replace the aging infrastructure. Substantial investment is needed in the EU to replace electric generation capacity needed to deal with peaks, provide necessary reserves to prevent disruption during high demand periods, and serve as backup for intermittent renewable energy sources. The Green Paper asserts that "for timely and sustainable investment, a properly functioning market is needed, giving the necessary price signal, incentives, regulatory stability and access to finance."

Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003, concerning common rules for the internal market for electricity, has stated that security of supply is a key objective for the successful operation of the internal market. That Directive gives the member states the possibility of imposing public service obligations on electricity undertakings, *inter alia,* in relation to security of supply. However, the Directive also states that these public service obligations should not create generation capacity that goes beyond what is necessary to prevent undue interruption of distribution of electricity to final customers.[39] Directive 2005/89/EC Article 5 (2006) requires member states to take appropriate measures to maintain the balance between the demand for electricity and the available generation capacity, but gives member states flexibility in how to accomplish that goal. It reasserts Article 7(1) of Directive 2003/54/EC, stating that tendering procedures or any procedures equivalent in terms of transparency and non-discrimination are acceptable.

Currently, there are three divergent major approaches in the EU to generation adequacy assurance and those are further split into variants. As Figure 9-1 shows, Spain and Italy have implemented capacity payments, although the methodology of determining these payments is different in each country.

Capacity Payments in Spain

In Spain,the capacity payments are bundled with stranded cost recovery. The total amount of capacity payment is fixed by the finance minister. The payments are then allocated among the competing generation firms, self producers, and long-term bilateral contracts based on a complicated formula involving the technology mix of each company, availability factors, and the actual dispatch. It has been argued that these payments create incentives that distort the spot market bidding process. Furthermore, there is little evidence that these payments do much toward incentivizing new investment.

Capacity Payments in Italy

In Italy, capacity payments were instituted on a temporary basis after the blackout of 2003 in order to stimulate investment in new generation and reduce Italy's dependence on imports. The payment consists of two-part, fixed part, and variable part features. The fixed part (per megawatt of available capacity) is defined as an incentive rate that varies according to four predefined time periods and is further differentiated according to highly critical days and critical days within each of the four periods. The variable part is paid as a makeup payment when the estimated revenues of a generator fall below the administrative remuneration that would have been paid to a single buyer, and it is capped at that level.

[39] Restated in Directive 2005/89/EC of The European Parliament, 2006.

Capacity Payments in Nord Pool

In Nord Pool (Norway, Sweden, and Finland), as well as in the Netherlands, and the United Kingdom, the generation adequacy mechanism consists of variants of the strategic reserve approach. As described earlier, under this approach the system operator procures resources on a long-term basis and holds them in reserve. Variants of this approach differ in terms of the degree of ownership by the system operator, the dispatch authority of the system operator, and the pricing of energy dispatched from strategic reserves. At one extreme, the system operator actually owns peaking units (in Finland and Sweden). The more common scheme is a contractual arrangement that allows the system operator discretionary dispatch at predetermined prices (in Sweden, Norway, the Netherlands, and United Kingdom). In Norway, the system operator also procures reserve capacity on a monthly basis through an auction from generators and demand-side resources. Sellers of capacity in the monthly auction can sell energy of that capacity in the real-time market at prevailing spot prices but cannot offer that capacity in the day-ahead market.

Capacity Payments in France, Germany, and Portugal

France, Germany, and Portugal opted for competitive tendering for new generation (if needed) as the mechanisms through which they will ensure resource adequacy. The determination of how much capacity is needed in terms of technology and location is based on traditional resource planning criteria, including the standard three hours per year LOLP. So far, no new resources have been procured in France since Directive 2005/89/EC was issued. Given that a new nuclear power plant will be added around 2012 and taking into account the potential life extension of existing nuclear plants, it is unlikely that the competitive tendering protocol will be tested in France in the near future.

10
QUALITATIVE EVALUATION OF ALTERNATIVE RESOURCE ADEQUACY MECHANISMS

This section provides a qualitative comparison of the alternative resource adequacy mechanisms discussed in the previous sections, evaluates how they meet certain criteria, and examines how they may fit in a range of market environments. In particular, it considers the suitability of various approaches to EU markets, given the current state of these markets.

The specific mechanisms evaluated include the following:

1. Capacity payments (Peru, Korea, Spain, Italy)
2. Mitigated energy market with short-term ICAP obligation and central procurement (New York)
3. Strategic reserves and peak units procured by an ISO (United Kingdom, Netherlands, Nord Pool)
4. Mitigated energy market with central forward looking ICAP procurement (New England FCM, PJM-RPM)
5. Bilateral contracts with existing generation and competitive tendering or negotiated bilateral contracts for new generation (California RAR, France, Germany, Portugal)
6. Full-strength energy scarcity pricing with backstop call options obligations
7. Energy-only full-strength scarcity pricing with voluntary hedging (ERCOT, Australia)

The above mechanisms will be compared with respect to the following criteria:

- Stabilization of income to investors
- Effectiveness in securing new generation in an open market
- Dealing with regional shortages and locational reliability requirements
- Dealing with market power in energy
- Dealing with market power in capacity
- Addressing environmental constraints
- Stimulating demand response
- Getting customers the best deal
- Supply-side efficiency

- Feasibility in environments with no liquid energy spot markets
- Compatibility with decentralized systems
- Experience

The above mechanisms will be assessed on each of the criteria as *Very good, Good, Fair or Poor* along with a short justification in Table 10-1.

Table 10-1
Comparison of Generation Resource Adequacy Mechanisms

Mechanism	Capacity payment	Short-term ICAP	Strategic reserves	Forward looking ICAP	Bilateral and tendering	Call options obligations	Energy-only
Stabilization of income to investors	*Very good* Fixed income to generators	*Very good* Fixed income to generators	*Fair* Only guarantees cost recovery for procured resources	*Good* Effective if auction price is set by new generators	*Very good* Income to generators ensured in contracts	*Very good* Cost recovery through option premium	*Fair* Generators accept risk but are free to contract
Effectiveness in securing new generation in an open market	*Poor* Payment to incumbents may not ensure new investment	*Poor* Payment to incumbents may not ensure new investment	*Poor* New investment not guaranteed unless contracted by ISO	*Very good* New investment ensured, either through the auction or bilateral contracts	*Very good* Capacity procured through tendering as needed	*Very good* Entrants can participate by selling call options	*Fair* Sufficient entry not guaranteed; depends on investor willingness to take risk
Dealing with regional shortages and locational reliability requirements	*Poor* Even if capacity payment varies by region, it may not attract investment to the right location	*Poor* Locational clearing prices help, but it is still not clear that they will attract investment to the right location	*Very good* Resources can be procured where needed but unclear that they will attract investment	*Very good* Target procurement and auction can be locational	*Very good* Location can be specified in tendering procedure	*Good* Can work if options requirements are locational and settled based on LMP	*Fair* Depends on investor response to LMP that will signal load pockets
Dealing with market power in energy	*Very good* Price caps and market mitigation control market power in energy	*Very good* Price caps and market mitigation control market power in energy	*Fair* Depends on ISO authority to mitigate price spikes through strategic resources deployment	*Very good* Provided peak energy rents are not capped and can exceed capacity payment	*Very good* Energy prices locked in contract	*Good* Call options replace cap, but supplemental risk management required	*Poor* Protection to customers depends on voluntary risk management

Table 10-1 (continued)
Comparison of Generation Resource Adequacy Mechanisms

Mechanism	Capacity payment	Short-term ICAP	Strategic reserves	Forward looking ICAP	Bilateral and tendering	Call options obligations	Energy-only
Dealing with market power in capacity	*Very good* Payment fixed by regulator	*Very good* Administrative demand function mitigates market power	*Fair* Market power can be exercised in strategic reserve capacity auction (Norway) and in reserve contracts if capacity is scarce	*Very good* Opportunity for new entrants and cap at twice the cost of new entry (CONE); controls market power	*Very good* Competitive tendering for new generation controls market power in capacity	*Very good* Opportunity for competitive new entrants controls market power in capacity	*Good* Financing risk may create barriers to entry
Addressing environmental constraints	*Fair* It is possible to have differential payments for preferred resources	*Poor* Difficult to give preferential treatment to environmentally superior resources; intermittent renewables are not eligible	*Fair* Strategic reserve procurement can remove dirty resources from the market and keep them in reserve	*Poor* Does not deal with environmental constraints and intermittent renewables are not eligible	*Very good* Tendering and contracting can target clean resources	*Poor* Does not deal with environmental constraints, and intermittent renewables are not eligible	*Poor* Voluntary investment does not address environmental constraint unless there are explicit incentives to do so
Stimulating demand response	*Poor* Capacity payments suppress energy prices and demand response	*Poor* Demand resources cannot participate directly	*Very good* Strategic reserves can be demand-side resources	*Good* Demand-side resources can participate, but strike price for peak energy rents must be significantly above marginal cost of peaking units	*Very good* Competitive tendering can include demand-side resources	*Very good* Demand-side resources can offer call options	*Very good* Unmitigated energy prices provide strong incentive for demand response

Table 10-1 (continued)
Comparison of Generation Resource Adequacy Mechanisms

Mechanism	Capacity payment	Short-term ICAP	Strategic reserves	Forward looking ICAP	Bilateral and tendering	Call options obligations	Energy-only
Getting customers the best deal	*Poor* Payment is at customer expense	*Fair* Payment is at customer expense, but determined through a competitive process	*Poor* Procurement decisions are not market based	*Good* Opportunity for new entry and peak energy rents recovery helps reduce cost, but incumbents may still be overpaid	*Very good* Enables discrimination between new and incumbent generation	*Good* Call option premium caps energy prices, but does not differentiate between new and old generation	*Very good* Generators assume investment risk and must sign contract with customers to reduce their risk
Supply-side efficiency	*Poor* Favors incumbents and does not promote renewal of resource portfolio	*Poor* Favors incumbents and does not promote renewal of resource portfolio	*Fair* Can help by keeping inefficient resources in reserve	*Very good* Promotes entry of efficient resource	*Poor* Does not promote renewal; new capacity procured if needed for reliability, but not to replace inefficient capacity	*Very good* Promotes entry of efficient resources	*Very good* Competition in energy forces retirement of inefficient resources and entry of efficient ones
Feasibility in environments with no liquid energy spot markets	*Very good* Can be easily administered in any system	*Poor* Requires an organized liquid market for energy and reserves	*Very good* Does not require a market of any kind	*Poor* Determination of peak energy rents requires a liquid energy market	*Very good* Does not require any market	*Poor* Valuation of call option requires a liquid energy market	*Poor* Recovery of cost depends on a liquid energy market with accurate price signals for scarcity
Feasibility in Europe	*Good* To work well must be homogenized across countries	*Poor* Lack of an organized central market makes it impractical	*Very good* Gives significant discretion to the system operator	*Fair* Implementation will require homogenization of energy market and transition from balancing mechanism to real-time energy markets	*Good* Easy to implement, but reinforces old paradigm and slows transition to competitive market	*Good* Can be implemented in a decentralized setting through bilateral trading but valuation requires a reference energy spot market	*Poor* The level of energy market liquidity needed for such a mechanism is unlikely in Europe in the near future

Table 10-1 (continued)
Comparison of Generation Resource Adequacy Mechanisms

Mechanism	Capacity payment	Short-term ICAP	Strategic reserves	Forward looking ICAP	Bilateral and tendering	Call options obligations	Energy-only
Compatibility with decentralized systems	*Very good* Payment based on steel in the ground or availability	*Poor* Requires centralized auction for all capacity resources	*Very good* ISO procurement independent of the energy market	*Poor* Requires centralized auction for all capacity resources	*Very good* All procurements are bilateral	*Good* Can be implemented through bilateral contracting, but correct pricing requires liquid real-time market	*Poor* Adequate incentives require centralized real-time market that provides accurate scarcity price signals
Experience	*Very good* Used in Europe, South America, Korea	*Fair* Used in NYISO, PJM and ISO-NE	*Good* Used in Scandinavia and the Netherlands	*Fair* Based on regulated resource planning; adopted in California, France, Germany, and Portugal, but there is little experience	*Good* Adopted in PJM and ISO-NE, but no experience yet	*Fair* Adopted in Brazil and Colombia; limited experience in Brazil	*Good* Successful in Australia, New Zealand, and Alberta; recently adopted in ERCOT, but no experience yet

11
SUMMARY

In an ideal competitive energy market, generators always offer supply at marginal cost, but inframarginal profits (from scarcity rents resulting from clearing prices set by peaking units and demand-side bids) produce sufficient income to cover generators' fixed costs. This provides sufficient incentive for investment when needed. In such an ideal market, generators bear all the investment risks and load bears the price risk. However, financial instruments and long-term contracts between sellers and buyers enable them to manage their risk exposures. Unfortunately market imperfections—including technological barriers to demand response, local market power, and price mitigation measures—result in depressed energy prices and "missing money," which prevent generators from recovering their fixed costs. Such revenue shortfalls discourage investors from expanding generation capacity needed to meet socially desirable reliability levels. Various mechanisms have been proposed and implemented in the United States and around the world to rectify this problem by stabilizing generators' income, creating incentives for investment in generation capacity.

For all practical purposes, most restructured electricity markets abandoned the notion of letting the market determine the socially desirable level of generation capacity in favor of a central planning criterion for reserves based on technical and social considerations. Such treatment is often justified by the view that supply reliability of electricity is a public good. The various approaches to ensuring generation adequacy vary, however, with respect to how explicit is the regulator in prescribing the level of generation capacity as opposed to providing financial incentives and relying on market forces to provide the desired level. These approaches fall into three general categories: 1) Mechanisms based on capacity remuneration through direct capacity payment or capacity markets, 2) Energy-only markets with various degrees of backstop measures, and 3) Centralized procurement of generation resources by the system operator or designated agent charge by the regulator.

This report has reviewed the development of capacity markets in the United States and variants of direct capacity payments adopted throughout the world. It has also discussed practical implementations of energy-only approaches that have no explicit capacity remuneration and highlighted backstop mechanisms used to ensure cost recovery for suppliers and attract investment if new capacity is needed. Finally, the report discussed approaches that require direct intervention by the regulator or system operator and involve competitive tendering for new capacity or strategic reserves that the system operator procures on a long-term basis.

As long as the EU energy market is decentralized, not homogenized, and there are no liquid real-time spot markets, some of the sophisticated approaches adopted in the United States—including energy-only approaches and the more recent centralized forward capacity markets—cannot be easily adopted in Europe. The most market-friendly approach compatible with a decentralized

market is the call option approach, which can be implemented through contractual obligations met with bilateral contracts. Competitive tendering, and strategic reserve procurement are workable ways to ensure resource adequacy and supply reliability, but they are not compatible with the EU stated objective of achieving a truly competitive energy market across Europe.

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