Ensuring Generation Resource Adequacy through Enhancing Spot Market and Facilitating Long-term Forward Markets

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Thesis Committee
Prof. Marija Ilic
Prof. Lester Lave
Dr. Michael Rosenberg[1]
Dr. Jovan Ilic

Prepared by
Zhiyong Wu

Department of Engineering and Public Policy
Carnegie Mellon University
Pittsburgh, PA 15213

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[1] Department of Market Monitoring, ISO New England

1. Introduction

The reliability of electricity supply has been one of the most important concerns guiding the restructuring of the electric power industry. National Electric Reliability Council (NERC 2006) 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". Electric system reliability can be addressed by considering two basic and functional aspects of the electric system: adequacy and security. Adequacy is “the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements” and security is “the ability of the electric system to withstand disturbances such as electric short circuits or unanticipated loss of system elements.”

The notion of security focus on the short term operational aspects of the system which are characterized through contingency analysis and dynamic stability assessments. Security is provided by protection devices and operation standards and procedures that include security constrained (N-1/N-2 constraints) economic dispatch and the requirement for so called ancillary services such as: voltage/reactive power support, AGC/frequency control, spinning and un-spinning operational reserves, etc. In real industry practice, especially by the northeastern Independent System Operators (ISO) like ISO-New England, such requirements are enforce by Reserve Adequacy Accessment (RAA) procedure to commit additional capacity for various security reasons. Such practices tend to depress the real time price signal. The notion of adequacy on the other hand represents the systems ability to meet demand on a longer time scale basis, considering 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 traditionally measured in terms of the amounts of planning and operable reserves in the system and the corresponding loss of load probabilities (LOLP) that served as criteria for planning and investment decisions.

However, there is no scientific consensus whether the liberalized electricity market under the current northeast model can be expected to produce adequate capacity level s on a continuous basis. On the contrary, several recent studies show that there may be a capacity shortage in almost all ISOs in the next five years and ISO New England (ISO-NE) estimates that they are missing over $2 billion generation capital costs recovery per year (Cramton and Stoft, 2006). This thesis research is intended to identify the generation resource adequacy problem, evaluate the current solutions and solve the problem by both improving the short-term energy market/ancillary service market dispatch mechanism so that the prices reflect the real time supply and demand conditions and by introducing centralized long-term markets to reduce short-term price volatility and restore the missing money.

2. The Resource Adequacy (RA) Problem

The generation planning in the regulated industry (Ilic et al, 1998) is typically done by a vertically integrated electric utility that is responsible for generation, transmission and distribution of electricity. The utility has an exclusive franchise right for certain defined geographic area and also has an obligation to provide electricity to any and all customers within the area at a certain level of reliability. For a monopolistic electric utility, the obligation to provide a reliable service implies an obligation to build new generation and transmission capacity necessary to meet the expected demand growth and recover all the costs through the electricity rates determined by Public Utility Commission (PUC). This ability to recover all "prudently incurred" costs within a regulated return on equity effectively protects the utility from many business risks facing a competitive enterprise. Thus, investors are willing to accept the relatively low returns on the new investments in exchange for low exposure to risks. On the other hand, the guaranteed rate-of-return regulation also protects the utility from the full consequences of bad investments and this may lead to the over building of generation and transmission capacity, which sometimes referred to as a "gold plating" problem since the more capacities the utilities build, the more incomes they receive. Another concern with guaranteed rate-of-return is that there is no direct incentive for technical innovations.

These concerns, among others, have led to the arguments for the introduction of competitive electricity markets.

2.1 RA problem in Economic Wonderland

In a perfectly competitive electricity market, RA should not be a problem (Oren 2005). There are three scenarios with regards to supply and demand conditions in the energy-only markets such as the original California design, Nordpool and the Australian Victoria pool. Firstly, when supply can intersect with demand curve (energy offer and necessary operating reserve requirement), the price will be set by marginal cost of the last unit meeting the demand. The infra-marginal units will get a profit margin while marginal unit will not get any profits. Secondly, when demand curve and supply curve do not intersect with each other but total capacity is still within the maximum and minimum limits of demand curve, the price at such hours are determined by the last consumer's willingness to pay expressed in the demand bids by price-responsive customers when the demand quantity equals maximum supply capacity assuming it is viable to obtain such demand response curve in short-term market. All units will get a scarcity rent and infra-marginal units will also get additional profits margin. Finally, when demand curve and supply curve do not intersect with each other and demand quantity is smaller than the minimum quantity of demand curve, the rotating blackout operating procedure will be activated by ISO and the prices at such hours are determined by the Value of Lost Load (VOLL) which reflects the cost to society of involuntary curtailments.

The optimal investments in generation capacity and the optimal technology mix is achieved in a long-term equilibrium that reflect supply and demand choices for reliability and cost. Economic theory tells us that such optimal capacity is determined by last peaking unit that all the profits occurred to this marginal unit during all the above three cases will exactly cover its capital cost. When the capacity is smaller than the optimal, the additional profits in the markets will attract new entry and/or generation expansion. On the other hand when the current system capacity is bigger than the optimal, the excess capacity will lose money and result in early retirement or mothballing of plants which will reduce capacity and drive prices back. Fig. 1 below illustrates the above argument.

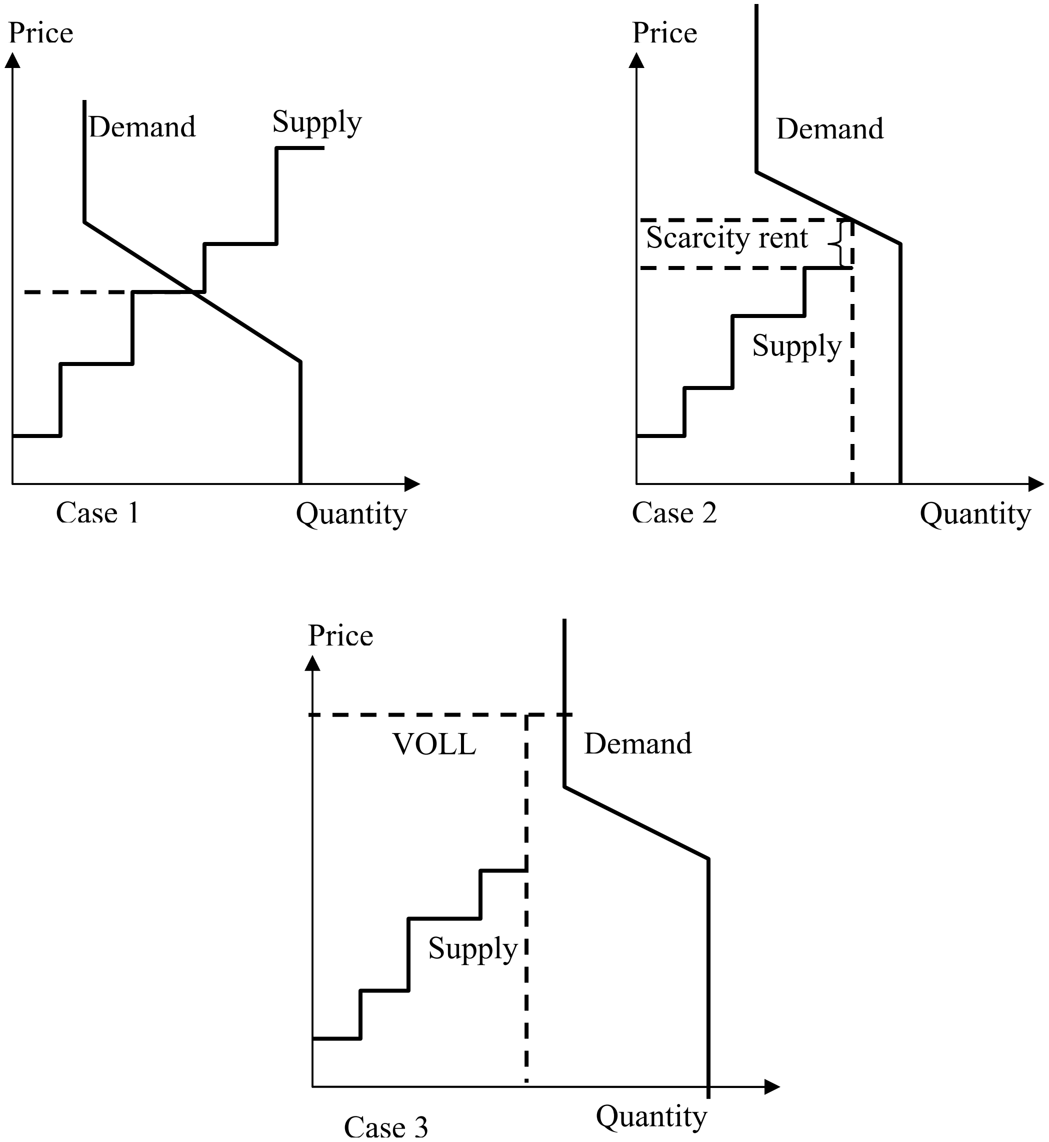

Fig. 1: Recovery of generation cost in ideal energy only markets

2.2 RA Problem in Reality

However, in reality the RA problem does exist. In the last decade many of the merchant generating companies made new investments almost all in combined-cycle (CC) gas turbine technology based on low natural gas predictions. The rising natural gas prices caused serious financial problems and several went bankrupt. As a result, the average credit rating of merchant project financing by agencies like Standard and Poor's dropped to the sub-investment grade, BB+ and below, which is an important threshold for many investors whose prime consideration is not social benefits like lower electricity costs and greater reliability but return on the money (Krellenstein 2004). Project financing for new generating plants is difficult to arrange unless there is a long term sales contract with a creditworthy buyer to support it. The quantity of new generating capacity coming out of the construction pipeline is falling significantly (see Table 1, EIA 2006). Very little investment in new merchant generating capacity is being committed at the present time, aside from wind and other renewables that can obtain favorable tax credits and other financial incentives. As of January 2005, the generation capacities under construction are 3 MW, 3700MW and 1800MW in ISO New England, NYISO and PJM respectively (Joskow 2005c).

Table 1: U.S. Generation Capacity Added (1997-2005)

YEAR	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*
CAPACITY ADDED (MW)	4,000	6,500	10,500	23,500	48,000	55,000	50,000	20,000	15,000

Numerous analyses by ISOs in Northeast indicate that energy and ancillary services markets do not appear to generate enough net revenues to support a new combustion turbine peaking plant with the administrative reliability criteria that are still applicable in that region. Table 2-4 (PJM 2006) shows the net revenues that a hypothetical new combustion turbine (CT), combined cycle (CC) and pulverized coal (CP) would have earned from the energy market, capacity market and ancillary services markets in PJM if it were dispatched optimally to reflect its marginal running costs in each year 1999-2005. Based on current markets structure and engineering practice, it would not be rational for an investor to investment in any technology since the average total revenues would have been significantly less than the fixed costs alone.

Table 2: New entrant gas-fired CT: Theoretical net revenue for calendar years 1999 to 2005

	energy	*capacity*	*ancillary*	**total**
1999	$62,065	$16,677	$2,248	$80,990
2000	$16,476	$20,200	$2,248	$38,924
2001	$39,269	$30,960	$2,248	$72,477
2002	$23,232	$11,516	$2,248	$36,996
2003	$12,154	$5,554	$2,248	$19,956
2004	$8,063	$5,376	$2,248	$15,687
2005	$15,741	$2,048	$2,248	$20,037
average	$25,286	$13,190	$2,248	$40,724
annualized fixed cost				$72,207

Table 3: New entrant gas-fired CC: Theoretical net revenue for calendar years 1999 to 2005

	energy	*capacity*	*ancillary*	**total**
1999	$89,600	$16,999	$3,155	$109,754
2000	$42,647	$19,643	$3,155	$65,445
2001	$68,949	$29,309	$3,155	$101,413
2002	$51,639	$10,492	$3,155	$65,286
2003	$50,346	$5,281	$3,155	$58,782
2004	$49,600	$5,241	$3,155	$57,996
2005	$68,308	$2,054	$3,155	$73,517
average	$60,156	$12,717	$3,155	$76,028
annualized fixed cost				$93,549

Table 4: New entrant gas-fired CT: Theoretical net revenue for calendar years 1999 to 2005

	energy	*capacity*	*ancillary*	**total**
1999	$101,011	$17,798	$7,288	$126,097
2000	$112,202	$20,755	$5,184	$138,141
2001	$106,866	$30,862	$3,048	$140,776
2002	$101,345	$11,493	$3,810	$116,648
2003	$166,540	$5,688	$3,910	$176,138
2004	$136,280	$5,537	$3,091	$144,908
2005	$232,351	$2,100	$3,419	$237,870
average	$136,656	$13,462	$4,250	$154,368
annualized fixed cost				$208,247

This phenomenon is not unique to PJM. Every organized market in the U.S. exhibits a similar gap between net revenues produced by energy markets and the fixed costs of investing in new capacity measured over several years time (Joskow 2006).

2.3 The Causes

As described in (Joskow and Tirole 2005a; Joskow and Tirole 2005b), the causes of the resource adequacy problem are two-folded. First, the various market regulations and engineering reliability practices which have not been harmonized with economic incentives and tend to depress the spot market price:

- Price caps in energy/ancillary service markets
- Price caps in capacity markets
- Marginal cost based market power mitigation methods adopted by ISOs
- Actions by ISOs that have the effect of keeping prices from rising fast enough and high enough to reflect the VOLL or scarcity price during operating reserve

emergencies when small changes in system operating procedures can lead to very large changes in prices and scarcity rents needed to cover fixed costs

  - call on emergency imports/cancel scheduled exports
  - call interruptible load contracts
  - reduce reserve margin requirement
  - overload transmission facilities
  - relax the frequency/voltage requirement
  - shed firm load

- Reliability actions taken by ISOs that rely on Out-of-Merit (OOM) calls on generators that pay some generators premium prices but depress the market prices paid to other suppliers

ISOs perform the so-called Reserve Adequacy Access (RAA) after clearing the Day-ahead market (DAM) in order to ensure that there is sufficient capacity available to meet the forecasted Real-Time (RT) demand, operating reserves requirements including 10 minutes and 30 minutes spinning and un-spinning reserves and replacement reserves and various system reliability and security constraints. The reliability and security constraints include:

- Voltage control during light load periods
- Special Constraint Resource request by Satellite, Transmission Owner
- 1st line contingency for local and import congested area
- Reliability Must Run to meet 2nd line/generator contingency in an import area
- Regulation Requirement
- System Operating Reserve Requirement

If insufficient capacity is scheduled in the DAM, RAA process will commit additional OOM units to meet ISO-NE system, congestion, and/or local area requirements. The effects of flagging additional OOM units in the RAA process tend to reduce the RT market price (Fig. 2). For detailed discussion, please refer to Appendix A.

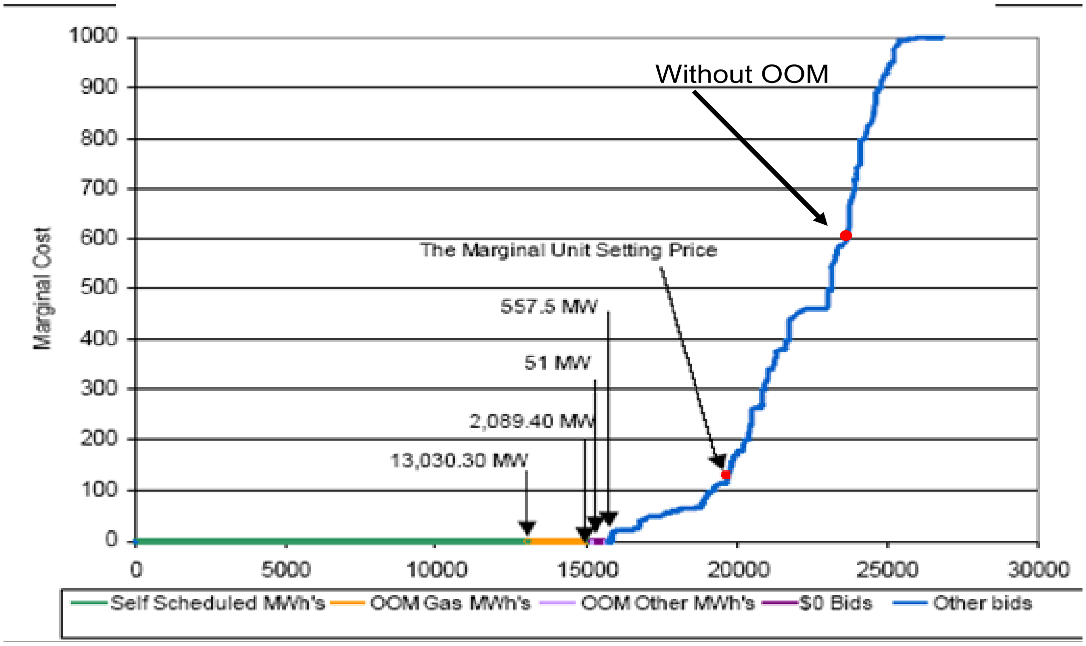

Fig. 2: OOM units depress the price (ISO-NE, 2004)

Secondly, the market imperfections also systematically lead organized wholesale energy markets to produce inadequate incentives for new investment, especial the demand-side flaws. Such imperfections include:

- Absence of adequate spot market demand response to allow prices to play a larger role in balancing supply and demand under tight supply conditions
- No real-time metering and billing/pricing
- No devices to cut off given loads from the network like price-controlled circuit breakers even if the loads are price-sensitive

2.4 The Core of RA Problem

The core of RA problem is risk sharing between different parties. In regulated industry, consumers take all the risks of generation expanding and the producers take zero risks after PUC approved the plan because of guaranteed rate-of-return. In liberalized electricity markets, the risks of new generation investment shift to the other end of spectrum. The investors bear all the risks. Due to the non-storability of electricity and the instantaneous balance of supply and demand at every second, the price and revenue volatility/uncertainties under the current spot market setup are too huge for generation companies and investors to take. How to distribute the risks fairly between different parties and align their economic incentives and desire to reduce risk with system's the short-term and long-term social welfare is the key to the problem.

Missing money (Cramton and Stoft 2006) is another important exhibition of the problem. But the solution for missing money requires better market designs which provide good risk management tools to dampen the boom-bust investment cycles and improve the stability of power systems.

3. The Literature Review of Solutions

Basically, there are two schools of thinking to solve the problem: the energy markets based energy-only approach and explicit capacity market based centralized administrative approach. They both have benefits and flaws.

3.1 The Energy-only Approach

Chao and Wilson (2004) address the resource adequacy problem with the option-portfolio approach. In particular, they propose an annual auction of a specified quantity of multi-year option contracts at each strike price in a specified range. Each contract is an option on physical capacity since it requires the supplier to back the contract with available capacity, to submit a standing bid at the ISO for the contracted quantity at a price no higher than the strike price, and to be dispatchable for either energy or reserve capacity. Thus, even though the option contracts might be tradable in secondary markets, they are not solely financial instruments. Three theorems are demonstrated through a simple market model that (1) supplier's with more option contracts exercise less market power (2) without a requirement to buy options, suppliers will buy none and (3) consumers will be better off with an option requirement. However the paper does not address how to ensure the resource adequacy through the option-portfolios.

Oren (2005) also proposes a long-term supply contracts in the form of call option with premiums that depend on the contracts' strike prices (see Fig. 3). The value of call option at a certain strike price is determined by expected average prices during the hours when price is higher than the strike. Unless the price cap in spot markets is removed, the value of options would not reinstate the missing money to ensure adequate capacity.

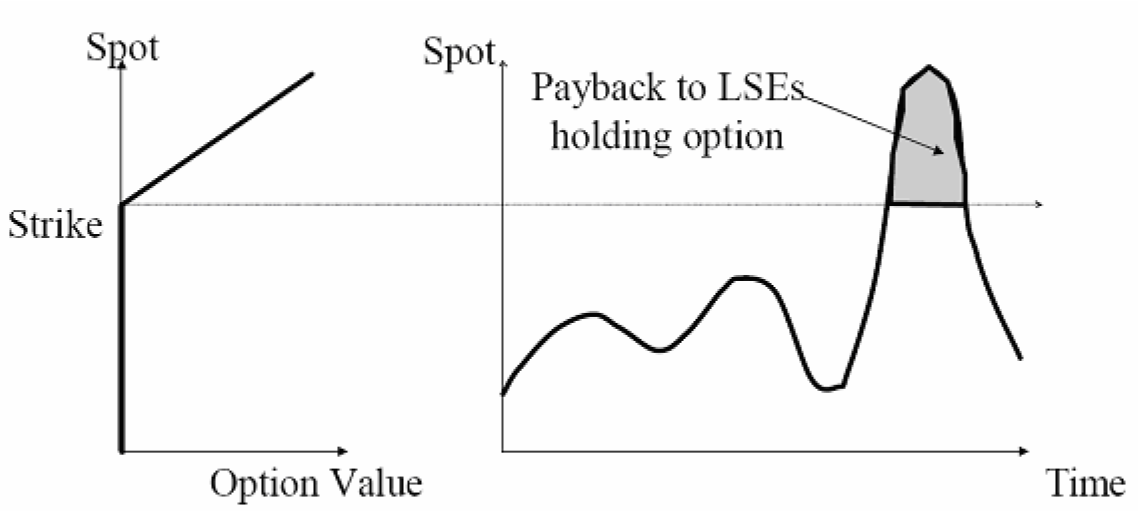

Fig. 3: Call options (Oren, 2005)

The above two approaches are good risk management and market power suppression tools. In order for them to work, the underlying asset of the options should reflect the true value described in the ideal economic model in section 2.1. However, due to the market imperfections and ISOs' reliability practices, the ideal model is still in economic wonderland.

Hogan (2005) presents an illustrative energy plus reserve demand curve model. The curve is controlled by three parameters: price cap $10,000/MWh, and two operating reserve parameters of 3% and 7% (Fig. 4). These parameters are determined not by the market but by a central administrator. This demand curve is not set by consumers or LSEs but predetermined by ISOs. A small change in these parameters may result in big changes in terms of money and in addition decide how many new capacities are needed. Although Hogan argues that a capacity market approach would overturn the electricity market while an energy-only approach could and should leave major economic decisions surrounding investment to be voluntarily arranged by the parties, this proposal still can not avoid administrative demand curves.

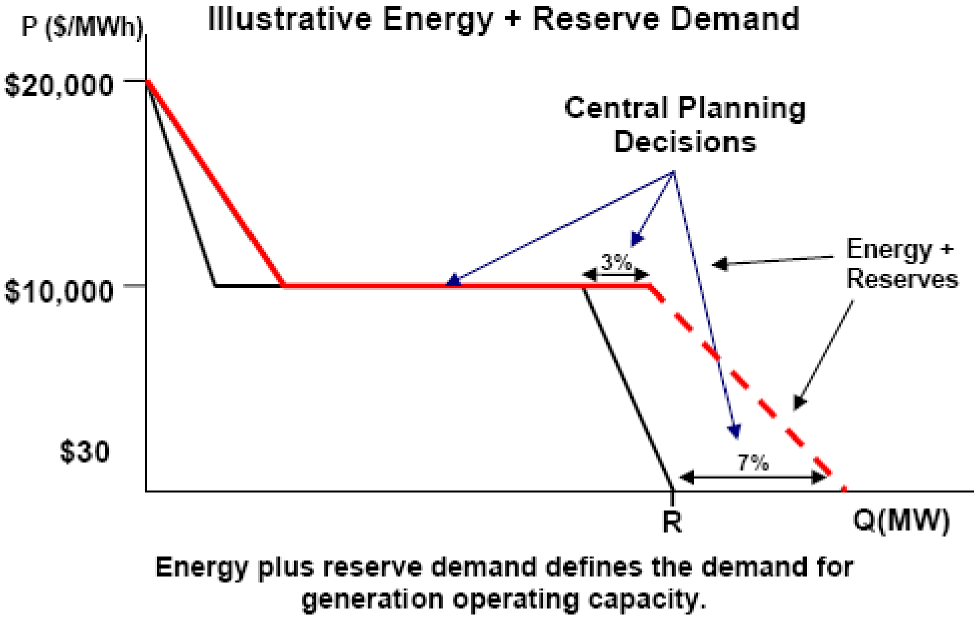

Fig. 4: Energy plus reserve demand curve (Hogan 2005)

3.2 Capacity Markets Approach

Another way to ensure resource adequacy is to let ISOs forecast and select the “appropriate” level of capacity and the load serving entities (LSEs) are required to buy its share so that the total capacity purchased equals the forecasted adequacy target. When current installed capacity would not meet the forecasted peak load and operating reserve requirement, the capacity price ($/MW-year) will be set by the annualized fixed cost of the cheapest new entry that could meet the administrative requirement. When current installed capacity exceeds the forecasted target, the price will fall to zero and the system would not attract any new investment assuming no market power in the capacity markets. The underlying argument beneath this approach is that there are two products in the electricity markets: energy and reliability. Energy should be settled on the spot market to ensure the short-term efficiency while the reliability should be achieved through capacity market design.

Currently every ISO in Northeast has an operational installed capacity market (ICAP). However, due to the following reasons, they have worked poorly.

- The markets only cover one month or half a year, which is too short to encourage new investment.

- Price caps are too low
- As a result, the prices fluctuate between zero during the off-peak months and price cap during the peak months
- The ICAP revenue is far less than the annualized fixed cost.

ISO New England also proposes a locational installed capacity market (LICAP) to solve the problem (Fig. 5). However, similar to Hogan's proposal for reserve demand curve, ISO-NE basically administrates a demand curve for capacity payment in each reliability zone based on the annualized capacity costs of a new natural gas fired CC unit and other operating reserve parameters. All the LSEs are required to pay the capacity payment based on ISO's peak load forecast. This is not a capacity market but a compulsive capacity payment requirement set by ISO.

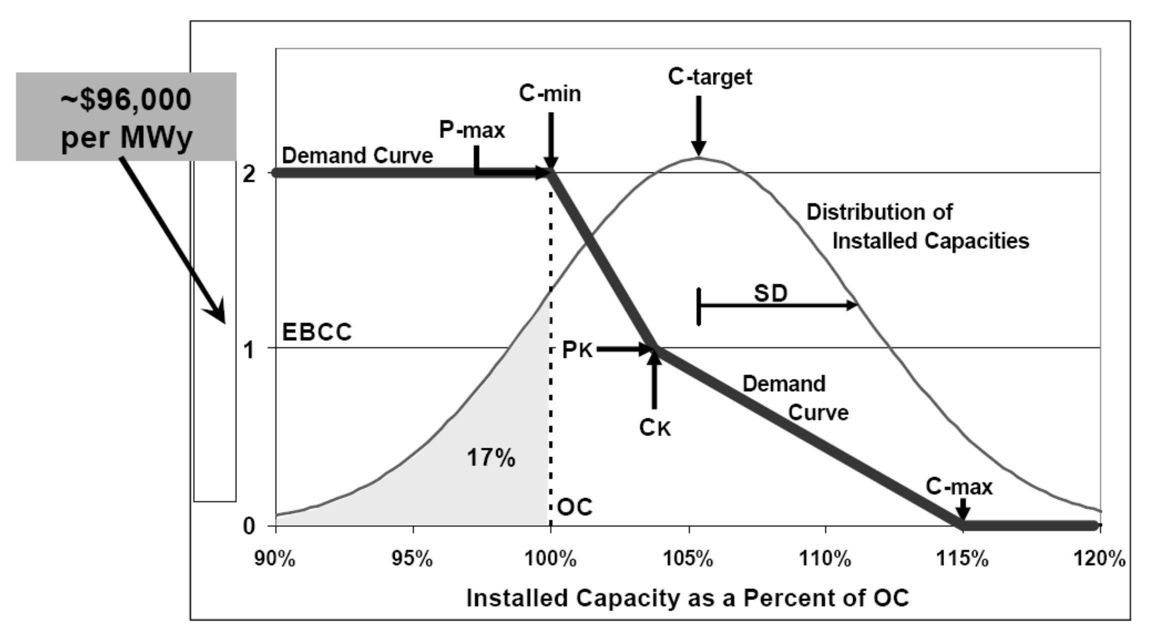

Fig. 5: ISO-NE's proposed LICAP

PJM is now considering a another capacity market called Reliability Pricing Model which is long-term ICAP with 3-5 lead time and lasting for 3-5 years. This improved design averts several problems in ICAP. However, as every explicit capacity obligation approach, it does not deal with the risk sharing problem and relies on the accuracy of ISO's capacity prediction. If ISO over-forecasted the peak load, LSEs and end users would bear the risk of overbuilding and Gencos would bear the risk of lower spot energy market payment. If ISO under-forecasted the peak load, LSEs and end users would bear the risk of high energy market prices during the reserve deficiency hours and Gencos would bear the risk of lower capacity market payment. So the decision maker does not bear the consequence.

A summary of key elements of different approaches are listed below (Cramton and Stoft 2006).

Table 5: Comparison between different approaches

	Administrative Reliability Targeting	*Missing Money Recovery*	*Contract Type*	*Spot Market Incentives*
Energy-Only Approaches				
Oren: call options	No	No if price cap still exists	Physical	Yes
Chao-Wilson: call options	No	No if price cap still exists	Physical	Yes
Hogan/MISO	Yes	Yes	Financial	Yes
Capacity Markets Approaches				
ICAP	Yes	Yes	Physical	No
LICAP	Yes	Yes	Physical	No
PJM RPM	Yes	Yes	Physical	No

4. Short-term Spot Market Improvements

The “resource adequacy” problems arising from imperfections in spot energy markets are now widely recognized by policymakers. FERC’s proposed SMD rules contained requirements that system operators implement mechanisms to assure resource adequacy. As demonstrated above, a lot of efforts are being made to reform capacity obligations or energy-only based mechanisms in long-term. However, since the causes of RA problem is dichotomal, in the paper we try to propose a hybrid solution, which deals with not only to reform short-term spot energy markets to allow prices to rise to appropriate competitive levels and to better harmonize reliability rules and reliability actions taken by system operators with market mechanisms but also a centralized sequentially cleared long-term energy contract markets ranging from five years ahead till monthly ahead. In this section we focus on the spot market improvements.

4.1 OOM Units

ISO needs to assure adequate resources for a variety of reliability and security reasons like voltage support, N-1 and N-2 contingencies, system-wide operating reserves and other constraints. All these constraints lead to committing additional more expensive generators that are OOM at times during the day, especially in the import constrained regions (load pockets). For example, in ISO-NE these units are defined as (ISO-NE 2005):

1. Special Constraint Resource generators are committed to meet a requirement on the low voltage network that is not visible to the ISO. These commitments are made at the request of the local transmission owner.
2. Generators are committed to provide reactive power to control voltage during light-load periods when voltage on the 345 kV network can increase to unacceptable levels.
3. Generators are committed to meet first transmission-line contingency requirements for local or import-congested areas.
4. Reliability Must Run generating units are committed specifically to meet the second transmission-line or second generator contingency in import-congested areas.
5. Generators are committed to meet the system wide spinning reserve requirement when the Day-Ahead Energy Market and supplemental real-time commitment do not provide sufficient spinning capability to meet the real-time requirement.
6. Generators are committed to meet the system wide regulation requirement when the Day- Ahead Energy Market and supplemental real-time commitment do not provide sufficient regulating capability to meet the real-time requirement.
7. Generators are committed to meet the system wide operating-reserve requirement when the Day-Ahead Energy Market and supplemental real-time commitment do not provide sufficient capacity to meet the real-time requirement.

The required OOM generators do not earn enough revenues in the energy market to cover startup, no-load cost, and cost to run at economic minimum (EconMin), which then require extra reliability-related payments (Uplifts). Moreover, generation committed OOM will depress locational marginal energy prices (LMP), reducing energy revenues for the "economic" generators in the load pocket. Depending on the types of uplifts, they are paid by customers in the load pocket or socialized by all the customers eventually and these payments become a significant unhedgable unpredictable expense. Theoretically marginal cost pricing leads to economically efficient prices in ideal economic world when cost curves are convex. When costs are non-convex, marginal cost pricing no longer efficient. Startup costs, minimum run times, no-load costs, and other factors addressed in the unit commitment decision create non-convex cost curves.

4.2 Potential Solutions

There are many potential solutions to this uplift costs, such as increasing transmission import limits; adding flexible generation in the import constrained areas; and well designed ancillary service market to give appropriate investment incentives. This proposal explores changes in market operations that will improve marginal price signals and reduce OOM related reliability costs. The objectives of these improvements are

- Calculate LMPs that are not depressed by OOM units in load pockets and more closely reflect efficient marginal cost pricing including the externality of reliability and security requirements
- Reduced uplifts
- Incentive compatibility. Attracting appropriate levels of investment on right technology in the right locations

The main idea is to let the OOM units which operate at EconMin be able to set the LMPs instead of depress them. This can be done by imposing additional the maximum power flow limits on the import constrained area. For example, suppose the demand in a load pocket is 200MW and there are three generators G1-G3 within the area whose EconMin and EconMax are all 10MW and 100MW and bidding prices are \$50/MWh, \$80/MWh, \$100MWh respectively. For reliability reasons, G2 has to be turned on. Then the max power flow into the area should be set at 90MW so that G2 is able to set the price at \$80/MWh while G1 outputs at EconMax.

4.3 An Example

To demonstrate the implications of such rule change, a simple two bus system example is illustrated here.

Fig. 6: Two bus system demostration

At bus1 there is a cheap generator G1 whose EconMin and EconMax are 0 and 210MW. The bidding price is $50/MWh and demand at bus1 L1 is 100MW. At bus2 there is an expensive generator G2 whose EconMin and EconMax are 10 and 100MW. The bidding price is $100/MWh and demand at bus2 L2 is 100MW. Assuming the transmission line constraint is 100MW. Then the economic dispatch solution should be G1 at 200MW, G2 at 0MW, LMP1 equals LMP2 at $50/MWh. Power flow from bus1 to bus2 is 100MW.

Let's say Voltage support at bus2 requires G2 has to be turned on. Then under current operating rules, G2 will be flagged as a must run unit during the RAA process. The solution is G2 at 10MW, G1 at 190MW. LMP1 and LMP2 both are $50/MWh and power flow from bus1 to bus2 is 90MW. The transmission line is not binding. Since G2 is OOM, there is uplift. Assuming startup cost= shutdown cost= $100 and minimum run time is one hr, then G2's uplift payment is,

G2's uplifts = $100*10 + 100 + 100 - $50 * 10 = $700

Under our proposal, in order to let G2 set the price, an additional interface limit 90MW is imposed between bus1 and bus2. The economic dispatch solution is G2 at 10MW, G1 at 190MW. LMP1 is $50/MWh and LMP2 is set by G2 at $100/MWh. We still have uplifts caused by startup and shutdown cost, but much smaller. The G2's uplift payment is, Gen2's uplifts = \$100*10 + 100 + 100 - \$100 * 10 = \$200

A comparison of two solutions are shown in Table 6.

Table 6: Solutions comparison of the two bus system

	G1 output (MW)	*G2 output (MW)*	*LMP1 (\$/MWh)*	*LMP2 (\$/MWh)*	*Uplift (\$)*	*Cost of Electricity (\$)*
Current solution	190	10	50	50	700	10,000
Proposed solution	190	10	50	100	200	10,500

Similarly, other types of OOM units can also become marginal units to set the LMP at its location if appropriate additional limits are imposed. The main features of letting OOM units to set the price are

- Let the LMP reflect the true costs of providing electricity including various hidden reliability and security costs
- Preserve Incentive Compatibility and provide right price signal for new investment in reserve constrained area

Other spot market improvements may include

- Encourage demand response program
- Remove the price cap
- Well designed reserve markets that provide payment not only to the generators who produce energy but also reserves

5. Stratum Electricity Market (SEM)

As the second part of the hybrid solution to the RA problem, a centralized sequentially cleared long-term energy forward markets, Stratum Electricity Market, are introduced.

5.1 Stratum Electricity Market Structure

As it is shown in the PJM study in section 2.2, the current spot only market structure would not provide sufficient incentives toward new investments for a long-term sustainable power system. Moreover, the ability of financing capacity payments through the volatile ICAP markets and existing ancillary service markets is declining and they are not sufficient to recover capital costs of power plants. New types of long-term markets are needed to fill in the gap.

Our alternative market design focuses on a long-term energy supply rather than on the capacity obligation. The Stratum Energy Market (SEM) structure proposed in this paper is motivated by the lack of transparent liquid long-term energy markets for power trading in current spot market (Wu and Ilic 2005; Wu and Ilic 2006). Although now a big portion power is traded through long-term bilateral contracts, current rules and regulations for such trading are insufficient in terms of their ability to create liquid active trading environment. Consequently, most of the existing forward and futures markets are not transparent, and, therefore, they do not provide the right information for investments.

The SEM structure is a combination of several parallel markets: a series of forward sub-markets with different duration. Forward sub-markets are designed for physical or financial energy trading with periodic bidding and clearing processes on daily, weekly, monthly, seasonal, annual and multi-annual basis. The short-term spot sub-market is designed to balance the residual demands that are not covered in forward markets and the deviations from forecasted the real time loads. The SEM structure resembles ways in which the electric power capacity was planned and used in the regulated industry: large, base-load power plants were built and dispatched to cover big portion of the base load; medium-size plants were turned on and off according to the seasonal variations, and small peaking plants were used to follow short-term high load demands. Fig.7 is an illustration of load partition for various sub-markets within the SEM.

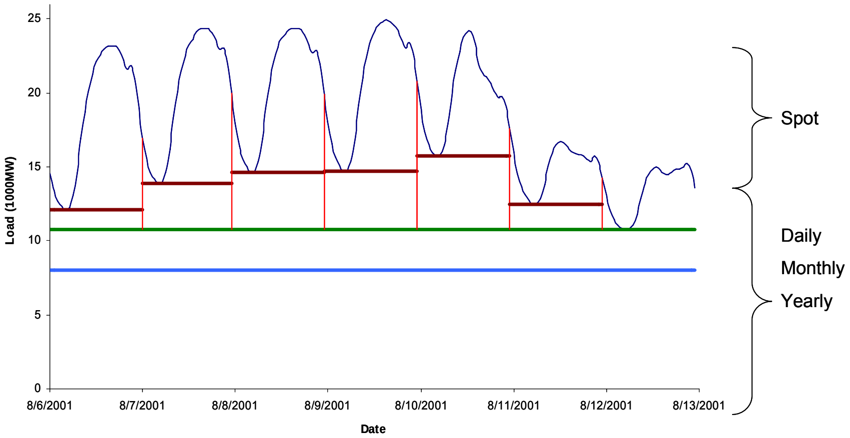

Fig. 7 SEM structure

The forward markets can be subdivided into 5 year ahead, annual, seasonal, monthly, weekly or even daily markets according to the load cycles. All forward markets are cleared sequentially from longer-term to shorter-term. For example, at the end of 2005 an annual forward auction for 2006 would be held and annual forward position and price are determined before January 1st 2006. Then the monthly forward auction for January 2006 would be held successively. The quantity for trading in each forward market can be decided in two ways.

- The administrative approach: ISO uses the forecasted minimum load (or a portion of it) as the demand quantity and require LSEs to acquire their shares.
- The market approach: supply and demand sides can submit bids/offer for the forward markets and the price and quantity are determined by the market.

The forward markets are organized and monitored by ISO. The price in each sub-market is determined by the uniform auction rule: The last offer that meets the demand if supply side opens only or by the equilibrium point of supply and demand if both sides are open. The long-term forward markets are cleared on zonal level instead of nodal level. Simultaneous feasibility tests are enforced to make sure the market solutions are viable. Intra-markets trading are allowed to mitigate the uncertainties. For example, suppose generator A cleared 10 MW in annual market. It can offset its position by buying 10 MW in monthly market.

5.2 Key Features of the SEM Model

- Well-defined products and quality of service. Because of little storage, the values for the same amount of energy at different time and different location are disparate. This is reflected by hourly spot market dynamics. Moreover, for the same hour, the values for the same amount of power at base level or at peak level are different due to the different generation technologies used and other non-convex constraints like unit commitment. The multiple forward submarkets are designed to reflect more realistic demand and supply conditions for different strata.
- Risk management. A good market structure should provide sufficient risk management tools to reduce short-term volatility and hedge against physical and financial uncertainties. Multiple forward markets are perfectly designed instruments to hedge the spot market risks. The consumers and producers could use them to reduce volatility of revenue/payments.
- Means of capital cost recovery. The price of long-term forward contracts is decided by expectation of spot market prices realization plus a risk premium. Along with the spot market design reforms described in section 4 and relaxation of price cap, the long-term prices should provide the missing money to recover the capital costs.
- No administrative demand curves. Unlike LICAP capacity demand curve or Hogan's reserve demand curve, ISO would not administrate the explicit generation capacity or reserve price requirement. The investments are guided by expectations and economic incentives. However, there may be predetermined forward quantities if they are set by the administrative approach.
- Although spot market price may rise above the roof during the peak hours, most of energy has already been settled in forward markets and such high prices will have less impacts on total costs of electricity. It is very important to observe these high prices since they are important market signals to encourage the participation of the long-term risk management instruments.
- Natural solution for unit commitment (UC) constraints. The UC problem (Allen and Wollenberg 1996) is straightforward in the SEM market because the on/off decisions are made implicitly by individual units when they compete in the sub-markets. All the units may easily include startup and shutdown costs into their single bids due to the known hours for each sub-market. Only the units that are within the physical unit

commitment constraints, such as must run hours, minimum startup and shutdown time, can submit their bids into the corresponding forward market. In this way, a system operator need not maintain these constraints explicitly as in a pure spot market.

- Market power may be more efficiently reduced by long-term contracts than by market power mitigation regulations. Although this claim still needs further investigation.
- Long-term contracts may capture the long-term demand elasticity which is higher than short-term.

5.3 Modeling of SEM

In the remainder of this paper we illustrate the models and the decision-making process for assessing long-term electricity market performance with an inelastic stochastic load model, which was introduced by Skantze and Ilic (2000).

5.3.1 A brief review of the stochastic load model

The key characters for electricity demand which we want to capture in the model are: seasonality, mean reversion and stochastic growth. To simplify the problem, weekend loads are eliminated from the model and the load is assumed price inelastic. The daily load is modeled as a 24 hours vector Ld where each row represents an hourly load. This vector is defined as :

$$\vec{L}_d = \vec{\mu}_m + \vec{r}_d$$

where µ m ([24*1] vector) is the monthly average hourly load and the stochastic component rd is the deviation from the monthly mean and it has 24 hourly random variables. However, because of high intra-daily correlations between these hours, we applied Principal Component Analysis (PCA) on rd. Although some information may be lost, PCA enables us to reduce the number of variables. We keep only the first Principle Component (PC) and its associated weight wd. Statistical results show that the first PC could explain more than 90% of the total variance of the demand.

$$\vec{L}_d = \vec{\mu}_m + w_d \vec{v}_m \qquad (1)$$

New vector vm is the new Principle Components in each month m and wd is its daily evolving score, which incorporates all the stochastic uncertainties. We choose a two factor mean reverting model to describe the wd process.

$$
\begin{aligned}
&w_d = \delta_m + e_d \\
&e_{d+1} - e_d = -\alpha e_d + \sigma_m z_d ,\, z_d = N(0,1) \\
&\delta_{m+1} - \delta_m = \kappa + \sigma \ z_m , z_m = N(0,1)
\end{aligned}
\qquad (2)
$$

w_d is represents by the long-term growth component δm and short-term mean-reverse deviation component ed. The δm process characterizes the long-term growth trend with expected value κ and stochastic component σ on a monthly basis. The ed process represents the daily short-term deviation from the monthly mean, which is mean-reverting at the rate α with stochastic component σm. Both stochastic factors are assumed to be normally distributed white noise.

Using the historic hourly load data from 1993 to 2003 from ISO-NE (2003), the parameters [δm α κ σm σ] in the load model can be obtained using the following procedure:

1. Construct a time series vector of scores of the first Principle Component, wd, by applying the PCA to the historic load data. δm is calculated by the monthly average of wd.
2. The mean reversion factor α is determined using linear regression between (wd+1-wd) series and (δm-wd) series.
3. The short-term process stochastic component σm is calculated as standard deviation between the estimated and actual values of wd.
4. The long-term drift parameter κ is calculated from the increase trend of δm.
5. The long-term process stochastic component σ is measured by the standard deviation between the estimated and actual values of δm

After all parameters are calculated, the load model is run 100 times to generate the forecasted load samples used in the simulations. Each series lasts for a 10 year period. The annual average and standard deviation of hourly load are shown in Fig 8 and Fig 9.

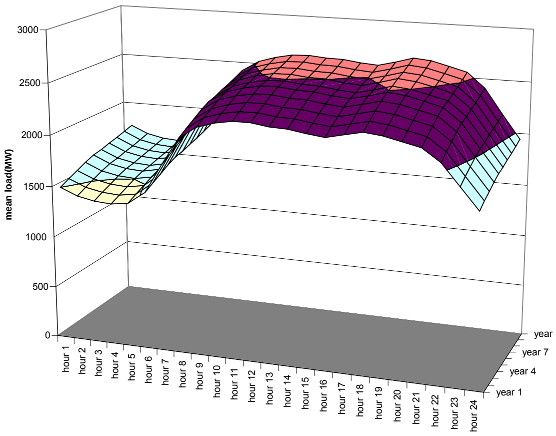

Fig. 8 Annual average of forecasted hourly load

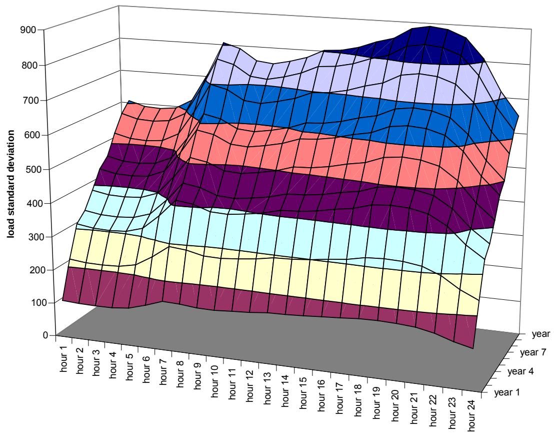

Fig. 9 Annual standard deviation of forecasted hourly load

The average hourly load level is increasing over time. Two daily peaks, the morning peak which reaches at around hour 11 and the evening peak which reaches at hour 19, can be observed in Fig III.1. The standard deviation increases at a much faster pace than the average load on the annual basis. This shows that viewed from year zero, the uncertainties are much higher in the year 10 than year 1.

5.3.2 Fuel price forecast and generator characteristics

For illustrative purposes, a reduced generation fleet based on generation characteristics in the IEEE Reliability Test System (1996) and fuel price projections from the EIA (2005) are used in simulations. Generator and fuel characteristics obtained from these sources are summarized in Tables 6 and 7, respectively. The nuclear unit variable cost is assumed as $0.4/MWh.

Since the EIA fuel cost are based on the last year's data, the gas price prediction is relatively low. In order to illustrate the effects of high gas prices on the electricity market, a high gas price is constructed. For this case, the price is assumed starting at $10/MMBtu with a 2% annual increase. Two fuel price forecasts, low gas profile and high gas profile, are both used in the simulations. The short term marginal cost (STMC) can be defined as:

STMC=Heatrate*Fuel price+ Variable O&M

The long-run marginal cost can be defined as:

LRMC=STMC+ Annualized Capitcal Cost

TABLE 7
FUEL PRICE FORECASTS

Year	Coal ($/1000btu)	Low Gas ($/1000btu)	Oil ($/1000btu)	High Gas ($/1000btu)
1	1.29	5.27	5.36	10.00
2	1.28	4.83	4.96	10.21
3	1.28	4.50	4.77	10.41
4	1.27	4.39	4.61	10.63
5	1.25	4.27	4.55	10.85
6	1.24	4.31	4.58	11.07
7	1.24	4.41	4.60	11.29
8	1.24	4.54	4.66	11.53
9	1.23	4.70	4.71	11.76
10	1.23	4.81	4.77	12.00

TABLE 8
GENERATOR TECHNOLOGY CHARACTERISTICS

unit #	Unit Type	Capacity (MW)	Capital cost ($/KW)	Varible O&M ($/MWh)	Heatrate (MMbtu/kw)
1	Nuclear	800	3000	10	--
2	Coal	600	1200	5	9.501
3	Coal	600	1200	5	9.504
4	Gas	300	500	10	6.501
5	Gas	300	500	10	6.504
6	Gas	300	500	10	6.507
7	Oil	200	350	10	9.501
8	Oil	200	350	10	9.504
Total	--	3300	--	--	--

5.3.3 Assumptions and simulation methods

Two market structures are investigated in this paper. The hourly spot market where price is set by the offer of the last unit that meets the demand at each hour and the newly proposed SEM model. Transmission network constraints are neglected.

Two kinds of decision makers, central planner (ISO/RTO) and individual generator, are both explored in the paper. The evaluation period for new investment decision is set for the next 10 years. At the beginning of year one, decision makers try to make their optimal investment decisions for given scenarios.

To simplify the problem, several assumptions are made throughout the simulations:

1. Two submarkets for SEM setup: hourly spot market and long-term annual market.
2. Bidding strategies: In spot only market generators submit their short term marginal costs (STMC). In SEM setup, generators submit their full capacity at the long run marginal costs (LRMC) for long-term markets and then submit the left over capacity at short run marginal costs (SRMC) for spot markets.
3. Simple linear cost function is adopted and marginal cost is a scalar.
4. Auction quantity for long-term markets set by minimum annual forecast.

To simulate the new capacity expansion results in different scenarios, Monte Carlo technique are adopted. Since the only uncertainty in the simplified problem comes from the load, for a given load forecast series and fuel price profile, a deterministic nonlinear optimization problem can be solved by simulations. The average and standard deviation of all the deterministic results are calculated as final results.

5.3.4 Scenarios under investigation

All together six scenarios are studies in this paper. The only decision variables are the new capacity investment of the generator i in the system kim.

Scenario 1 Central min cost. In this setup, a system planner (ISO) makes coordinated investment decisions for all units facing the uncertain demand in the future under a spot market only setup.

The problem can be posed as an optimization problem with the system-wide objective of minimizing the total expected cost. Total cost includes production cost, investment cost and blackout cost. Blackout hour variable at hour n un is defined as 1 if system demand is larger than total capacity and 0 otherwise.

$$u^n = \begin{cases} 0, \sum_i K_i^m \geq L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

The blackout cost in this industry structure is defined as the social costs of the value of lost load (VOLL). The VOLL is calculated as the product of total demand and the penalty factor μblackout, which is set at $1000/MWh in the simulations.

$$VOLL^n = D^n \mu_{blackout}$$

The objective function of central planner can be represented as following:

$$\min_{(k_i^m),1\leq i\leq G,1\leq m\leq M} \mathrm{E}(\sum_i \sum_{m=1}^{M} e^{-\rho mTm} (\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n} (\underbrace{(1-u^n)\sum_i STMC_i^n(P_i^n)}_{\text{short-term production costs}} + \underbrace{u^n VOLL^n}_{\text{blackout costs}}) + \underbrace{\mathrm{CC}_{\mathrm{i}}^{\mathrm{m}}(K_i^m)}_{\text{long-term capital costs}}))$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum_i K_i^m \geq L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

(d) ISO economic dispatch process for hour n:

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

$$\forall u^n = 0 \begin{cases} \min\limits_{P_i^n} \sum\limits_i STMC_i^n(P_i^n) \\ s.t. \sum\limits_i P_i^n = L^n : \lambda^n \\ P_i^n \le K_i^m \end{cases}$$

Scenario 2 Central min revenue. Central planner makes coordinated investment decisions in spot only market to minimize total costs of electricity to consumers, investment costs and blackout costs. The costs of electricity to consumers are determined by the hourly spot market clearing prices.

The objective function of ISO can be represented as follows:

$$\min_{(k_i^m),1\le i\le G,1\le m\le M} \mathrm{E}(\sum_i \sum_{m=1}^{M} e^{-\rho mTm} (\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n} (\underbrace{\lambda_i^n P_i^n}_{\text{short-term production costs}} - \underbrace{u^n VOLL^n}_{\text{blackout costs}} - \underbrace{\mathrm{CC}_{\mathrm{i}}^{\mathrm{m}}(k_i^m)}_{\text{long-term capital costs}}))$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum\limits_i K_i^m \ge L^n \\ 1, \sum\limits_i K_i^m < L^n \end{cases}$$

(d) ISO economic dispatch process for hour n:

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

$$\forall u^n = 0 \begin{cases} \min\limits_{P_i^n} \sum\limits_i STMC_i^n(P_i^n) \\ s.t. \sum\limits_i P_i^n = L^n : \lambda^n \\ P_i^n \le K_i^m \end{cases}$$

Scenario 3 Spot. Generators make their own investment decisions in spot market only setup to maximize their expected profits. The profits are defined as total revenue minus total production cost, investment cost and possible blackout costs. Here we assume

ISO may introduce a market rule to charge individual generators if there is a blackout due to the resource inadequacy. The blackout costs are defined as the product of total capacity Kim and the penalty factor μblackout, which is set at $1000/MWh in the simulations.

$$BC_i^n = K_i^m \mu_{blackout}$$

To test the effect of such rule, two cases with or without such rule, SpotA and SpotB respectively, are both simulated. The SpotA case is illustrate as an example in the following model. Furthermore, we make the assumption that each generator make their own decision assuming the others would not expand at all.

The objective function of generator i can be expressed as

$$\max_{(k_i^m),1\le m\le M} \mathrm{E}(\sum_{m=1}^{M} e^{-\rho mTm}(\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n}((1-u^n)(\underbrace{\lambda^n P_i^n}_{\text{short-term revenue}} - \underbrace{STMC_i^m(P_i^n)}_{\text{short-term production costs}}) - \underbrace{u^n BC_i^n}_{\text{blackout costs}}) \text{ - } \underbrace{\mathrm{CC}_\mathrm{i}^\mathrm{m}(K_i^m)}_{\text{long-term capital costs}}))$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum_i K_i^m \ge L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

(d) ISO economic dispatch process for hour n:

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

$$\forall u^n = 0 \begin{cases} \min_{P_j^n} \sum_j STMC_j^n(P_j^n) \\ s.t. \sum_j P_j^n = L^n : \lambda^n \\ P_j^n \le K_j^m \end{cases}$$

Scenario 4 Stratum. In this scenario generators make their own investment decisions in the newly proposed SEM market to maximize their expected profits. The profits are defined as total revenue from both long-term and short-term markets minus total production cost, investment cost and possible blackout costs. Similar to Scenario 3, we also introduce a market rule to charge the individual generators if there is a blackout due to the resource inadequacy. The blackout costs are defined as the product of total capacity Kim and the penalty factor μblackout, which is set at $1000/MWh in the simulations.

$$BC_i^n = K_i^m \mu_{blackout}$$

To test the effect of such rule, two cases with or without such rule, StratumA and StratumB respectively, are both simulated. We use StratumA case as an example in the following problem description. Furthermore, we make the assumption that each generator make their own decision assuming the others would not expand at all.

The objective function for generator i can be expressed as:

$$\max_{(k_i^m),1\le m\le M} \mathrm{E}(\sum_{m=1}^{M} e^{-\rho mTm}(\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n}(\underbrace{\lambda_i^m P_i^m}_{\text{long-term revenue}} + \underbrace{\lambda_i^n P_i^n}_{\text{short-term revenue}} - \underbrace{(1-u^n)STMC_i^n(P_i^m + P_i^n)}_{\text{short-term production costs}} - \underbrace{u^n BC_i^n}_{\text{blackout costs}}) - \underbrace{\mathrm{CC}_{\mathrm{i}}^{\mathrm{m}}(k_i^m)}_{\text{long-term capital costs}}))$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum_i K_i^m \ge L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

(d) The auction quantity. The load demand for long-term market in year m Dm is determined by the minimum load level within that year for a given load forecast series and the remaining load belongs to the load demand to be supplied by the short-term market Dn.

$$D^m = \min(L^n), n \in [(m-1)Tm, mTm]$$

$$D^n = L^n - D^m, n \in [(m-1)Tm, mTm]$$

(e1) ISO economic dispatch process for long-term market at year m assuming current capacity will cover the long-term market demand Dm:

$$\min_{P_j^n} \sum_j LRMC_j^m(P_j^m)$$

$$s.t. \sum_j P_j^m = D^m : \lambda^m$$

$$P_j^m \le K_j^m$$

(e2) ISO economic dispatch process for short-term market at hour n:

$$\forall u^n = 0 \begin{cases} \min\limits_{P_j^n} \sum\limits_j STMC_j^n(P_j^n) \\ s.t. \sum\limits_j P_j^n = D^n : \lambda^n \\ P_j^n \le K_j^m \end{cases}$$

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

Scenario 5. Repeated spot. In this case new market rules are introduced to allow information gathering by those making investment decisions about what the others intend to do. This is done iteratively as follows:

1) Each generator makes optimal investment decisions assuming the some initial values of the others' decisions. The decision making process is the same as in SpotA. Here we set the initial value to zero.

2) The market maker will publish the market clearing prices and quantities of every unit at the end of each bidding round r. Then from these results each unit could estimate the optimal expansion decisions made by the others for round r, $\bar{k}_{i,r}^m$.

3) Using the $\bar{k}_{i,r}^m$ as the updated decisions about the others, each unit re-evaluates the expansion problem and chooses its updated best response $k_{i,r+1}^m$ for round (r+1). If the difference of decision variables between round n and (n+1) is smaller than some value ε, iteration stops and it is assumed that the bidding process had reached the market equilibrium. Otherwise, the process is repeated starting from Step 2).

Scenario 6. Repeated stratum. In this case new market rules are introduced to allow repeated bidding and results feedback on top of the scenario stratumA setup. The iteration follows the same logic as in Scenario 5.

5.3.5 Preliminary Results

Altogether, eight scenarios are simulated. The results under low gas price forecast are shown in Figures 10-13. The resulting generator investment decisions for this case are shown in Fig 10. The resulting market attributes of interest, such as costs and revenues, are shown in Fig 11. The expected average electricity prices and associated standard deviations are shown in Fig 12. The expected average blackout hours and associated standard deviations are shown in Fig 13.

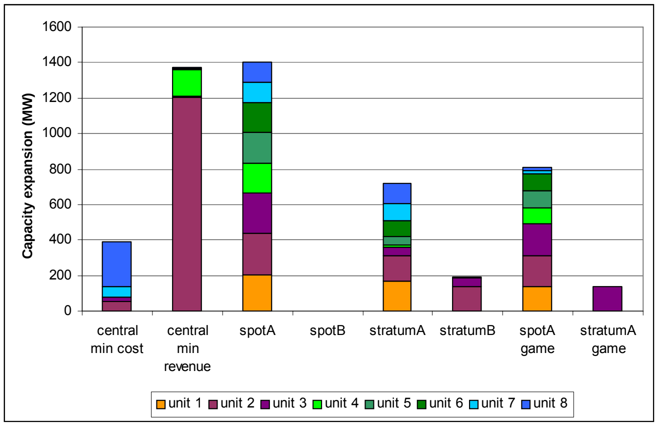

Fig. 10 Generation capacity expansion under low gas price profile

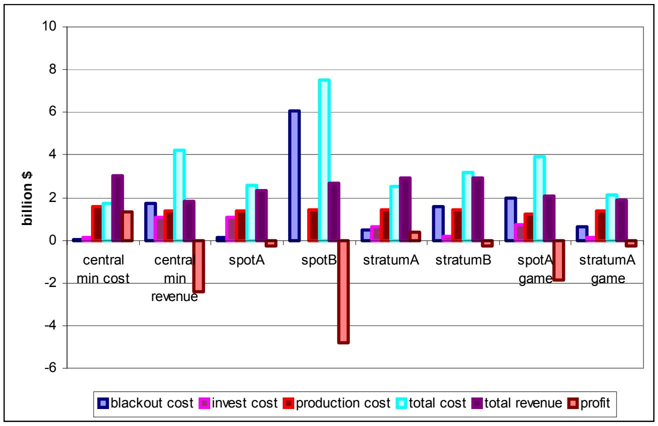

Fig. 11 Revenue, production costs and profits under low gas price profi

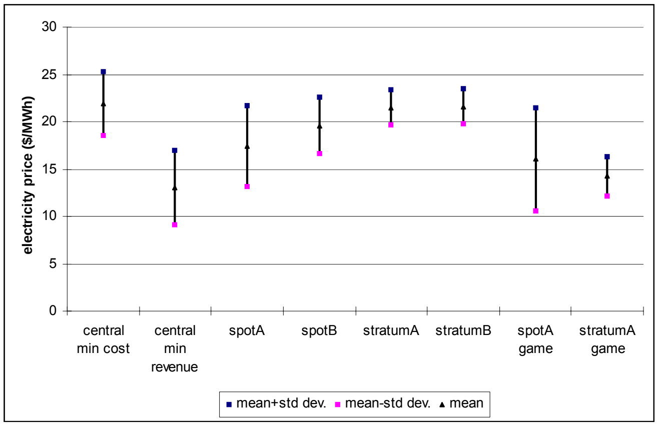

Fig. 12 Average and standard deviation of electricity price under low gas price profile

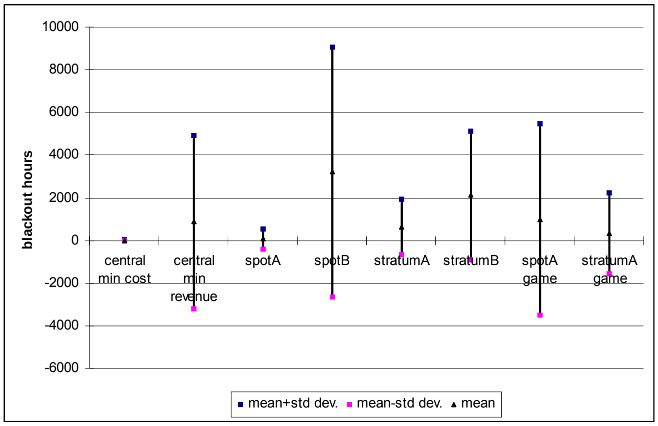

Fig. 13 Average and standard deviation of blackout hours under low gas price profile

It can be concluded based on these simulations that if the investment decisions are made by a coordinating planner like ISO, the results are very sensitive to the objective chosen by the ISO. As shown in Fig IV.1, if the objective is to minimize total costs of electricity generation (central min cost), more peak-load generators should be built, which would lead to a higher market price. On the other hand more base-load generators should be built if the objective is to minimize total electricity charges to the consumers (central min revenue). If the decisions are left to generators themselves, market structure and market rules will affect results dramatically. In particular, the blackout cost rule has a substantial effect. No one would expand anything in spot only market with no blackout costs charge in place (SpotB) since they would never recover the investment; a much larger investment decision is made when considering the blackout cost (SpotA). As expected, a market rule explicitly charging market participants for lack of service may encourage more investments to avoid a bigger loss even under low fuel price profile. Similar effect can be drawn for the SEM structure.

However, the solution under spot market only setup is not sustainable since generators would lose money no matter whether they invest or not. Under the SEM setup, generators can make reasonable profits if the blackout rule is applied and the average electricity prices are much less volatile comparing to the spot market only setup. The gaming between generators will reduce the investment immensely for both market structures, which will jeopardize generator’s financial viability and expose the system to higher blackout risks. This can be seen by comparing the corresponding scenarios with and without the repeated bidding.

The simulation results under the high gas price forecast are shown in Fig 14-17.

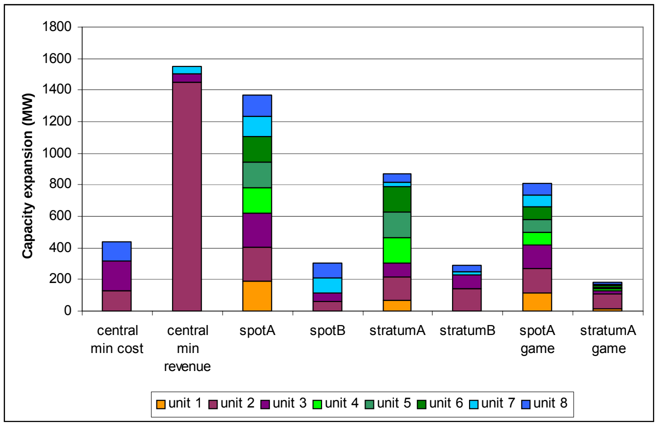

Fig. 14 Generation capacity expansion under high gas price profile

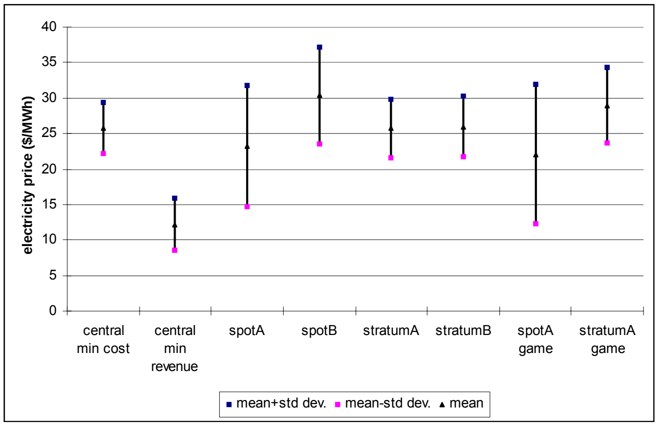

Fig. 16 Average and standard deviation of electricity price under high gas profile

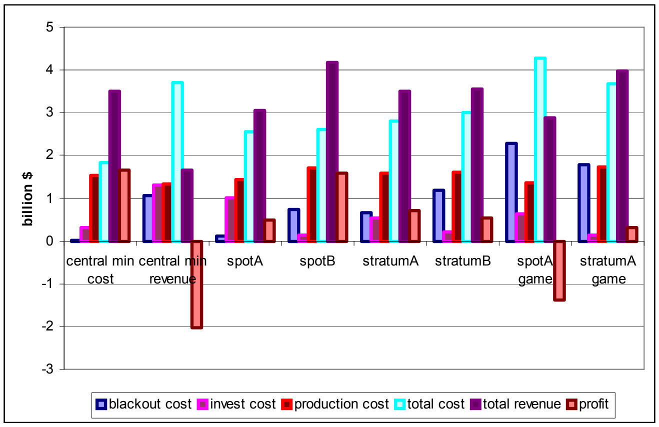

Fig. 15 Revenue, production costs and profits under high gas price profile

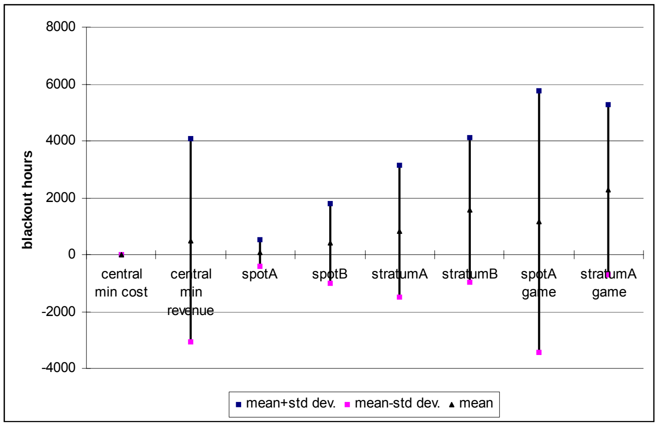

Fig. 17 Average and standard deviation of blackout hours under high gas price profile

The basic results remain the same under high gas price profile as in the case of low gas price scenarios. Different goal of central planners and market makers may lead to different results; in particular, the blackout risk sharing with generator will encourage more investments in both scenarios. The SEM structure will lead to smaller price volatility and gaming between players will always decrease the investment and increase the blackout risks. However, generators will continue to make good profits under most scenarios and the results are sustainable if the high fuel price continues into the future.

5.4 Future Research Works

The investment problem in physical electricity generation assets can be treated as an example of a more general asset investment and valuation problem. The conventional method of asset valuation is the net present value (NPV) approach described. However, when considering long-term forward markets, other risk management decision criteria should also be investigated.

The second approach is based on the mean-variance criteria. The firm can define its risk preference by stating its utility in terms of the tradeoff between the expectation and variance of the future return on the investment. Given the risk preference r of each firm, the investment option with the highest mean-variance utility would be chosen.

$$U(\sum_t \psi_t) = E\{\sum_t \psi_t\} - r \times Var\{\sum_t \psi_t\}$$

The third approach is based on concept of value-at-risk (VAR). VAR estimates the amount of the capital at risk of being lost during a given period of time. Capital is defined to be at risk if the probability of loss is greater than a threshold acceptable by the management (Holton 2003).

$$\begin{aligned} & Max(E\{\sum_t \psi_t\}) \\ & s.t. \Pr ob(\sum_t \psi_t \le V) \le x\% \end{aligned}$$

Further research concerns in the following areas are still under investigation.

1. Incorporating price-sensitive consumers into the demand model.
2. Developing stochastic fuel price model.
3. Studying more complicated bidding strategies and their inter-dependence within the markets.

4. Simulating and comparing with other energy-only and capacity market proposals
5. Including the network constraints.

5.5 Some Discussions

5.5.1 Why not capacity market?

First, the targeted capacity with sufficient reserve margin set by ISOs may not guarantee reliable operation in electric system. As shown by the ISO-NE capacity suppliers (Cramton and Stoft 2006) in Fig 18, the operating reserve shortage hours which lead to price spikes do not correlate with capacity surplus levels. In addition, ISO's forecast may not be accurate and the producers and consumers have to bear the risk of forecast error. And the price volatility may still be very high in spot market if no forward hedging mechanisms are adopted.

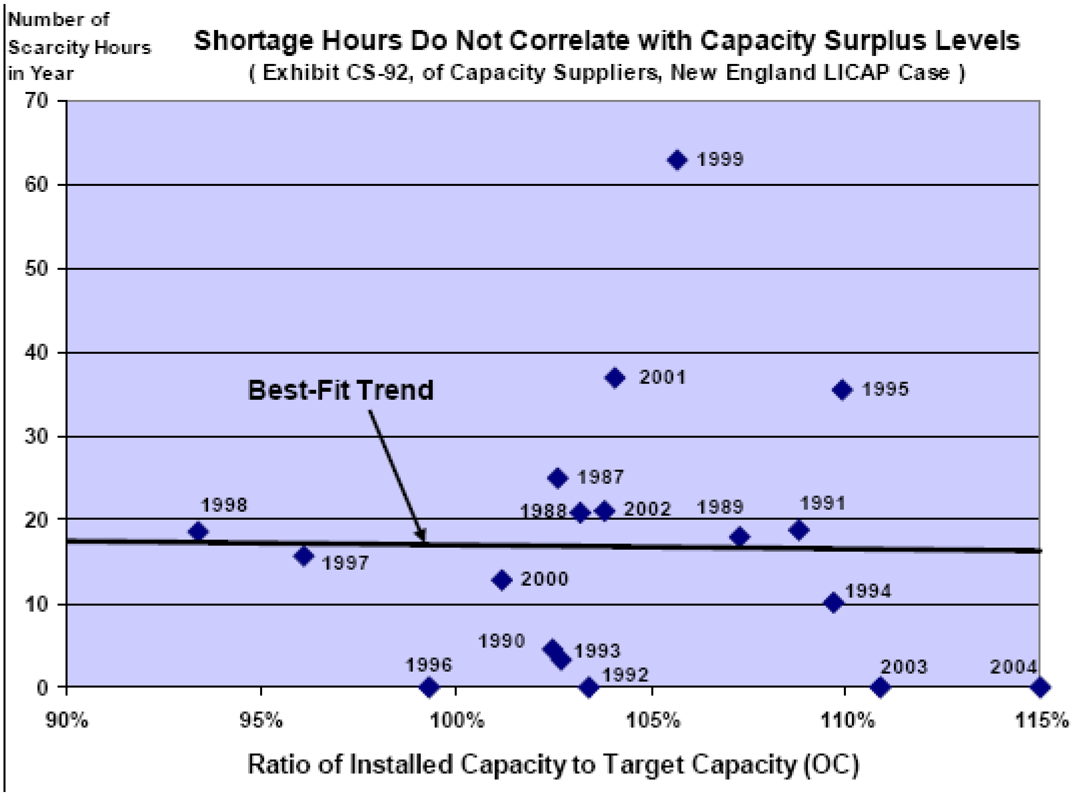

Fig. 18 ISO-NE Capacity Suppliers Exhibit CS-92 (Cramton and Stoft 2006)

5.5.2 Why sequential clearing of long-term markets?

Different LSEs/Gencos has individual risk preference within different time frames, so this portfolio of sequentially cleared long-term markets will fine tune the needs of both supply and demand sides as uncertainties unveil (Fig. 19).

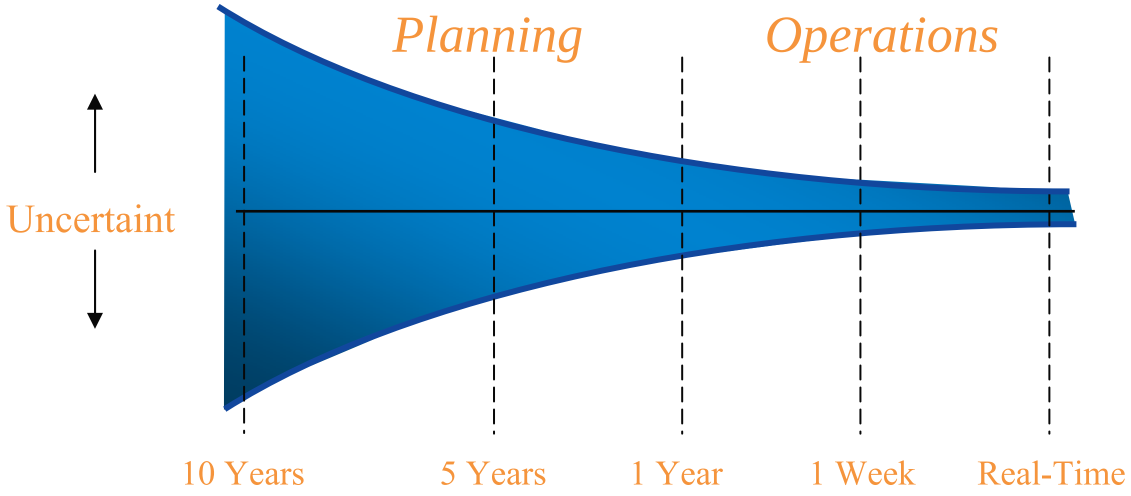

Fig. 19 Uncertainty as a function of time frames

5.5.3 Are long-term contracts physical or financial?

They are physical in a sense that the offers must be based on real physical generation assets. They are financial obligation in a sense that you can cancel your position in the higher stratum. For example you sell X MW in annual market but in month Y you need to do maintenance, then you can notify ISO and buy back the same X MW in monthly market to cancel out your position.

5.5.4 What about the contradictions between optimal solutions in different markets?

As demands and time frames approach to real time, the security constrained economic dispatch solutions in more recent market may contradict with the ones in the earlier long term market. To avoid such inconsistency, the previously settled position in long-term market will be flagged as must run quantity in the more recent market so that the new solution will always satisfy the previous solutions.

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Appendix A: the broad impact of daily reliability commitments on the markets

The broad impact of daily RMR commitments on the market is to generally depress the market marginal clearing price (ISO-NE, 2005).

Reliability commitment in the DAM can at times offset other generators that would have been committed had the ISO not intervened via the reliability commitment. When the generator committed for reliability is "in merit" and would have been committed by the software, the impact to the market is minimal or zero. When the generator committed for reliability is not "in merit" and would not have been committed by the software, it displaces the commitment of other economic generators.

Generally, if a reliability commitment is "in merit" it has little or no impact on the DAM, and if a reliability commitment is not "in merit" it can impact generator commitment and tends to reduce DA LMP.

Reliability commitment in the Real-Time Market can at times have significant impact on the LMP whether or not the generator is "in merit" based on its 3-part offer and operating characteristics.

The key indicator for Real-Time impact is whether or not the DAM generator commitment schedules meet the hourly Real-Time system-wide capacity requirements (ISO demand + 10MSR + 10MNSR + 30MR + ReplRes).

If the DAM solution meets the system-wide capacity requirement but does not meet the reliability requirements (sub-area voltage, local transmission, RMR, SCR) then additional generators will be committed for Real-Time operations. This supplemental reliability commitment will tend to reduce the RT LMP in the following two ways; (1) If they are not "in merit" they will operate at EcoMin output and will displace output from generators committed in the DAM thus reducing RT LMP and (2) If they are "in merit" they will operate above their EcoMin and further displace output from generators committed in the DAM, and reducing RT LMP.

If the DAM solution does not meet the Real-Time system-wide capacity requirements and does not meet the reliability requirements, the impact on the Market of reliability commitment tends to be reduced. When the two sets of requirements are not met by the DAM solution the ISO commits to meet the reliability requirements first. This is done as the generators that are committed to meet the reliability requirement can also meet the system-wide capacity requirement, thus minimizing the total supplemental capacity commitment. If the generators are not “in merit” they will operate at EcoMin output. To the extent the sum of the generators’ EcoMin output does not meet the difference between the cleared DA demand and the Real-Time demand, the RT LMP will be greater than the DA LMP. If the sum of the EcoMin output exceeds the difference between the DA cleared demand and the Real-Time demand, the RT LMP will be less than the DA LMP.