Stratum Electricity Markets: Toward Multi-temporal Distributed Risk Management for Sustainable Electricity Provision

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Prepared by
Zhiyong (Richard) Wu

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Carnegie Mellon University
Pittsburgh, PA 15213

Abstract

Motivated by the overall challenge of ensuring long-term sustainable electricity service, we view this challenge as a long-term decision making problem under uncertainties.

We start by recognizing that, independent of the industry organization, the uncertainties are enormous and often exogenous to the energy service providers. They are multi-dimensional and are result of fundamental drivers, ranging from the supply side, through the demand side, to the regulatory and policy sides. The basic contribution of this thesis comes from the recognition that long-term investments for ensuring reliable and stable electricity service critically depend on how these uncertainties are perceived, valued and managed by the different stakeholders within the complex industry organization such as the electric power industry. We explain several reasons why price signals obtained from current short-term electricity markets alone are not sufficient enough for long-term sustainable provision. Some enhancements are presented in the thesis to improve the short-term electricity market price signals to reflect the true cost of operation.

New market mechanisms and instruments are needed to facilitate the stakeholders to better deal with long-term risks. The problems of ensuring long-term stable reliable service in the sense of the traditional resource adequacy requirements are revisited in both the restructuring industry and regulated industry. We introduce a so-called Stratum Electricity Market (SEM) design as the basic market mechanism for solving the problem of long-term reliable electricity service through a series of interactive multi-lateral market exchange platforms for risks communication, management and evaluations over various time horizons and by the different groups of stakeholders. In other words, our proposed SEM is a basic IT-enabled framework for the decision making processes by various parties over different time. Because of the uniqueness of electricity as a commodity, the values for the same amount of energy during different time and at different location can vary dramatically. Moreover, for the same hour, the values for the same amount of power at base load level or at peak load level are different due to the different generation

technologies and other non-convex constraints like unit commitment. The multiple market products at zonal/nodal levels with different time horizon and time of use categories are designed to reflect more realistic demand and supply conditions at various temporal and spatial granularities. Detailed market rules, rights and regulations (3Rs) concerning the sub-markets interactions, product hierarchy and financial settlements are also examined.

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1. Introduction

This thesis is motivated by the challenges underlying sustainable long-term electricity provision in a reliable, efficient and environmentally responsible way. Long-term reliable electric energy provision is essential to the healthy economy and the national security. It is also essential to the basic means of modern living. However, this problem is inherently difficult to solve as it requires decision making under major uncertainties spanning a long time horizon. Notably, sources of the uncertainties are multifold, rooted from not only the supply side and demand side but also the public policies domains from regulatory agencies. These decisions and associated system outcomes depend on how the risks associated with these uncertainties are perceived, valued and managed by various involved stakeholders. We stress that the fundamental distinction between different regulatory and market solutions to the long-term electricity provision ultimately revolves around the risk management rules and implementations of these rules by the concerned parties. Some of the important questions are who are bearing the major risks, what are their expected returns and under what assumptions, and whether the risks could be hedged through various market and regulatory instruments. While much effort has gone into designing short-term electricity markets (day-ahead and shorter), the industry restructuring has fallen short of designing transparent mechanisms for managing long-term risks at value. This thesis attempts to begin to fill this void by introducing systematic mechanism for managing long-term risks.

One of the reasons that makes the problem of long-term reliable electricity service provision unique relative to other service industries is the complexity of underlying electric power systems. The power system is the most complex interconnected physical system in the world. Unlike other commodities, electric power has some unique characteristics, i.e. lack of cost-effective ways for large storage and the need to balance supply and demand instantaneously. It has been recognized only recently by the regulatory bodies that one must value different technologies with respect to the rate at which they can response to the changes of underlying system conditions (FERC, 2011). Accurate valuation of such temporally-differentiated products requires very careful regulatory and/or market design that accounts for real time supply-demand balancing.

Such level of temporal accounting is highly unusual in typical commodity markets. In other words, the value of storage must be appreciated with respect to the time over which it is available. In the well-established literature concerning the value of inventories, it is not necessary to account for multi-temporal aspects of storage. While the objective of this thesis is not to value storage, we point out that decision making for ensuring long-term reliability services inherently depends on how power is balanced in near real-time. Therefore, we propose that in order to value the contributions of qualitatively different technologies to ensure long-term reliable service and, at the same time, experience minimal real time service interruptions, incentives must be introduced to distribute risks over different stakeholders and over various future time horizons efficiently. As we review today's operating and planning practices, we recognize that improvements must be made in regulatory rules and/or market designs to account for the inherent risks and their financial implications across different generation technologies over short-, medium- and long-term time horizon.

The reliable electricity service is also subject to various spatial and environmental externalities. In particular, power delivery is subject to the underlying transmission and delivery system. Today's electricity markets take into consideration of short-term network constraints in day-ahead and real-time markets, and, to a lesser extent, medium-term network constraints in the long term Financial Transmission Rights markets. However, detailed full network models with thousands of commercial pricing nodes which are adopted in today's short-term markets may not be suitable for long-term forward markets. The right balance needs to be struck between specific network constraint details and promotion of market liquidity. Moreover, new transmission investments are not valued in sync with the long-term generation investments. Most of the long-term transmission projects are still studied under the traditional transmission planning frameworks without adequate consideration of their market impacts. We point out that much the same way as generation planning must be done for long-term reliable service at value, transmission must be built keeping in mind its long-term societal values and values to various stakeholders. The design of regulatory and/or market mechanisms for enabling valuation of transmission investments with respect to long-term benefits they may bring is suggested as the topic for future research.

There are also other relevant externalities, notably on the environmental impacts. Much the same way as generation investments, these externalities should be viewed as an integral part of value-based long-term reliable electricity service. The value of emissions allowance needed to be internalized to the system end users, both consumers and producers, as they make their long-term electricity purchase decisions. One of the approach to integrate the emission constraints with the energy services is by co–designing longer-term electricity and emissions markets. The design of market mechanisms to value the effects of long-term transmission and emissions constraints on attributes of long-term electricity services could be pursued as a direct outgrowth of the stratum market proposed in this thesis.

Another important question concerning the long-term reliability provision is how to safeguard the system against the fat-tail events of abnormal equipment breakdowns. There are two qualitatively different ways of approaching this problem. The first would put the burden of ensuring the long-term reliability standards on the service providers. A simplified approach would be to penalize the providers when such criterion is violated. However, in this case penalties must reflect the opportunity cost of not investing into expensive stand-by equipment and/or inefficient equipment utilization to ensure that the users are served despite such low probability high impact failures. Alternatively, different rates for electricity services could be put in place depending on whether the system is in normal operation or in an abnormal condition. For all practical purposes, today's electricity markets only reflect the value of technologies during vastly different load patterns (Kurlinski, 2008). There are no explicit incentives to the service providers and to the energy users to value service differently during major equipment failures. In this thesis we recognize the need for insurance-like mechanisms during major equipment failures. However, the thesis has the much more narrow objective of posing the problem of resource adequacy as the risk management problem against the basic risk of hard-to-predict demand during normal operations only. The simplified approach of penalty prices considering the value of lost load is introduced as a set of market rules. Future generalizations of this problem accounting for variety of other risks are possible. Our problem formulation does stress that due to the capital intensiveness and long construction time of new power generation and transmission projects, merchant generation/transmission companies and/or public utilities face large risks when they try to make long-term investment decisions. The inability to invest and provide new capacity in response to short-term signals only comes in part from the delays associated with building these large projects. The recent focus toward smaller-scale power plants, i.e. distributed generation technologies, may change qualitatively the time required to implement and recover investment costs. One possible solution to enabling vastly diverse technologies to manage their risks is our proposed Stratum Electricity Market. Basically, different generators should be treated differently on the market place according to their own unique characteristics. The technologies which take longer to build and need longer time to recover cost must be evaluated over much longer future time horizons than the smaller-scale less expensive technologies.

1.1 Summary of Thesis Contributions

Motivated by the overall challenge of ensuring long-term sustainable electricity service, we view this challenge as a long-term decision making problem under uncertainties. We start by recognizing that, independent of the industry organization, the long-term uncertainties are large and often exogenous to the energy service providers. They are multi-dimensional and are the result of fundamental drivers, ranging from the supply side (fuel availability and price, technology innovations, renewable resources), through the demand side (macro-economic outlook, impact of plug-in electricity cars and demand response programs), to the regulatory and policy sides (greenhouse gas emission rules, transmission cost allocation methodology). Historically, the innovation dynamics has been by and large exogenous and driven by government policy incentives. In particular, the most recent push for renewable generation technologies is mainly driven by the policy makers and technology developers outside the traditional energy service providers. Also, new technologies for managing power grids, such as smart grid, may qualitatively change the way we operate the system, and, consequently, affect the amount of generation and reserve capacities deemed adequate.

The basic contribution of this thesis comes from the recognition that long-term investments for ensuring reliable and stable electricity service depend critically on how these medium- and long-term uncertainties are perceived, valued and managed by the different stakeholders within the complex industry organization such as the electric power industry. New market mechanisms and instruments are needed to facilitate the stakeholders to better deal with such risks.

In order to support this claim we review in Chapter 2 the notion of reliable electricity service according to today's industry operating and planning standards. The problems of ensuring long-term stable reliable service in the sense of the traditional resource adequacy requirements are revisited in both the restructuring industry and regulated industry. We point out the sharp contrast between achieving resource adequacy in theoretical conditions and the challenges under actual electricity markets operations. In Chapter 3 we explain several reasons why price signals obtained from short-term electricity markets alone are not sufficient for the long-term sustainable provision of electricity. In short, they are significantly related to the difficulties in aligning ideal short-run marginal cost (SRMC) signals with the actual cost of operating the system in a long run according to today's engineering practices, regulatory standards and market conditions. The challenge of implementing efficient short-term electricity markets has been grossly under-estimated at the early stages of electricity market design worldwide, despite some very early warnings by engineers that these effects are not second order effects (Graves, 1993). Some relatively straight forward enhancements are presented in the thesis to improve the short-term electricity market price signals to reflect the true cost of operation.

Perhaps the most difficult challenge in providing long-term reliable and efficient electricity services comes from the lack of innovations on technological solutions and market instruments that allow the stakeholders to manage the long-term risks effectively. Much progress has been made recently toward both in the context of specific technologies. What is missing is a framework for assessing different technological and regulatory solutions with respect to their effects on long-term social welfare as well as on the utilities of individual participants. This thesis is an attempt to formalize one possible framework for posing the long-term reliability problem as a problem of multi-level interactive decision making problem by different stakeholders working to manage their inherent risks. The subject is very complex and much work remains to be done. It is our hope that the thesis contributes to the overall recognition that in today's age of Information Technology much can be done to communicate risks and willingness to manage risk through transparent and liquid market mechanism over multiple time horizons and over different groups of stakeholders.

After further describing the problem in Chapter 2 and visiting the traditional resource adequacy problem in Chapter 3, in Chapter 4 we extend the concept of sustainable long -term electricity provision to incorporate the engineering, economic, financial and environmental attributes. The performance metrics which can be used to evaluate the performance of different regulatory and market solutions in terms of meeting the sustainability objectives are established accordingly. We conclude that the current structures under both the regulated industry and the short-term electricity markets are incomplete and insufficient to manage the long-term risks in a way that provides the right incentives to ensure sustainable services. It is with the above overall objective in mind that we introduce a "Stratum Electricity Market" (SEM) design as the basic market mechanism for solving the problem of long-term reliable electricity service through a series of interactive multi-lateral market exchange platforms for risks communication, management and evaluations over various time horizons and by the different groups of stakeholders. Our proposed SEM is a basic IT-enabled framework for the decision making processes by various parties over different time. The values for the same amount of energy during different time and at different location can vary dramatically. Moreover, for the same hour, the values for the same amount of power at base load level or at peak load level are different due to the different generation technologies and other non-convex constraints like unit commitment. The multiple market products at zonal/nodal levels with different time horizon and time of use categories are designed to reflect more realistic demand and supply conditions at various temporal and spatial granularities. Detailed market rules, rights and regulations (3Rs) concerning the sub-markets interactions, product hierarchy and financial settlements are also examined.

In Chapters 5, we assess the performance of various market designs including the newly proposed SEM in terms of resource adequacy, i.e. new investments on generation capacity. Of particular interests are monetary incentives for inducing near-optimal capacity by means of longer-term market mechanisms. We also investigate how these new investment decisions affect the economic performance of individual players and the long-run social welfare of the system as a whole. By having an overall SEM framework in mind, it becomes possible to understand the underlying assumptions made in different existing designs and to ultimately propose the solutions that is capable of managing risk at well-understood and perhaps predictable long-term performance. Only relative comparisons are possible, since the absolute benchmark would require assuming perfect information, no economies of scale and no delays in building new assets. Detailed models of the decision-making process for individual market participants as well as the ISO market clearing process under spot-only market and the newly proposed SEM markets are presented.

In chapter 5, bidding strategies are assumed to be based on Short Run Marginal Costs and Long Run Marginal Costs. The objective function of the optimization problem is also the expected value based on Net Present Value methodology, which does not account for the long-term value at risk. The decision making processes of individual market participants in both the short-term spot energy market and the long-term forward markets under the proposed SEM structure are reexamined in the chapter 6 and 7. The spot market is modeled as a bilevel non-cooperative game with the consideration of strategic bidding behaviors from market participants. A generic method to reach the possible Nash Equilibrium solutions is illustrated through iterative learning process. A closed form solution of a pure strategy Nash Equilibrium under certain simplifications is also presented here. The decision making process in the long-term forward markets is formulated based on mean-variance criteria which maximizes not only the expected future profits but also the associated risks (variance) of those future earnings. The market equilibrium argument is adopted to derive the optimal forward hedging positions and market clearing prices for long-term markets. Possible implications of such hedging activities are discussed.

Classic microeconomics theory tells us that the social welfare maximization can be obtained at the market equilibrium when the supply curve intersects the demand curve. In this thesis, a new social utility measurement is proposed in chapter 7 as the criteria to evaluate the performance of different market structures, including the proposed SEMs. We expand the traditional concept by introducing the Long-Term Social Utility (LTSU) which considers both the expected value and variance of social welfare in a longer period of time. The new criteria are based on the similar mean variance concept in the long-term forward market decision making process: maximizing the expected value of social welfare and minimizing its variance over a long-run. By minimizing the variance of social welfare, we assume the society as a whole values stability and depreciate volatility.

We observe that the very notion of reliability takes on a qualitatively different meaning depending on the industry rules for managing risks and available technologies to implement those rules. Planning for new resources cannot be done without taking into consideration how these assets are expected to be utilized in short-term as well as long-term time frames. How much new generation would be needed also depends on both short- and long-term demand for electricity and the willingness of demand side to adjust in response to system signals. For example, the amount of highly flexible fast-responding generation will depend on the predictability of intermittent resources and the scale of their penetration. Similar examples range across all the existing and emerging generation, delivery and consumption technologies. Any meaningful framing of the problem given these complexities must take into consideration the effects of temporal and spatial aggregations. Such aggregations could take place by different stakeholders ranging across utilities, competitive energy service providers and/or system operators themselves. Some risks could be managed by demand side aggregations of many often small users and by supply side portfolio optimization of different generation technologies.

SEM is one proposal to give stakeholders the opportunity to reveal their willingness and to provide the actual mechanisms for managing the risks which are created by aggregators and decision makers within the complex electricity service supply chain. In theory, risks are best managed by those who have better knowledge about the future. In the electricity industry, such knowledge is distributed across many different stakeholders. The SEM serves as a platform for various participants to interact and adjust their portfolio according to their own risk perception as time goes on and more information becomes available.

We close in Chapter 8 by discussing the policy implications of SEM. Given that today's measurement of market power in the spot market is classified as any bids higher than the SRMC cost, we suggest that it is essential to introduce other means to provide incentives of new generation capacity installation in a timely manner. This can be done by designing flexible and well-adopted longer-term physical and/or financial market mechanisms tailored specific to the electricity industry. SEM is one of such attempts to enhance the short-term DART markets. This market mechanism would eliminate the need for various installed capacity and reliability markets currently under consideration. Possible future research topics are listed in chapter 9.

1.2 Regulated Industry

Traditionally, reliable long-term electricity provision has been done with vertically integrated electric utilities that are responsible for generation, transmission and distribution of electricity with exclusive franchise rights for a defined geographic area. Traditional Integrated Resource Planning (Andrews, 1995) assumes such a vertical business structure. Its objective is to meet expected load demand growth at least costs while maintaining the reliability standards, such as withstanding the largest transmission and/or generation equipment outages under the peak forecast demand conditions. Historically, Integrated Resource Planning has met such engineering design criteria fairly well. On the economic side, the regulated utilities have the ability to recover all costs that have been prudently incurred according via a guaranteed rate-of-return on equity. This regulation has protected utilities from the full consequences of investment decisions while the rate payers eventually bore the financial risks as long as they were deemed "prudent" by the Public Utility Commissions (PUC). Moreover, since the return was linked with equity, the utilities faced an incentive to increase their revenue bases by over-building the generation and transmission capacity to receive a bigger return. This is sometimes referred to as the "gold plating" problem. Another concern with guaranteed rate-of-return is the lack of direct incentives for technical innovations, such as low carbon generation technologies and demand response projects, because cost reduction does not necessarily translate into revenue increase. Some effort has been made, notably toward design of performance-based regulation, to address the problem in the regulated industry (Comnes, 1995). These concerns, among others, have led to the arguments for the industry restructuring and introduction of electricity markets.

1.3 The Restructured Electricity Markets

In the restructured parts of the industry, on the other hand, most of the works are mainly focused on the efficiency of short-term Day-ahead and real-time (DART) markets while maintaining a certain level of system security. Those markets are administrated and executed by a non-for-profit Independent System Operators (ISOs) and/or Regional Transmission Organizations (RTOs). At the same time, RTOs/ISOs still have the responsibility to comply with the long-term reliability standards such as resource adequacy requirements mandated by the North American Electric Reliability Corporation (NERC) and various other regulatory agencies. Theoretically, under perfect conditions, the DART market prices should be set by the short-run marginal costs (SRMC) of generators. These SRMC generally does not include any risk premium derived from long-term uncertainties, while the resource adequacy requirements are long-term based reliability standards. There is no consensus on whether the liberalized electricity market under the current DART market structures can be expected to produce adequate capacity levels on a continuous basis. On the contrary, recent industrial experience in such markets point in the opposite direction (ISO-NE, 2004 Annual Market Report, 2005). Moreover, there are no centralized authorities which can dictate mandatory generation/transmission expansion plans for a certain geographic area in a market environment. Market participants and stakeholders make their own investment decisions based on expected profits from the markets just like any other industry. Concerns are raised about whether the price signals coming out of current organized electricity markets, which mostly focus on short-term energy and ancillary service and security of system operations, provide sufficient incentives to sustain the long term resource adequacy. Therefore, in the deregulated industry the risks associated with the long-term investment decisions to meet those requirements have shifted to the investor side. Potential investors need to make their long-term business decisions based on short-term prices which are inherently volatile. Notably, there is major lack of market signals for long-term investments. This has led to the problem of "missing money", namely the inability to recover fixed cost and justify future investments (Cramton, 2006).

Recently, some efforts have been made to address the missing money problem by introducing some forms of capacity markets. For example, the Reliability Pricing Model (RPM) is one of such attempts in PJM Interconnection LLC (PJM). It is based on an administrative capacity demand curve, whose shape is determined using PJM long-term system demand forecast plus the reserve margin, and the cost-of-new-entry (CONE) which is the annualized capital cost of a new combined cycle natural gas peaker (Brattle Group, 2008). Such administrative demand curves are set by the PJM not by market participants. In particular, they do not account for their valuation of long-term uncertainties and risk preference. Ultimately, the capacity market results are dependent upon ISO's own assumptions about CONE price and other parameters, instead of energy users' willingness to pay for future reliable energy provision.

1.4 Basics of Stratum Electricity Market

Our Stratum Electricity Market framework rests on three fundamental premises, as follows:

1. It is impossible to implement a short-term electricity market perfectly.

2. The energy service providers (load aggregators) need a better prediction of future energy needs of their customers as well as of their willingness to pay for such

services.

3. The electricity suppliers have the best understanding of the characteristics of their technologies. They are also the ones who should decide when to invest and at what price.

4. ISO/RTOs have the best understanding of the underlying transmission network and other market information. They also have hands-on experience of the DART market administration.

We stress that if system users (suppliers and consumers) and the service providers (T&D owners) were given the opportunity to internalize the inter-temporal and inter-spatial uncertainties into their bids/offers, the market prices would clear closer to the actual values of such services. This statement could be illustrated in the context of unit commitment type constraints when balancing the system with inherently intermittent generation and responsive demand. We also emphasize that it is going to be very difficult to design more efficient short-term reliable unit commitment software for centralized decision making. The robust adaptive unit commitment is still more conservative than what one could achieve when inter-temporal constraints and costs are internalized by users themselves using an AC Optimal Power Flow (AC OPF) platform which is capable of managing the controllable T&D equipment. Another major issue recently discovered when attempting to integrate many distributed resources, such as Plug-in Electrical Vehicles, concerns the often counter-intuitive scheduling by ISOs (Verzijlbergh, 2013 (estimated)). It has been known for quite some time that the centralized unit commitment generically has a very flat optimum and it is not capable of producing the rationale for selecting one combination of bids over the other (Tseng, 1998).

The potential investors may have better knowledge of capacity and type of energy they would like to provide and at which price over different future time horizons. We believe that an extension of current DART to enable stakeholders to express their preferences and conditions for long-term energy provision and consumption is necessary. We, therefore, propose the SEM as a means for market participants to provide long-term, mid-term and short-term bids/offers based on their own best knowledge and risk preferences. These bids/offers are used by ISOs to create system aggregated demand and supply curves for reliable energy services over various temporal and spatial horizons. The SEM also provides a vehicle for market participants to manage their own risks through a price premium expressed in their bids/offers.

The SEM is a coordinated sequentially clearing series of forward energy sub-markets of different duration and at different spatial granularity. The short-term nodal markets, similar to the current DART operated by the ISOs, are designed to balance the short-term deviations from mid-and long-term commitments. Heat rates are chosen as market products in the mid- and long-term instead of power products in order to hedge against fuel price uncertainties. The investors could fully shield themselves from fuel price fluctuations if the associated long-term fuel contracts could be realized. Alternatively they can partially hedge their fuel risks through long-term fuel supply contracts according to their risk preference and leave the rest to be realized in near-term markets. Heat rate trading is possible due to the fact that the existing major load centers are usually accompanied by the existing fuel hubs. We propose market rules, rights and regulations (3Rs) concerning the sub-markets interactions, product hierarchy and financial settlements. The products cleared in longer-term sub-market have a higher hierarchy in term of financial settlements. The 3Rs are flexible and effective for distributing inter-temporal and inter-spatial risks across market participants according to their risk preference at the premium determined by the market mechanism. In particular, an inter-stratum adjustment is achievable because awards in longer-term stratum can be offset in short-term stratum. Long-term cleared quantities could be bought back entirely or partially in the short-term market.

The incremental settlement rule is proposed to simplify and expedite the accounting and settlement across multiple strata. This market design shifts the responsibility of tracking net position across multiple markets from ISO to the individual market participant. This design gives the participants the flexibility to use multiple markets to achieve multiple goals, such as hedging and speculating. Also, the proposed settlement rules promote the price discoveries across different markets because only the transactions that converge the prices are profitable. It is not in market participant's interest to intentionally make prices in sub-markets diverge. Detailed numerical examples are given in the chapter 4.

Stratum markets also serve as an essential tool to manage the price risks across multiple geographical locations. For long-term market, contracts are settled against the prices at the aggregated zonal locations which have higher open interests instead of more detailed intra-zonal nodal locations. This design would promote liquidity and concentrate the trading activities to only a handful of locations, mainly Generator Hubs and/or Load Aggregation Zones. Moreover, these arrangements also align the SEM electricity trading activities with the current fuel hubs. Consequently, market participants would be less susceptible to the sudden price disturbances in short-term markets. We demonstrate that in our proposed SEM the risk is distributed rationally among different parties and the long-term prices reflects the premium over SRMC, while in the spot only market generators will no longer invest and/or go bankrupt.

The system sustainability can further be achieved by integrating the proposed SEM with the existing long-term Financial Transmission Rights (FTR) markets, and the proposed Cap-and-Trade Emission Market. This integration would enable us to manage other externalities unique to the electricity such as transmission congestion and emission control. A complete long-term energy, FTR and Cap-and-trade emission markets SEM setup would lead to the long-term sustainability by addressing all risk premiums and their inter-dependencies.

2 Electricity reliability and Resource Adequacy

2.1 Electricity Reliability

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, 1985) defines reliability in a bulk power system 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. The degree of reliability in operations may be measured by the frequency, duration and magnitude of adverse effects on consumer service. The degree of reliability in operational and long-term planning is measured by the predicted performance of the system in studies to provide acceptable performance for credible contingencies while considering sensitivity in the assumptions that define the operational state being studied. ".

Simply put, the reliability of electricity supply is the ability to "keep lights on". Electric system reliability can be addressed by considering two basic and functional aspects of the electric system: *adequacy* and *operating reliability*. *Adequacy* is defined by NERC as following:

"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"

Operating reliability is defined by NERC as:

"The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components"

The notion of operating reliability focus on the short term operational aspects of the system which are characterized through contingency analysis and dynamic stability assessments. It is provided by protection devices, operation procedures and industry practices that include but not limited to:

- Security constrained economic dispatches with *N-k* Contingency Analysis
- Generation and/or Transmission Operation Procedures, Special Protection System (SPS), Remedial Action Scheme (RAS) and other protection schemes and devices
- Ancillary Services Requirements, i.e. AGC/frequency control (Regulation Up/Down operating reserves), spinning and un-spinning (10 minutes/30minutes) operating reserves

In addition to defined ancillary service products mentioned above, some essential reliability services are difficult to design as standard market products, i.e. voltage/reactive power support, due to system modeling and software limitations such as convergence of Alternative Current Optimal Power Flow (A/C OPF). In real industry practice, especially by the U.S. Independent System Operators (ISO) and/or Regional Transmission Organizations (RTO) like ISO-New England or California ISO (CAISO), such requirements are enforce by Reserve Adequacy Accessment (RAA) or Exceptional Dispatch / Reliability Must Run Dispatch procedure to commit additional capacity for various security reasons before and/or after Day-ahead Market (DAM) is cleared. Such practices tend to depress the day-ahead and/or real time price signal since such Out-Of-Merit reliability must run commitments would usually participate as self-schedules under current market rules and would displace the commitments of more expensive In-the-Merit economical units.

2.2 Resource Adequacy

The notion of reliability on the other hand represents the system's ability to meet demand on a longer time scale while considering all the inherent uncertainties governing supply, demand and regulatory side of electricity industry. Some of those uncertainties, which have significant impacts on long-term adequacy of electricity supply, includes but not limited to: long-term load growth and macro economy outlooks, fuel prices (natural gas/coal), water conditions for hydro-electric generation, the uncertainty of regulatory policy changes such as Green House Gas Cap-and-Trade regulations, the prospects of new technology break-through, and the long lead time for capacity expansion.

In regulated industry, adequacy has been traditionally measured in terms of the amounts of planning and operable reserves in the system. The so-called loss of load probabilities (LOLP) is used as the criterion in long-term power system planning process. The LOLP criterion requires significant investment in capacity expansion so that adequate operating reserve level would be sustained to prevent the service interruptions even when the large equipment outages occur under the peak forecast demand. As a result of these technical requirements, more is built than is typically utilized. Moreover, most of the costs associated with the long-term investment decisions could be recovered through the rate payers, often after the fact, based on the guaranteed rate-of-return regulatory policies. While such traditional engineering standards of resource adequacy works relatively well to keep the lights on, the costs are high and consumers bear most of the risks. Such uneven distribution of risk and reward structure sometimes may lead to over-expansion problems. Some effort has been made to reduce the overcapacity in the regulated industry, i.e. design of incentive based regulation (Comnes, 1995). In addition, integrated resource planning (IRP) has been an effort to optimize generation mix to meet the planning criteria.

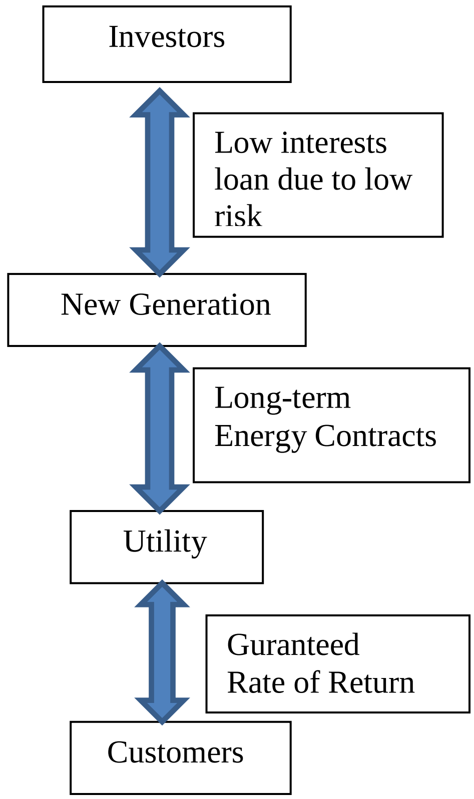

Figure 1: Resource Adequacy in regulated industry

2.3 RA Problem in Theory

In a perfectly competitive electricity market, RA should not be a problem (Oren, Ensuring Generation Adequacy in Competitive Electricity Markets, 2005). There are three scenarios with regards to supply and demand conditions in the energy-only markets such as the original California design. Three cases are demonstrated below:

Case 1: when supply can intersect with demand curve, the price will be set by offer price of the last unit meeting the demand. The infra-marginal units will get a profit margin while marginal unit will set the price.

Case 2: when the demand curve and supply curve do not intersect with each other but maximum supply capacity is still within the range of the demand curve, the price is determined by the consumer's willingness to pay expressed in the demand bids by price-responsive customers when the demand quantity equals the 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.

Case 3: Finally, when the demand curve and supply curve do not intersect each other and the minimum quantity of demand curve is larger than the maximum of supply capacity, a rotating blackout operating procedure is activated by the 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 should be achieved in a long-term equilibrium that reflects supply and demand choices for reliability and cost. Economic theory tells us that optimal capacity is achieved when all the profits collected by the last marginal unit during all the above three scenarios will exactly cover its capital investments cost and Operation and Maintenance (O&M) costs (Joskow P. a., 2007). When the capacity is smaller than the optimal, the additional profits in the markets will attract new entry and generation expansion. When the current system capacity is larger 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. Figure 2 below illustrates the above arguments.

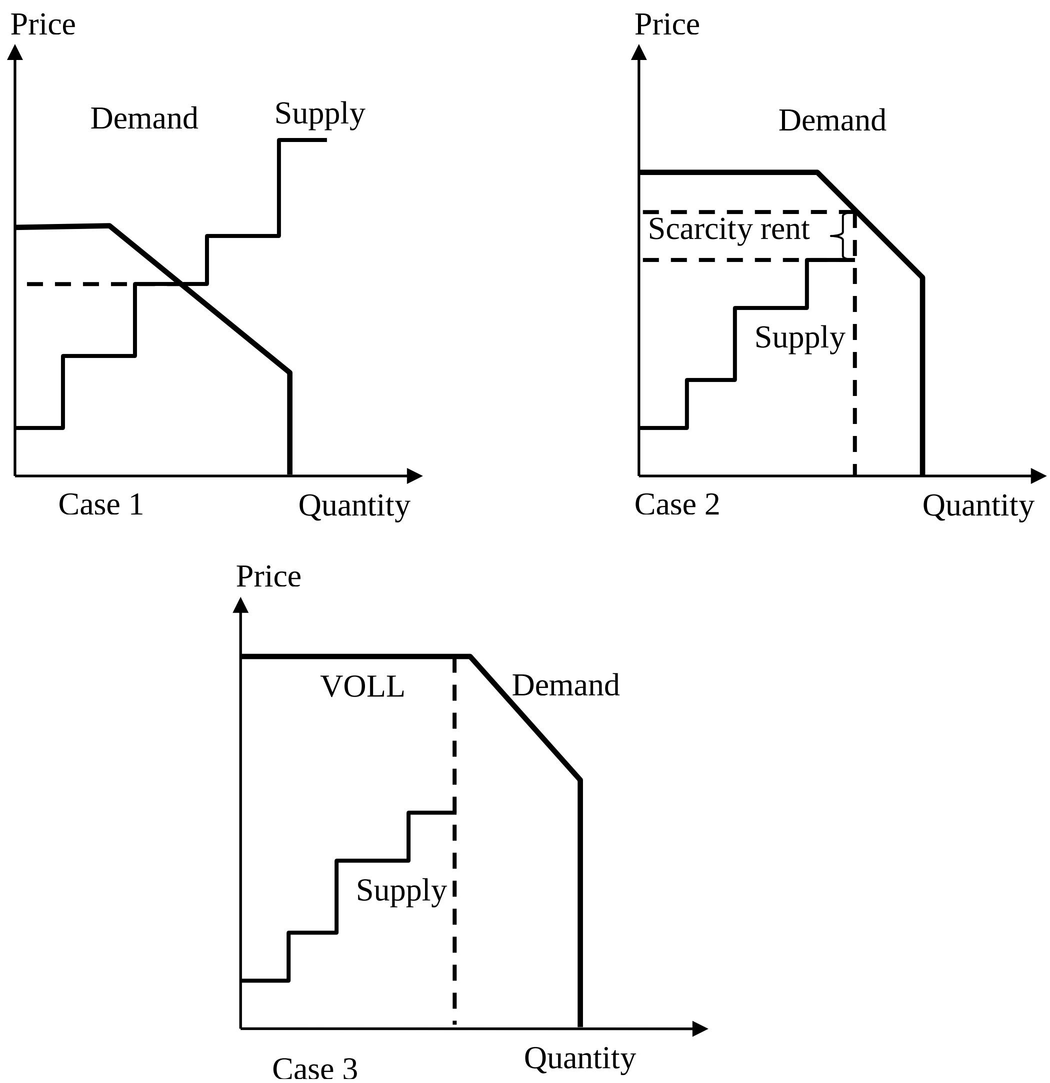

Figure 2: Recovery of generation investments in ideal energy only markets

2.4 RA Problem in Reality

However, in reality the RA problem does exist. The quantity of new generating capacity coming out of the construction pipeline is falling significantly. Few investments in new merchant generating capacity are being committed at the present time, aside from wind, solar and other renewables that can obtain favorable tax credits and other regulatory financial incentives. Still, the net summer capacity in U.S. considering the generator retirement from 2002 to 2010 has been relatively flat (Figure 3).

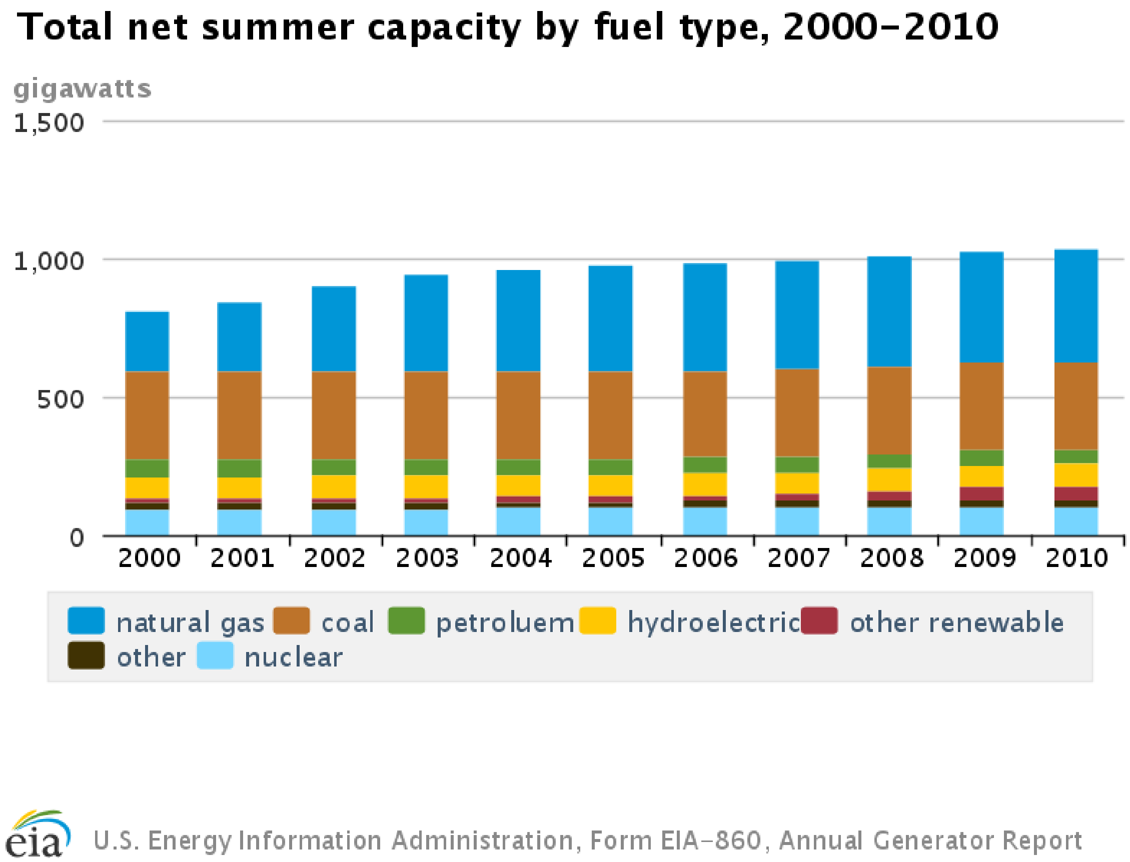

Figure 3: Total net summer capacity by fuel type 2000-2010 **(EIA, 2011)**

Several recent studies show that there may be a capacity shortage in almost all ISOs and ISO New England (ISO-NE) estimates that they are missing over $2 billion generation capital costs recovery per year (Cramton and Stoft, 2006). 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 1-Table 3 (Monitoring Analytics, 2010) shows the net revenues that a hypothetical new combustion turbine (CT), combined cycle (CC) and pulverized-coal plant (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 1999-2010. All net revenues are presented in dollar per MW-year units. The net revenue from PJM operated energy markets (Day-ahead and real-time markets) fluctuated dramatically from year to year for all technologies. This is primarily due to the volatility of short-term energy market prices. The profits from ancillary services markets are relatively small and cannot be counted on for fix cost recovery. The revenues associated with the sale of capacity resources increased significantly from 2007 for all technologies due to the fact that PJM introduced the new Reliability Pricing Model (RPM) capacity market model. However, based on current markets structure and engineering practice, it would not be rational for an investor to investment in Combustion Turbine and Pulverized Coal technology since the average total profits would have been significantly less than the fixed costs alone even under the new capacity market design. This phenomenon is not unique to PJM alone. Similar studies can be found from the Annual Reports from almost all organized markets in the U.S. with similar conclusions.

Table 1: New entrant gas-fired CT: Theoretical net revenue for calendar years 1999 to 2010

	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
2006	$10,996	$1,758	$2,194	$14,948
2007	$17,933	$28,442	$2,154	$48,529
2008	$12,442	$35,691	$2,398	$50,532
2009	$5,113	$48,441	$2,384	$55,939
2010	$36,925	$55,309	$2,384	$84,619
average	$21,701	$21,831	$2,271	$44,970
annualized fixed cost				$72,207

Table 2: New entrant gas-fired CC: Theoretical net revenue for calendar years 1999 to 2010

	energy	*capacity*	*ancillary*	**total**
1999	$80,546	$16,999	$3,155	$10,070
2000	$24,794	$19,643	$3,155	$47,592
2001	$54,206	$29,309	$3,155	$86,670
2002	$38,625	$10,492	$3,155	$52,272
2003	$27,155	$5,281	$3,155	$35,591
2004	$27,389	$5,241	$3,155	$36,785
2005	$35,608	$2,054	$3,155	$40,817
2006	$44,692	$1,743	$3,094	$49,529
2007	$66,616	$31,098	$3,094	$100,809
2008	$62,039	$38,691	$3,198	$103,928
2009	$31,581	$46,596	$3,198	$81,376
2010	$88,275	$38,588	$3,198	$130,061
average	$48,461	$20,478	$3,156	$64,625
annualized fixed cost				$93,549

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

	energy	*capacity*	*ancillary*	**total**
1999	$92,935	$17,798	$7,288	$118,021
2000	$108,624	$20,755	$5,184	$134,563
2001	$95,361	$30,862	$3,048	$129,271
2002	$96,828	$11,493	$3,810	$112,131
2003	$159,912	$5,688	$3,910	$169,510
2004	$124,497	$5,537	$3,091	$133,125
2005	$222,911	$2,100	$3,419	$228,430
2006	$177,852	$1,810	$2,799	$182,461
2007	$244,419	$29,343	$3,522	$277,284
2008	$179,457	$26,107	$2,579	$208,143
2009	$49,022	$43,931	$2,014	$94,967
2010	$128,990	$36,117	$1,957	$167,064
average	$140,067	$19,295	$3,552	$162,914
annualized fixed cost				$208,247

The RA problem has several causes. First the "missing money" as demonstrated above shows that not enough revenues are received by market participants from the current short-term energy and ancillary service markets operated by ISOs. This is mainly due to various market regulations and engineering reliability practices which have not been harmonized with economic incentives and tend to depress the spot market price, as described in (Joskow P. T., 2005). Some of such practices are listed below.

- Price caps in energy and ancillary service 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 others
- The fact that during the true emergence conditions such as system wide power outages, energy prices are usually set by the artificial administrative prices afterwards, not the VOLL. For instance, during the 2012 CAISO San Diego Power Outage, the price was set manually at $250/MWh and $100/MWh for the outage hours (CAISO, 2011).

Most 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 Requirements
- Minimal Capacity Requirements
- 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.

Even if all the price caps are removed and various practices were mitigated so that short-term energy and ancillary service prices could rise high enough to reflect real system supply and demand conditions, there is still one basic difficulty. Short-term market prices are too volatile to attract long-term investors who are risk averse. The volatility of hourly Day-Ahead and 5-minutes Real-Time energy prices are the highest among all commodities. This is mainly due to the Locational Marginal Pricing (LMP) Mechanism employed by the ISOs, which is designed to reflect the true instantaneous cost of supplying one additional mega-watt (MW) at each location. LMPs are very sensitive to transmission congestion, generator ramping limits and other constraints in the system. A lot of factors, like real-time demand supply conditions, planned and forced generation and transmission outages, new generations and transmission network upgrades, impact congestion patterns in the system. The investment projects based on historical congestion patterns and LMPs at certain locations may not be accurate in the long run. Even if there is no congestion in the system and the price are purely decided by supply stacks, it is still hard to estimate the future revenue streams. For example, a peaking unit may only operate a few hours per year on the very hot days when the operators run out of the supply stack and the prices are sufficiently high so that the unit can recover their fixed costs. The number of such hours is hard to forecast and varies dramatically from year to year due to weather patterns. No risk-averse investors would invest millions of dollars based on this high year-to-year variability. Moreover, the volatility originating from fuel prices poses another big challenge to the investor. The natural gas prices in U.S. markets has been quadrupled in the past decades while then dropping to an historical low recently because the new fracking technology is widely used by the gas industry. Many of the merchant generating companies who made new investments almost all in combined-cycle (CC) gas turbine technology based on natural gas predictions when the plant was built face serious financial problems and several went bankrupt. As a result, the average credit rating of merchant project financing by credit rating agencies like Fitch and Moddy's dropped to the sub-investment grade, B- and below (Fitch, 2011), 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 (Krellenstain, 2004). Project financing for new generating plants is difficult to arrange unless there is a very long term Power Purchasing Agreement from a big utility and a long term fuel supply contract can be obtained with a creditworthy buyer to support it.

2.5 The Literature Review of Solutions

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

2.5.1 The Energy-only Approach

Chao and Wilson (Chao, 2005) 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 (Oren, 2005) also proposes a long-term supply contracts in the form of call option with premiums that depend on the contracts' strike prices (Figure 4). 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. However, unless the price cap in spot markets is removed, the value of options would not reinstate the missing money to ensure adequate capacity.

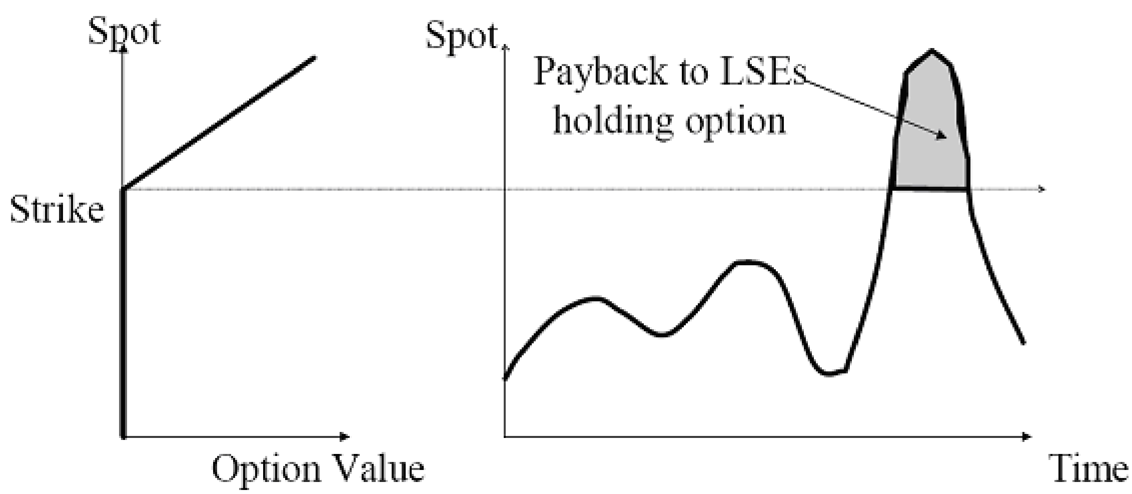

Figure 4: Call options (Oren, 2005)

The above two approaches are good steps towards long-term risk management and market power suppression. 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 2.3. However, due to the market imperfections and ISOs' reliability practices, these models may not work under current market environment.

Hogan (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% (Figure 5). These parameters as well as the demand curve are predetermined by a central administrator, not by market participants. A small change in these parameters may result in big changes in terms of money and in turn decide how many new capacities are needed. Hogan argues that a capacity market approach would overturn the electricity market and an energy-only approach could and should leave major economic decisions surrounding investment to be voluntarily arranged by the parties. However, this approach still needs administrative demand curve.

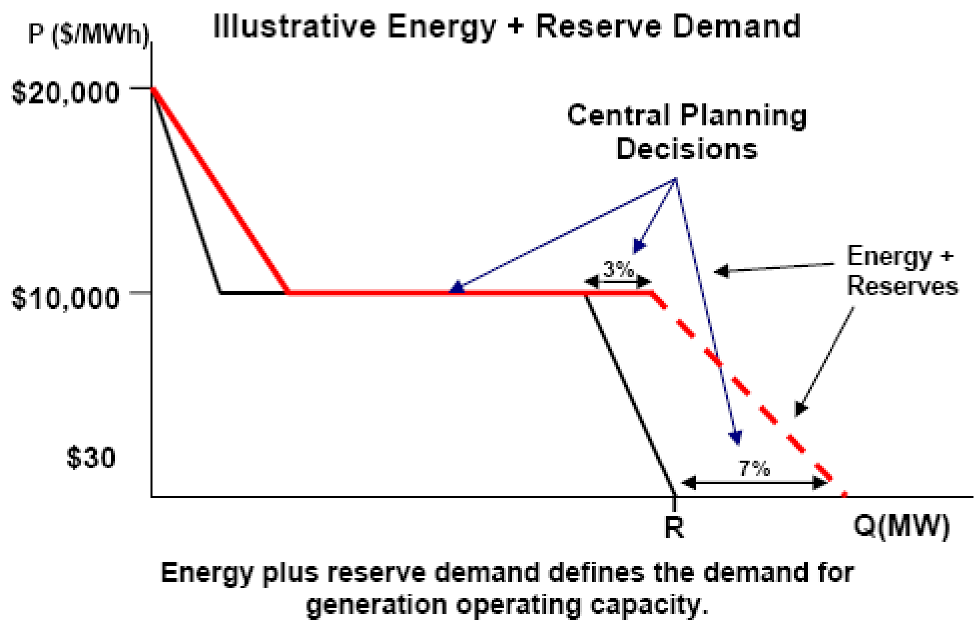

Figure 5: Energy plus reserve demand curve (Hogan, 2005)

2.5.2 Capacity Market Approach

Another way to ensure resource adequacy is to let ISOs forecast and select the "appropriate" level of capacity. 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 administrative demand curve which are determined by the annualized fixed cost of the cheapest new entry and other assumed parameters like forced outage rate and generation availability rate. When current installed capacity exceeds the forecasted target, the price will fall to zero and the system would not attract any new investment assuming there is 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. Also, under this approach the central planners and regulators becomes the decision makers. These “regulated investment” would create more unintended consequences.

Currently ISOs in Northeast has an operational installed capacity market (ICAP). However, due to the following reasons, their effects are questionable.

- The markets only cover one month or half a year, which is too short to encourage new investment.
- Price caps are low
- Prices are volatile and 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.

PJM implemented their own capacity market called Reliability Pricing Model in 2007 (Monitoring Analytics, 2010). The RPM is a forward-looking zonal capacity markets with must offer requirement for generator’s capacity and mandatory participation by LSEs. Capacity obligations are annual with base residual auctions (BRA) held for delivery years that are three years in the future and First, Second and Third Incremental Auctions (IA) conducted 20, 10 and 3 month prior to the delivery year. RPM prices are zonal and may vary depending on transmission constraints. Currently there are 25 regions defined as Locational Deliverability Areas (LDAs). Usually there are two to three zonal price separations during a real auction due to transmission capacity limits (RTO, EMAAC, SWMAAC). The supply curves are provided by capacity offers. The demand curve (Variable Resource Requirement VRR) is determined by PJM administratively prior to each auction for each LDA and RTO as a whole. VRRs are based on but not limited to the following parameters.

- Target level of capacity
- Cost of New Entry (CONE)
- Net energy and Ancillary Services Offsets (E&AS)

Target level of capacity is in turn determined administratively by forecasted peak load, installed reliability margin (IRM) and generator availability assumption and expected forced outage rates. CONE is based on an imaginary new combustion turbine natural gas generator. Net energy and ancillary services revenue offsets is calculated using the most recent three calendar year historical average revenue from a reference combustion turbine generator.

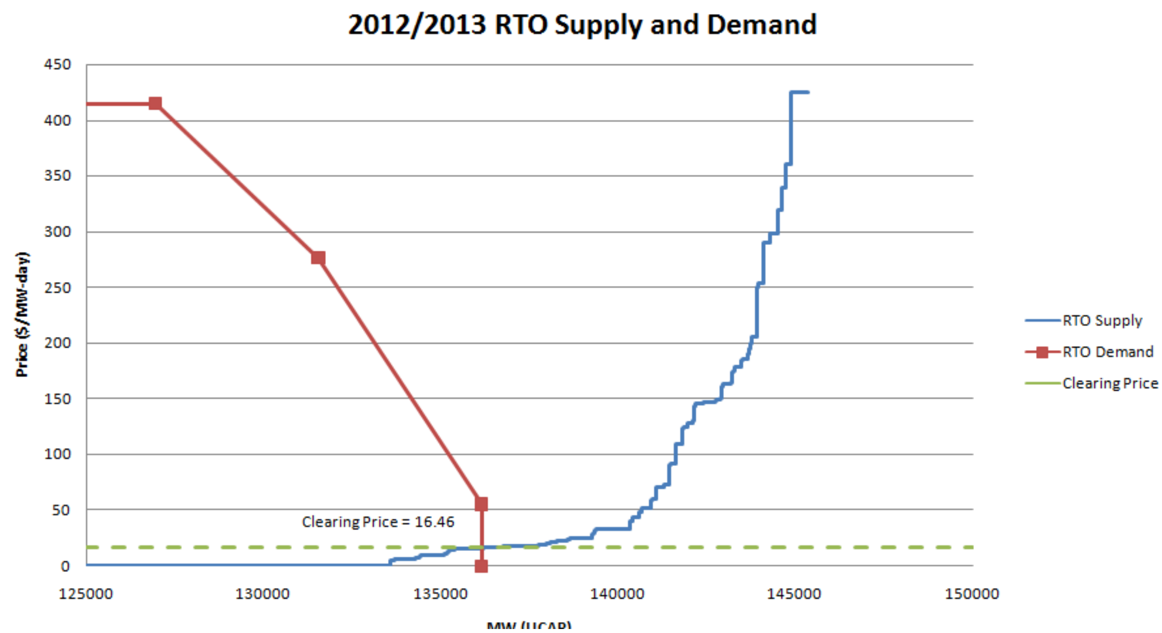

Figure 6: PJM 2012/2013 RTO RPM supply and demand (PJM, 2012)

Although RPM is an improvement comparing to the old ICAP design, experience reveals unintended consequences and problems. RPM's highly concentrated market structure was evaluated consistently as not competitive by independently market monitor (Monitoring Analytics, 2010). Both RTO market and the local LDA markets failed the three pivotal supplier market structure tests. The very steep administrative demand curve invites physical or economically withholding from supply side to raise price since a small withholding would translate into a very price increase, i.e. every 1% decrease in supply would increase the price by 20%. On the demand side, uneconomic entry or subsidies from states would drive down the prices significantly. Please note that from Figure 6 already a large portion of supply curve is zero dollar offers. The recent controversy regarding the New Jersey generation subsidy legislation is one of such issues. Most part of New Jersey lies in the EMAAC zone with significant importing transmission capacity limitations and the RPM capacity prices usually clears several times higher than the RTO base prices. New Jersey state legislations passed a bill to subsidize the new generation with contract for differences out-of-market payments provided the generators would submit very low offers into the RPM model and exempt from the market power mitigation procedures. NJ Rate Counsel provided comments in the June 24 2010 BPU Technical conference suggesting new, in-state generation could save NJ ratepayers approximately $465 million/year in capacity payments (LS Power, 2010). Consumers subsidize the new plants and state gains jobs while artificially depressing the capacity prices. PJM market monitor indicated in a responding report (Monitoring Analytics, 2011) that “if implemented, the result of such a subsidy by NJ ratepayers would be artificially depress the RPM auction prices below the competitive level, with the result that the revenues to generators both inside and outside the NJ would be reduced as would the incentives to customers to manage load and to invest in cost effective demand side management technologies”. Similar problem also showed up in Maryland and New England Forward Capacity Auctions.

However, since state and federal energy policy play a key role in the electricity industry, similar uneconomic entry would distort the capacity market prices in the future. For example, the target of installed renewable capacities is 33% of total installed capacity in 2020 in CAISO. PJM also forecast 52,000 MW nominal for solar and wind in 2026 scenario. Because the investments of these renewable generators can be recovered from long-term PPA and tax credits and these subsidies are tied with their actual outputs, they don’t depend on incomes from energy and capacity markets and usually submit zero dollar offers into both markets. The impacts of such expansion of price-taker offers on the supply curve in capacity market would be much more dramatic than the current NJ in-state generation controversy and basically drive the capacity price to near zero. In the end, it is very likely without subsidies from policy makers, no one would invest in the electricity industry. Similar conclusion could be reached if the promotion of Demand Response projects by the federal regulators is not done correctly. After all, when politicians could hand pick winners through various Out-Of-Market payments, the markets would not be competitive and sustainable.

Another unintended consequence of such capacity markets is the delay of retirement time of old coal plants and reactivation of mothballed plants. Most of these old plants are uneconomic to produce power in DART markets and have a higher emission rate of air pollutants due to old technology. However, due to the large capacity payments, they have incentive to stay in the market just to receive the “free” capacity payments even though most of them have recovered their capital costs through long-term PPAs and don’t require a capacity payment in the first place.

The main issue about the RPM design is the administrative demand curve by central planners and regulators. All the parameters are set by PJM. The forecasted load number is made three years in advance and may not be accurate in the delivery year due to economic recessions. The CONE price and net E&AS offsets are all based on historical prices, sudden changes in the these values would result in over-capacity or under-capacity situations. 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, 2006).

Table 4: Comparison between different approaches (Cramton, 2006)

	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

3 Short-term Market Improvements

The “resource adequacy” problems arising from imperfections in spot energy markets are now widely recognized by policymakers. A lot of efforts are being made to reform capacity obligations or energy-only based mechanisms in long-term. However, since the causes of the RA problem are dichotomal, in this thesis we propose a hybrid solution. This solution tries not only to reform short-term spot energy markets to allow prices to rise to appropriate competitive levels and to better harmonize reliability requirements and 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 chapter we focus on the spot market improvements.

3.1 Day-Ahead Market Commitment Requirement

In most ISOs, the day-ahead market is a financial market. The DA prices are determined by bid-in supply offers and demand bids and other operational and regulatory constraints. The RT market prices are cleared against RT load forecasts thus the RT prices reflect the true fundamental supply and demand conditions in the power system. However, all the cleared DA positions are settled against DA prices while only the difference between DA and RT cleared quantities is settled against RT prices. For LSEs there may be an incentive to systematically under-schedule in the DA markets to suppress the DA prices and reduce procurement costs given that the ISO would take care of the difference in RT eventually. One policy recommendation here is to establish market rules that require the LSEs to clear the majority of their forecasted load in DA markets, i.e. 90%, so that the DA prices reflects the true economic signals of the underlying system.

3.2 Uplift Costs Distribution Enhancement

As described in previous chapters, most ISOs need to do system reliability analysis after the DAM are cleared, for a variety of reliability and security reasons like voltage support, N-k contingencies, system-wide operating reserves and other constraints. All these constraints lead to additional commitment of more expensive so called

Reliability Must Run (RMR) generators that are Out-Of-Merit (OOM) especially in the import constrained regions (load pockets).

These required OOM generators usually do not earn enough revenues in the energy market to cover startup, no-load cost, and cost to run at economic minimum levels. To make these units whole financially, ISOs issue extra reliability-related payments or "uplifts" according to unit's bid-in profiles. Moreover, generators committed OOM will displace the In-the-Merit generators inside and outside the load pocket, reducing their energy revenues. Excessive use of RMR and OOM units would artificially distort the short-term market prices and send wrong signals of the underlying system supply and demand conditions. This in turn would impact the future investment decisions. Depending on the types of uplifts, some of them are paid by the deviations between DA cleared position and RT metered generation/consumption while the others are socialized by all the LSEs and rate payers eventually. The effects of OOM units and price distortions are illustrated in Figure 7.

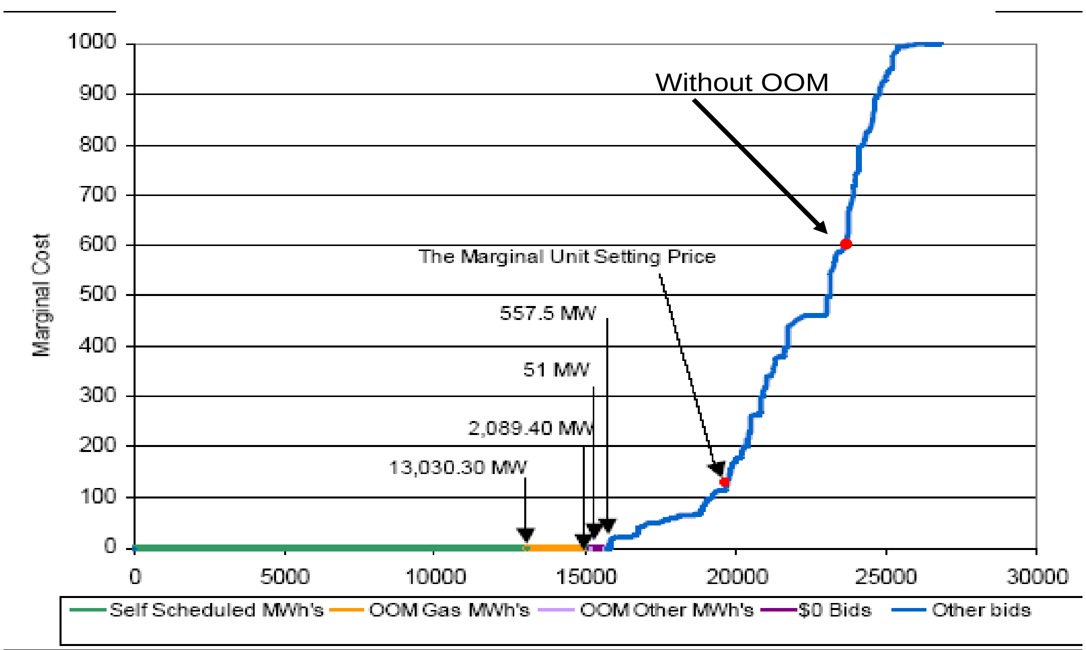

Figure 7: OOM units depress the price **(ISO-NE, 2004 Annual Market Report, 2005)**

In order to converge the DAM and RTM prices, ISOs introduced Virtual Bidding as a financial tool to reduce the price discrepancy. Virtual generations/loads are treated as real generators/load in DAM and if cleared, the payoff is the spread between DA and RT prices. For virtual generation, the profit is positive when DA price is higher than RT price and vice versa for virtual load. For example, if market participant expects that the DA price at a location would be higher than RT price, he may clear virtual generation at that location to arbitrage between the DA and RT prices. By clearing virtual generation, he would implicitly lower the DA prices thus help to converge the price difference. However, since by definition virtual load/generations are treated as 100% deviation between DA and RT positions, they are subjected to large share of uplift costs, sometimes as high as $20/MWh which may offset any possible profit margin. These costs may impede any financial players from arbitraging between the markets and exacerbate the problem identified in the previous section. One policy recommendation here is to exempt the Virtual Bidding from the uplifts that are charged to the DA and RT position deviations and thus facilitate the price discovery and convergence in short-term electricity markets.

3.3 LMP Pricing Mechanism Improvements

Theoretically marginal cost pricing leads to economically efficient prices when cost curves are convex. When costs are non-convex, market efficiency claims may not hold anymore. Startup costs, minimum run times, no-load costs, and other factors addressed in the unit commitment decision create such non-convex cost curves in the electricity markets. There are many potential solutions to the uplift costs due to OOM dispatches, such as increasing transmission import limits and adding flexible generation in the import constrained areas. In this thesis we explores changes in market operations that may improve marginal price signals and reduce OOM related uplift costs. The objectives of these improvements are to;

- Calculate LMPs that are not depressed by OOM units in load pockets. The new prices would more closely reflect the true cost of meeting the demand which includes the externality of reliability and security requirements.;
- Reduce uplifts;

- Provide incentive compatibility so as to attract appropriate levels of investment in the right technology at the right locations

The main idea is to allow the RMR units which are committed OOM and most likely operated at economical minimum capacity to set the LMPs at those locations so that as much as possible the hidden uplift costs could be exposed in the market price signals. One way to do it is to impose additional transmission limits on the import constrained area where such units are deployed. By reducing the importing capacity on the interface, more expensive units within the load pockets may have a chance to set higher price and therefore diminish the uplift costs.

3.4 Example

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

Figure 8: Two bus system demonstration of new Pricing mechanism

At bus1 there is a cheap generator G1 whose EconMin and EconMax are 0 and 210MW respectively. The bidding price of energy is $50/MWh and demand L1 at bus1 is 100MW. At bus2 there is an expensive generator G2 with EconMin at 10 MW and EconMax at 100MW. The bidding price of G2 is $100/MWh and demand L2 at bus2 is 100MW. Assuming the transmission line constraint is 200MW. Then the economic dispatch solution should be G1 at 200MW, G2 at 0MW, LMP1 is $50/MWh. Power flow from bus1 to bus2 is 100MW. Since the power flow on the transmission line already reaches the limits, the additional demand at bus2 has to be satisfied by G2. Thus the LMP2 is $100/MWh. This solution is named the “Solution without RMR”

Suppose that due to voltage support operating procedures G2 is required to be turned on at bus2. Then under current market rules, G2 will be flagged as a RMR unit with an OOM dispatch of EconMin 10 MW. The economic dispatch solution with OOM dispatch is G2 at 10MW, G1 at 190MW. LMP1 and LMP2 both are $50/MWh and power flow from bus1 to bus2 is 90MW which is below the transmission limit. Since G2 is OOM unit, there is uplift. Assuming startup cost equals shutdown cost which is set at $100 and minimum run time is one hour, then G2's uplift payment is $700. This second solution is called "Solution with RMR".

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

Under our proposal, in order to let G2 set the price, a reduced interface limit 90MW is imposed on the transmission line. Under the new limit, 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 they are much smaller. The G2's uplift payment is $200. This solution is called "Proposed solution".

Gen2's uplifts = $100*10 + 100 + 100 - $100 * 10 = $200

All three solutions are compared in Table 5 listed below.

Table 5: Comparison of the three solutions

	G1 output (MW)	*G2 output (MW)*	*LMP1 ($/MWh)*	*LMP2 ($/MWh)*	*Uplift ($)*	*Cost of Electricity ($)*
Solution w/o RMR	200	0	50	100	0	10,000
Solution with RMR	190	10	50	50	700	10,700
Proposed Solution	190	10	50	100	200	10,700

Similarly, the RMR unit commitments costs due to other types of reliability and security reasons, such as Minimal Online Capacity Requirements or N-2 line/transformer and generator contingency requirements, can also be reduced if appropriate transmission limits adjustments are enforced. The new price mechanism which makes the RMR units eligible to set the prices has the following benefits:

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

4 Proposed Stratum Electricity Market (SEM)

Our proposed market solution to the Resource Adequacy problem is motivated by the need to manage long-term uncertainties at various temporal and spatial scales from the both supply side and demand side of the electricity industry. In the regulated industry, consumers bear the risks associated with the crucial decisions regarding the long-term reliability made by regulated utilities, i.e. generation expansion and transmission network upgrades decisions. The regulated utilities recover most of their costs through guaranteed rate-of-return tariffs. On the other hand, in liberalized electricity markets, the risks associated with such decisions shift to the other end of the spectrum, namely to the investors. Due to the unique characteristics of electricity as a commodity, such as non-storability and the related need to continuously balance the supply and demand, the price and associated revenue streams are inherently volatile in the current DART market setup. Such high price risks prevent both generation companies (GenCos) and the Load Serving Entities (LSE) and energy service providers (ESPs) from making long-term investment decisions which are essential for long-term sustainable energy provision. Since in most states consumers are still shielded from wholesale electricity prices by regulated tariffs at the retail level, they do not have the incentives to hedge against the unstable spot prices. Facing such challenges, most Gencos and LSEs are willingness to mitigate their risks with their own risk preference through forward hedging. Therefore, how to provide a sensible vehicle for different parties to manage their risks and align their economic incentives with the goal of long-term sustainable electricity provision as well as social welfare is the key to solve this problem.

Our proposals for solving the problem are twofold. First, as described in chapter 3 we should improve the current short-term energy market/ancillary service market dispatch mechanism so that the prices reflect the real time supply and demand conditions and other externalities more accurately. Secondly, a centralized inter-temporal and inter-spatial market mechanism is proposed in this chapter as a platform for facilitating forward contracting and hedging by the stakeholders from all spectrums and for ensuring long-term sustainable energy provision at value.

4.1 Long-term Uncertainties and Risks

Whether in regulated or unregulated industry, the long-term uncertainties and associated risks for resource adequacy decisions are enormous. They stretch from the supply side to the demand side and also involve regulation/policy. Also, new technologies to manage power grids, such as smart grid in particular, may dramatically change the way the power systems are operated.

On the supply side, uncertain natural gas and coal prices pose substantial risks to anyone who is willing to build a new generation facility or sign long-term Power Purchasing Contracts (PPAs). The expansion and transmission interconnection of generation capacity from the renewable resources, such as wind farms or solar plants which directly use photovoltaic or indirectly use concentrated solar power, may also potentially have big impacts on electric power system operations and future electricity prices. These effects need to be studied before one can make new investment decisions. Moreover, new technology innovations like distributed generations and smart grids may fundamentally change the way we operate the current electric power system.

On the demand side, long-term load forecasts are notoriously inaccurate (Lave, 2005). Unlike other fuels, no one consumes electricity directly. The demand for electricity is mediated by the devices that are available to satisfy human needs. The widespread adoptions of new devices in the future such as plug-in electric vehicles may dramatically increase consumption. On the other hand, deeper penetration of efficient appliances, demand response projects and smart meter technology may lower the peak demand as well as ancillary services requirements. An energy service provider can help clients to lower the demand through energy audits or by installing new, more energy-efficient appliances. Retail energy providers may lower the customer bill by aggregating the end-user demands and obtaining lower rates from the wholesale markets. Retail market competitions will help end-user switch providers and lower the electricity bill.

Changes in Individual behavior at household level, like installation of more energy efficient applicants or doing laundry during off-peak hours, may also have significant impacts on long-term demand if real-time price is transparent to the end users. Econometric studies have shown that although short-run price elasticity of electricity is low, the long-run price elasticity is much higher if consumers' perception of price movements persists. More importantly, unclear long-term macro-economic outlooks also contribute to the inaccuracy of long-term demand forecasts.

Investors face huge uncertainties from regulatory agencies as well. The possible implementation of new Cross-State Air Pollution Rule (CSAPR) from Environmental Protection Agency (EPA) requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states (EPA, 2012). If implemented, a total of 28 states will be obligated to reduce their annual SO2 and NOx emissions and/or ozone season NOx emissions. The power sector also account for more than 60% of green house gas emissions annually (EPA, 2012). Were it to be implemented, a nationwide Cap-and-Trade (CAT) programs on greenhouse gas emissions would considerably increase the production costs of both the existing generation fleet and future generation facilities using the conventional fossil fuels as input. Other policy decisions like subsidies for renewable resources, the long-term transmission congestion outlook and methods for allocating transmission costs among stakeholders are also crucial to the future revenue expectations. All the above risks post big challenges to the stakeholders as well as the RTO/ISOs who are mandated to meet the long-term reliability requirements set by NERC.

Given these large long-term uncertainties, sustainable energy provision critically depends on a mechanism for the stakeholders to mitigate their long-term risks through forward hedging. These forward prices should include a risk premium determined by market participants based on their own risk preferences. These risks are asymmetric to different market participants. In theory, risks are best managed by those who have the best knowledge about the future. In the electricity industry, due to the complexity of the system, such knowledge is distributed among many different stakeholders. For example, the LSEs should have a better prediction of future energy needs of their customers as well as of their willingness to pay for such services. Also, the potential investors on the supply side may have better knowledge of the capacity and type of energy they would like to provide and at what price over different future time horizons. Of particular importance is that the market participants should make their own decisions based on their own perceptions without the pre-determined administrative objectives, like the demand curve in the PJM RPM capacity market model. Sustainable electricity provision requires forward decision making process ahead of actual operation time due to long lead time of power plant constructions and/or accompanied transmission upgrade projects. Without adequate risk management/mitigation mechanisms, it is virtually impossible for any party to undertake such huge capital intensive endeavors.

4.2 Performance Metric for Long-term Sustainable electricity provision

We start here by observing that the traditional definition of reliability of electricity supply should be expanded in the new era of deregulation with a focus to include long-term sustainable electricity provision. The sustainability of long-term electricity provision should include several attributes as described below:

4.2.1 Keep the Lights On

First of all, sustainability must include the traditional reliability of keeping the lights on. This is self-evidence since reliable electric energy provision is essential to the healthy economy and the national security. It is also the essential to the basic means of modern living.

4.2.2 Efficient and Economical Viable Market Solution

Secondly, the solution should be sustainable in terms of efficiency in the short-term market and economical viable in the long run. Microeconomics theory shows that short-term electricity prices should be set by short-run marginal costs (SRMC) of the marginal units in the system under the competitive markets assumption. However, these SRMC based spot market prices may not be sufficient to recover capital cost investments.

Such short-term price signals would not lead to long-term sustainable energy provision. Any long-term sustainable solution should provide means to resolve the "missing money" problem described in chapter 2. Otherwise, nobody would have the incentive to invest for the future infrastructure needs. Long-term market mechanisms are needed so that the following concerns could be addressed:

1. Long-term forward price signals should be provided so that a portion of the capital costs for new generation projects can be secured before the units actually come online. The California energy crisis demonstrated that it is not sustainable for LSEs or Gencos to rely purely on short-term markets as the only revenue source. Forward power contracts would also stabilize a generation company's cash flow and smooth out the impacts of short-term market price spikes caused by transient system disturbances from both supply and demand sides, i.e. fuel supply disruptions due to hurricanes.

2. The underlying uncertainties associated with the long-term decision making process unwinds as time moves closer to the operation dates and more information becomes available. Market participants should be able to readjust their expectations and risk preference and realign their existing portfolios along the way.

3. The mechanism should be able to dampen the traditional boom and bust industrial business cycle which may lead to extreme high or low prices and stymie the investment decisions in the long run.

4.2.3 Unique commodity characters

Thirdly, sustainability requires accommodation of the characteristics of electricity as a unique commodity. These characteristics include but not limited to;

1. demand seasonality and on/off peak hours;

2. spatial price separation due to transmission congestion management;

3. instantaneous balancing of supply and demand in real time

The proposed solutions should address such challenges at proper spatial and temporary granularities so that they would not be too complicated to solve technically, nor should it be too simplified that the uniqueness of the electricity as a commodity is not addressed. The right balance would promote the market liquidity and participation, which is crucial for any market design.

4.2.4 Environmental sustainability and promoting right technology

Sustainability in terms of promoting better technologies comparing to the traditional power generation technologies. Long-term market mechanism should provide opportunities for the developments of such innovations if they are superior to the conventional power generation technologies.

Last but not least, sustainability should include the minimization of environmental impacts. To reduce environmental impacts, including green house warming, renewable energy should be promoted in a responsible way. However, fundamental policy and technology issues need to be resolved before renewable projects can implemented on a large scale. Some of the challenges are listed below:

1. A responsible way must be found to distribute the transmission upgrade projects expenses associated with renewable energy integration into existing transmission network.

2. New technology are needed to control the outputs of the renewable resources, such as wind turbines, to minimize system disturbance.

3. Due to inherent characteristics, the real-time outputs of renewable resources such as wind turbines are difficult to estimate and the output deviation between day-ahead and real-time markets sometime can be significant. A responsible way to distribute the uplift costs and/or ancillary service costs associated with such deviations and keep system in control.

4. Most renewables are treated as RMR units in DAM. It is possible that the large scale renewable energy commitment would artificially depress the energy prices yet increase the ancillary service prices by requiring more stand-by gas turbines for sudden wind deviation or cloud cover.

4.3 Stratum Electricity Market Design

A market based solution, Stratum Energy Market (SEM) which focuses on a long-term energy supply rather than on the capacity availability, is introduced here. The SEM structure proposed in this thesis is motivated by the lack of transparent liquid long-term energy markets for power trading in current market structure (Wu, 2008). The large percentage of cleared energy transactions in current DART market are self-schedules. Most of the self-scheduled energy is predetermined long-term bilateral contracts that have to be submitted into the ISO markets. However, most of these contracts are obtained through over-the-counter (OTC) bilateral markets since there is no centralized market mechanism to promote the liquid active trading environment for long-term deal-makings. Consequently, most of the existing forward contract and futures OTC markets are not transparent, and, therefore, they may not provide the right price signals for investments.

Unlike the Henry Hub index for natural gas or West Texas Intermediate (WTI) index for domestic cruel oil, the long-term power contracts don't have a national index price that can be actively traded on the market place. All power contracts are defined by spatial and temporal attributes (location and seasonality specific), i.e. PJM West Hub Calendar Year 2013 On-peak contract or MISO Indiana Hub Calendar Year 2013 Off-peak contract. Long-term power prices are based on long-term fuel price forecasts and the expectation of short-term LMPs realizations which are in turn determined by congestion pattern as well as the supply and demand condition within a specific region. In addition, long-term power trading involves significantly more risks than most other commodities due to fuel prices volatility, transmission and generation outages/upgrades, inaccurate long-term load growth forecasts, regulatory uncertainties like carbon tax and capacity market payments, etc., many of which are too big to be borne by investors alone. All these inherent characteristics of electricity subdue a long-term liquid trading environment.

On the other hand, the current short-term energy and ancillary services markets operated by ISOs would not provide sufficient new investments incentives for a sustainable long-term electricity provision. And even if those short-term revenues could recover the capital costs, the intrinsic price volatility attributed to non-storability of electricity and the need to balance of supply and demand instantaneously prevent investors to undertake such endeavors. New types of long-term market mechanism which can provide more stable revenue stream for the investors are needed to fill in the gap.

The SEM structure is comprised of a series of sequentially cleared forward sub-markets with various temporal durations and spatial granularities. Forward sub-markets are designed for physical and financial market participants with periodic bidding and clearing processes on daily, monthly, seasonal, annual and multi-annual basis. Short-term sub-markets, similar to the current DART markets operated by ISOs, are designed to balance the deviations from real load pattern and cleared commitments from mid- and long-term markets. The SEM structure resembles the way in which the electric power capacity was planned and used in the past by the industry: large, base-load power plants were built and dispatched to supply a large 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. Figure 9 is an illustration of the market partition for various sub-markets within the SEM.

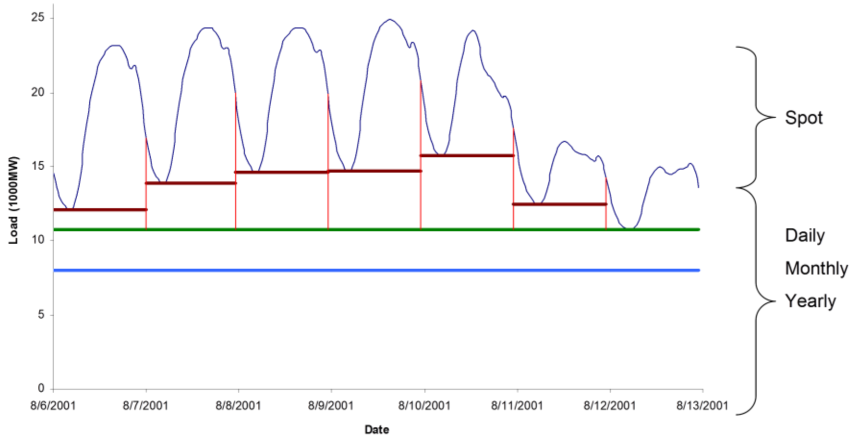

Figure 9: SEM market partition

Different LSEs or Gencos have individual risk preference within different time horizons. Uncertainties are larger under longer planning horizon and diminishes in shorter term operation horizon as more information becomes available and uncertainties abase along the way. This dampening effect is shown in Figure 10. These layers of forward markets with different time horizons will provide the opportunities for both supply and demand sides to reevaluate their risks and adjust their decisions as time goes by.

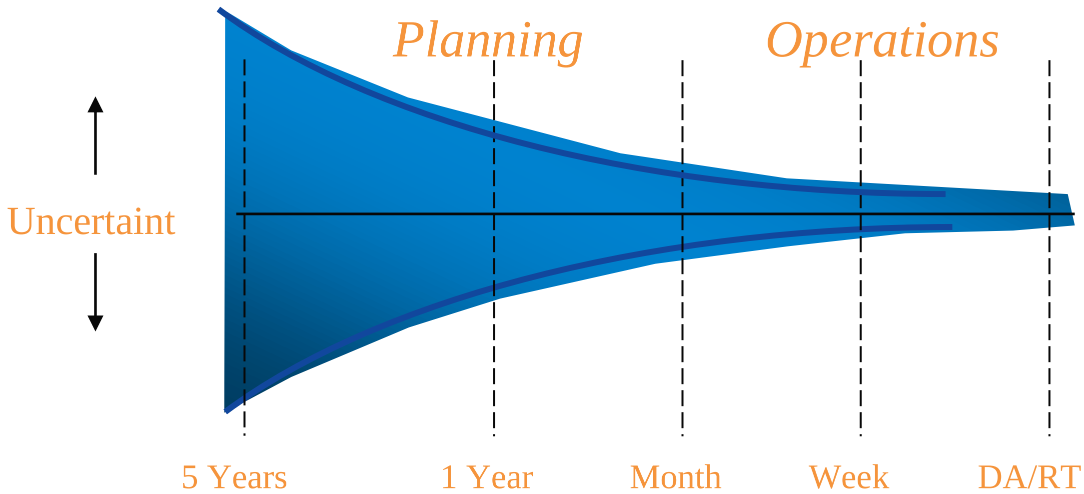

Figure 10: Uncertainty as a function of time horizons

4.4 *Market Designs and Rules*

In this section, we discuss detailed market product designs. Market products in SEM can be categorized on both temporary granularity as well as spatial granularity. We propose market rules, rights and regulations (3Rs) concerning the sub-markets interactions, product hierarchy and financial settlements.

4.4.1 Temporary Granularity

The products can be generally grouped into two categories based on their temporary durations: Long-term heat-rates and short-term energy.

Long-term heat-rate market auctions are held on an annual basis with terms extending to as far as Year N in advance. To account for possible construction time, one-year lead time is provided as a buffer. For example, in year Y, the long-term auctions are held with terms ranging from Y+1 to Y+N. In each such auction, long-term products can be further refined by different seasons and time-of-use (TOU) to capture the seasonality of the electricity as a special commodity. Assuming that two seasons (Winter and summer) and two TOU of on-peak and off-peak hours are considered and that the maximum number of years we considers into the future (N) is five, there are a total of twenty products available for market at year Y. They are:

Y+1 winter on-peak, Y+1 summer on-peak;
Y+1 winter off-peak, Y+1 summer off-peak;
Y+2 winter on-peak, Y+2 summer on-peak;
Y+2 winter off-peak, Y+2 summer off-peak;
Y+3 winter on-peak, Y+3 summer on-peak;
Y+3 winter off-peak, Y+3 summer off-peak;
Y+4 winter on-peak, Y+4 summer on-peak;
Y+4 winter off-peak, Y+4 summer off-peak;
Y+5 winter on-peak, Y+5 summer on-peak;
Y+5 winter off-peak, Y+5 summer off-peak;

Market participants may elect to participate in the auctions of any of above products. The total number of products can be calculated by the following equation.

Number of products = Number of Seasons * Number of time-of-use period * N

Trading transactions across the sub markets are allowed. The long-term contracts purchased in a previous auction can be offset by sales in a later auction. For example, if market participant A bought 10 MW of Y+5 winter on-peak energy contract in year Y auction, they can sell up to 10 MW of same product in the following year long-term auctions, namely Y+2 to Y+4 long-term auctions. In this sense the long-term contracts are financial in nature. The financial players without the physical assets could also arbitrage among the markets if sufficient credits are posted under the designated accounts. Also in long-term auctions, the cleared products are heat-rate instead of actual MWhs. This feature will be discussed in detail in section 4.4.3.

For short-term DART markets, the energy products are similar to current 24 hour DAM and hourly RTM arrangements with MWh as quantity and $/MWh as price. The outstanding heat rate positions obtained from long-term auctions are carried into DAM/RTM on daily basis and settled against the reference fuel prices for the specific trade day. The market participants are required to demonstrate that they can fulfill their obligations by physical assets in real time, i.e. generators or tolling agreements or firm importing contracts. Otherwise, the market participant is subject to a heavy penalty for non-delivery. In this sense, these obligations are physical in short-term DA/RT markets.

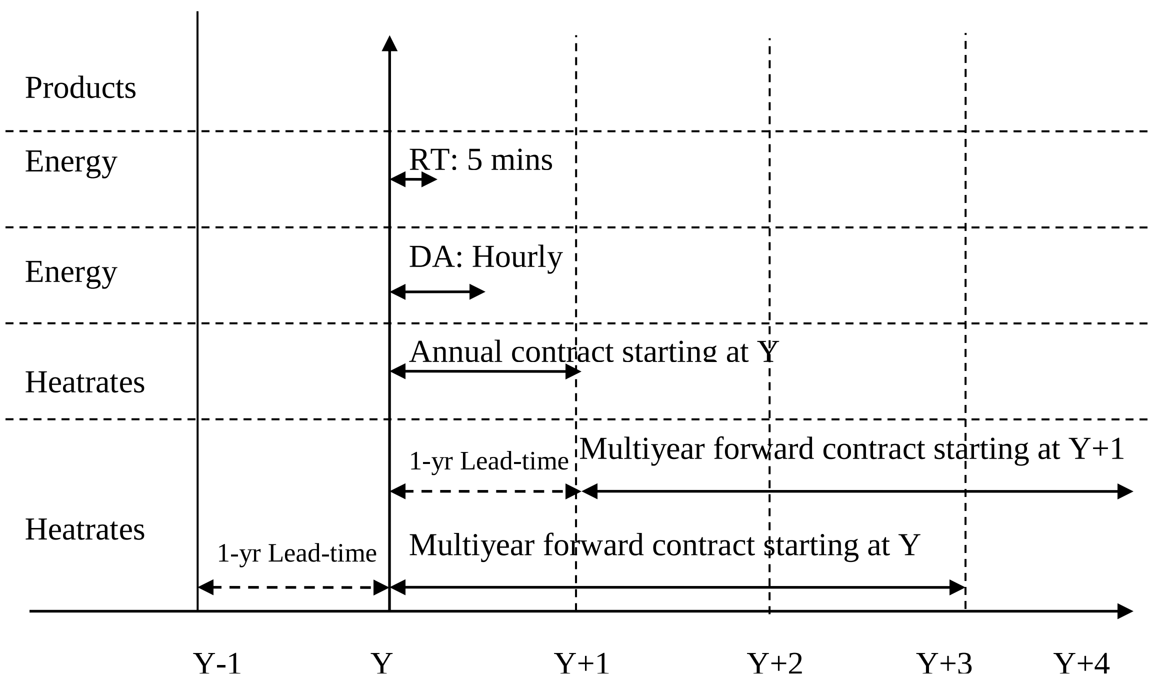

Figure 11: SEM market products

4.4.2 Spatial Granularity

For the long-term market, futures contracts are settled against the prices at the aggregated zonal locations which have higher open interests instead of more detailed intra-zonal nodal locations. This design would promote liquidity and concentrate the trading activities to only a handful of locations, mainly Generator Hubs and/or Load Aggregation Zones. Moreover, these arrangements also align the SEM long-term electricity trading activities with the current long-term bilateral OTC energy deals, which mostly settle on the widely traded zones or hubs. This configuration also implies that only inter-zonal transmission constraints such as interface and/or branch group limits will be enforced in long-term auctions. The intra-zonal and local transmission constraints and nomograms would be relaxed in these auctions to simplify the clearing process and facilitate trading activities. For example, within CAISO control area, only NP15, ZP26 and SP15 three zonal locations would be available in long-term markets even though currently there are more than three thousand LMP locations calculated in DART markets. Only Path 15 and Path 26 branch group constraints and other significant intertie constraints would be enforced in long-term market.

For short-term markets, all the existing LMP locations in current short-term markets would be available and full network model will be utilized in LMP calculations the same way as they are administrated today in DART markets. In addition, all short-term positions need to be backed with physical generation assets/demand loads and/or firm import/export from neighboring balancing authorities at intertie locations. The long-term zonal positions are broken down into nodal locations based on Generation Distribution Factors or Load Distribution Factors. More design principles on product hierarchy and market interactions will be discussed in section 4.5. Examples are given to demonstrate such design principles.

4.4.3 Heat Rate as long-term market product

One innovation of SEM market design is the adoption of heat rate instead of energy as the means of settlement in long-term markets. Cost of power generator can be approximately estimated from the physical heat-rate of certain power plants and the designated fuel price.

Electricity price ($/MWh) = Heat rate (MMBtu/MWh) * Fuel price ($/MMBtu)

In recent years the fuel prices have became increasingly volatile. As shown in Figure 12, the natural gas settlement price for flow date delivered at Henry Hub from 2002 to 2011 has experienced wild swings (Platts, 2012). The price of gas started at $2/MMBtu and ended at $2/MMBtu with huge spikes as high as $18/MMBtu in between.

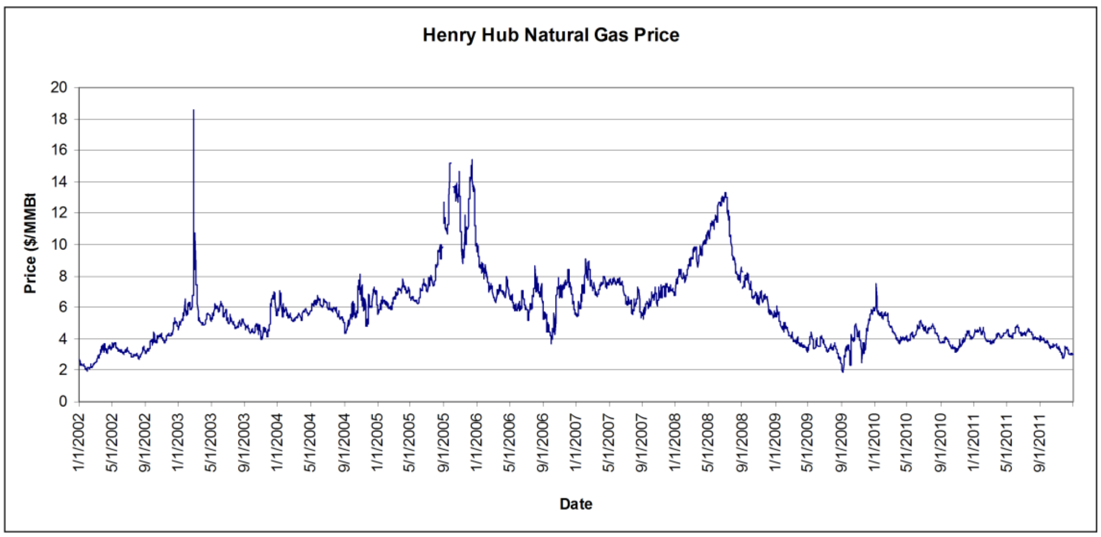

Figure 12: Platts Gas Daily Henry Hub Flow Date settlement prices

Such fuel price fluctuation poses substantial risks for long-term energy contracts in SEM, especially annual auction or multi-year auctions. For example, suppose one generator with heat rate of 10 clears 100 MW at $50/MW for one specific long-term contract. If the fuel price drops below $5/MMBtu, then this transaction is profitable; otherwise, the plant would lose money. In order to mitigate such risks, long-term market products can be organized in terms of heat rate instead of energy price. For example, if the same market participant is awarded with 100 MW at the price of 12 heat rate, then this unit would have a profit of 2 heat rate. Of course, the exact dollar value of the profit depends on the realized gas price in short-term market. If the daily natural gas settlement price is \$10/MMBtu then the implied electricity price is \$100/MWh and implied profit margin is \$20/MWh. If the daily natural gas price is \$5/MMBtu then the implied electricity price is \$50/MWh and implied profit margin is \$10/MWh. No matter whether the market participant decides to carry the position over to the short-term energy market, or to cancel out the existing position with sell offers in the later long-term auctions for the same product, they would make a profit above their cost no matter how gas price fluctuates as time goes by. In this sense, heat rate trading allows market participants to partially hedge against fuel price risks.

If the investor is risk-averse, the profit could be lock-in with a long-term gas contract of the same duration term as the heat rate contract. Assuming the unit is able to obtain a long-term gas contract at \$6/MMBtu, then the secured long-term profit is \$12/MWh. If the long-term gas contracts are illiquid and can not be purchased, settlements against heat rate rather than energy price at least provide the assurance that the unit will not lose money by this transaction. Therefore, heat rate as a product would promote long-term trading activities by limiting the risks associated with fuel price adverse movements while providing the possibility of fully or partially hedge option if the corresponding long-term fuel contracts could be obtained.

For each long-term product in the market, i.e. different season and/or time-of-use categories, different fuel types could be designated as the settlement fuel price according to the generator's own technical characteristics. Unlike the current capacity markets designs such as PJM RPM model where capacity prices are set uniformly by a new entry of natural gas Combustion Turbine unit, the long-term heat rate trading is fuel source specific and generation technology specific, such as coal heat rate for off-peak hours or natural gas heat rate for on-peak hours. Basically, different generators should be treated differently in the market place according to their own unique characteristics. This design makes more sense since the technologies which take longer to build and need a longer time to recover cost must be evaluated over much longer future time horizons than the smaller-scale less expensive technologies. Since the marginal units under current markets are most likely fossil fuel units, these heat rates also provide the indication of opportunity costs for the generation technologies that are not fossil fuel dependent, i.e. hydroelectric and renewable resources in the markets.

In addition, such designs are made feasible since most actively-traded regional electricity market zones/hubs coincide with a regional gas/coal price hub. For example, PG&E citygate natural gas hub price could be used to settle the NP15 zonal in CAISO and SoCal natural gas hub price for SP15 zone. A detailed mapping between major electricity hubs and corresponding fuel hubs is listed in Table 6.

Table 6: Electricity Hubs and corresponding Fuel Hubs

Electricity Hub	**ISO**	**Natural Gas Hub**	**Coal Hub**
Western Hub	PJM	Texas Eastern M-3	Central Appalachia
Indiana Hub	Midwest ISO	Chicago Citygate	Illinois Basin
Zone G	New York ISO	Transco Zone 6 NY	Central Appalachia
Mass Hub	ISO New England	Algonquin	Central Appalachia
North Hub	ERCoT	Henry Hub	Texas Lignite
NP15	California ISO	PG&E Citygate	N/A
SP15	California ISO	SoCal Gas Citygate	N/A

4.5 Product Hierarchy and Market Interactions

Due to the fact that multiple products with various temporal time horizons and spatial granularities are cleared in both long-term and short-term markets under SEM design, their interactions should be dealt with properly. The basic market rules are listed below:

1. Already obtained long-term position can be sold back in sequential long-term auctions. In this sense, all long-term market positions are financial in nature.

2. Market participants with cleared long-term positions and the intention to carry them over into short-term markets need to submit their bids/offers again in short-term markets. If the market participants don’t resubmit their bids/offers to cover the cleared positions from long-term auctions, the existing positions would be deemed as sellback at the price in short-term market. This setup would simplify the financial settlement process and reduce the confusions generated by positions cleared at multiple strata. Detailed examples are provided in the section 4.5.1.

3. All bids/offers/self-schedules submitted into short-term DA/RT markets need to be associated with physical power generation facility/ load demand and/or firm import/export from neighboring balancing authorities at intertie locations. If the long-term cleared positions cannot be tied to a physical facility, then it will be treated as sellback in short-term markets and may be subjected to a penalty price for non-delivery.

One importance implication of such a setup is that only the arbitrages that converge the prices between different markets are profitable. Assuming that the prices for the same long-term product at Y+1 auction and Y+2 auctions are P1 and P2 respectively and P1 is less than P2. Then the profitable trade for financial players would be buy at P1 at Y+1 auction and sell at P2 at Y+2 auction. By submitting buy bids at Y+1 auction, the financial player actually increases demand and raises the P1 price. Similarly, by submitting sell offers at Y+2 auction, the financial player actually increase supply and lowers the P2. Thus, this transaction effectively converges the price between the two auctions. Only the financial transactions which smooth out the price difference between those auctions are profitable.

4.5.1 Financial Settlements

The key to financial settlement under SEM market structure is the incremental settlement rule: only the additional cleared positions at higher strata are settled against the price of higher strata.

For example, assuming unit A

1. cleared position Q1 at price P1 for year Y + 2 contract in year Y auction

2. cleared position Q2 at price P2 for year Y + 2 contract in year Y+1 auction

3. cleared position Q3 at price P3 in short-term market within one day in year Y + 2

Then the final financial settlement for the market participant for that day is demonstrated in Table 7 below:

Table 7: Market Settlement Formulations

Markets	**Price**	**Quantity**	**Settlement**
Y+3 contract at Y auction	P1	Q1	P1Q1
Y+3 contract at Y+1 auction	P2	Q2	P1Q1 + (Q2-Q1)P2
Short-term DA Markets	P3	Q3	P1Q1 + (Q2-Q1)P2+ (Q3-Q2)*P3

The above example simplifies the problem by ignoring some key features of the SEM market mechanism, i.e. the different products traded in long-term and short-term markets are at difference spatial granularities. Some more detailed examples are shown below to demonstrate the financial settlement process for different market participants.

4.5.1.1 Incremental offers by Gencos

Assuming Gencos X

1. sells 20 MW at 5 heat rate for year Y + 2 zone A contract at year Y auction

2. sells 30 MW at 7 heat rate for year Y + 2 contract in year Y+1 auction

3. sells 10 MW at $5/MWh at location A1 within zone A and 30 MW at $30/MWh at location A2 within zone A within one day in year Y+2.

Assuming the daily reference fuel price is $2/MMBtu, the final daily settlement for Genco X is

20*5*2+(30-20)*7*2+(10+30-30)*10/(10+30)*5 + (10+30-30)*30/(10+30)*30

Effectively, for that day, player X sells 20 MW at $10/MWh at year Y auction, sells additional 10 MW at $14/MWh at Y+1 auction and sells additional 10 MW in DAM at two different locations at $5/MWh and $30/MWh. The total generation from X is 40 MWh in zone A. Before the short-term market, a large portion of energy (30 MW out of 40 MW) was already locked in the long-term markets. Only the additional 10 MW were subjected to the short-term market price volatility. In this way, risks are distributed among different layers of market.

4.5.1.2 Arbitrage by financial player

Assuming financial player Y

1. clears 20 MW at 5 heat rate for year Y + 2 zone A contract at year Y auction

2. clears 30 MW at 7 heat rate for year Y + 2 contract in year Y+1 auction

3. In short-term DAM, the financial player cannot back up their existing positions with physical generation facilities and clears 0 MW at the price of $20/MWh.

Assuming the daily reference fuel price is \$2/MMBtu, the final settlement for Y in that hour is

20*5*2+(30-20)*7*2+(0-30)*20

Effectively, player Y sells 20 MW at \$10/MWh at year Y auction, sells additional 10 MW at \$14/MWh at Y+1 auction and buy-back all 30 MW in DAM at a higher price of \$20/MWh. The total generation for that day is 0 MWh.

4.5.1.3 Purchase in long-term and sell-back in short-term

Assuming market participant Z

1. clears 20 MW at 5 heat rate for year Y + 2 zone A contract at year Y auction

2. clears 30 MW at 7 heat rate for year Y + 2 contract in year Y+1 auction

3. In short-term DAM, Z clears 5 MWh at \$5/MWh at location A1 within zone A and 10 MWh at \$30/MWh at location A2 within zone A.

Assuming the daily reference fuel price is \$2/MMBtu, the final settlement for Z for that day is

20*5*2+(30-20)*7*2+(5+10-30)*5/(5+10)*5 + (5+10-30)*10/(5+10)*30

Effectively, player Z sells 20 MW at Y auction, sells additional 10 MW at Y+1 auction and buys back 15 MW in DAM. The net generation for that day is 15 MWh.

4.5.2 Role of ISO/RTO

The forward markets can be subdivided into long-term markets and short-term markets according to the load cycles. All forward markets are auctioned off sequentially from longer-term to shorter-term. For example, at the end of year Y an annual forward auction for year Y+1 would be held and annual forward positions and prices are determined. Then the monthly forward auction for January Y+1 would be held successively. The total demands in each forward market can be decided in two ways.

1. The administrative approach: The ISO uses the forecasted minimum load (or a portion of it) as the demand quantity and requires LSEs to acquire their shares.

2. The market approach: supply and demand sides submit their bids/offer for the forward markets and the price and quantity are determined by the market.

The forward markets are organized and administrated by the ISO. The market clearing prices are published by ISO to public to increase price transparence. The credit worthiness is also monitored by a central agency to reduce credit risks like defaults. The price in each sub-market is determined by the uniform auction: the last offer that meets the demand sets the price. Power system models such as full network models are also maintained by ISO to facilitate the market execution.

4.6 Key Features and Comparisons

The values for the same amount of electricity at different time and at different location can vary dramatically. Moreover, for the same hour, the values for the same amount of power at base load level or at peak load level are different due to the different generation technologies and other non-convex constraints like unit commitment. The multiple forward submarkets at zonal/nodal levels with different time horizon and TOU categories are designed to reflect more realistic demand and supply conditions at various temporal and spatial granularities.

SEM provides a good platform for the stakeholders to interact through a centralized flexible market place to make their commitment decisions in both long-term forward markets as well as short-term balancing markets. The strata of energy markets with different lead time and terms allow both demand and supply sides to adjust their portfolio according to their own risk preference levels and manage the volume risk and price risks as market evolves and more information becomes available. A good market structure should provide sufficient risk management tools to reduce short-term volatility and hedging physical and financial uncertainties. Multiple forward markets are perfectly designed instruments to hedge the spot market risks.

No administrative demand curves. Unlike LICAP is ISO-NE or RPM in PJM, ISO would not administrate the explicit generation capacity or reserve price requirement. The investment decisions are guided by expectations and economic incentives..

No price caps. Although short-term market price spikes may rise very high during the peak hours, most of energy has already been settled in long-term markets beforehand. Such high prices will have much less impacts on market participants' bottom line as well as the total costs of electricity. These price spikes are important market signals since they encourage the participation of the long-term markets and forward hedging.

Natural solution for unit commitment (UC) constraints. The UC problem (Wood, 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 also 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 short-term markets. In this way, a system operator need not maintain these constraints explicitly.

As mentioned before, demand elasticity is higher in the long run. Long-term markets may provide a vehicle to capture the long-term demand elasticity.

The following table compares SEM with other proposed solutions using the performance matrix proposed at the beginning of this chapter.

Table 8: Performance Matrix comparison between SEM and other proposed solutions

	Regulated	Market – current	Market-SEM
Keep the lights on	Good	Focus on short-term. Not much long-term mechanism to encourage the new investments. Capacity markets have their own problems. Available capacity does not mean sufficient energy supply. Old units can just sit there collecting $$ w/o generation.	The market will decide what is the right capacity. LSE and Genco will hedge their long-term risks by entering into long-term energy markets.
efficiency and economic solution	Gold plate: over capacity. How much do we need? Utility forecast inaccurate: consumers bear the consequences. Inelastic demand curve	Good for short-term DA/RT LMP based dispatches. Not good for long-term. What is the right number for capacity? Administrative demand curve for capacity market may be wrong. LSE and eventually consumers pay the price.	Keep the same RT/DA structures for short-term efficiency. The long-term efficiency will be achieved through the long-term market dynamics. LSE also participant in the markets by submitting elastic demand curve for their long-term energy needs.
Tools for risk management	Little: no need to manage risk: all guaranteed cost recovery. Consumers pay the bill.	Not much. Long-term fuel price risks not easy to mitigate.	People can adjust their portfolios through different layers of markets to manage their risks. Encourage long-term commitments by assigning higher priority to long-term cleared quantities. Promoting stability and reduce volatility. Hedging long-term fuel price risks by clearing heat-rates instead of electricity in long-term markets.
business model	Large	Centralized markets. Counterpart default risks low and costs are socialized.	Centralized markets. Counterpart default risks low and costs are socialized. Collateral requirements and penalty prices for non-delivery.
environment impacts	No measures to address the environment issues	Up to one year cap and trade emission markets. Not long enough.	Cap-and-trade emission markets. Similar to energy structure.
encourage new technology	No incentive due to fully recovery of costs.		Encourage the new technology with lower costs comparing to conventional fossil fuel generation technologies

4.7 *Enhancing the FTR and Emission markets*

The basic electric energy SEM described in this chapter could be expanded to integrate other markets, such as the long-term Financial Transmission Rights (FTR) markets, and the cap-and-trade Emission markets. This integration would enable us to manage other long-term uncertainties which are unique to the electricity, i.e. transmission congestion and environmental constraints, through market mechanisms. Similar market rules could be construed to provide the participants a flexible and effective way to readjust their decisions as more information unveils along the way. A complete long-term SEM setup, which includes FTR and cap-and-trade emission markets would achieve the long-term sustainability by addressing risk from various spectrum of the electricity industry.

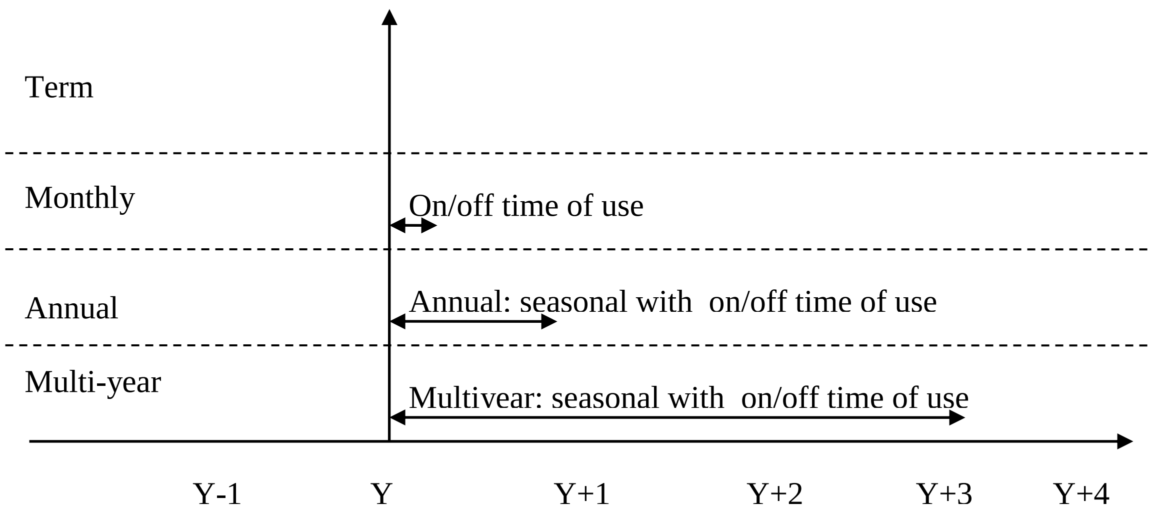

Figure 13: Long-term FTR markets

Exploration of integrating the basic electric energy SEM with the long-term Financial Transmission Rights (FTR) markets, and ultimately, with the cap-and-trade Emission Market are suggested as future open problem. Only the basic vision for aligning long-term electric energy SEM with the long-term FTR markets and cap-and-trade emission markets is described here. This integration would enable us to manage other externalities unique to the electricity such as transmission congestion and emission control. A complete long-term energy SEM, FTR and cap-and-trade emission markets setup would lead to achieving long-term sustainability by addressing all risk premiums and their inter-dependencies.

5 Implications of Market Designs on Long-term Sustainable Electricity Provision

In this chapter, we illustrate the effects of different market designs in the electricity industry on the long-term sustainable electricity provision in terms of resource adequacy, i.e. new investments on generation capacity, through simulations. Of particular interests are monetary incentives for inducing near-optimal capacity by means of long-term market mechanisms. We also investigate how these new investment decisions affect the economic performance of individual market participant and the long-run social welfare of the system as a whole. Detailed models of the decision-making process for individual market participants as well as the ISO market clearing process under spot-only market and the newly proposed SEM markets are presented. A stochastic long-term load model, which was first introduced by Skantze and Ilic (Skantze, 2001), is adopted here to represent the long-term uncertainties derived from load forecasts.

In Section 5.1 we briefly review the generation investment problem and in section 5.2 a generic modeling approach based on fundamental physical and economic drivers in the markets is proposed. In Section 5.3 a simplified realization of the generic model with stochastic load and deterministic fuel prices is introduced. The objective of social welfare maximization is used as the basic benchmark for evaluating different market structures (Ross, 2005). Both spot market only structure and our newly proposed Stratum Electricity Market (SEM) structure are studies. The effects of centralized system planner versus decentralized decision maker, different assumed bidding strategies, and interactions among various decision makers through the interactive learning process are also analyzed and simulated. Section 5.4 offers preliminary results concerning the problem of generation expansion in the changing industry. Conclusions are summarized in Section 5.5.

5.1 Survey on Basic modeling methods

5.1.1 Objective function

The problem of investment 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 (Ross, 2005).The NPV is calculated by integrating the expected payoff ψ from the market, which is a spread between revenue received in the market and the cost of providing electricity, adjusted by the discount rate ρ over the period of evaluation T.

$$NPV = \int_t e^{-\rho t} E\{\psi_t\} d\,t$$

Given multiple investment options, the NPV rule states that the firm should choose the option with the highest positive NPV. The revenue received in the market depends on the market rules and price predictions. One big challenge is to determine the appropriate discount rate, which must reflect the time value of money and the level of risk evolved in the investment.

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 selected.

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

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.

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

The fourth approach is based on real option theory which applies principles from financial option valuation for appraisal of investments in real assets (Dixit, 1994). Its basic argument is that investment projects with uncertain future cash flows should be considered as options, if the decision is irreversible and the timing is flexible, which are often true for generation investment decisions. The optimal investment can be made when net cash flow from the project equals the value of having the option to invest in the future.

The results in this chapter are based on the conventional NPV method. Further extensions to other criteria are explored in later chapters.

5.1.2 Modeling electricity prices

It is self-evident that the expected payoff of the investment depends on the electricity market prices. Currently, there are a number of methods to model the price process.

1. *Statistical modeling* (Schwartz, 1997). The user attempts to find the lowest order model possible to describe the stochastic properties of the prices. The parameters are derived from historic data.

2. *Economic equilibrium based modeling* (Hobbs, 2000). Game theory based economic models like Cournot pricing are one of such applications.

3. *Agent based modeling* (Visudhiphan, 2000). Depending on the objective function of each agent and observation of current price levels, agent updates his strategy using artificial intelligence methods. The market prices are the output of individual bids.

However, electricity markets are constantly evolving, driven by the physical demands, supply and market rules. All the above methods are static in the sense that they only apply to certain market setup and neglect the underlying drivers in the system.

5.1.3 Fundamental modeling approach

To model electricity markets we start by modeling the dynamics of physical drivers in the system, such as load demand, generation capacity and fuel prices. Then the economic drivers, such as bidding strategies of market participants, as well as the public policy variables, such as market structures and rules, also need to be defined in the problem. Based on the dynamic interactions among all physical, economic and public policy variables, the expected financial outcomes such as electricity prices, individual participant’s profits and total social welfares become the outputs of the overall model. This should be contrasted with the priori postulated models such as Black-Sholes. Examples of this approach can be found in (Skantze, 2001) where electricity price was modeled for a spot market only structure with the aggregated system supply and demand processes. The applications of such approach on valuing generation assets are introduced in (Botterud, 2005).

The basic participants in the electricity markets are generation companies (Gencos), Load Serving Entities (LSEs), and the market administrators/policy makers, the Independent System Operators (ISOs). A system diagram depicting these participants and their interactions is illustrated in Figure 14. Depending on how detailed models are used, and on which component is exogenous or endogenous within the diagram, the actual electricity market process can be captured at different level of accuracy. The main objective of fundamental-drivers-based electricity market modeling is to retain variables and parameters that shape the market outcomes to the greatest extent.

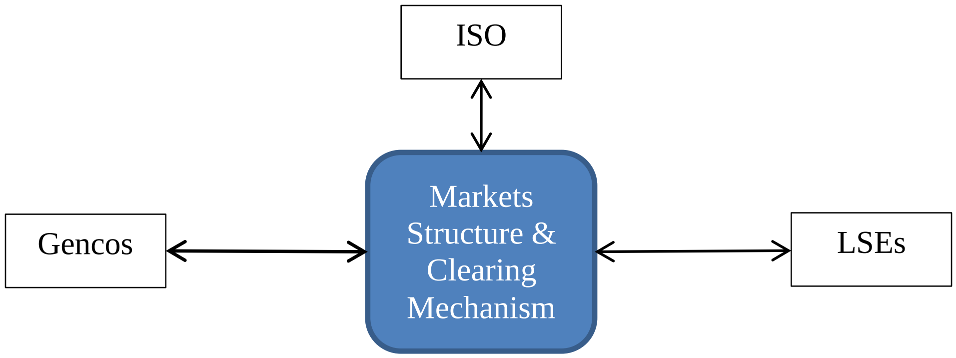

Figure 14: Market Participants and their interactions

In this chapter, the fundamental modeling approach is further developed by the following three decision making sub-processes:

1. Decision making by the generators
2. Decision making by the LSEs
3. Decision making by ISOs with the market clearing mechanisms

Using this modeling approach, the prices seen by various market participants become the results of interactions within this complex decision making process. This modeling extension is critical for managing and valuing physical and financial risks over a variety of time horizons. When the approach is extended to a very long time period, it can be applied as a means of evaluating and making the investment decisions for a given market design. It can be further used to evaluate the effects of market structures and rules on various market attributes.

5.2 Simulation Model formulation

In the remainder of this chapter 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 in (Skantze, 2001) and briefly reviewed in section 5.2.1.

5.2.1 Stochastic load model

One of major risks facing potential generation investors is the uncertain load forecast. The key characters for electricity demand which we want to capture in the model are: seasonality, mean reversion and stochastic noises in short-term process and stochastic growth in long-term process. To simplify the problem, the load is assumed price inelastic. The daily load can be modeled as a 24 hours vector L_d where each row represents an hourly load ([24*1] vector). This vector is defined as :

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

where μ_m is the monthly average hourly load and the stochastic component r_d is the daily deviation from the monthly mean. It has 24 hourly random variables. However, because of high intra-daily correlations between these hours, we applied Principal Component Analysis (PCA) on the stochastic component r_d. PCA enables us to dramatically reduce the number of random variables while keep most of valuable information. Only the first Principle Component (PC) and its associated weight w_d is kept in our model. Statistical results show that the first PC could explain more than 90% of the total variance of the demand. Now the daily load process can be further simplified as following:

$$\vec{L}_d = \vec{\mu}_m + w_d \vec{v}_m \qquad (5.1)$$

The vector v_m is the new Principle Components for each month m and w_d is its daily evolving score. In order to capture the demand growth uncertainties which incorporate both long-term growth and short-term excursions, we choose a two factor mean-reverting model to describe the w_d process.

$$\begin{aligned} & w_d = \delta_m + e_d \\ & e_{d+1} - e_d = -\alpha e_d + \sigma_m z_d, z_d = N(0,1) \\ & \delta_{m+1} - \delta_m = \kappa + \sigma \ z_m, z_m = N(0,1) \end{aligned} \qquad (5.2)$$

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

Using the historic hourly demand data from 1993 to 2003 on ISO New England website (ISO-NE, 2006), the parameters [δ_m α κ σ_m σ] in the load model can be estimated from historical demand data. For a more detailed description, please refer to (Skantze, 2000).

After all parameters are calibrated, the load model can be used to generate the forecasted load series. The time horizon for our investment problem is set at 10 years. Total 100 sample load series for the next 10 years are generated to use in the simulations. The annual average and standard deviation of hourly load are shown in Figure 15 and Figure 16.

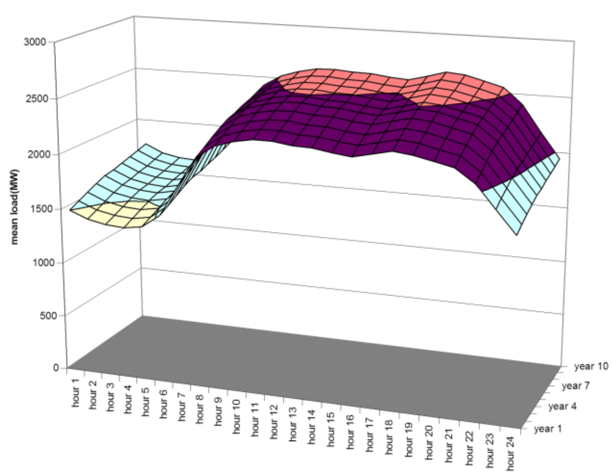

Figure 15:Annual average of forecasted hourly load

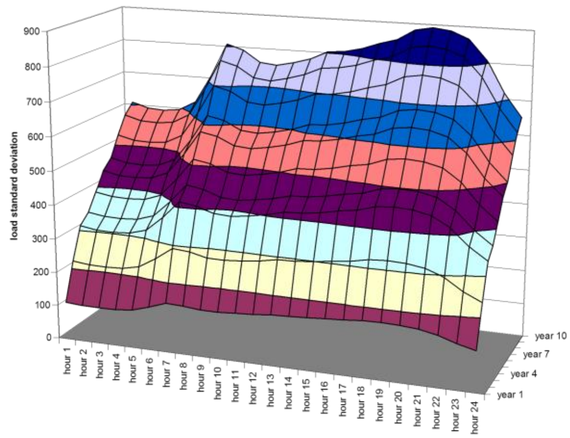

Figure 16:Annual standard deviation of forecasted hourly load

Not surprising, the average hourly load level is increasing from year to year due to long-term load growth. 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 Figure 15. The standard deviation increases at a much faster pace than the average load on the annual basis due to increased uncertainties.

5.2.2 Fuel price forecasts

Another long-term uncertainty described in chapter 4 derives from the fuel prices. Some of the main characteristics of fuel prices are similar to those of the load processes, such as seasonality, mean reversion to average after short-term shocks and growth in long-term. A two-factor stochastic model described in last section could be adopted to account for fuel price uncertainties. However, to simplify the problem, fuel price projections from the 2005 Electricity Information Agency Annual Report are utilized in our model.

Table 9: 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

Since the EIA fuel cost is based on the 2005 data, the gas price prediction is relatively low. In order to demonstrate the effects of high fuel price on electricity markets, a high gas price scenario is constructed manually for illustration purpose. The price series is assumed starting at $10/MMBtu with a 2% annual increase. Both fuel price forecasts, low gas profile and high gas profile, are used in the simulations to demonstrate the impact of fuel price uncertainties.

5.2.3 Generator Characteristics

A reduced generation fleet based on generation characteristics in the IEEE reliability test system are adopted in simulations. Generator and fuel characteristics obtained from these sources are summarized in Table 9 and Table 10, respectively. The nuclear unit variable cost is assumed as $0.4/MWh.

Table 10: 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**	**--**	**--**	**--**

Given the above generator technology characteristics and forecasted fuel prices, the Short Run Marginal Cost (SRMC) and Long-Run Marginal Cost (LRMC) for generator i in year m can be estimated using the following equations:

$$STMC_{im}=HR_i*FP_{im}+VOM_i$$

$$LRMC_{im}=STMC_{im}+LACC_i$$

where HR stands for heatrate, FP stands for fuel price, VOM stands for variable O&M cost and LACC stands for levelized annual capital cost. LACC can be calculated based on generator's capital cost, the discount rate and assumed number years of operation. Some of the bidding strategies in our model are based on the SRMC and LRMC of individual unit.

5.3 Market Design Scenarios under investigation

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

The decision making processes of both the central planner (ISO/RTO) and individual generators are explored in the chapter. The evaluation period for new investment projects is set at 10 years. At the beginning of year one, decision makers try to make their optimal investment decisions for given scenarios.

5.3.1 Assumptions

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

1. The SEM setup contains two sub-markets: an hourly spot market and a long-term annual market

2. In spot only market, generators submit their STMC as offers. In SEM setup, generators submit their full capacity at the LRMC for long-term annual market and the SRMC for spot markets.

3. A linear cost function is adopted and the marginal cost curve is a scalar.

4. A uniform auction clearing mechanism is employed for both markets.

5. The auction quantity for long-term market is set by the lowest hourly forecast in that year.

6. Each generator makes their own investment decision assuming the others will not expand.

To simulate the new capacity expansion results under different scenarios, a Monte Carlo technique is adopted. Since the only uncertainty in this 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 can be derived as final results.

There are total of six scenarios studied in this analysis. The only decision variable is the new investment decision of generator i at the beginning of simulation period.

5.3.2 Scenario 1: Centralized cost minimization

Under this setup, a system planner (ISO) makes coordinated investment decisions for all units facing the uncertain future under a spot market only market structure.

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. The blackout cost can be interpreted as an incentive based regulation which penalize the generation company if resource adequacy criteria cannot be met. Blackout hour variable u_n at hour n is defined as 1 if system demand L_n is larger than total capacity $\sum K_i^m$ and 0 otherwise. The long-term annual process is denoted by subscript m and short-term hourly spot market process is denoted by subscript n.

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

The blackout cost then can be 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 price $\mu_{blackout}$, which is set at \$1000/MWh.

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

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

$$\min_{(k_i^m)\, 1\leq i\leq G, 1\leq m\leq M} E\Big(\sum_i \sum_{m=1}^{M} e^{-\rho m T_m}\Big(\sum_{n=(m-1)T_m}^{m T_m} e^{-\rho n}\big(\underbrace{(1-u^n)\sum_i STMC_i^n(P_i^n)}_{\text{short-term production cost}} + \underbrace{u^n VOLL^n}_{\text{blackout cost}}\big) + \underbrace{CC_i^m(K_i^m)}_{\text{long-term capital cost}}\Big)\Big)$$

where

P_i^n: output of generator i at hour n

K_i^m: total capacity of generator i in year m

subject to

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

b. The capacity K expansion process:

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

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:

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

$$\forall u^n = 0 \begin{cases} \min_{P_i^n} \sum_i STMC_i^n(P_i^n) \\ s.t. \sum_i P_i^n = L^n : \lambda^n \\ P_i^n \leq K_i^m \end{cases}$$

5.3.3 Scenario 2: Centralized revenue minimization

Under this scenario, the central planner makes coordinated investment decisions in the spot-only market to minimize the 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 λ_i^n.

The objective function of the ISO can be represented as follows:

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

subject to:

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

b) Capacity expansion process:

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

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:

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

$$\forall u^n = 0 \begin{cases} \min_{P_i^n} \sum_i STMC_i^n(P_i^n) \\ s.t. \sum_i P_i^n = L^n : \lambda^n \\ P_i^n \leq K_i^m \end{cases}$$

5.3.4 Scenario 3 and 4: Decentralized Spot-only market design.

Generators make their own investment decisions in the spot-only market setup to maximize their expected profits. The profits are defined as total revenue minus total production cost, investment cost and possible blackout costs.

One possible enhancement of blackout costs is to consider the scarcity pricing rules under current DART market setup. The spot market price would jump to scarcity prices if the system demand is within a close range of total available capacity in the system. Here we use 90% utilization of capacity as a trigger for the scarcity pricing. To test the effect of such rule, two cases with or without such a rule, Spot A and Spot B respectively, are both simulated.

The objective function of generator i can be expressed as:

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

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:

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

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

5.3.5 Scenario 5 and 6: decentralized SEM market design

In this scenario generators make their own investment decisions in the 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 investigate the blackout costs with and without the scarcity pricing rule. Two cases, Stratum A and Stratum B respectively, are both simulated. The long-term market price is denoted as λ^m and the spot market price is denoted as λ_i^m

The objective function for generator i can be expressed as:

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

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. The load demand for long-term market in year m D^m 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 D^n.

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

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

e. The ISO economic dispatch process for long-term market at year m, where :

$$\min_{P_j^n} \sum_j LRMC_j^m (P_j^m)$$
$$s.t. \sum_j P_j^m = D^m : \lambda^m$$
$$P_j^m \leq K_j^m$$

f. The ISO economic dispatch process for short-term market at hour n:

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

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

5.3.6 Scenario 7: Repeated spot-only market design

In this case we examine the effect of information sharing and exchanges among different decision markers. This is done iteratively as follows:

1. Each generator makes optimal investment decisions assuming some initial values for the other partys' decisions. The decision making process is the same as in Spot A. The initial value of investment decision is set to zero.

2. The ISO will publish the market clearing prices and quantities of every unit at the end of each bidding round r. Optimal expansion decisions made by the others $\bar{k}_{i,r}^{m}$ for round r are also shared among potential investors.

3. Using the $\bar{k}_{i,r}^{m}$ as the updated initial value, 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 r and r+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.

5.3.7 Scenario 8: Repeated SEM market design

The iteration follows the same logic as in Scenario 7. Only this time we examine the effect of information sharing and exchanges with the stratum A market structure.

5.4 Numerical Results

Altogether, eight scenarios are simulated. The results under the low gas price profile are shown in Figure 17-Figure 20. The resulting generator investment decisions for these cases are shown in Figure 17. The resulting market attributes of interest, such as costs and revenues, are shown in Figure 18. The expected average electricity prices and associated standard deviations are shown in Figure 19. The expected average blackout hours and associated standard deviations are shown in Figure 20.

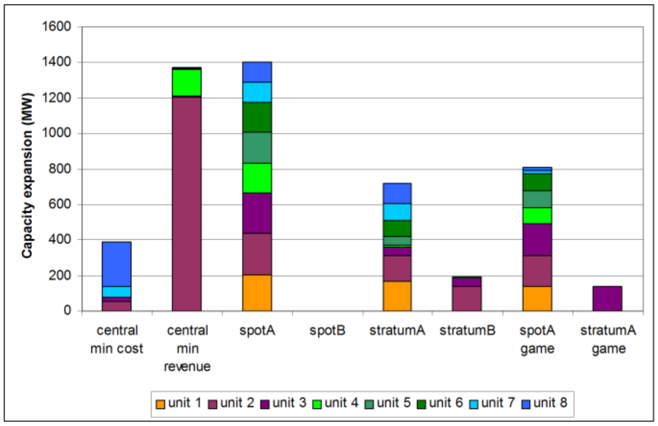

Figure 17: Generation capacity expansion under the low gas price profile

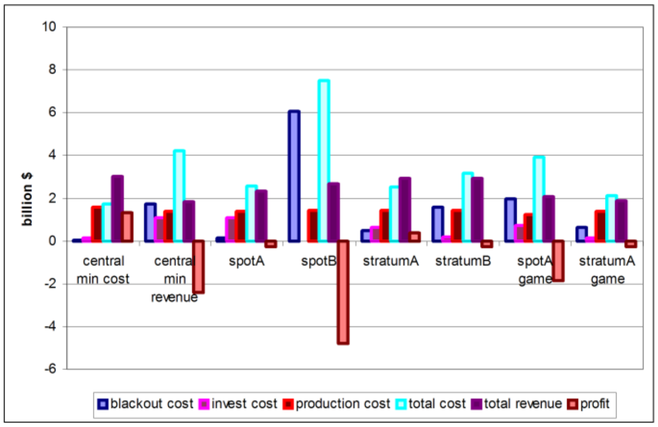

Figure 18: Revenue, production costs and profits under the low gas price profile

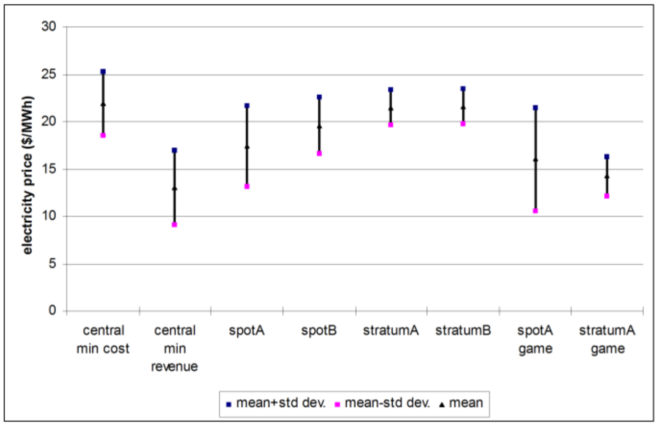

Figure 19: Average and standard deviation of electricity price under the low gas price profile

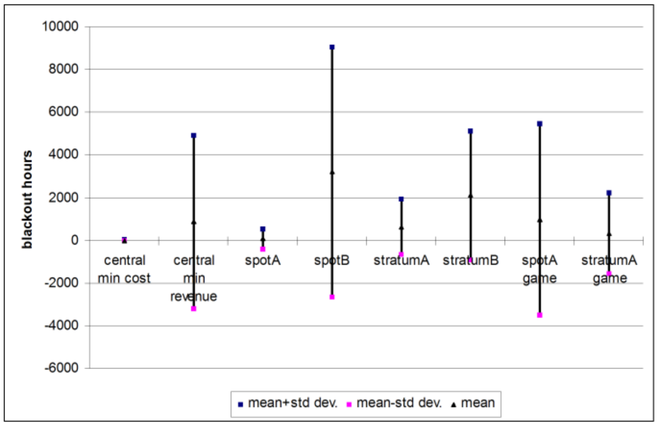

Figure 20: Average and standard deviation of blackout hours under the low gas price profile

The results show that if the investment decisions are made by a coordinating central planner like the ISO, the results are very sensitive to the objective chosen by the ISO. As shown in Figure 17, if the objective is to minimize total costs of electricity generation (central min cost), more peak-load generators should be built. However, this 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 instead 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 build anything under the spot-only market with no blackout costs charge in place (Spot B) since they would never recover their investment; a much larger capacity is added when the blackout cost is included (Spot A). 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 a spot-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-only setup.

Gaming among generators will reduce the investment incentives in both market structures, which will jeopardize generators' 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 Figure 21-Figure 24, respectively.

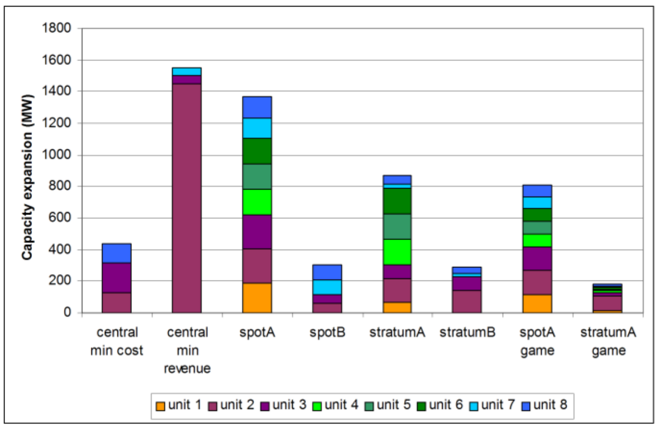

Figure 21: Generation capacity expansion under high gas price profile

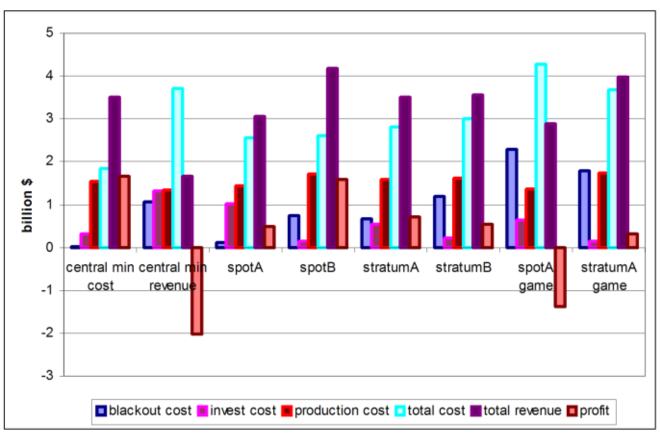

Figure 22: Revenue, production costs and profits under high gas price profile

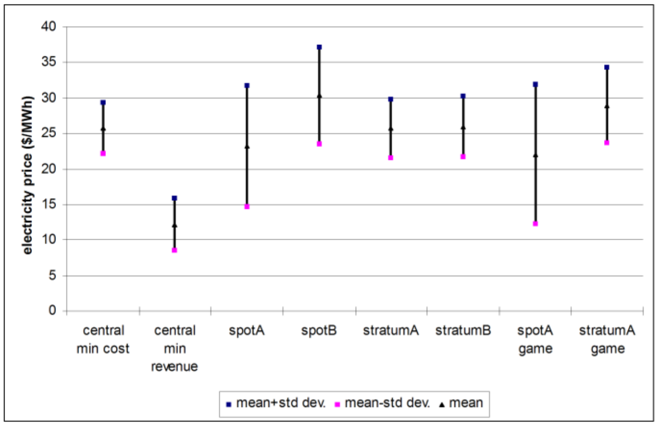

Figure 23: Average and standard deviation of electricity price under high gas profile

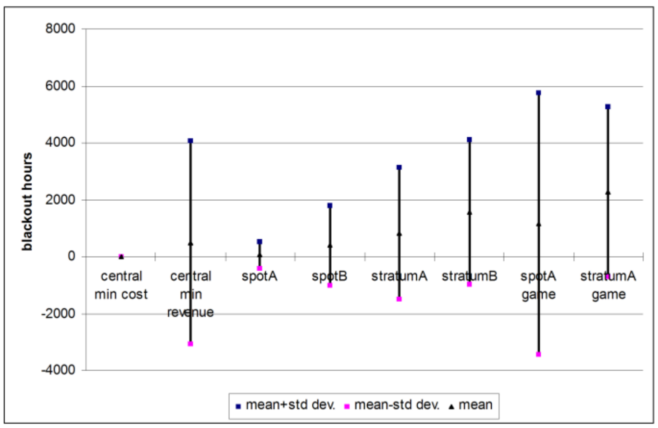

Figure 24: Average and standard deviation of blackout hours under high gas price profile

The basic results remain the same under high gas prices as in the case of low gas price scenarios. Different goals 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 lower price volatility. Gaming between players will always decrease investment and increase 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.

5.5 Conclusions

Given that today's measurements of market power in the spot-only market are classified as any bids higher than the SRMC cost, we suggest that it is essential to introduce other means to provide incentives for new generation capacity expansion in a timely manner to meet the long-term uncertain demand. This can be done by designing longer-term physical and/or financial mechanisms for valuing future investments. The Stratum Electricity Market (SEM) structure is one of such attempts. This market would eliminate the need for various installed capacity and reliability markets currently under consideration.

A fundamental modeling approach is further applied to model and simulate the SEM structure as well as the spot-only markets under different market setup. The following conclusions are reached:

1. Different market structures will affect both technical and economic outcomes of those of the individual market participants, generators in particular, and the system as a whole.

2. Short-term marginal costs based bidding rules currently implemented in the ISOs which focus on the spot-only structure do not provide sufficient signals to attract new generation investment, unless very high fuel prices are forecasted for the future.

3. The newly proposed SEM structure provides long-term price signals for investments as well as short-term price signals for supply meeting demand. It has the potential of drastically reducing the price volatility risks seen by the generators and others comparing to spot market only setup.

4. Market rules which encourage resource adequacy, such as blackout charges to generators, may lead to the better system reliability.

In this chapter, we have illustrated through simulation the effects of market designs on the financial outcomes of individual generators and resource adequacy problem for the system as a whole. Assumed bidding strategies for both short-term and long-term markets are used in the decision making process based on generator's SRMC and LRMC.

Moreover, the objectives of individual market participants in both spot market and long-term markets are measured in NPV based expected values. The risks associated with long-term and short-term uncertainties are not considered in the decision making process. In the next chapter, we will relax the above assumptions and reexamine the decision making process for both short-term and long-term markets.

6 Decision making in multi-temporal markets

In the previous chapters, SRMC and LRMC are assumed as the bidding strategies in short-term and long-term electricity markets. The objective function of the optimization problem is also NPV based expected values, which does not take into consideration associated risks. The decision making processes of individual market participants in both the short-term spot energy market and the long-term forward markets under the proposed SEM structure are reexamined in this chapter. The spot market is modeled as a bilevel non-cooperative game with the consideration of strategic bidding behaviors from market participants. A generic method to reach the possible Nash Equilibrium solutions is illustrated here through iterative learning process. A closed form solution of a pure strategy Nash Equilibrium under some simplifications is also presented here. The decision making process in the long-term forward markets is formulated based on mean-variance criteria which maximizes the expected future profits and minimizes the associated risks (variance) of those future earnings. The market equilibrium arguments are adopted to derive the optimal forward hedging positions and market clearing prices for supply side as well as demand side of the electricity wholesale market. Possible implications of such hedging activities are discussed.

6.1 Problem Formulation

In the traditional electric utility environment, system planning and operation used to be mainly driven by least-cost and reliability concerns. Under the restructuring and deregulation, new market participants with profit-maximizing business models are entering into the markets. Centralized, monopolistic decision-making organizations are replaced by heterogeneous, decentralized decision structures. The "single" decision-maker is replaced by a host of decision makers each with their own, unique business strategies, risk preferences, and decision models.

In the previous chapters, bidding strategies under different market setup were studied. In this chapter, we propose a more realistic decision making process for a Genco in the multi-temporal markets setup, i.e. the proposed SEM. Particularly, the following decisions making process needs to be revisited:

1. Bidding strategies for the short-term energy markets, i.e. DART markets

2. Optimal hedging strategies for the long-term energy markets, i.e. optimal hedging positions

3. New generation capacity expansion decisions, i.e. when to invest in new generators

Short-term markets, i.e. DART markets, are cleared on a daily, hourly, or even shorter 5-mins bases. Thus decisions need to be made more frequently. Long-term markets are cleared on seasonal or even longer annual bases. Such decisions need to be evaluated on a longer time horizon. New investment decisions are based on the evaluations of an even longer time horizon, most likely the lifetime of a plant. The uncertainties diminish from long-term to short-term as the market conditions evolve and unfold. When making long-term decisions, the associated risks need to be evaluated and priced-in in the process.

Each decision above depends on answers to the following basic questions:

1. What are known about the market structure: design/rules, inter-temporary relationships (LT/ST) and information exchanges mechanism between markets and players?

2. What is known about other decision makers?

3. What is the market clearing process?

4. How are future uncertainties in the bidding process valued?

Answers to these questions will determine:

1. The cleared market price and quantities for each market participant

2. The investment decisions made by investors and their profitability

3. The sustainability of the system as a whole and societal impacts, i.e. social welfare

In the following sections of this chapter, detailed models are formulated to address the above questions.

6.2 Decision making in Short-term markets

In the short-term markets, the long-term decisions have already been made. The long-term market prices and hedging positions are known at that time. The market rules and information flows are outlined below:

1. The ISO publishes load forecast and other system conditions

2. Players submit their bids/offers into the market to maximize their expected profits

3. The ISO clears the market and publishes price and quantities

If repeated auctions are adopted as the market rules, market participants adjust their bidding behaviors according to the information released in step 3. The private information such as competitor's cleared results is withheld by the ISO. Then players resubmit their updated bids/offers to the ISO markets. Step 2 and step 3 are repeated until a market equilibrium is reached. A Nash equilibrium is reached when nobody has an incentive to adjust their bidding strategies.

Under these rules, the short-term market could be modeled as bilevel non-cooperative game with the consideration of strategic bidding behaviors from market participants. A generic method to reach the possible Nash Equilibrium solutions is illustrated here through an iterative learning process. A closed form solution of a pure strategy Nash Equilibrium under some assumptions is also presented. Detailed models and assumptions are discussed in the section 6.2.1 - section 6.2.4.

6.2.1 Short-term market uncertainties

In the short-term market, the capacity expansion decision has already been made. Long-term market results are also given. Traditional long-term uncertainties such as long-term demand growth are also realized. However, strategically bidding behaviors from market participants add another dimension of uncertainties and complication to the problem. Our model addresses these concerns accordingly.

6.2.2 Generized bilevel problem setup

The realized short-term market profit $\pi^{j}_{s,i}$ for generator i is a function of spot market cleared price λ_s and cleared quantity $q_{s,i}$. λ_s and $q_{s,i}$ in turn are determined by load realization D_s^j which are introduced in Section 5.2.1 as well as short-term market bidding strategy k_i and the other competitors' strategies k_{-i}. By introducing the bidding strategies instead of assuming SRMC as offers, this model may explain why prices rise above short-term marginal cost-based levels and how the interactions among the market participants may impact the market results. It is reasonable to assume the generator's marginal cost, capacity and load forecast are public information since technical parameters of certain generator such as heat-rates can be obtained fairly easily. This problem then can be modeled as a bilevel non-cooperative game which is described in (Hu, 2007).

At the top level, a generic formulation of the generator i's profit maximization in spot market s with k_i as bidding strategy is described in equation (6.1)

$$
\begin{aligned}
&\max_{k_i} \pi(k_i, \lambda_s, q_{s,i}) \\
&s.t. \\
&g_i(k_i, q_{s,i}, q_{s,-i}) \geq 0 \\
&h_i(k_i, q_{s,i}, q_{s,-i}) = 0 \\
&\lambda_s = \lambda + \sum_l SF_i^l \mu_l
\end{aligned}
\tag{6.1}
$$

Where $q_{s,i}$, $q_{s,-i}$ and λ_s solve the lower level problem below which is a generic formulation of ISO/RTO's market clearing process with the objective function of minimizing production costs/maximizing social welfare.

$$
\begin{cases}
\min\limits_{q_{s,i}, q_{s,-i}} F(k_i, k_{-i}, q_{s,i}, q_{s,-i}) \\
s.t. \\
H(k_i, k_{-i}, q_{s,i}, q_{s,-i}) = 0: \qquad \lambda \\
G(k_i, k_{-i}, q_{s,i}, q_{s,-i}) \geq 0: \qquad \mu_l
\end{cases}
\tag{6.2}
$$

Spot market price λ_s could be presented as a linear function of supply and demand balance constraint shadow prices λ, the transmission constraint shadow prices μ_l and Power Transfer Distribution Factors or Shift Factors (SF), which are determined by the underlying network topology in the current LMP based ISO markets if marginal loss component is ignored.

6.2.3 Nash Equilibrium solution

The top level and lower level problems are intertwined with each other since the generator i's optimal bidding strategy k_i depends on market outputs ($q_{s,i}$, $q_{s,-i}$ and λ_s) which in turn are functions of all the other generators' strategies k_{-i}. Because electricity market rules prohibit collusion among market participants, this problem can be modeled as a non-cooperative game.

If a pure Nash Equilibrium could be found, spot market clears at price λ_s and quantity $q_{s,i}$ and short-term market profit $\pi^j_{s,i}$ can be calculated. Two methods are presented in this thesis to try to reach the equilibrium solution.

1. If the closed form solution of this bilevel problem can be found under certain assumptions and simplifications, then the equilibrium can be calculated directly.

2. If the closed form solution of such equilibrium cannot be obtained, the Equilibrium can be attained indirectly through simulation if the iterated process converges within some predefined criteria.

The simulation process is further explained by the following steps:

1. Every generator i formulates its best responding bidding strategy k_i^1 by solving the profit maximization problem (top level problem) under the assumed initial condition about the aggregated bidding strategy of the other competitors k_{-i}^1.

2. Every generator follows the same logic in step 1 and submits their offers under strategy k_i^1 to ISO. ISO clears the market by solving the lower level problem and publishes the market price λ_s^1 and cleared quantities q_i^1

3. Using ISO published results, generators update their estimation of other competitors aggregated strategy k_{-i}^2. This estimation could be sharpened through the adaptive learning process. Best response strategy k_i^2 could be calculated by resolving the top level problem with updated competitors' strategy estimations.

4. The ISO clears the market with new bidding strategies of k_i^2 and publishes the result.

5. Step 3 and 4 are repeated until the equilibrium is reached. The market equilibrium is reached when the distance between the optimal strategies of two consequent round n+1 and n is smaller than a predefined criteria.

For demonstration purpose, assuming generator i's best response function is

$k_i=f_{-i}(k_{-i})$

the competitor's best response function is

$k_i=f_{-i}(k_{-i})$

Then this iteration process could be illustrated by Figure 25.

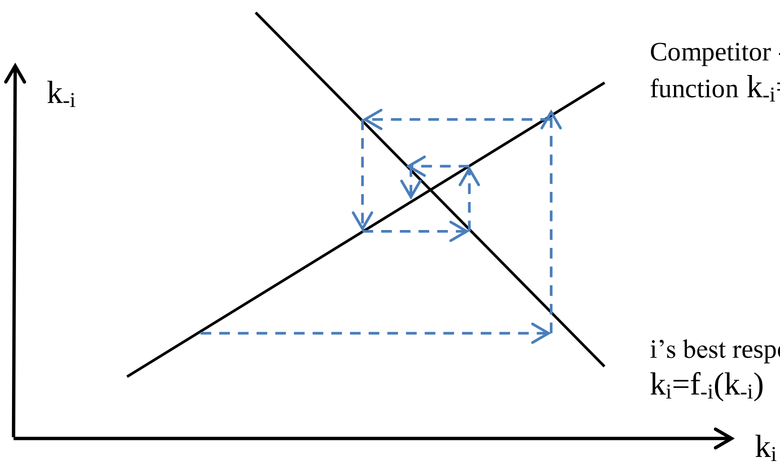

Figure 25: Nash Equilibrium by iteration

6.2.4 Simplified short-term energy market

In this section, we adopt a simplified version of bilevel game formulation to calculate the short-term expected profits $\pi^j_{s,i}$. Under the such simplifications, a pure Nash Equilibrium would always be obtained, as proved in (Hu, 2007).

Linear SRMC curve with two parameters is chosen here:

$SRMC_i=a_i+b_iq_i$

where q_i is quantity, a_i is the interception and b_i is the slope of the linear curve.

Furthermore, we assume that generators adjust their bidding strategy by only adjusting the interception part a_i of the SRMC curve while leaving the slope b_i unchanged.

$Offer_i=k_i+a_i+b_iq_i$

where k_i is the decision variable and bidding strategy.

We ignore transmission network constraints as well as generator's physical constraints such as ramping limits. The lower level short term ISO market clearing problem can be simplified as:

$$\min_{q_{s,i}} \sum_i [(k_i + a_i)q_{s,i} + 0.5b_i q_{s,i}^2]$$

$$s.t. \sum_i q_{s,i} = D_s^j : \lambda_s$$

where D_s^j is the realization j of load forecast model in hour s.

The following market clearing results can be obtained by applying first order condition:

$$\lambda_s = (D_s^j + \sum_i \frac{k_i + a_i}{b_i}) / \sum_i \frac{1}{b_i} \tag{6.3}$$

$$q_{s,i} = \frac{\lambda_s - k_i - a_i}{b_i} \tag{6.4}$$

where λ_s and $q_{s,i}$ represent the cleared price and quantity in the spot market. The upper level problem is presented as

$$\max_{k_i} \pi_{s,i}^j = \lambda_s q_{s,i} - (a_i q_{s,i} + 0.5 b_i q_{s,i}^2) \tag{6.5}$$

Substituting (6.3), (6.4) into (6.5) and applying first order condition with respect to k_i, the closed form Nash Equilibrium solution for bidding strategy k_i could be found. In the interest of space, the detailed solutions are not presented here.

This solution assumes that no capacity limits (Pmax) are considered in the system, due to the fact that response function may not be continuous after Pmax constraints are introduced. However, Pmax is crucial to the capacity expansion problem. To overcome this dilemma we first obtain the optimal strategies without Pmax limits and then reinforce the limits and adjust λ_s and $q_{s,i}$ accordingly, assuming the optimal strategies would not change after the adjustments.

6.3 Decision making in long-term markets

When making long-term market decisions in year k, the spot price λ_s and position $q_{s,i}$ are random variables due to the fact that the load forecast and fuel price process and other uncertainties have not been realized. Since supply and demand has to be balance instantaneously in spot market, and no feasible storage method is available, the spot market prices are inherently volatile. Most market participants in energy industry are risk-averse, they may use the forward market not only as means to maximize the profit expectation but as a risk management tool to reduce the market risk exposure.

6.4 Decision criteria in long-term markets

As discussed in section 5.1.1, the mean-variance criteria are chosen here as the object function for forward market. The generator i choose the optimal long-term position $q_{k,i}$ to maximize the expected total profits from both forward and spot markets while minimize their variance (risk). This formulation of forward market decision is first introduced in (Schwartz, 1997).

$$\max_{q_{k,i}} E\left(\sum_{s \in k} \pi_{s,i} + \pi_{k,i}\right) - 0.5 A_i Var\left(\sum_{s \in k} \pi_{s,i} + \pi_{k,i}\right) \qquad (6.6)$$

The coefficient A_i is risk-averse parameter which implies the tradeoff between expected value and variance of total profits in year k. We assume they are greater than zeros, which implies the risk is viewed negatively.

6.4.1 Demand uncertainties

The fundamental modeling approach for the electricity markets similar to that used in chapter 5 is utilized here. Dynamics of key physical and economic variables are considered in the model. The same two-factor load model described in section 5.2.1 is utilized here to take into consideration of long-term load uncertainties.

$$l_{k+1} = l_k + \kappa + \sigma_l z_k \tag{6.7}$$

$$l_{s+1,k} = (1-\alpha) l_{s,k} + \sigma_s z_s \tag{6.8}$$

where

l_k: long-term load mean at year k

$l_{s,k}$: short-term load deviation in day s of year k

σ_l: volatility of long-term load growth process

σ_s: volatility of short-term load deviation process

z_k: long-term load growth stochastic factor at year k

z_s: short-term load deviation stochastic factor at month s

6.4.2 Optimal forward hedging by supplier

Profits for generator i in year k is the sum of profits in both spot and forward energy markets.

$$\sum_{s\in k}\pi_{s,i} + \pi_{k,i} = \sum_{s\in k}\lambda_s q_{s,i} + M\lambda_k q_{k,i} - \sum_{s\in k} C_i(q_{s,i} + q_{k,i}) = \sum_{s\in k}\rho_{s,i} + q_{k,i}(M\lambda_k - \sum_{s\in k}\lambda_s) \tag{6.9}$$

where

$q_{k,i}$: long-term position of generator i in year k

λ_k : price of forward market k

C_i: production cost function of generator i

M: number of short-term periods in year k

$\rho_{s,i} = \lambda_s (q_{s,i} + q_{k,i}) - C_i(q_{s,i} + q_{k,i})$: expected profits from spot market if the generator i clears all its position in spot market and leaves nothing for forward market. It is defined as *unhedged profit*.

The optimal forward position is obtained by applying first order condition on (6.9),

$$q_{k,i} = \frac{\lambda_k - E(X_k)}{A_i Var(X_k)} + \frac{Cov(X_k, Y_{k,i})}{Var(X_k)} \tag{6.10}$$

where

$$X_k = \lambda_s, s \in k$$

$$Y_{k,i} = \rho_{s,i}, s \in k$$

X_k are the short-term (spot) market clearing price series in year k and $Y_{k,i}$ is the expected hourly unhedged profits from spot market in year k. After short-term load process are realized in year k, the expected value as well as the variance and covariance of X_k and $Y_{k,i}$ can be derived based on bilevel non-cooperative game formulation described in the section 6.2.

The second term in (6.10) indicates that the supplier has the incentive to hedge in the long-term market if there is a positive correlation between the unhedged spot-only profits $Y_{k,i}$ and spot-only prices X_k. Suppose a baseload generator operates at Pmax all year long, then its profits are perfectly correlated with the spot market prices. Such a generator may have a bigger desire to hedge through long-term markets. On the other hand, for a peaking unit who operates only a few days per year when demand level is very high, the covariance between its profits and spot market prices are relatively small since most of time the cleared quantity is zero. Such a generator may have less incentive to hedge in long-term markets. In addition, the optimal hedging positions depend on the long-term market prices λ_k and the expected average spot-only market prices X_k. If the long-term market prices are higher, then the generators are more likely to enter into long-term hedging contracts. This relationship is first discussed in (Schwartz, 1997).

The equilibrium long-term price λ_k can be derived from the long-term supply and demand balance condition,

$$\sum_i q_{k,i} = D_k \tag{6.11}$$

where D_k represents the total forward market demand in year k. First, let's consider first the forward market demand D_k can be express as a function of long-term load process l_k, where l_k follows the process in equation (6.7).

$$D_k = f(l_k)$$

Combining (6.10) and (6.11), λ_k can be reformulated as,

$$\lambda_k = E(X_k) - [-D_k Var(X_k) + \sum_i Cov(X_k, Y_{k,i})] / \sum_i (1/A_i) = E(X_k) + PREM \tag{6.12}$$

The forward price λ_k will converge to the average expected spot price $E(X_k)$ if any of the Gencos' risk averse parameters A_i is zero or the number of Gencos approaches to infinite. The second term on the right hand side of (6.12) can be defined as a forward market premium PREM. If the market participants have high risk averse parameters A_i , which means they are more risk averse, then they would have more incentive to participant in the long-term market, which would in turn drive down the long-term price. The long-term market price also depends on the covariance between spot market prices X_k and unhedge spot market profits $Y_{k,i}$ of all suppliers in the market. The sum of these covariance measures the hedging pressure from all the suppliers in the market. If such hedging pressure is high, then the long-term market price would be lower since more suppliers would enter into long-term markets.

Finally, the equilibrium forward position could be obtained by plugging (6.12) back to (6.10).

$$q_{k,i} = -\frac{PREM}{A_i Var(X_k)} + \frac{Cov(X_k, Y_{k,i})}{Var(X_k)} \tag{6.13}$$

6.4.3 Forward hedging by both demand and supply

The quantity for trading in each forward market Dk can be decided in two ways.

1. The administrative approach: ISO decide the quantity as a function of the forecasted load and require LSEs to acquire their shares.
2. 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 since both sides have the incentive to hedge against long-term risks.

Now we expand the previous formulations by considering the second approach above. The decision making process of demand side market participants, i.e. Load Serving Entities (LSEs), are discussed below.

Suppose there are R identical LSEs that purchase power from spot and forward markets and sell it to end users in its exclusive franchise area at a fixed price $\lambda_{R,j}$. The retail demand for electricity in its area is unknown when the LSEs make the decisions for forward markets. The demand is inelastic and LSEs have the obligation to serve its customers in real time. End users do not see the spot price fluctuations and they are guaranteed a fixed retail price.

The profit for retailer j for the forward period k is as following,

$$\Pi_{k,j} = \sum_s \pi_{s,j} + \pi_{k,j} = \sum_s (\lambda_{R,j} - \lambda_s) q_{s,j} + (\lambda_{R,j} - \lambda_k) q_{k,j} \tag{6.14}$$

Following a similar procedure as in the last section, the optimal forward quantity for LSEs can be obtained by applying the first order condition on (6.14),

$$q_{k,j} = \frac{-\lambda_k + E(X_k)}{A_j Var(X_k)} + \frac{Cov(X_k, Z_j)}{Var(X_k)} \tag{6.15}$$

where

$$X_k = \lambda_s, s \in k$$

$$Z_j = \rho_{s,j}, s \in k$$

Similarly, $\rho_{s,j}$ is the expected profits from the spot market if LSE j procure all the electricity from the spot market. This is defined as unhedged spot profits for LSE j. The optimal forward positions for a Genco and a LSE are very similar. The only difference is the expression of unhedged profits and the sign in the first term. Applying the market equilibrium condition that supply should meet demand at all time, the equilibrium forward price can be formulated as,

$$\sum_{j=1}^{N_P} Q_{Pj}^{F*} = \sum_{j=1}^{N_R} Q_{Rj}^{F*} =>$$

$$P^{F*} = E(X) + \frac{T}{M}\Big[\underbrace{\sum_{j=1}^{N_R} Cov(X, Z_{Rj})}_{\text{Total LSEs unhedged profits risk}} - \underbrace{\sum_{j=1}^{N_P} Cov(X, Y_{Pj})}_{\text{Total Gencos unhedged profits risk}} \Big] = E(X) - PREM \tag{6.16}$$

where

$$M = \sum_{j=1}^{N_P} \frac{1}{A_{Pj}} + \sum_{j=1}^{N_R} \frac{1}{A_{Rj}}$$

Now the premium between the expected spot market prices and long-term market prices is determined by the covariance between LSE's unhedged profits, which are the LSE's profits from short-term only market setups, and the short-term only market prices X as well as the covariance between Gencos' unhedged profits, which are the Genco's profits from short-term only market setups.

The first covariance can be interpreted as LSEs' hedging pressure and the second one can be interpreted Gencos' hedging pressure. If LSE's hedging pressure is high, which implies the short-term market prices would have a big impact on their profitability, then LSE would have a stronger incentive to enter into long-term markets to hedge and raise the long-term market prices accordingly. Similarly, Genco's hedging pressure is high, they would have a stronger incentive to enter into long-term markets to hedge and lower the long-term market prices by providing more supply in long-term markets. This premium also is affected by the risk averse parameters from both supply and demand sides. More risk averse the market participants are, the higher the premium would be. This relationship is first presented in (Schwartz, 1997).

Finally, the equilibrium forward position for LSEs could be obtained by plug the price (6.16) back to (6.15).

$$Q_{Rj}^{F*} = \frac{PREM}{A_{Rj} T Var(X)} + \frac{Cov(X, Z_{Rj})}{Var(X)}$$

$$Q_{Pj}^{F*} = -\frac{PREM}{A_{Pj} T Var(X)} + \frac{Cov(X, Y_{Pj})}{Var(X)}$$

In this case, the forward market quantities are not decided artificially by an administrative agency like ISO through the use of an administrative demand curve, i.e. a percentage of total forecasted demands. It is derived by both supply side and demand side market participants who make their own long-term business decisions based on their own risk preferences.

7 The investment problem under SEM

In this chapter, first we introduce a new performance objective for the potential investors that takes into consideration both the expected profits and the risks associated with those long-term decision. We also propose a new benchmark to evaluate the performance of different market structure which takes into consideration not only expected social welfare but also its variance. The tradeoff between the expected value and its variance is measured by the risk aversion parameter at the society level. We discuss the generator investment problem for the newly proposed SEM structure comprising both spot and forward sub-markets as an alternative solution to the long-term resource adequacy problem. The investment problem is modeled as a stochastic dynamic programming problem for a profit maximizing generator over a long time horizon. The long-term growth and short-term deviation of demand are represented as stochastic processes.

The interrelated dynamics of different markets and its effect on investment decision and profitability of market participants are analyzed and comparisons with other market structures such as spot only energy markets.

7.1 Benchmark to evaluate market performance under uncertainties

The social welfare is defined in a traditional sense as the combination of producer surplus and consumer surplus. The consumer surplus is the amount that consumers benefit by being able to purchase a product for a price that is less than the most that they would be willing to pay. The producer surplus is the amount that producers benefit by selling at a market price mechanism that is higher than the lowest value at which they would be willing to sell.

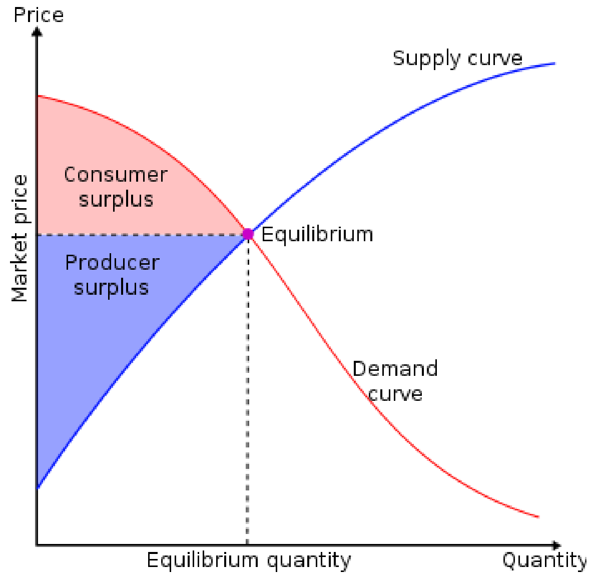

Figure 26: Consumer surplus and producer surplus

On a standard supply and demand diagram, consumer surplus is the triangular area above the price level and below the demand curve, since intra-marginal consumers are paying less for the item than the maximum that they would pay. Producer surplus is the triangular area below the price level and above the supply curve, since that is the minimum quantity a producer can produce. Combined, the consumer surplus and the producer surplus make up the social surplus or the social welfare. This is the primary measure used in welfare economics to evaluate the benefits of a proposed policy.

Classic microeconomics theory tells us that the social welfare maximization can be obtained at the market equilibrium when supply curve intersects the demand curve. In this thesis, a new social utility measurement is proposed as the criteria to evaluate the performance of different market structures, including the proposed SEMs. We expand the traditional concept by introducing the long-term social utility (LTSU) which considers both the expected value and variance of social welfare over a longer period of time. The new criteria is based on the same mean variance concept described in section 5.1.1: maximizing the expected value of social welfare and minimizing its variance in the long-run. By minimizing the variance of social welfare, we assume the society as a whole values stability and wishes to avoid volatility.

$$LTSU = E\left(\sum_i \Pi_{k,i} + \sum_j \Pi_{k,j}\right) - 0.5A_s Var(\sum_i \Pi_{k,i} + \sum_j \Pi_{k,j})$$

Where

$\Pi_{k,i}$ is producer i surplus in period k

$\Pi_{k,j}$ is consumer j surplus in period k

In our investment problem setup, producer surplus is the profits from both long-term and short-term markets, and the consumer surplus is also the profits from LSEs from both long-term and short-term markets.

We argue that LTSU concept should be used as a criteria to evaluate the performance of difference market structure since it take into consideration of not only the expected utility in the traditional sense but also the uncertainties of future market conditions. Superior market structures should have the ability to withstand market shocks like short-term price spikes or crashes and be able to bring the market back to a normal state, i.e. the mean-reverse price behavior. Also the right market structure should weather out the uncertainties from supply and demand and regulatory sides while still maintaining a relatively good and stable level of social welfare under different scenarios. If certain market structure is very sensitive to initial market conditions or future market uncertainties, even if it may achieve a higher expected value of social welfare on average, it may not be a good policy decision to implement since the social and economic outcome of so-called low-probability-high-consequence long-tail events may be devastating.

7.2 Investment problem formulation

In this section, a detailed investment problem formulation is presented by combining the decision making models discussed in chapter 6 and a dynamic programming technique. Different market structures are compared using the LTSU criteria proposed above.

7.2.1 Demand model

The same two-factor demand model as used in chapter 5 and chapter 6 is adopted here to represent the demand side uncertainties. The subscripts k and l denotes the long-term process and s denotes short-term process. The load forecast process is decoupled into two stochastic processes; the long-term growth process of l_k with increase κ and volatility σ_l and short-term deviation process $l_{s,k}$ with mean-reverse speed of α and volatility σ_s. Detailed demand modeling can be found in section 5.2.1.

$$l_{k+1} = l_k + \kappa + \sigma_l z_k$$

$$l_{s+1,k} = (1-\alpha) l_{s,k} + \sigma_s z_s$$

where

l_k: long-term load mean at year k

$l_{s,k}$: short-term load deviation in day s of year k

σ_l: volatility of long-term load growth process

σ_s: volatility of short-term load deviation process

z_k: long-term load growth stochastic factor at year k

z_s: short-term load deviation stochastic factor at month s

7.2.2 SDP formulation

The investment problem is formulated over a planning period of T years with a granularity of one year. The optimal decision can be made at the beginning of each year. A backward SDP is used to solve the problem based on Bellman's principle. Detailed formulation is presented in (7.1)–(7.5).

$$J = \max_u \underset{l}{E} \sum_{k=1}^{T} \left[(1+r)^{-k} \Pi_k (x_k, l_k, l_{s,k}, u_k, \sigma_s, \sigma_l) \right] \qquad (7.1)$$

$$x_{k+1} = x_k + u_{k-l+1} \qquad (7.2)$$

$$l_{k+1} = l_k + \kappa + \sigma_l z_k \qquad (7.3)$$

$$l_{s+1,k} = (1-\alpha) l_{s,k} + \sigma_s z_s \qquad (7.4)$$

$$\Pi_T(x_T, l_T, l_{s,T}, \sigma_s) = \Pi_T(x_T, l_T, l_{s,T}, \sigma_s \mid u_T = 0) \qquad (7.5)$$

where

$\Pi_k(x_k, l, l_{s,k}, u_k, \sigma_k, \sigma_l)$: expected profits at year k

$\Pi_T(x_T, l_T, l_{s,T}, \sigma_s)$: expected profits at end of planning period year T

x_k: total installed capacity at year k

u_k: investment decision at year k

l_k: long-term load mean at year k

$l_{s,k}$: short-term load deviation in day s of year k

σ_l: volatility of long-term load growth process

σ_s: volatility of short-term load deviation process

z_k: long-term load growth stochastic factor at year k

z_s: short-term load deviation stochastic factor at month s

r: discount rate

lt: construction lead time

The state variables include the long-term growth l_k , short-term deviation $l_{s,k}$ and the investor fleet's total installed capacity x_k. The decision variable (control variable) is u_k, which is the capacity expansion at year k. A construction lead time delay of lt is introduced in (7.2). The end condition is specified in (7.5) with no investment decision to make. The original problem (7.1) can be transformed into the following DP formulation.

$$\begin{aligned} J(x_k, l_k, l_s, k) = \max_{u_k}\{ \underset{l_k}{E}\{ \underset{l_s}{E}[\sum_{t=1}^{lt-1} \Pi_k(x_k, l_{k+t}, l_s, u_k) \\ + J(x_k + u_k, l_{k+lt}, l_s, k+lt)]\}\} \end{aligned}$$

The expected total profits Π_k at year k are a function of all the state variables [x_k, l_k, $l_{s,k}$], disturbance [σ_l, σ_s] and the control variable u_k. It can further decomposed into the sum of expected profits from short-term spot market $\pi_{s,i}$ and long-term forward energy market $\pi_{k,i}$.

$$\Pi_{k,i} = \sum_{s \in k} \pi_{s,i} + \pi_{k,i} - C_{invest,i} x_k \tag{7.6}$$

where

$\pi_{s,i}$ profit of generator i from spot market on day s

$\pi_{k,i}$ profit of generator i from forward market at year k

$C_{invest,\,i}$ annualized capital cost of generator i

7.2.3 Short-term market

The expected profit in the spot market is the sum of the product of the probability distribution function $\Pr(z_s^j)$ and the short-term market profit $\pi^j_{s,i}$ over j short-term load realizations from the load forecast model:

$$\pi_{s,i} = \sum_j \Pr(z_s^j) \pi_{s,i}^j (x_k, l_k, l_{s,k}, \sigma_s, z_s^j) \tag{7.7}$$

x_k: total installed capacity at year k

l_k: long-term load mean at year k

$l_{s,k}$: short-term load deviation in day s of year k

σ_s: volatility of short-term load deviation process

z_s: short-term load deviation stochastic factor at month s

The realized short-term market profit $\pi^j_{s,i}$ is a function of spot market cleared price λ_s and quantity $q_{s,i}$. Please note that the long-term uncertainty has been materialized and long-term decisions have been made for that year at this stage. The bilevel non-cooperative game described in chapter 6 is adopted here to solve the short-term spot market.

7.2.4 Long-term forward market

Using the methods described in chapter 6, the long-term market price and quantities can be calculated using mean-variance criteria and market equilibrium condition. The long-term load uncertainty would impact the forward market price and positions. Note that short-term load uncertainties also influence the long-term decision making since they are implicitly considered when X_k and $Y_{k,i}$ are calculated.

$$\pi_{k,i} = \sum_j \Pr(z_k^j)\pi_{k,i}^j(x_k, l_k, \sigma_k, z_k^j, l_s, \sigma_s, z_s) \tag{7.8}$$

where

x_k: total installed capacity at year k

l_k: long-term load process at year k

$l_{s,k}$: short-term load deviation in day s of year k

σ_l: volatility of long-term load growth process

σ_s: volatility of short-term load deviation process

z_k: long-term load growth stochastic factor at year k

z_s: short-term load deviation stochastic factor at month s

Similarly to (7.7), the expected revenue in forward market k is the summation of probability distribution function $\Pr(z^j_k)$ and realized forward market profit $\pi^j_{k,i}$ over all j load realization in year k.

7.3 Numerical Example

In this section, a simplified numerical example is presented. The SDP technique is used to demonstrate the solution of the problem.

7.3.1 Model simplification

As described in section 5.2.1, the load model can be further reduced to the following process:

$$\begin{aligned} w_d &= l_k + l_s \\ l_{k+1} &= l_k + \kappa + \sigma_l z_l \\ l_{s+1} &= (1-\alpha)l_s + \sigma_s z_s \end{aligned}$$

w_d is represents by the long-term growth component l_k and short-term mean-reverse deviation component l_s. Both stochastic factors are assumed to follow normal distribution. Please notice that σ_l is constant and σ_s has twelve unique values, one for each month, and will not change between years. Using the historic hourly load data from

1993 to 2003 from ISO New England (ISO-NE, Hourly load data, 2006), the deterministic parameters [α κ σ_s σ_l] in the load model can be estimated.

Table 11: Load Model Parameters

α	κ	σ_s	σ_l
0.4696	1084	1792	7953

After the parameters are calibrated, the forecasted load samples used in the simulations were generated. The study period T is set at 10 years.

The simplified version of bilevel game formulation discussed in section 6.2.4 is adopted here to calculate the short-term expected profits $\pi^j_{s,i}$. Under such assumptions, a pure Nash Equilibrium would always be obtained, as proved in section 6.2.4.

7.3.2 Dynamic Programming Formulation

In order to use the SDP technique to solve the problem, Markov transition probabilities must be specified among the states. The l_k process was transformed into a binomial tree structure with p=0.5 of high load growth (k+0.43σ_l) and p=0.5 of low load growth (k-0.43σ_l) for each year, where 0.43 is the value for standard normal distribution when CDF=2/3.

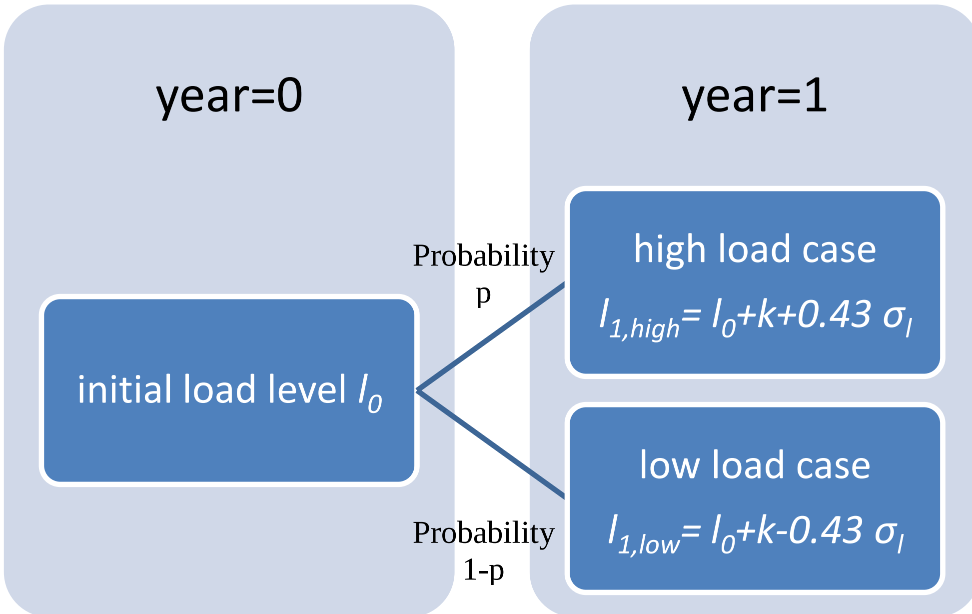

Figure 27: Long-term load growth transition probability in single stage

The risk-aversing parameter A_i in the long-term market is set dynamically so that the variance is always viewed as 50% of the expected value.

For illustrative purposes, a small generation fleet of four units was used in simulations. Generator characteristics are summarized in Table 12. a and b are parameters of the linear marginal cost curve. Unit #4 is operated by a decision maker who is making capacity expansion decisions described by (7.1)-(7.5).

Table 12: Generator technology characteristics

unit #	Capital cost ($/KW)	Capacity (MW)	b	a
1	3000	1000	0.02	40
2	1200	400	0.04	40
3	500	300	0.2	20
4	350	300	0.5	20

The lead time lt for a new generator construction is set at 3 years. To reduce the curse of dimension problem in dynamic programming, investment decisions cycle is set at every three years. Only one new unit expansion will be considered when making the decision. All feasible states of unit #4's capacity are presented in Figure 28. The end states were fixed with u_9=0 and the problem can be solved by backward SDP.

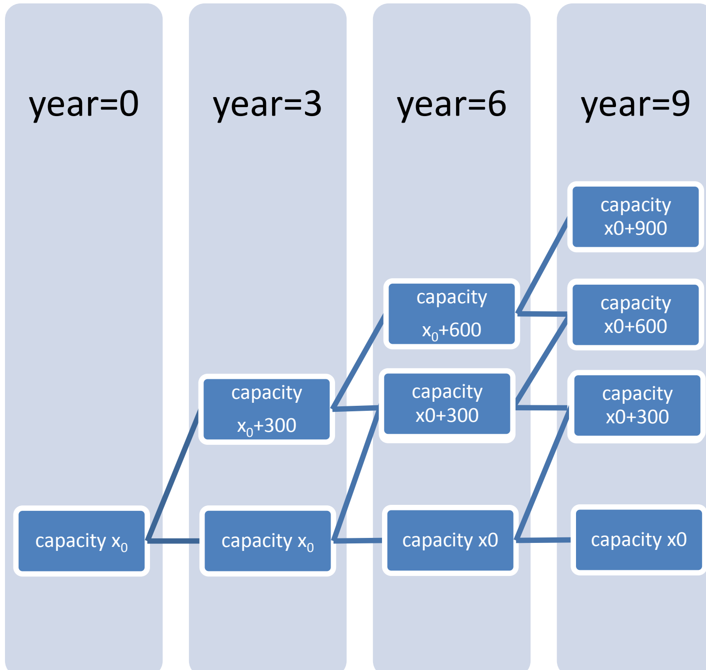

Figure 28: Feasible capacity expansion path

7.3.3 Simulation results and discussions

The optimal investment decisions for unit #4 under three different market structures are examined: the SEM market structure with spot market gaming, spot only market structure with gaming and spot only market with short-run marginal cost bids. The results were presented in Table 13.

Table 13: Simulation Results

Market Structure	u_0	u_3	u_6	Expected Utilities
SEM	300	300	0	2.30E+8
Spot Only	0	0	0	1.12E+8
Spot Only w/ MC bids	0	0	0	6.36E+7

The SEM market structure induced two new unit investment at year 0 and year 3 while the spot only market structure discouraged any investment decision with or without the consideration of gaming opportunities. This demonstrates that the spot-only energy markets without any long-term market mechanism like capacity markets or SEM are not sustainable. Under them boom and bust cycles are inevitable. Also the unit obtained the highest expected profits under SEM. This is mainly due to the fact that without new capacity the system would frequently slip into blackouts emergencies when total demand is higher than installed capacity. The blackout penalty prices reduced the unit’s profit margin substantially.

7.4 Multi-stage long-term decision making

All the formulations derived so far are single stage decision making in a sense that the investors are trying to make their optimal investment decision path for the period of interests at the beginning of year k. However, when the time moves forward to year k+1, the results for year k are realized and more information is available. The uncertainties accessed at beginning of year k for year k+1 also shrinks when accessed at the beginning of year k+1. Given these feedbacks from markets and other competitors, now the investors need to re-evaluate their optimal decisions again. The problem becomes multi-stage. The SEM market structure are flexible in a sense that they serve as vehicles for market participants to readjust their expectations and risk preference and realign their existing portfolios along the way. Similar simulations could be done using the SDP technique outlined in this chapter to demonstrate such effects.

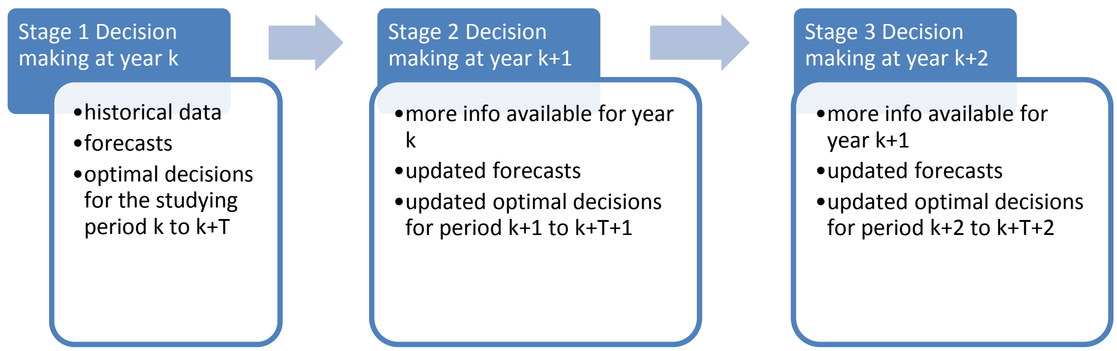

Figure 29: Multi-stage decision making

8 Policy implications and conclusions

Given that today's measurement of market power in the spot market is classified as any bids higher than the SRMC cost, we suggest that it is essential to introduce other means to provide incentives for new generation capacity installation in a timely manner in order to ensure sustainable electricity supply in the long-term. This can be done by designing longer-term physical and/or financial mechanisms for valuing future investments. In this thesis we propose a Stratum Electricity Markets (SEM) structure as an enhancement to the short-term DART markets. This market mechanism would eliminate the need for various installed capacity and reliability markets currently under consideration.

This thesis has developed a fundamental modeling approach is further developed to model and simulate the SEM structure. A simple example was solved using the SDP method to demonstrate the importance of SEM structure. Some of the policy implications are listed below:

1. In the regulated industry generation was tend to over built or under built depending on the central planner's assumptions about the future

2. The current spot only market is not sufficient to ensure resource adequacy

3. The capacity market design also depends on ISO's assumptions about future uncertainties on technology and load growth, etc. It too may lead to an overbuilt or underbuilt system.

4. Traditional bilateral long-term contracts are not liquid and transparent. They are not a good indication for long-term investment needs.

5. In additional to the spot market, we need a long-term market mechanism to manage long-term risks, which are multi-dimensional.

6. The right market design is also crucial to ensure the sustainability of long-term electricity provision. The SEM approach proposed in this thesis is one such attempt.

7. The well-designed market mechanism would ensure that a sustainable long-term electricity service is provided according to the preference and risks specified by both supply and demand.

9 Future Research

In this thesis, the only long-term uncertainties studied is the demand side load forecast. However, a similar two factor model could be extended to include fuel prices and planned / forced outage process. One such implementation can be found here (Skantze, 2001).

The optimal long-term forward hedging strategy for both supply and demand has been derived in formulations. However, the simulation results are limited to only supply side hedging scenario. More simulations could be done to investigate the impact of LSE forward hedging strategies.

The investment problem is formulated as a single-stage problem in the sense that the generators make their decisions at the beginning of their study period. Such decisions could be reexamined at the beginning of each year as the market conditions evolve and unfold. The SEM market dynamics then could be modeled as a multi-stage stochastic dynamic programming problem that evolves over multiple time horizons.

The basic electric SEM described in this thesis could be expanded to integrate other markets, such as the long-term Financial Transmission Rights (FTR) markets, and the Cap-and-Trade Emission markets. This integration would enable us to manage other long-term uncertainties which are unique to the electricity, i.e. transmission congestion and environmental constraints, through market mechanisms. Similar market rules could be construed to provide the participants a flexible and effective way to readjust their decisions as more information unveils along the way. A complete long-term SEM setup, which includes FTR and Cap-and-trade emission markets is the subject of future research topics.

Other future research areas include:

- Incorporating price-sensitive consumers into the demand model.

- Simulating long-run capacity market mechanisms like the Reliability Provision Market (RPM) model proposed by PJM and comparing the results with SEM.
- Including more realistic constraints into the power system, i.e. network constraints.

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