Long-term Contracts for New Investments in Power Generation Capacity: *Pain or Gain?*

by

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Abstract

In recent years, a debate has ensued regarding the role of long-term power purchase agreements for securing investments in power generation capacity in organized wholesale markets. This thesis illuminates the issues surrounding the debate and provides a framework for understanding the nature and use of long-term contracts. The main questions of interest for the formulation of a policy on long-term contracts are (1) whether parties encounter obstacles to their beneficial use and (2) in what situations should policy encourage or compel market entities to enter into such agreements?

The analysis finds that long-term contracts do not appear to be "essential" for securing new investments in generation capacity. Long-term contracts are desirable in cases where the investments are highly specific to the relationship. Relationship-specificity is not a general feature of the industry; power producers or customers that find themselves in relationship-specific situations can identify the gain available through the use of specific assets and choose to use a long-term contract. However, this is a voluntary business decision and does not call for explicit policy guidance. Additionally, contracts are inherently "incomplete" and create the possibility of ex post regret and stranded costs. The electricity industry in the U.S. is familiar with the potential for significant economic distortions in the aftermath of the indiscriminate use long-term contracts. Policymakers should avoid mandating their use, and be careful to disapprove contracts that present a significant risk of ex post regret.

Obstacles appear to exist for the beneficial selective use of long-term contracts. Current rules in restructured markets preclude the consideration of long-term contracts for most types of generators and make it unfeasible for the economy to benefit from relationship specific circumstances. Policies should encourage or require the selective use of long-term contracts only in relationship-specific situations where identified non-zero sum gains are not being realized under dominant practices. In cases where these gains are not observable or are insignificant, the long-term contracts are more likely to cause pain than gain.

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Acknowledgements

This thesis is an exercise in sense-making. Without a good map, it is difficult to plot a course to any destination. Like all maps, however, it is prone to the surveyor's errors and can only be revised with time and further exploration.

This work also represents the culmination of a small research endeavor but only the beginning of a very long journey. It has been a joy to complete, but at times has required sheer will power. There is something about MIT that enables constant exhilaration and frustration. When I have learnt to balance the two; I will have learnt to drink patiently from a fire hose.

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My family and friends have always been a beacon of love and guidance and they have my undying devotion.

Finally, I wish to thank all those who encouraged me to ask 'why' and never let my ignorance interfere with my learning.

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Chapter 1 Motivation and Thesis Question

This introductory chapter will briefly describe a current issue in U.S. energy policy for securing new investments in electricity generation capacity. The focus is on the use of long-term power purchase agreements as a policy mechanism to secure investments. Various aspects of the debate on the use of long-term contracts are discussed. This chapter concludes by stating the main hypothesis and thesis question.

1.1 The Policy Issue

In recent years, a debate has ensued regarding the role of long-term power purchase agreements for securing investments in power generation capacity in organized wholesale markets. The parties to the debate have included project developers, distribution utilities, regulatory agencies and customer interest groups (Federal Energy Regulatory Commission 2007). Without complete resolution of the issues, legislation has been enacted in many states requiring some wholesale customers like distribution utilities to purchase electricity from renewable generation projects through long-term contracts (Massachusetts General Laws Ch. 169, Section 83 2008; Maine P.L. 2005, Ch. 677 2006). A number of fundamental questions are left unanswered: are long-term power purchase agreements essential for securing adequate investments in generation capacity, renewable or otherwise, in the presence of functioning wholesale spot markets for generation? Will necessary investments in generation capacity not occur in the absence of such contracts? Will the resulting mix of generation technologies be undesirable in the long run? Are such contracts valuable in realizing some measurable economic gain? In short, what do these contracts enable and should policymakers intervene and require their use? This thesis illuminates the issues surrounding the debate and provides a framework for understanding the nature and use of long-term contracts.

Clarity around these issues is important because long-term power purchase agreements present the risk of a significant downside. Power generation investments are large and irreversible and influenced by many uncertain factors. Long-term contracts are legally binding, bilateral agreements that lock in the buyer and seller for long periods of time, typically ten to fifteen years. If these contracts are imprudently used, power generators may be unable to recover their large investment costs and their customers may be stuck with an obligation to pay for a product they may not have wished to purchase. Amidst regret by contracting parties, litigation is bound to ensue at further costs to the contracting parties and society. The indiscriminate use of long-term contracts therefore raises the possibility of significant economic losses, which is of policy concern.

The literature on long-term contracts suggests that they may present an upside opportunity in limited cases. Parties are in a unique buyer-seller relationship and one or both of them may have to undertake significant dedicated investments before any goods or services can be exchanged. In such relationship-specific circumstances, large investments will be undertaken only if each party commits to fulfilling their obligations in the relationship. To ensure that the commitment is credible and that each party has appropriate incentives for performance, they may choose to enter into a long-term contract. This is a voluntary business decision by the parties and must be evaluated appropriately using information available to the parties. If the contract is prudent, then they should be able to identify or quantify the gains that the contract enables relative to the situation without the contract and enter into the agreement accordingly. The benefits realized by the parties are also ultimately reflected in the larger economy. If the contract doesn't enable a gain, the parties wouldn't be interested in the agreement. Identifying the limited cases for the use of long-term contracts and the specific economic gain in those situations is not in of itself of importance to policy, because the contracting parties are best able to make those decisions.

Electricity policymakers should therefore be concerned if long-term contracts are being used indiscriminately and present the possibility of significant economic losses, as evidenced by ex post regret. Policymakers should also be concerned if parties in relationship-specific situations are able to identify clear economic gains, but are unable to realize them because the existing framework of statutes and regulations does not support the use of long-term contracts. The main questions of interest for the formulation of a policy on long-term contracts are (1) whether parties encounter obstacles to their beneficial use and (2) in what situations should policy encourage or compel market entities to enter into such agreements? Bearing these questions in mind, this thesis offers evidence to inform the formulation of policy on the use of long-term contracts for power generation investments.

1.2 Financing Projects

New power projects, especially base load power plants, usually require large, up front capital investments and are difficult to finance. Investors often prefer projects with long-term contracts with customers, because such contracts provide assurance of future cash flows and serve as an indicator of the projects' financial viability. Project developers may therefore attempt to enter into a long-term power purchase agreement with electricity buyers to obtain access to low-cost capital, as these agreements are looked upon favorably by investors. In addition to assurance of cost recovery, long-term contracts allow project developers and buyers to negotiate the terms of the transaction prior to developing the project, allowing them to manage risks and voluntarily enter into the agreement if the terms are favorable to the transacting parties. Thus, the existence of a bilateral long-term contract typically indicates that the transacting parties were able to agree upon terms and conditions that were valuable to each party, or they would not have voluntarily entered into the contractual arrangement. However, the record of comments and views on the subject reveals opposing perspectives. In some cases, project developers have urged that long-term contracts are essential for securing financing, without which the projects cannot be built (U.S. General Accounting Office 2002; Electric Energy Market Competition task Force 2007). In others, developers have chosen to build plants without such arrangements, and sell their production through spot market or short-term transactions (Worenklein 2003). Correspondingly, wholesale customers such as distribution utilities have either been cautious of getting locked in to an arrangement that may be unfavorable to them in the long run, or voiced concerns about not having adequate opportunities for bilateral contracting with generators (Federal Energy Regulatory Commission 2007). It could be inferred that buyers and sellers do not always agree on the benefits of long-term contracts, especially if the terms are more favorable to one of the parties than the other, but also that there may systematic disagreements among different types of buyers and sellers about the appropriateness of contract duration and terms. Thus, an important goal of this study is to identify circumstances when long-term contracts are favorable and the types of entities that stand to benefit from, and therefore support their use, and vice versa.

The revenues that a plant receives must be sufficient to cover its operating costs in the short run and its capital costs in the long run, along with the investors' required returns. Investors will decide to invest in a technology and plant scale that is expected to be profitable over the life of the plant. Investors' expectations for the profitability of various types of plants are therefore central to the amount and types of capacity investments that eventually occur.

1.3 Nature of Long-term Contracts

Understanding the role of long-term contracts in other capital intensive industries is helpful in analyzing the value of the contracting mechanism in wholesale power generation. Such contracts are not the norm for most types of commodities and investments, even in other capital intensive industries. Most commodity related investments rely on selling their output in the spot market, and investors routinely assume the risks associated with spot market transactions. This is observed in the automotive, commercial aviation, hotels, natural gas development and pipelines and other industries (CRA International 2008). What is common to these sectors is that a well-functioning spot market exists for the end-use product being supplied. Thus, it is rarely in either the buyer's or the seller's interests to enter into a long-term contractual arrangement. However, specific instances have been realized within these industries, when a long-term relationship between a producer and a consumer has allowed both parties to realize measurable economic gains that would not have been realized in the absence of the mutual commitment between the two parties. These instances have been characterized by a high degree of asset or relationship specificity; that is, a capital intensive project or supply arrangement that is specifically designed to fulfill the unique needs of the contracting parties. Additionally, the potential for "hold up" was significant - if one of the parties were to decide not to fulfill either the supply or the purchase obligation, the other party would not be able to reasonably obtain the substitute product or an alternative buyer in a short-term market. Some natural gas field development projects, automotive and aircraft body part supplies, and mine-mouth coal fired power plants are representative examples of long-term contractual arrangements that have been realized in the past. In these instances, investment by the producer did not occur until a voluntary commitment from the purchaser was obtained. Thus, long-term contracts in capital intensive industries are typically realized in very specific circumstances, and to meet the unique needs of individual parties.

As in other industries, it is plausible that some types of power projects will only be executed under long-term contracts if they exhibit a high degree of relationship-specificity. However, power generation technologies are relatively standardized and the final product, electricity, is homogenous in most respects. Moreover, organized wholesale markets for electricity offer a venue for producers to sell the undifferentiated product, and for buyers to purchase it. In markets with a large number of buyers and sellers, the nature of electricity as a product does not create the need for specific relationships. Entities may nonetheless choose to contract for other reasons such as smoothing of price and demand volatility, and management of electricity production and load. For these reasons, electricity markets typically have provisions for short- to medium-term bilateral contracts (1 – 3 years), in addition to daily and intra-daily transactions. In most cases, such provisions should be sufficient to meet the needs of both buyers and sellers. If two contracting parties prefer a longer-term contractual arrangement, then they must be obtaining benefits other than smoothing of volatile prices and demand, such as prices that are consistently below expected market prices but sufficient to cover the operating and capital costs of the new generating facility. What makes this situation relationship-specific is that the new generator would not be built, but for the long-term assurance of demand from the buyer at prices that are favorable to both. Moreover, the respective parties must have quantified the resulting cost savings or increased profits that led them to favor the new investment and the subsequent decision to use the long-term contract.

1.4 Risk Management

The risk management aspect of contracts is an important consideration for transacting parties. Different market entities have differing risk preferences and abilities to bear and manage risks. A distinction must be made between short-term hedging for the management of cash flows and long-term management of more fundamental systemic risks. Buyers that do not want to be exposed to the volatility in electricity market clearing prices can choose to sign a short- or medium- term contract with generators to obtain some certainty about their expected costs. Similarly, generators can find a suitable buyer for the assurance of guaranteed sales and to avoid the uncertainty of bid selection and dispatch in the spot market. This is why most of the firm electricity transactions by volume in organized markets are bilateral forward contracts. These short-term agreements are primarily used to organize the cash flows of the respective firms. In longer-term contracts, some of this certainty is obtained as a consequence of the price terms, but short-term financial management is not the objective. Long-term contracts help to manage a more fundamental risk – one that arises from committing to a large investment in an uncertain market environment. Long-term contracts do not make the risk disappear, but only reflect an agreement of the parties as to what type of risk each one will bear. Contractual arrangements will therefore involve negotiations around risk allocation by structuring price and duration terms that are acceptable to both of the transacting parties. The voluntary agreement indicates that each entity may think that the terms are favorable to them, or they would not have contracted based on those terms.

1.5 Ex post Regret

As information about previously uncertain factors is revealed, one or both parties may realize that the contract was not the most prudent choice. One or both might try to renege, or refuse to meet obligations. If this possibility is not anticipated and terms are not included to address the situation, then the contract is not a meaningful one, because there is no way to enforce the obligations of the transacting parties (Klein, Crawford, and Alchian 1978). Most contracts therefore have penalties or rewards as incentives to ensure fulfillment of the obligations. However, not every contingency can be anticipated and it is impossible to structure a contract that addresses every relevant state of the world. Parties may therefore try to restructure the contract and engage in costly renegotiation, or ex post bargaining. Parties may reach an impasse in some situations, where the prudency and validity of the contract may be called into question. Costly litigation may be involved in trying to resolve the conflict. The prudency of the contract would have to be evaluated in hindsight, and the evaluation becomes even more problematic if the initial contract was subject to regulatory approval. Not only do the parties have to demonstrate why the contract was prudent, but the regulatory body also has to defend its approval. To avoid ex post regret, long term contracts must be carefully evaluated before parties are encouraged to enter into such agreements.

1.6 Regulatory Status

Regulatory ambiguity regarding the necessity and use of long-term contracts is a complicating factor in the debate. Legislative and regulatory language is not always clear as to whether long-term contracts are desirable or undesirable and vague about factors such as contract duration and pricing procedures. Often, policies have encouraged the use of long-term bilateral transactions with the goal of fostering competitive wholesale markets, but without being specific as to the maximum duration and pricing methodologies. On the other hand, contract durations for certain types of customers such as distribution utilities providing "basic" or "default" service to end-use customers are strictly regulated by states in terms of their duration and bidding processes and supervised to ensure low-cost procurement. The ambiguous language and possibly competing objectives have been the source of confusion for various market entities. Additionally, market entities are concerned due to the regulatory risk with respect to how the contracts will be evaluated if market conditions are different from expectations.

1.7 Distortions in the Generation Mix

The issues surrounding the use of long-term contracts in wholesale electricity markets suggest that buyers and sellers would prefer to avoid long-term relationships in most cases. Why then might there be policy interest in explicit guidance regarding long-term contracts? The answer is likely associated with the issues that make it difficult for certain types of power plants to obtain financing in the first place. Large base load projects such as nuclear or coal plants are much more capital intensive than smaller load following or peaking units. The base load plants often take a long time to build, and it is hard to predict what the state of the market will be once construction is complete. Since revenues can only be obtained once the project is completed, investors will incur large costs before realizing any returns on their investments. Moreover, there is substantial risk that a project may not be completed on time and without complications, even after permits are obtained and costs are incurred. Consequently, investors prefer projects that are more likely to get built in time to meet market demand, and begin generating revenues soon after the investments are made. It is possible to demonstrate this effect through a simulation, and empirical evidence on completed projects in the last two decades also supports this reasoning. However, the cheaper, short time-to-build technologies such as natural gas produce electricity at a higher average cost than the base load plants. In the long-term, the investment strategy that favors the lower capital cost technology results in a higher average cost of electricity. To avoid this distortion, investors could be provided with incentives to invest in technologies that result in lowering the average cost of electricity. The long-term contract can be used as an incentive mechanism, but it must provide measurable economic gains to both the investor and the contracting parties for it to make sense. If a buyer such as a distribution utility is willing to commit to purchasing a significant fraction of its end-use demand at a price that is consistently below the spot price, and the price is sufficient to generate a revenue stream that is satisfactory to the project developer, then a long-term contract might be justified. This project would be consistent with the properties of asset and relationship specificity described earlier. In such cases, the long term contract also makes the financing possible, because the investor's needs are met.

1.8 Hypothesis and Thesis Question

Based on prior literature on the subject of long-term contracts and experiences in the electricity industry, the main hypothesis for the subsequent analysis is that policymakers should allow the use of long-term contracts only when these instruments allow contracting parties to secure measurable economic gains in relationship-specific circumstances. The gains must be identified and quantified before the decision to execute the contract is made, to ensure that the intended benefits are available. Although this task is left to the contracting parties, policymakers should have a good sense of what circumstances make the gain possible and some insight into how the underlying dynamics are to be evaluated. Otherwise, they have no way of establishing the prudence of the contract, or understanding whether it is likely to result in more gain than pain. This thesis therefore asks the question:

> "how can the gain available through the use of a long-term contract in a relationship-specific investment be identified?"

This analysis contributes one methodological framework for quantifying the relationship-specific gains that a long-term contract may be enable for investments in power generation. Economic and policy literature is synthesized and the use of a model based on published investment strategies is demonstrated. Some insights are developed as recommendations for policy regarding the use of long-term contracts.

1.9 Thesis Outline

Before delving into the various issues surrounding the use of long-term contracts, a contextual description of the U.S. electricity industry is provided. Chapter 2 describes the current context and trends in the U.S. electricity industry with regard to the need for new power generation capacity, the large size of the investments required, and the fact these investments have to occur in a fragmented regulatory environment.

Chapter 3 describes the theory of long-term contracts. The concepts of relationship specificity and opportunism are defined and illustrated. A game theory perspective is used to illustrate the value of contracts for providing parties with appropriate incentives to secure economic gains.

Chapter 4 describes the recent role of contracts in financing new power generation investments. Utility procurement practices in regulated and restructured states are discussed. The prevalence of project financing as the primary financing mechanism and its emphasis on contracts is also described. A risk-management approach is used to understand the advantages and disadvantages of long-term contracts.

Chapter 5 describes the modeling approach used to understand the effects of uncertainty and competition on investment strategies. Established investment strategy models are adapted for the purpose of studying investments in power generation. The theoretical framework predicts results that are consistent with the literature discussed.

Chapter 6 summarizes the results of the simulation. Some scenarios are identified in which the use of long-term contracts could be justified.

Chapter 7 synthesizes the analysis and presents a central recommendation for policy makers to consider while evaluating the use of long-term contracts for new investments in power generation.

Chapter 2 Context: The U.S. Electricity Industry

This chapter briefly discusses how new power generation capacity is needed from time to time. It presents some data to show that the total size of investments is large and the average plant costs for base load capacity technologies are high. The chapter concludes by depicting the regulatory structure of the electricity industry in the U.S. and highlights the fact that these investments occur in a highly fragmented regulatory environment.

2.1 New Power Generation Investments

Investments in power generation capacity are desirable in a number of scenarios. In the simplest case, capacity addition is needed to meet future demand for electricity under expectations of demand growth. Even if demand does not increase, new investments will eventually be required to replace existing generation capacity at the end of its useful life. Additionally, redundant generation capacity to ensure technical reliability of the electric grid in the event of outages may also require periodic capacity additions. It is thus reasonable to assume that investments in generation capacity may be desirable from time to time.

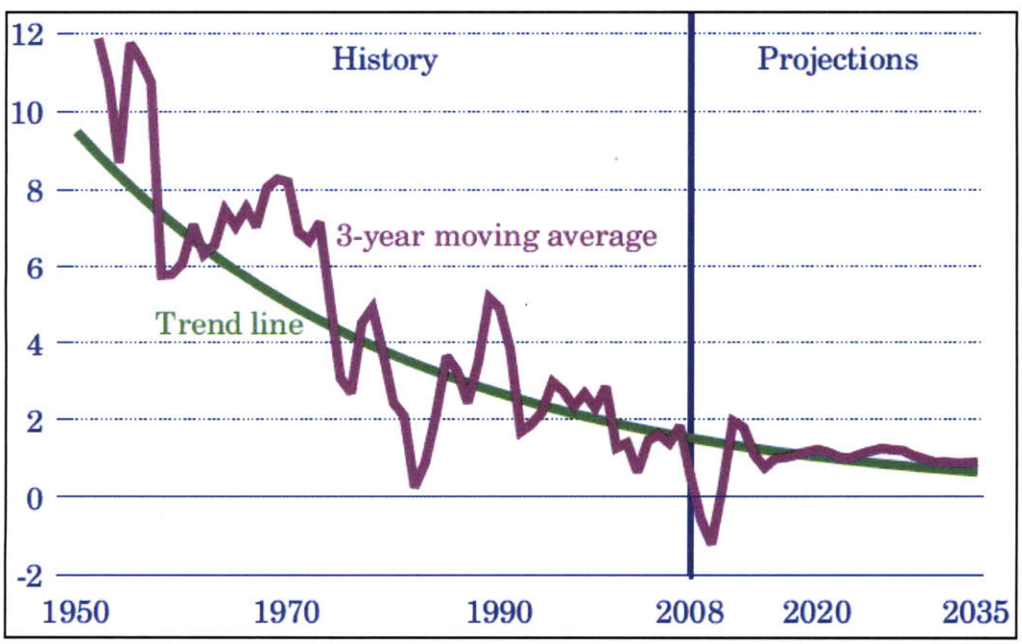


Figure 1. U.S. Electricity Demand Percent Growth, 1950-2035
Source: (Energy Information Administration 2010a)

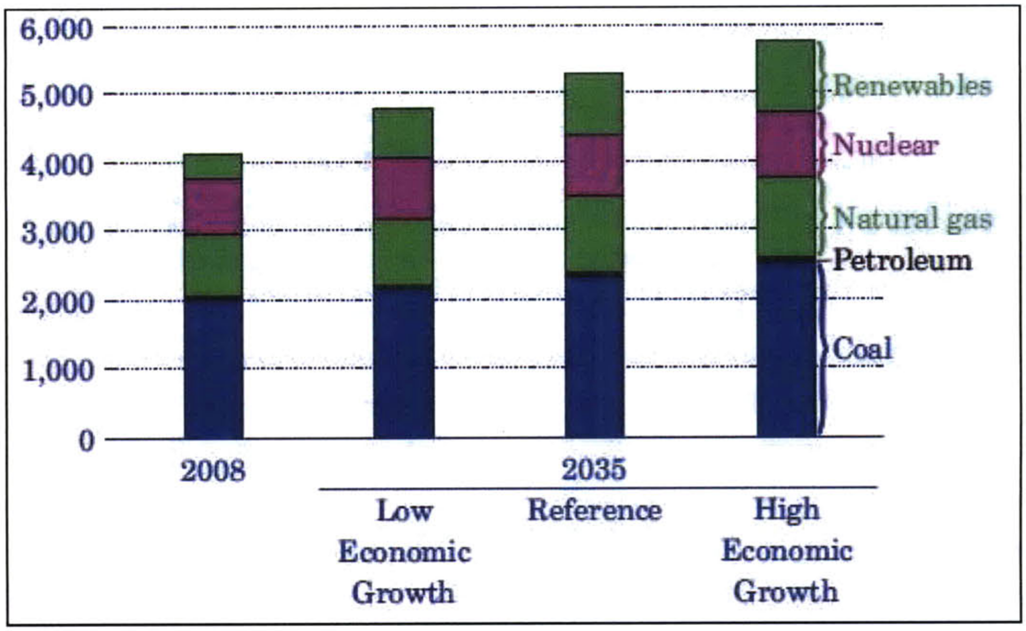


Figure 2. **U.S. Electricity Generation by Fuel in 2035, 3 Economic Cases**
Source: (Energy Information Administration 2010a)

Electricity demand in the U.S. is expected to continue to grow at an average rate of 1 – 2 % / year until 2035, as shown in Figure 1. Although small in percentage terms, this rate would still imply a significant change in total electricity consumption from 3,873 billion kilowatthours (kWh) in 2008 to 5,021 billion kWh in 2035 (Energy Information Administration 2010a).

Electricity generation is forecasted to increase correspondingly to meet growth in demand. Figure 2 shows the forecasted generation in 2035, in terms of aggregate generation by fuel type. The expectations for three economic cases are shown: low economic growth, a reference case, and high economic growth. The differences in expected total generation in each case underscore the dependence of economic growth on electricity consumption. Irrespective of the specific case that is realized, total electricity consumption is expected to increase, leading to a need for new generating capacity. However, there are concerns about whether generation capacity additions will occur in the types of generation technologies that are most beneficial for society in the long-run.

2.2 Size of the Investments

The size and nature of power generation investments vary on the basis of factors such as generation technology, size of the plant, and scale of production. A variety of generation technology options are available, viz. nuclear, conventional fossil fuel plants such as coal or natural gas, and renewables such as wind or hydro. Plants could be of different scales such as base load, load-following or peaking units depending on the type of load they are expected to serve. For example, nuclear and coal plants are better suited to operating at high constant output levels and are typically used to meet base load demand. Natural gas plants are able to alter their output levels more easily and can be used as load-following or peaking units. Nuclear plants require a high up front capital investment but have relatively low operating and fuel costs, whereas natural gas plants have lower capital requirements, but their operating costs are high and may be quite volatile because of their dependence on natural gas prices. The technology, size and scale selected therefore dictate the amount of capital required for the investment.

The size of the investments in planned generating capacity in the near term is very large. Table 1 lists planned investments for the period 2009 – 2013 for some selected generation technologies. Over 530 new plants are expected to come online during this period for a total generating capacity of almost 82 gigawatts (GW). The total overnight costs are estimated to be 2008 $ 111 billion, of which coal plants form the largest share in terms of cost, requiring $ 45 billion. The single planned nuclear plant alone is estimated to cost almost $ 5 billion.

Table 1. Estimated Investments in Selected Generation Technologies (2009-2013)

Data Source: (Energy Information Administration 2010c; Energy Information Administration 2010b)

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)	Average Plant Size (MW)	Overnight Cost (2008 $/kW)	Average Plant Cost (2008 $ billions)	Total Nominal Costs (2008 $ billions)
Coal	45	21,340	474	2,233	1.06	47.65
Natural Gas	330	45,541	138	685	0.09	31.20
Nuclear	1	1,270	1,270	3,820	4.85	4.85
Wind	161	13,650	85	1,966	0.17	26.84
Total	**537**	**81,801**				**110.54**

The costs described here do not include the recurring operating and fixed costs of the plants, rather they can be thought of as the "overnight" plant costs incurred to enter the market, assuming that all the capital costs are paid up front as a lump sum. As such, coal, nuclear and wind plants have much higher overnight costs than gas plants.

This analysis assumes that it is easier to finance plants with lower overnight costs, and that policymakers are more concerned about securing investments in plants with very large overnight costs. It is also likely that the higher the overnight costs, the more buyers and sellers would prefer to have the security of a long-term contract.

2.3 Regulatory and Organizational Status

The U.S. electricity industry has long had a separation between federal and state regulatory frameworks, and the industry was regulated predominantly at the state level for a large part of the 20th century. However, the last two decades have seen significant changes in the structure of the industry. Federal oversight of the industry has increased in some parts of the country, whereas states in those parts have limited their regulatory focus to a smaller number of activities. Restructuring has increased the number and variety entities participating in the generation and supply of electricity, and not all of them are regulated. Furthermore, many states did not choose to restructure the entities in their footprint and continue to function as they did for the better part of the 20th century. The separation of federal and state regulatory authority, the number and types of entities participating in the industry and differing state regulations create a patchwork of industrial organization and regulatory environments.

2.3.1 Vertical Integration and Cost-of-Service Regulation

Prior to the Energy Policy Act of 1992 (EPAct 1992), states primarily regulated the electricity industry within their boundaries, pursuant to prior legislation such as the Public Utilities Holding Company Act of 1935 (PUHCA 1935) and Public Utilities Regulatory Policy Act of 1978 (PURPA 1978). Federal oversight by the Federal Energy Regulatory Commission (FERC) was limited to interstate electricity transactions, if any, and the supervision of some federally owned electricity utilities.

Electric utilities were vertically integrated – the same company owned assets for and performed the function of generation, transmission and distribution of electricity. Utilities also supplied electricity directly to all end-use customers whether residential, commercial or industrial. Many utilities were investor-owned and were subject to regulation under the authority of state regulatory commissions. Others such as municipal utilities that were owned by local governments or cooperatives were not subject to state regulation, although some states were an exception. The regulatory paradigm was that of cost-of-service regulation, where the utility would pass through its generation and delivery costs to end-use customers in the form of administratively fixed rates. Investor-owned utilities (IOUs) were subject to rate-of-return regulation, which is essentially the same as cost-of-service regulation but also includes pre-determined returns to investors as a cost of providing electricity services. The main implications of this structure were that the utility company primarily owned all the assets including power plants and wire networks and that its revenues were regulated based on the cost of service. When new generation capacity was needed, investments were proposed by the utility and approved by the state commissions (or municipal governments), under the objective of delivering electricity at low costs of service. This system allowed for generation planning to be centralized within the vertically integrated company and decision-making authority to be vested in the state government.

A number of issues with the cost-of-service model such as information asymmetry between regulators and the vertically integrated companies, and the lack of incentives to reduce or maintain low-cost electricity service eventually led regulators to consider introducing competition into the industry.

2.3.2 Restructuring and Wholesale Competition

Pursuant to the EPAct 1992, utilities were allowed to purchase electricity from non-utility power producers who generated electricity for the purposes of sale to load-serving entities. The decision was undertaken to harness the benefits of competition in electricity generation and ensure that electricity was in fact being provided at least cost, which was not clear in the cost-of-service model. Proven generation technologies and experiences of non-utility companies with building generation facilities suggested that the function of generating electricity could be opened up to markets. By the year 2000, twenty-four states and the District of Columbia passed legislation and implemented some form of restructuring.

Independent power producers were not subject to state regulation and could choose the utilities to which they would sell their output. Investors could observe the market price of electricity and develop expectations for the profitability of a plant, on which the investment decision was based. The decision to build a plant therefore did not have to be approved by the state commissions. State commissions therefore lost the ability to secure investments in electricity generation, since the decision making process became driven by markets.

To enable the functioning of the wholesale generation market, the FERC and state regulations required utilities with transmission and distribution assets to allow any eligible generating facility to connect to their networks and thereby sell electricity into the network. Most states also required electric utilities to divest their generation assets by sale either to affiliated subsidiaries or other entities. They were allowed to retain ownership of transmission and distribution as natural monopolies. Transmission and distribution utilities in restructured states are no longer allowed to own generation assets, with a few exceptions. Consequently, they must procure electricity from power producers to be able to serve end-use demand. The new laws did not apply to municipal or federal utilities and cooperatives that were not previously subject to state regulations.

For the efficient and reliable operation of the electricity system, restructured states have formed independent system operators (ISOs) or regional transmission organizations (RTOs) in many regions of the country. ISO/RTOs are independent not-for-profit entities subject to FERC authority that ensure the proper functioning of regional electricity markets and network operations. The markets include short-term (intra-day or day-ahead) "spot" transactions that are organized by the ISO. The markets also include mid- to longer-term (months, one to three year) transactions based on standardized bilateral forward contracts that are not arranged by the ISOs, but reported to them by the contracting parties. Many states have prohibited long-term transactions of durations greater than 5 years to enable liquid shorter-term markets that would represent the true short-run marginal costs of providing electricity.

Half of the U.S. states did not pursue restructuring and elected to continue with the traditional cost-of-service model. Such states still have vertically integrated utilities and fully regulated generation and network functions. They also do not participate in the organized wholesale markets set up by the ISO/RTOs. Utilities in non-restructured states also continue to obtain regulatory approval for generation investments from state utility commissions.

2.3.3 The Current Organization

There are over 3,200 entities in the U.S. that can be generally described as electric utilities. Some statistics about the various types of utilities are listed in Table 2.

Table 2. Summary Statistics for U.S. Electric Utilities

Data Source: (Energy Information Administration Form EIA-860 2008; Energy Information Administration 2008)

	Type	Number	Generating Capacity (GW)	Number of Customers (millions)	Retail Sales (billion kWh)
Utility	Investor-Owned	210	375	101	2,479
	Public	2,009	88	21	561
	Federal	9	69	0	42
	Coop	883	37	18	386
	Other	162	2	0	14
	Total	**3,273**	**571**	**139**	**3,482**
Non-Utility		N/A	424	3	283
Overall Total			**995**	**142**	**3,765**

There are a large number of public (municipal) and cooperative utilities, but they own relatively small amounts of generation capacity and supply a small share of the end-use retail electricity consumption, with some exceptions such as CPS Energy (Texas) and LA Department of Water and Power (California). Investor owned utilities serve 71% of the end-use customers and distribute 65% of the retail electricity consumed in the U.S. Generation capacity shares are largest for non-utility power producers with 43% (including independent power producers, cogeneration facilities, and small renewable generators) and IOUs with 38% of capacity. The end-use retail sales by non-utility producers are very small, because most of their output is procured by load-serving utilities that may not own or require additional sources of generation capacity.

Most non-utility power producers and IOUs that do not own generation are located in states that comprise the ISO/RTO systems with wholesale markets for electricity. Figure 3 depicts the regions of the country that are comprised of restructured states that participate in either an ISO or RTO system. Some Canadian provinces like Alberta and Ontario also have transmission interconnections with U.S. ISO/RTOs. These systems are concentrated among the eastern, mid-Atlantic, mid-western U.S. states, Texas and California. Notable among them are the PJM interconnection, New York ISO, New England ISO and ERCoT in Texas. In these regions, generation investments are largely influenced by prevailing and forecasted electricity market prices.

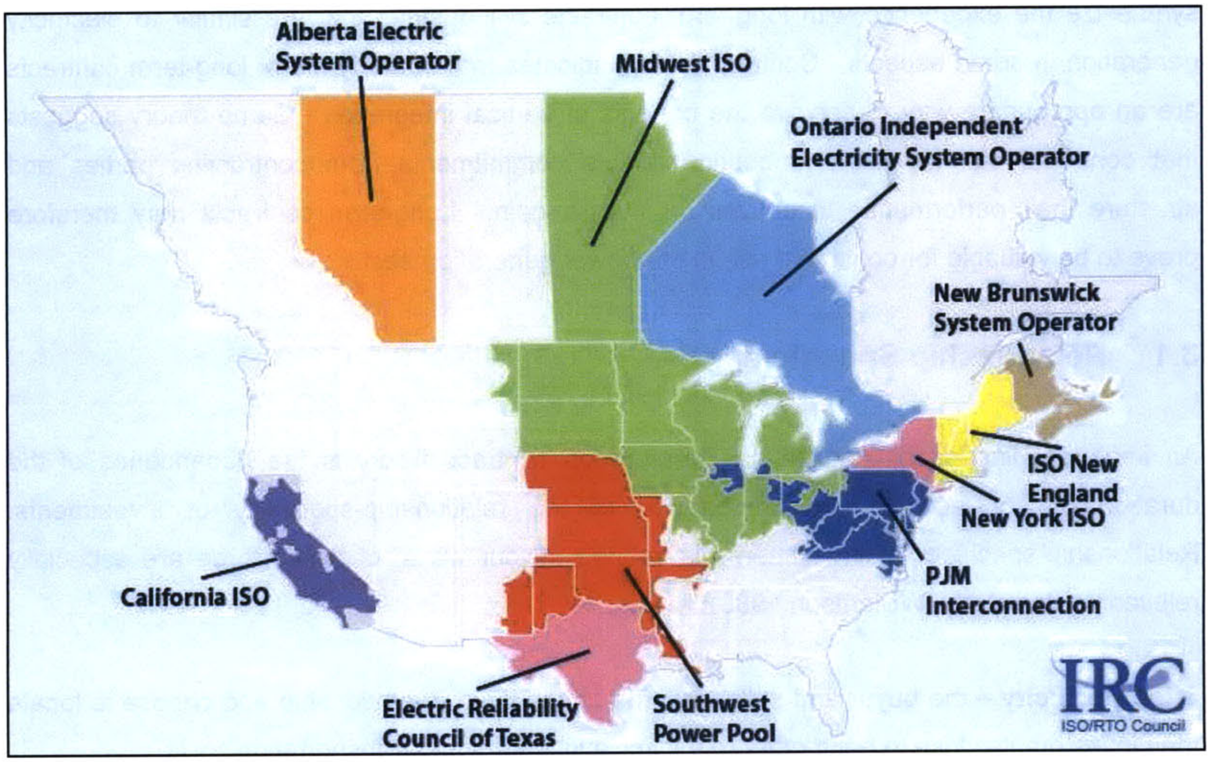


Figure 3. ISO/RTO Regions in North America
Source: ISO/RTO Council 2010

The preceding discussion illustrates the context for the rest of the analysis. So far, the periodic need for new generation capacity has been established and the significant size of the investments has been noted. Attention has been drawn to the fact these investments will need to occur within the specific organizational and regulatory regimes that govern the industry today. The stage is now set for a more focused discussion on power plant financing and long-term contracts.

Chapter 3 The Rationale for Long-term Contracts

This chapter discusses the theoretical and empirical literature on long-term contracts. The discussion will prove useful for two reasons - firstly, it will provide a context and nomenclature for contract-related concepts that are to be applied to the electricity industry, and secondly, it will synthesize the experience with long-term contracts in industries that are similar to electricity generation in some aspects. Contract theory indicates that some types of long-term contracts are an appropriate way to achieve the benefits of vertical integration. Game theory suggests that contracts can be used to obtain credible commitments from contracting parties and structure their performance incentives for mutual gain. Long-term contracts may therefore prove to be valuable for continued use in the power generation sector.

3.1 Relationship Specificity:

An important line of thinking in the literature on contract theory is the dependence of the duration of contracts on the importance of the relationship-specificity of investments. Relationship-specificity of investments is defined in four ways, of which three are especially relevant to this study (Williamson 1983):

Site specificity – the buyer and seller are in a cheek-by-jowl relationship and choose to locate their investments close to each other to minimize inventory and transportation costs.

Physical asset specificity – the investment is in equipment of particular design characteristics that have uses specific to the transaction. The equipment cannot be readily employed in alternative uses.

Specificity of dedicated assets – investments in assets by either a buyer or seller that would not otherwise have been made but for the prospect of exchanging a significant amount of product with a particular customer or producer. If the contract is terminated prematurely or breached, the supplier would be left with significant excess capacity, or the buyer may find it difficult and expensive to find another supplier.

The definitions of the three types of specificity imply that if one or more specificities are important to a buyer-seller relationship, then the parties will rely less on repeated negotiations over time and tend to enter into longer-term ex ante commitments. Extending this reasoning to the electricity industry suggests that generators would sign a long-term contract with a customer if their relationship was characterized by a high degree of one or more types of specificity.

The economics literature provides strong empirical support for Williamson's description of buyer-seller relationship specificity. For example, "mine-mouth" coal plants, which are particularly representative of site and asset specificity, have a greater likelihood of having long-term contracts (Joskow 1985). In most cases, the mines and the plants are developed at the same time, and the plant commits to taking most of or all the output of the mine. The benefit of the contracts in this case is the reduced inventory and transportation costs that reduce the overall cost of electricity production. Further, when coal plants are designed to a burn a particular type of coal (i.e. coal with a specific heat rate and chemical content), the narrow design constraints (physical specificity) enable equipment cost savings, thereby reducing overall electricity costs (Joskow 1985; Joskow 1986; Joskow and Schmalensee 1985). The specificity of the form of dedicated assets is included is identified by the fraction of output of a mine that is procured by a particular utility. Other things being equal, a mine that sells most or all its output to a particular utility is considered "dedicated" (Joskow and Schmalensee 1985). A study of 300 contracts between electric utilities and coal mines that were in force in 1979 and finds evidence for a more general hypothesis (Joskow 1986):

> [The] more important are relationship-specific investments, the longer will be the period of time (or number of discrete transactions) over which the parties will establish the terms of trade ex ante by contract.

These studies on coal contracts demonstrate that if the relationship between the mine (seller) and electric utility (buyer) is characterized by one or more of site, physical or dedicated asset specificity, then it is likely that the parties entered into a long-term contractual agreement because they gained by avoiding the possibility of ex post bargaining over the benefits of the arrangement. The potential for this gain was known to the parties ex ante – they knew in advance that they would continue to transact with each other for a significant period of time. The seller benefited from the buyer's assurance that it would continue to purchase the seller's product, and the buyer was assured that it would not have to seek out another supplier for the duration of the contract. The mutual benefit resulted in an ability to ultimately lower the cost of electricity produced by the utility (buyer), a measurable economic gain. Thus, long-term contracts can result in measurable economic gains when relationship specificity is important.

A note on the type of product being exchanged is worthwhile. The product that was exchanged between the buyer and seller in these cases was coal, which was an input into the production of electricity. The characteristics of coal as a commodity are fundamentally different from those of electricity. Coal is a differentiated commodity; its availability is limited geographically but it can be transported to the point of use and stored for extended periods of time. There is a variation in its intrinsic quality in terms of heat rate and chemical content. One unit of Powder River Basin coal may therefore be quite different from Appalachian coal. Supplies of coal of different characteristics cannot be easily substituted. Thus, a contractual arrangement in the case of coal is for a differentiated commodity. In contrast, electricity as a commodity is very different from coal. It cannot be stored easily, and must be transported immediately from the point of generation to the point of consumption. Moreover, electricity from a coal plant is indistinguishable from that produced by a nuclear or gas plant. Therefore, electricity does not readily lend itself to differentiation as a product. This fundamental characteristic is important in the consideration of long-term contracts for electricity, where electricity is the primary product exchanged. Unlike coal, where the quality of coal or the location of the mine may contribute some degree of specificity to the relationship between buyers and sellers, electricity as a commodity does not prima facie indicate specificity between its producers and consumers. If specificity is the driver for the long-term contract, the electricity generator or the consumer would have to make a case for the importance of specificity to their relationship to justify a long-term contract.

3.2 Opportunism

The issue of ex post opportunistic behavior in the presence of long-term contracts is particularly relevant to this discussion. The issue is important to understand because the duration of contracts in our case is very long (10 years or more), and longer contracts are more prone to "incompleteness." Acknowledgement of the issue allows the anticipation of problems that might arise long after a contract has been signed. If the terms of the contract are no longer favorable to any of the contracting parties in the future, then one or more parties may wish to renegotiate terms of the contract, or to terminate it. To do so, the parties will have to once again engage in a process of contract evaluation and negotiation, which can be quite costly. For example, if a coal mine (as in the example of the mine-mouth plants discussed in Joskow (1985)) finds that it is no longer able to supply coal of a stipulated quality to the adjacent plant, perhaps because it has exhausted its coal seams or found another buyer willing to pay higher price, then the mine may want to renegotiate or terminate its contract with the plant. The first case represents a situation where it is optimal for the mine to end the agreement because it can no longer deliver coal as stipulated in the contract, and compensate the plant for damages. In the second case, termination is optimal if the earnings from the higher prices exceed the damages the mine pays to the plant. In the meanwhile, the plant may be forced to procure its coal supplies at high spot market prices and incur transportation and inventory costs, the avoidance of which were the basis for the highly relationship specific contractual agreement. If the mine and the plant cannot arrive at a satisfactory renegotiation, then they might also have to bear the costs of litigation and adjudication. The mine or the plant could also be left with cost of stranded assets that do not have much value in alternate uses. In trying to alter the contract, the parties are trying to take advantage of an opportunity that was realized ex post. They were not aware that one or both of the parties would be presented with such an opportunity at the time of signing the contract. The contracting parties will be worse off than if they hadn't entered into a long-term contract, thereby precluding such future opportunities.

The inherent characteristics of long-term contracts that present the risk of ex post opportunistic behavior is that they are rigid, necessarily incomplete, or too vague to ensure performance. In the economic sense, an incomplete contract is one in which the performance of the contracting parties can be specified generally, but not in every possible state of the world that might result after the contract has been entered into. To illustrate these characteristics, four types of contracting modes can be specified (Williamson 1975):

(1) Sales contract - contract now for the specific performance of X in the future

(2) Contingent claims contract - contract now for the delivery of X_i contingent on event E_i obtaining in the future

(3) Sequential spot sales contract - Wait until the future materializes and contract for the specific X at the future time

(4) Authority relation - contract now for the right to select a specific X_i from within an admissible set X, the determination of the particular X_i to be deferred until the future.

3.2.1 Sales Contracts

Of the four modes, sales contracts are the most rigid because they require extremely specific performance irrespective of how the future unfolds. In other words, they do not allow for ex post "adaptation" in response to changing internal or market circumstances, where adaptation is the ability to alter the terms of the contract suitably to ensure favorable outcomes for the contracting parties. The risk of opportunistic behavior is high with rigid sales contracts because of their inflexibility. In any environment fraught with complexity or uncertainty, sales contracts of long durations can therefore be expected to be problematic. Parties would not ordinarily be expected to sign sales contracts for any extended period of time in uncertain environments. The other three modes are preferable because they are more conducive to adaptation (Williamson 1975).

3.2.2 Contingent Claims Contracts

Contingent claims, or "once-for-all" contracts attempt to make efficient choices for the selection of X_i depending on how the future unfolds, i.e. the realization of an event E_i. Suppose that the parties are instructed to negotiate a contract ex ante in which the obligations of the parties are fully stipulated at the outset for every possible event E_i. A number of problems can be anticipated in this type of contract. Firstly, it is not feasible to envision every possible future state of the world E_i. Even if such a contract were feasible, it would be extremely complex. Secondly, for such an agreement between the parties to be meaningful, every resulting X_i would have to be stipulated. Parties attempting to sign such a contract for a long duration would have to assess a much larger number of X_i and E_i. Thirdly, it is not likely that the parties can implement such complex agreements in a low-cost fashion. The parties would have to declare the state of the world E_i that has been realized, upon which there may not be an agreement. In any case, performance would have to be measured and non-performance would have to be enforced. Fourthly, if one party has more information about the state of the world, that party can represent the situation in a way that is most favorable to it, thereby behaving opportunistically. For all of these reasons, as the number of contingent claims increases, the complexity of such contracts in the face of uncertainty increases and their usefulness decreases. Williamson therefore distills and summarizes the issues in the following statement:

> The feasibility of writing complex contingent claims contracts reduces fundamentally to a bounded rationality issue.

Because of bounded rationality, useful contingent claims contracts would therefore have to be "incomplete," that is, stipulate only the most meaningful events E_i and consequent performance requirements X_i. Thus, if the number of meaningful claims cannot be reduced to a manageable few, especially with longer-term contracts, then the parties may be better of considering an alternative arrangement such as sequential spot contracts.

3.2.3 Sequential Spot Contracts

Sequential spot contracts avoid the bounded rationality issues of contingent claims or "once-for-all contracts" because the complex decision tree does not have to be generated ex ante. Parties simply wait to contract in a spot market until important information becomes available to them. By avoiding ex ante commitments, they reduce the risk of incurring costs related to ex post bargaining. By doing so, however, they may sacrifice the benefits of a relationship-specific long-term commitment that is not available in the spot market. Additionally, a significant advantage that spot contracts present to the contracting parties is the value of experience. If a particular spot contract turns out to be unfavorable, the contracting party can avoid similar agreements in the future. The spot contract does not lock the parties into an unfavorable situation for any extended period of time. Spot contracts allow parties to be more adaptable to uncertain circumstances in the long run; whereas contingent claims contracts do not allow the parties to easily adapt. However, these aspects of spot contracts only mitigate the risks related to bounded rationality; such contracts may still be impaired by opportunistic behavior in a "small-numbers bargaining" context (Williamson 1975). Although the spot market may be competitive at the outset due to a large number of agents, the number of agents might be much reduced when the contract is about to be renewed. The remaining small number of agents may experience bargaining problems amongst themselves due to limited choice, because most other agents have already entered into contracts that are favorable to them. Contractual terms in such a spot market may not be as favorable as under alternative arrangements. However, in the absence of a "small numbers" situation, opportunism due to ex ante commitments is not a concern.

3.2.4 Authority Relation

As an alternative to the three contracting modes that have just been discussed, the authority relation can also be used. In the authority relation, the party that exercises authority over the other can select an X from a pre-determined set of possibilities at some time in the future. This is typical of an employment contract where the firm hires an employee and the employee can be asked to deliver performance X (from a reasonable set of possibilities) at a future point in time based on the firm's needs. The employee receives some compensation in return for being able to deliver the range of performance. The employee may also receive some performance incentives if the employer does not know in advance what performance it may require the employee to deliver given a future need. The authority relation may be reasonable in a labor market context and considered extremely adaptable from at least one party's perspective, but would be difficult to establish in a market for electricity because of its vague terms. Parties would prefer to know the terms and conditions of their agreement ex ante, or at the very least to avoid an agreement that does not allow them to adapt in uncertain circumstances.

The brief discussion on contract modes suggests that adaptable contingent claims or sequential spot sales contracts are more suitable in highly uncertain environments such as electricity markets than rigid sales contracts or vague authority relations. In a relationship specific context, long-term contingent claims contracts may be preferred over spot contracts to avoid repeated sequential transactions between the same parties. Of the two types of adaptable contract modes, contingent claims contracts are more likely to be affected by opportunism arising out of bounded rationality. Such opportunism is evidenced in the case of highly relationship-specific context in the automotive industry (Klein, Crawford, and Alchian 1978; Klein 2000).

3.2.5 Empirical Example - Automotive Industry

Klein et al (1978) describe the contractual relationship between General Motors and Fisher Body. In 1919, General Motors entered into a long-term contract with fisher body for the supply of closed auto-bodies, which was a new automotive body technology at the time. Since Fisher did not own the equipment to make closed bodies, it needed to make specific investments in very specialized, capital intensive equipment. An exclusive dealing clause was therefore included in the contract whereby General Motors agreed to buy almost all of its closed bodies from Fisher. Because of this clause, Fisher was assured of the fact that GM would continue to buy its bodies at the ex ante determined price terms. GM could not demand a lower price or threaten to purchase from another supplier after Fisher's investments had already been made. Thus, the claims in the contract prevented GM from acting opportunistically. In other words, the exclusive dealing clause prevented "hold up" by GM. This assurance enabled Fisher to undertake a large capital investment for the purpose of supplying to GM. The price terms that were agreed to also avoided initial monopolistic behavior on the part of Fisher, by requiring it to charge prices that were in the range of average market prices for similar bodies. This term attempted to prevent the "reverse hold up" of GM by Fisher. Over the next few years, however, market conditions changed dramatically and General Motors' demand for closed bodies significantly increased. Given the new demand, Fisher's original price terms became unfavorable for GM. Fisher refused to alter its price terms or to relocate closer to GM's factory to reduce costs. GM was not able to anticipate these developments ex ante and specify contingent claims in a legally enforceable way. By 1924, GM found the long-term contract with Fisher intolerable and GM finally merged with Fisher in 1926. Vertical integration was sought as a solution to resolve the ex post bargaining that resulted from contractual "incompleteness" and opportunism (Klein 2000). In this example, it must be noted that the long-term contract solved one type of problem – the assurance needed by Fisher to undertake a relationship specific investment. However, it created another problem due to the limitations of the contract, viz. the problem of "hold up."

3.3 Relationship Specificity and Vertical Integration

The literature on transaction cost theory developed by Williamson and others suggests that vertical integration is a realistic alternative to long-term contracts in highly uncertain environments where relationship-specific investments are necessary, and where such integration is permitted. Vertical integration enables the firm to avoid the issues of opportunism and ex post bargaining, because the transactions are internalized within the firm. The proposal advanced by Crocker and Masten (1996) about the organizational decisions of firms in such environments is depicted in Figure 4, and is consistent with empirical evidence (Joskow 1985; Joskow 1986; Stuckey 1983; François Hennart 1988).

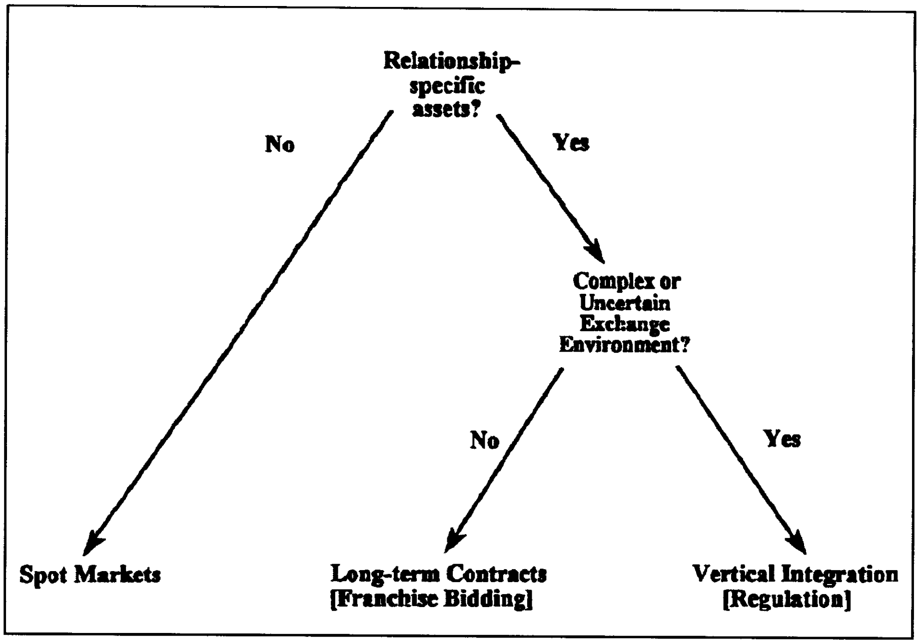


Figure 4. Determinants of Institutional Choice
Source: (Crocker and Masten 1996)

Joskow's studies of coal contracts indicated that mines and utilities in specific relationships such as mine-mouth coal plants benefited from contracts from relatively long durations. However, the same work also indicated that mine-mouth plants were six times more likely to become vertically integrated than non-mine-mouth plants. In the mining industry, bauxite refiners preferred to own their mines because of high transportation costs (Stuckey 1983). Additionally, refineries were often designed to process particular ores, which increased the specificity of the relationship between the mines and the refineries. Specificity was much lower in the case of tin refining because of lower transportation costs and the ability of refineries to handle ores from different mines and such firms were less likely to integrate (François Hennart 1988). Based on the large amount of evidence, Crocker and Masten (1996) conclude that:

> Although vertical integration is more common in the presence of asset specificity, the choice between integration and contracting—both of which provide some level of protection against hold up—turns on the relative ability of these alternatives to accommodate complexity and uncertainty. Because the limitations of contracting become particularly acute in complex and uncertain environments, greater uncertainty and complexity generally favor integration over long-term contracting.

In essence, Crocker and Masten attribute the preference for vertical integration to the issues of "bounded rationality" and contractual incompleteness, as discussed earlier. They do acknowledge, however, that in the absence of vertical integration, long-term contracts are the next best alternative for the organization of firms with relationship specific investments. This appears to be consistent with the trend of public utility regulation they discuss. The electricity industry is representative of the trend they observe. In recent years, the electricity industry in many parts of the world has undergone significant restructuring. The functions of generation, transmission and distribution that were previously bundled and performed by vertically integrated firms have now been exposed to different forms of organization. The generation sector has been exposed to wholesale markets for electricity, with a number of variations, with scrutiny by market commissions. Transmission and distribution are treated as natural monopolies and closely regulated by state or national companies. Vertical integration is prohibited by law in most restructured environments to facilitate the functioning of wholesale markets and separate regulatory governance of the transmission and distribution sectors. One would therefore expect that firms would resort to long-term contracts to obtain the benefits of specific relationships, and pay particular attention to the design of those contracts to safeguard against opportunism and provide incentives for efficient performance.

Given the advantages and limitations of long-term contingent claims contracts, firms are faced with the imperative of structuring contractual provisions in a manner that facilitates efficient adaptation. The use of "unilateral options" has been proposed to preserve flexibility, and to limit ex post bargaining or costly adjudication (Crocker and Masten 1988). Unilateral options are pre-specified provisions that allow one of the contracting parties to take a certain action at a future date if uncertain events result in an unfavorable outcome the party. An example of a unilateral option is a take-or-pay provision, where the buyer can choose to decline delivery in return for a specified minimum payment to the supplier (Masten and Crocker 1985). The minimum payment is designed to cover some or all of the specific investment costs of the supplier and serves as "liquidated damages." As a result, the parties can maintain the original contract and specific relationship. The pre-specified damages prevent haggling and are readily enforceable in court in the event of a disagreement. If the contracting parties can design a contract that allows them to adapt in a low-cost fashion, the risks of being locked in to a long term agreement are reduced. Contracts that enable efficient adaptation could therefore be of longer durations, because the number of contingent claims for dates long into the future can be reduced.

3.4 Contracts in Game Theory

Game theory is informative about the general nature and purpose of contracts in ensuring desirable outcomes. Contracts allow the players in a game to realize higher payoffs than would otherwise be realized under their normal strategies, by enabling players to cooperate with each other by credibly committing to a particular course of action. Some relevant games are discussed generally before developing the role of contracts.

3.4.1 Non-zero Sum Games

The players in a game each act in a way that serves their best interests, otherwise they would not benefit from playing. The payoffs to a player are dependent on the actions of the other players, or the rivals, in the game. A player therefore selects a strategy based on its expectation of the rival's moves. Each player follows a strategy that results in the maximum payoff to that player contingent upon the actions of the rivals. When the interests of the players conflict, they are said to be in a zero-sum (or constant-sum) game. That is, one player's benefit is another player's loss, as in the case of a basketball or football match where a player wins only if the other loses. On the other hand, rivals may also have some common interests such that some strategies may result in mutual benefits for the rivals. Such games are typical and called non-zero sum games. Players in a non-zero sum game may thus be able to realize some gains in their payoffs under certain strategies, instead of absolute losses in constant-sum games.

In some non-zero sum games, one or more players may have a dominant strategy that enables it to maximize its payoffs, irrespective of the actions of its rivals. Players with dominant strategies can be expected to use them, because their payoffs are maximized independent of rivals' strategies. When the players find strategies that are the best response to their rivals' strategies, the combination of strategies characterizes an equilibrium, according to which players should act. However, games exist where the players can become better off than in the equilibrium state if they were to select a strategy other than the dominant strategy. Such games can be illustrated in the form of a simple example analogous to the prisoner's dilemma, adapted from Dixit (1991).

An Example

Consider two oil-producing countries, X and Y, who face a production decision as described in the following non-zero sum game. Each country could produce at one of two possible production levels, 2 or 4 million barrels of crude oil a day. The resulting total output is 4, 6 or 8 million barrels a day, one of the various possible combinations of the different production levels for both countries. The price corresponding to each total output is $25, $15 and $10 per barrel, respectively. The costs of production are $2 in Country X and $4 in Country Y. Then, the profits of each country contingent on the choices of their respective production levels are shown in the payoff table in Figure 5.

Payoff Table for Production Level Selection (profits in $ millions)

		Country Y	
		2 million barrels / day	4 million barrels / day
Country X	2 million barrels / day	46, 42	26, 44
	4 million barrels / day	52, 22	32, 24

Figure 5. Prisoner's Dilemma – An Example of a Non-zero Sum Game
Source: Adapted from (Dixit and Nalebuff 1991)

The payoff (in $ millions) for country X is always higher when it produces 4 million barrels, $52 and $32, as compared to $46 and $26 when it produces only 2 million barrels a day. Similarly, the payoff for Country Y is always higher when it produces 4 million barrels a day ($44 and $24, versus $42 and $22). Both countries thus have a dominant strategy of producing at the maximum output level of 4 million barrels a day each with the resulting profits of $32 for Country X and $24 for Country Y. However, by selecting a strategy that is expected to maximize their individual payoffs, the countries realize a joint outcome that results in payoffs that are even lower than if they were to both produce only $2 million barrels each ($46 for Country X and $42 for Country Y). The joint payoff of $56 is the least compared to $74 (4, 2), $70 (2, 4) and $88 (2, 2). The outcome realized in the equilibrium of the dominant strategies is therefore sub-optimal.

If both countries were to choose the payoff minimizing strategy, they could each benefit from the higher joint payoffs. This combination of strategies is unlikely in the absence of a cooperative arrangement because each player still has an incentive to choose the higher production level, while the other is producing at the lower level. That is, if Country X is only producing 2 million barrels a day, Country Y still retains its incentive to produce 4 million barrels a day and maximize its payoffs, and vice versa. Thus, acting in their individual best interests always results in the sub-optimal outcome. The solution to this dilemma is a cooperative arrangement between the rivals to ensure that both will select strategies that are individually payoff minimizing, but will result in the highest joint payoffs. The value of such cooperation is the difference between the expected optimal joint payoff and the sub-optimal equilibrium joint payoff, a gain of $32. While cooperating, the players must also ensure that the incentives to cheat or behave opportunistically are not retained, or the cooperative arrangement will be meaningless.

Although not all non-zero sum games are of the prisoner's dilemma variety, this example clearly illustrates the benefits of cooperation. In general, the key insight developed here is that in some instances cooperation enables rivals in a game to realize gains that are otherwise unavailable to them, if they were to each pursue their dominant strategies. Contracts are widely seen as a method of credibly ensuring cooperative arrangements.

3.4.2 Securing a Commitment to Cooperation

Players can commit to a cooperative strategy by entering into a written contractual arrangement with each other. Contracts are a useful as a device of commitment to the cooperative strategy if the contracting parties have some independent incentive to enforce the contract. For instance, an employee could sign a performance contract with an employer that includes regular pay plus a bonus for performing work of a stipulated quality. The employer wishes the work to be completed at minimum, and has an incentive to enforce the contract if the employee decides to renege on the work. The employee wishes to earn the compensation in exchange for the work performed and will enforce the contract if the employer refuses to pay. Each contracting party would thus enforce the contract because the contract secures the benefits that the parties receive.

Incentives

In this example, the stipulation of the performance bonus provides the employee with an incentive to not only perform the work at minimum, but also to ensure that the work is of a quality desired by the employer. The employer's willingness to pay a bonus is an indicator of the value that is placed upon the quality of the work. In the absence of a bonus, the employer would be paying only for the minimum performance and the employee would only be earning the regular pay. This arrangement would therefore be a constant sum game. However, the players are in a non-zero sum game if there is a performance bonus; they both stand to gain more than the minimum payoffs that are available and have incentives to fulfill and enforce the contract.

Effective contracts can also include penalties or fines, as in the case of take-or-pay supply arrangements for a commodity. In the event of breach, the breaching party is responsible for payments to the other in lieu of damages. The buyer needs the commodity and will enforce the contract to ensure delivery, while the supplier needs the compensation for its output and will also choose to enforce the contract. In this example, the penalty is an incentive to ensure the performance of the contract by making it costly for the parties to renege. In general, such contractual arrangements indicate a credible commitment to a cooperative strategy because they include incentives or penalties for the performance of the stipulations in the contract. Breaching contracts is thus costly for the parties, and they are likely to follow the cooperative strategy.

A realistic example that illustrates the importance of appropriately structuring the incentives in a contract is provided by Hampson et al (1989). A contract between a state-owned oil resources authority and a private exploration company is studied. The authority has little expertise in exploring and developing wells and must contract with the company to benefit from the resources in the authority's country. The exploration company has the relevant expertise but must have access to the field to explore and develop the resources. The contract enables the authority to avail of the company's expertise and the company to earn compensation for its services. The company's work must be unmonitored because of the authority's inability to make informed decisions regarding exploration and development. To maximize the value of the country's resources, the company is given a share of the production as an incentive to select the optimal exploration and development program. However, the incentive in the contract is sub-optimal for two reasons. Firstly, the bonus to the company depends on the size of the find, but the choice of the exploration program does not affect the relative probability of larger finds versus smaller finds. Secondly, the company does not have an incentive to complete marginally profitable wells, because its costs of completing such wells are often much higher than its share of benefits from those wells. Hampson et al derive an optimal production sharing rule where the company receives nothing when no discovery is made and a fixed bonus for discoveries of any size. Under this incentive structure, the company selects an exploration and development program such that both its profits and the return to the authority are maximized (Hampson, Parsons, and Blitzer 1991). This work illustrates the point that an appropriately structured contract can be relied upon to ensure that company follows a strategy that is mutually optimal for the contracting parties.

Foregoing other Strategies

Another indicator of credible commitment through the use of a contract is the fact that the parties voluntarily give up the flexibility or choices to enter into such arrangements with other players. By signing a performance contract, the employee is assuring the employer of working only for that employer to meet the employer's needs and not abandoning the work before the contract is completed. In the take-or-pay example, the supplier is committing to deliver its output to the contracted buyer at the stipulated terms, and not other available buyers. The buyer is committing to purchase from the contracted supplier and foregoing the choice of purchasing from other available sellers. Thus, contracting parties must evaluate their options ex ante, that is, before entering into the contractual arrangement, to establish whether the arrangement is the best available strategy for them. If the parties choose to contract, it must be the case that they are likely to benefit more from the arrangement than in its absence and are willing to indicate this to their rivals by voluntarily giving up their flexibility to select other strategies.

Game theory suggests that contracts are thus an appropriate solution when rivals stand to maximize their payoffs in non-zero sum games by cooperating to secure gains that are otherwise unavailable. Prudent contracts may enable rivals to achieve optimal payoffs by ensuring that the players select the cooperative strategy, instead of other available dominant strategies. The value of the contract in such cases is the difference between the optimal joint payoffs and the sub-optimal payoffs that are realized as a consequence of the original equilibrium. However, contracts may fail to ensure the optimal outcome if the incentives are inappropriately structured or if the parties realize that the arrangement was imprudent. In such cases, the ex post regret may result in sub-optimal behavior by the contracting parties such as opportunism, breach of contract, attempts at renegotiation, or costly litigation.

The illustrations from prior literature indicate that long-term contracts have proved valuable, but only in particular circumstances. Such contracts may enable cost-minimization through asset specificity as in the case of mine-mouth coal plants. In situations where markets are imperfect, they have strategic value because they allow a firm to assess the demand for its capital intensive investment in production capacity, while ensuring that the expected returns are sufficient to cover the investment costs. Additionally, long-term contracts protect the parties' interest when they are engaged in a specific supply relationship. The contractual arrangements are not universally beneficial and cannot be generalized to the industries in which they have been observed. For such contracts to be prudent, the factors influencing an investment decision must reflect the specific circumstances that justify their use.

Chapter 4 Contracts and Financing Power Generation

This chapter first describes how utility procurement practices in traditional and restructured systems influence the generation investments. It then discusses the main sources of revenues that are available to generation companies in restructured states. The primary financing mechanism of project financing and its reliance on contracts is described. Finally, a risk management perspective is used to understand the advantages and disadvantages of contracts. This chapter concludes that the current rules for procurement practices in restructured states, and the inability of utilities to shift risk to end-use customers makes it difficult for generation companies to finance projects using long-term contracts. The possibility of economic losses and economic regret suggests that regulators must be cautious while approving contracts in an uncertain market environment.

4.1 Utility Procurement Practices

The ability of generators to compete in the modern U.S. electricity industry depends on whether they have buyers for their output and earn revenues that are sufficient to cover their costs in the short- and long-term. However, utility procurement practices differ considerably from fully regulated to restructured states and both paradigms must be examined.

4.1.1 Procurement under Cost-of Service Regulation

The cost-of-service system makes the process of paying for power plants relatively straightforward. The revenues of vertically integrated utilities are based on the costs of delivering electricity service, including the cost of adding new generation. Their revenues are recovered from customers through regulated rates that are administratively established by the associated state utility commission. Most state commissions operate under fairly general statutes that require rates to be "just, reasonable and non-discriminatory." Commissions also face statutory restrictions that only allow "prudently incurred" investments, or investments that are "used and useful." There exists a body of regulatory case law and court hearings at the state and federal level to guide commission decisions. However, these statutory instructions are open to interpretation and the utility commission is left with the task of determining rates during rate hearings. Commissions set rates so that both capital and operating costs are covered. (Joskow, Bohi, and Gollop 1989; Joskow and Schmalensee 1986).

In some cases, vertically integrated utilities do not have sufficient generating capacity to meet all the demand in their footprint and can procure electricity at the wholesale level from interconnected electric utilities. Often, a group of proximate utilities is also able to leverage economies of scale or increase the reliability of the grid by coordinating production across their portfolio of plants, thereby leading to lower rates for the pool of coordinating utilities. These transactions can occur through short- or long-term contracts and are subject to FERC's authority as wholesale power transactions. When such contracts are approved by FERC under wholesale tariffs, state utility commissions must allow utilities to pass these costs through to regulated rates unless the commission determines that the utility purchaser was imprudent to enter into the contract in the first place (487 U.S. 354, 108 S. Ct. 2428 Miss. Power & Light Co. v. Miss. 1988; 435 U.S . 972, 98 S. Ct. 1614 Burke v. Narragansett Electric Co.). Thus, if the commission approves the contract, the risk of the contract becoming imprudent in the future is ultimately borne by the utility's customers, as they will be responsible for regulated rates.

In the cost-of-service system, utility investments are thus ultimately subject to approval from state utility commissions. Although apparently straightforward, utilities have faced the regulatory risk of some investments being disallowed ex post. That is, they were denied cost recovery after some significant investments in power generation were already undertaken. Denial of cost recovery for nuclear plant related investments are notable examples of investment decisions that were deemed to be imprudent after costs had already been sunk. Consequently, utilities have been risk averse and careful to ensure regulatory approval of proposed investments well before investments are made (McConnell 1988; Congressional Budget Office 1998).

As discussed earlier, about half of the U.S. states have retained some form of traditional cost-of-service regulation. These include states like Idaho and Oregon in the western part of the U.S. and Georgia, Alabama and Mississippi in the Southeast.

4.1.2 Procurement in Restructured States

In restructured states, distribution utilities have been required to divest their generation assets and must procure electricity from affiliated generation companies or independent power producers that can sell into the wholesale markets. Residential and small commercial customers are captive and receive energy and delivery services from the incumbent distribution utility, unless they elect to contract separately with a retail electricity supplier.

Most restructured states have provisions for competitive retail electricity supply, where retail suppliers buy electricity directly in the market or under contract and sell it to end-use customers. Retail suppliers are not utilities; they have no generation or network assets of their own. They are merely the agent that procures electricity on behalf of the customer. The function of delivery continues to be performed by the existing distribution utility companies. Large industrial customers often transact with competitive retail suppliers based on the specific rates or services offered by them. In March 2010, such customers comprised 30% of the electricity sales by volume in Massachusetts (Table 3). These rates are based on retail suppliers' procurement costs, including a small profit margin for the supplier, and reflect prevailing market prices for electricity. As a result, retail suppliers often offer short term contracts for monthly, quarterly or annual terms with the terms of service stipulated in advance. Because retail suppliers' rates are not subject to regulation, customers bear the risk of rate volatility associated with price fluctuations in the wholesale market, unless they are offered fixed-price contracts.

Table 3. Massachusetts Basic Service and Competitive Supply Sales – March 2010

Data Source: (MA Energy and Environmental Affairs 2010)

	Total Sales	Basic Service			Competitive Supply		
	(GWh)	(number of customers)	(GWh)	(% of total sales)	(number of customers)	(GWh)	(% of total sales)
Residential -- Non Low Income	**1,254**	1,821,517	1,093	29%	270,412	161	4%
Residential -- Low Income	**136**	217,498	125	3%	17,604	12	0%
Residential -- Time-of-Use	**2**	289	1	0%	75	1	0%
Small Commercial & Industrial	**356**	212,122	218	6%	68,028	137	4%
Medium Commercial & Industrial	**549**	27,991	229	6%	18,001	319	8%
Large Commercial & Industrial	**1,465**	1,715	163	4%	5,356	1,302	34%
Farms	**2**	534	1	0%	55	1	0%
Street Lights	**28**	8,394	8	0%	7,534	20	1%
Total Sales to Ultimate Consumers	**3,791**	2,290,060	1,839	49%	387,065	1,952	51%

Most small customers remain on the distribution utility's service and are provided with "basic" or "default" service, i.e. the non-competitive option. In Massachusetts, 51% of the electricity consumed by volume (GWh) was supplied under the basic service program in the month of March 2010. Almost all residential customers were on basic service, whereas almost all large commercial and industrial customers were on competitive supply (Table 3). The utility is responsible for procuring sufficient electricity supplies to meet its basic service load, and the corresponding energy costs that it incurs are bundled with its regulated delivery charges. To pass through electricity procurement costs, the utility must follow strict procurement practices, and its costs are subject to regulatory approval. Such basic service tariffs that require regulatory approval are a hybrid of traditional cost-of-service regulation and competitive procurement.

Many states simply prohibit or disapprove longer-term contracts in their basic service model. For example, the state of Massachusetts prescribes the term of basic service contracts as one year, and longer-term contracts are considered case-by-case (Massachusetts General Laws Ch. 164 Section 94). In New Jersey, basic service procurements occur through a laddered process for contracts of one-, two-, and three-year durations (New Jersey Board of Public Utilities 2010). Utilities cannot ordinarily sign long-term contracts with an existing or a new generator even if their specific circumstances justify it. Recent laws passed by some states requiring utilities to enter into long-term contracts with renewable generators are therefore inconsistent with their basic service procurement practices.

Under basic service procurements, utilities typically request bids for "full requirements" service – the power producing company take responsibility for all the distribution utility's needs such as energy, capacity, ancillary services, transmission rights, and any other services needed as part of its bid offering. The wholesale supplier is free to choose whether it will meet its obligations through its existing generation, by procuring supplies from other power producers, or in the spot market. The risk of deviations in demand is borne by the supplier. If a utility's realized demand is higher than the expected load for which it contracts, the power supplier is responsible for purchasing additional supplies in the spot market. However, it still receives the contract rate ($/kWh) as originally approved by the commission. Similarly, if the realized demand in lower than expected, the supplier must find another customer for its output because the utility is not required to pay for the. The power supplier bears all the risk of being unable to recover its costs, whereas the utility and the customer have supply and price guarantees in this framework. Power producers are therefore reluctant to enter into longer-term contracts with distribution utilities (National Council on Electricity Policy 2007). Furthermore, the fixed rate full requirements service results in a deadweight loss, because it does not allow supply and demand to equilibrate according to the marginal value of electricity to power producers and end-use customers.

From the perspective of securing investments in generation, short-term contracts are not a reliable indicator of the long-term demand for electricity from the new plant, especially from a plant that hasn't been built. Generating companies will therefore make their decision to invest based on the presence or absence of other revenue streams.

4.2 Revenue Sources for Generators in Restructured States

In wholesale markets for electricity, generating companies have three primary categories of revenue sources (National Council on Electricity Policy 2007):

(1) Energy sales

(2) Ancillary services

(3) Capacity payments

Generators earn revenues through one or more of these sources. They are discussed in further detail here. As an example, energy payments accounted for 84% of the average cost of providing one MWh of electricity in the PJM ISO region in 2008, followed by capacity market payments at 10% and ancillary services at 2% (PJM 2009a).

4.2.1 Energy Markets

The primary source of income for power producers is the sale of energy (kWh) to utilities or other wholesale customers. Producers look for customers who wish to buy from them at their fixed or negotiable terms and enter into bilateral power purchase agreements with customers. Any uncontracted capacity is then offered into the short-term spot markets. For example, a 200 MW generator has contracted for 150 MW of output with a utility at fixed prices under a one-year basic service procurement. The generator can then find another customer for the remaining 50 MW of capacity, or sell 50 MW worth of energy production into the monthly, day-ahead or intra-day market. The vast majority of energy purchases are made through short- to mid-term bilateral contracts, to obtain certainty about costs in the short term. For example, 95% of the energy consumed by volume (MWh) in Texas' ERCoT RTO region is scheduled through bilateral contracts (Texas Comptroller of Public Accounts). In 2006, bilateral transactions supplied over 90% of the energy market load (MW) in PJM.

Spot market sales are essential to the system because they allow supply and demand to clear, that is generators and customers can make last minute adjustments to balance their output and load (National Council on Electricity Policy 2007). Whereas the generator receives pre-determined prices for contracted capacity, it receives market clearing prices for its spot market sales, depending on the bids by other generators, its relative location in the system and the prices that customers are willing to pay at the margin. However, spot market prices can be very volatile, as shown in Table 4.

Table 4. Real-time, Load-weighted Marginal Energy Price (LMP) in PJM (1998-2009)

Source: (Monitoring Analytics 2010)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)

In the spot market, the profitability of the generator depends on the price that it receives relative to its variable costs. Generators typically bid prices that are sufficient to cover their variable costs, which themselves may be volatile because of underlying fuel prices. If the generator can earn inframarginal rents, or revenues corresponding to the price difference between the clearing price and its own bid, then it can not only recover its variable costs but also some portion of its fixed capital costs. The higher the inframarginal rents to a generator, the more likely it is to be profitable in the long-run. As in the example above, many generators choose to contract for a large portion of their capacity so that they have some revenue assurance, and attempt to earn large inframarginal rents for their spot sales. However, many independent power producers have followed the practice of building generators at times of high prices without resorting to power purchase agreements and attempted to maximize their profits through spot sales. Such "merchant" power plants have satisfied high demand at certain times, but have subsequently been unable to recover costs due to prolonged periods of low prices and surplus capacity. Figure 6 and Figure 7 show that the percentage of fixed costs that have been recovered by new entrant combustion turbines and combined cycles plants in the PJM area have largely been below 50%. The merchant model doesn't always allow new entrants to recover the costs of entry through energy revenues (PJM 2009a; Chao, Oren, and Wilson 2008; Joskow 2007). Plants with large overnight costs therefore face a greater risk of investment cost recovery if they rely solely on spot market sales.

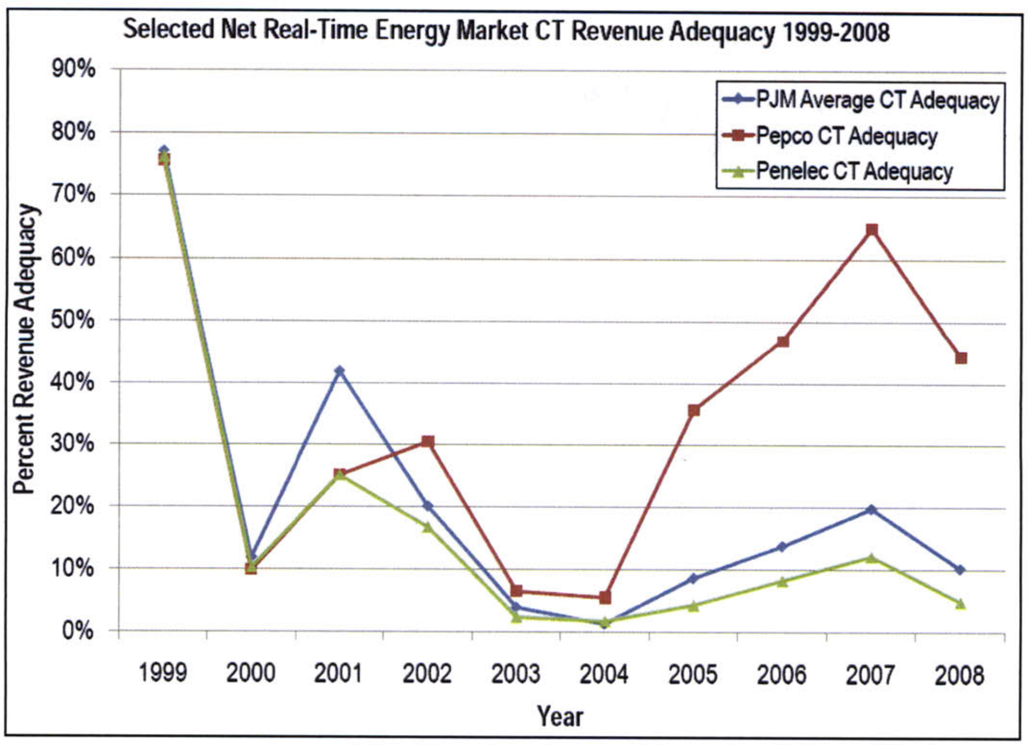


Figure 6. Energy Market Revenue Adequacy for New Combustion Turbines in PJM

Source: (PJM 2009a)

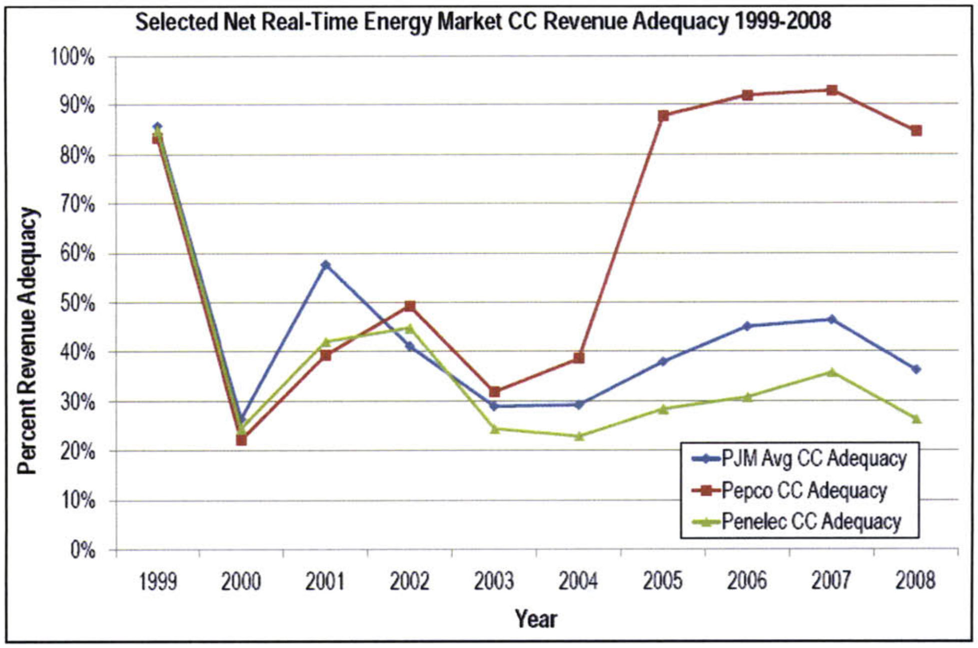


Figure 7. Energy Market Revenue Adequacy for New Combined Cycle Plants in PJM

Source: (PJM 2009a)

4.2.2 Ancillary Service Markets

Wholesale markets run by ISO/RTOs have smaller associated markets for other services that generators provide to maintain the efficient technical functioning and reliability of the power system. These services are called ancillary services and include voltage support, frequency and regulation, blackstart capability, spinning reserves, etc. Services such as regulation require instantaneous modulation of a generator's output to supply dynamically changing load. Spinning reserves require generators to be on stand-by to supply electricity at short notice, on the order of minutes. Generators that provide ancillary services therefore have specialized designs and equipment. Most generators are designed to meet the demand for energy, but may also be able to provide ancillary services. However, payments for ancillary services are not their main revenue stream. The decision to build a generator solely for one or more types of ancillary services depends on the size ancillary services markets.

In cost-of-service systems, the vertically integrated utility is expected to supply or procure ancillary services and the costs are included in the rate determination. Thus, the utility can determine whether it wants to use an existing generator to provide an ancillary service, build a new generator or procure it from another provider. The decision to invest in ancillary service generators is much easier in vertically integrated systems, because the utility does not have to rely on market prices.

Market rules and reliability requirements act together to limit the revenues that power producers earn in wholesale spot markets, thereby reducing their incentive for new investments. Market designers have formulated forward capacity markets to obtain an adequate supply of generation capacity in the mid- to longer-term.

4.2.3 Capacity Markets

Capacity markets are another type of market administered by ISO/RTOs in which generators receive payments to be available to generate electricity at a future point time. Under this market structure, generators get paid for providing capacity credits on a forward basis, irrespective of whether they actually generate electricity. For example, PJM's capacity auctions are conducted three year prior to the delivery of capacity (PJM 2009a). There is no requirement for generators to even exist at the time the capacity credits are sold. In fact, capacity payments are a financial incentive to generators to invest in new capacity in advance of when capacity is needed.

Prior to restructuring and the inception of capacity markets, regulators met the need for capacity adequacy by imposing reserve margins on utilities. Utilities were required to procure on the order of 10 – 15% more capacity than expected load to ensure that sufficient supplies of electricity were available to meet load. The costs of procuring reserve margins were included in the regulated rates established by the commissions. In the market environment, utilities can choose to meet reserve margin requirements by purchasing capacity credits. The decision to build new generators is therefore left to power producers.

To incent investments in new generation capacity, capacity market prices must be high enough to enable the generators to recover costs, in combination with future energy payments. If high prices prevail in the capacity markets, then generators can choose to invest so that additional capacity comes online in time to serve demand. On the other hand, additional capacity is not needed if prices are low. Capacity market prices have been low in various regions of the country, signaling that new generation capacity is not needed in those regions. Prices are relatively higher in regions such as the eastern seaboard where capacity surpluses are small and the grid experiences transmission congestion. New investments may be justified in those regions, and generators could supplement energy revenues with capacity payments. In many cases however, market design issues have led to capacity prices being low, thereby making the forward capacity payments low. Market operators have concluded that total revenues to generators have been inadequate to allow new generators to recover their fixed costs (Figure 8) (PJM 2009b).

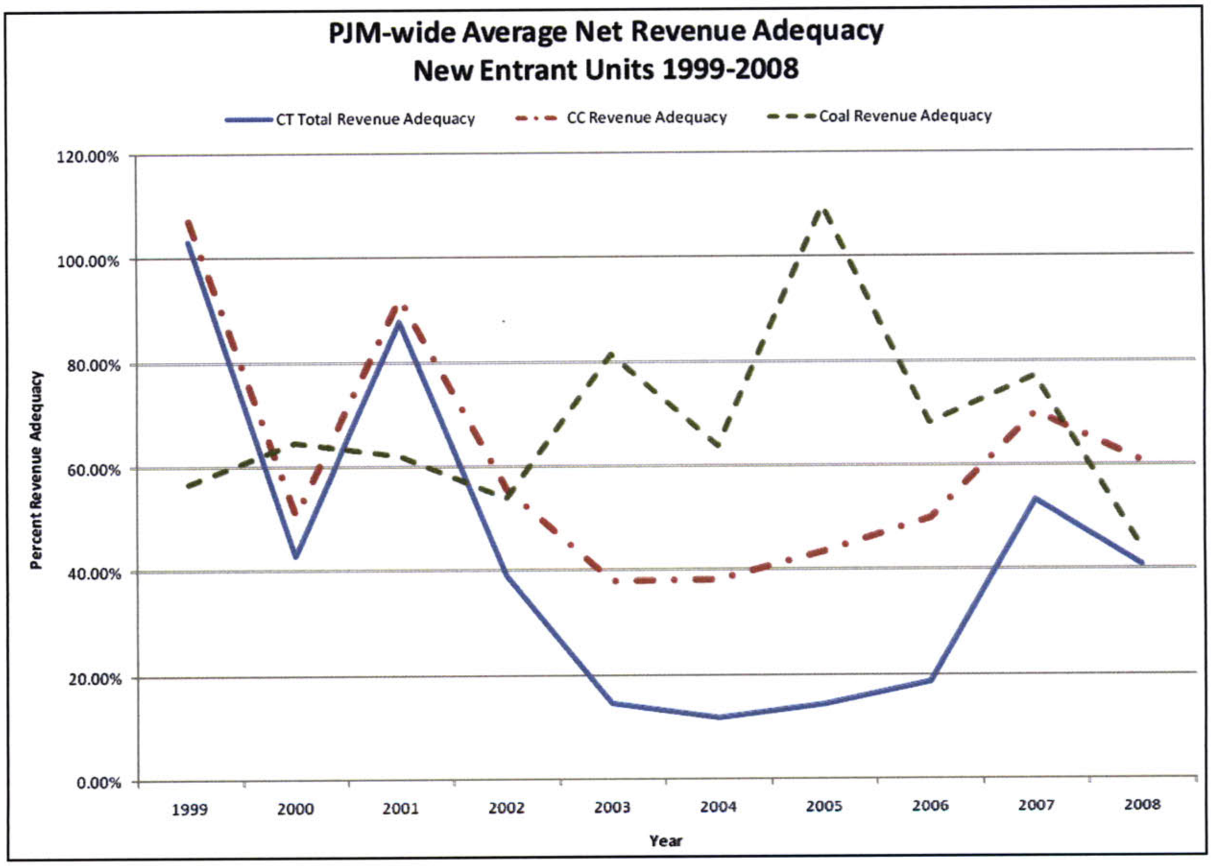


Figure 8. Average Net Revenue Adequacy Trends in PJM
Source: (PJM 2009b)

A general issue with the three market-based revenue sources discussed here is that the investment decisions are based on the short-term price signal. Generators that can quickly enter the market and earn large inframarginal rents in the spot market will invest. Because of the capacity addition by these "early birds," prices will be brought down and eliminate the incentive for future investments until price rise again. In this environment, power producers that want to invest in high entry cost, longer lead time technologies will not invest because they have no assurance of market demand or adequate revenue streams.

The description of utility procurement practices and revenue sources for generators indicates that there are two very different paradigms for making generation investments. In traditional cost-of-service systems, the final decision depends on the approval of state utility commissions and their assurance to the utility of allowing cost recovery. In restructured states that participate in wholesale markets, the decisions are quite decentralized and left to power producers. These companies evaluate investment decisions based on their ability to strike bilateral agreements with generators, and by observing market prices in spot, ancillary service or capacity markets.

Rules for short-term to medium-term basic service procurements, volatile spot energy markets, and relatively low capacity market prices should lead power suppliers and wholesale customers to avoid bilateral commitments that are very long. The question of how and when long-term contracts are useful in this context still needs to be explored. The discussion now proceeds to the role of contracts in typical power plant financing mechanisms.

4.3 The Dominance of Project Financing in Power Generation

There are many approaches to funding infrastructure projects such as power plants. Some involve public involvement; that is, government, or government-owned entities raise capital and contract for construction and management services. In the U.S., federal power agencies such as the Tennessee Valley Authority (TVA), or municipally owned entities fall into this category, but they own and operate only 6% and 9% of the country's generating capacity respectively. A predominant share of the activity in building plants in the U.S. is in the private sector, either by investor-owned utilities or non-utility power producers. The primary private sector approaches used by these companies for financing power generation investments are project finance and conventional corporate lending, of which project finance relies heavily on contracts.

4.3.1 Overview of Project Finance

Project finance is a specific type of infrastructure financing mechanism where the project under consideration is established as a separate company. It is defined as (Nevitt and Fabozzi 2000),

> A financing of a particular economic unit in which a lender is satisfied to look initially to the cash flow and earnings of that economic unit as the source of funds from which a loan will be repaid and to the assets of the economic unit as collateral for the loan.

and as (Esty 2004):

> Project finance involves the creation of a legally independent project company financed with nonrecourse debt (and equity from one or more sponsors) for the purpose of financing a single purpose, industrial asset.

The financial viability of the company is thus based on the viability of the project alone. The project company enters into detailed and comprehensive contractual agreements with various contractors, suppliers and customers. The sponsoring company or project manager has a large equity share in the company; the management and performance of the specific project are thus tied to the financing provisions. Importantly, the project operates with a high ratio of debt to equity and the lenders only have limited recourse to equity-holding parent company or sponsor. Liability in the case of default is limited to the project company (Nevitt and Fabozzi 2000; Brealey, Cooper, and Habib 1996).

In contrast, conventional lending involves the parent company directly and the loan is not generally based on the performance of any single project. The ability of the company to repay debt or provide returns to equity investors is evaluated by looking at the performance of the entire corporation. Contractual arrangements by the specific project are not very comprehensive, because the counterparties and lenders do not have to be provided with unique performance incentives for the success of the particular project. Default on the debt and bankruptcy can be much more costly for the corporation than for the project company; debt-equity ratios are consequently lower (Brealey, Cooper, and Habib 1996).

4.3.2 Prevalence and Value of Project Finance

Project finance has been used widely for power generation investments in the U.S. and around the world. The first major spurt of power projects financed using this technique in the U.S. was realized after the passage of the Public Utilities Regulatory Policy Act of 1978, where utilities were required to purchase power on a long-term basis from independent non-utility power producers. Many of these independent power producers established separate project companies to contract with utilities, and financed them with nonrecourse debt to limit the liability of the parent sponsor. More than two-thirds of all project financed investments in the 1980's were power projects. For this reason, project finance became synonymous with U.S. power financing until the early 1990s. Between 1998 and 2002, total global project finance lending amounted to $ 410 billion, of which almost $160 billion (40%) can be attributed to the power sector. Bank loans for projects to the U.S. power sector accounted for about $ 100 billion, while bonds contributed about $ 4 billion. (Nevitt and Fabozzi 2000; Esty 2004). Thus, the power sector has evidenced primary reliance on project financing in the last few decades, both domestically and internationally.

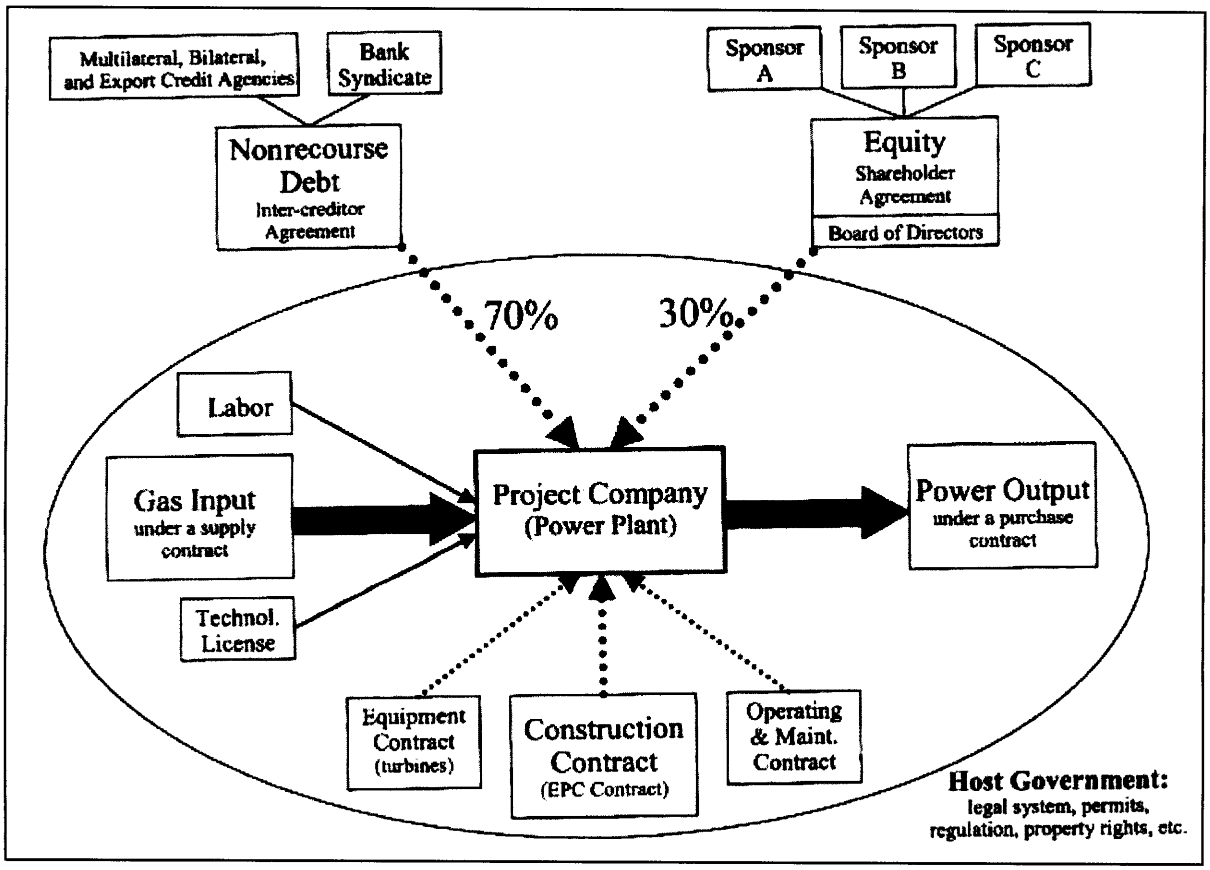


Figure 9. Typical Project Structure for an Independent Power Producer
Source: (Esty 2004)

The dominant reason for the importance of project finance is its ability to address incentive issues between various parties involved in an infrastructure investment such as lenders, the project company, construction firms, customers, etc. Complex contracts between the counterparties specify the obligations for each party and the financing arrangements for the project. In particular, bilateral agreements between parties struck separately are not sufficient for the project to move forward. A complete package of contracts covering various aspects of the project has to be completed before the funding is secured, some on a long-term basis. Project finance is therefore often referred to as "contractual finance" (Esty 2004). A stylized depiction of a power plant financed through this mechanism is shown in Figure 9.

Project sponsors usually bear the risk of project completion, operation and maintenance. The construction risk is usually borne by the main contractor. Lenders require assurances of various types from the sponsor in terms of timing and amounts of debt service payments, security for the loan etc. When there are only a few major suppliers for raw materials or buyers for the output, the contracts are long-term. Long-term take-or pay contracts, tolling agreements or fixed-price, fixed quantity contracts are often struck with the small number of buyers so that they can bear the revenue risk. Such long-term contracts are infeasible when the number of buyers is large or when they have many providers to buy from because the price and quantity terms will depend on the actions of other market agents, and not only the performance of the project itself. When government agencies are involved, concessionary agreements are obtained to ensure the government's support of the project. Because project finance explicitly appraises and allocates risk-bearing roles to various parties, it is an effective device for such parties to manage the incentives that are available to them for the successful performance of stand-alone projects. The main incentive for project managers and other parties to maximize efficiency is for them to be allowed to capture the economic gains of the performance and improvements they make, and this can often be done through contracts (Brealey, Cooper, and Habib 1996). This observation is consistent with the view of game theory on the role of contracts.

In the late 1990's, projects became less structured and more exposed to market risks and regulatory risks. Many of these were merchant power projects that relied mostly on revenues in the spot energy markets and did not have longer-term purchase assurances. It is estimated that \$ 30 billion worth of power plants defaulted in 2002 (Ryser 2002). Several hundred billion dollars were lost for equity and debt investors. The equity market capitalization of some of the largest developers was estimated to have declined from \$145 billion to \$ 11 billion in two years. The losses are attributed to the collapse of power prices due to excessive capacity and various aspects of deregulation (Worenklein 2003). Among these are excessive reliance on wholesale spot markets for revenues, and the prohibition of long-term contracts, which had the effect of allocating most of the risk to investors. As a result, plant developers now frown upon the pure merchant model, in which all their revenues are expected to come from markets sources. They tend to ask for more structured deals, and build plants only when they have longer-term commitments, because this enables them to shift some market risks to buyers of the output (Esty 2004).

Project finance emphasizes a reliance on long-term contracts because of the ability to allocate risks to the contracting parties and to create appropriate performance incentives. Where customers, i.e. mainly distribution utilities are able to effectively bear these risks, they will be be able to secure its benefits. However, it is not clear that utilities can bear the risk of the contract in restructured electricity markets.

4.4 Risk Management in Power Generation Investments

Generation investments in the late 1990's and early 2000's attempted to take advantage of newly formed wholesale markets by leveraging the merchant business model and earning all their revenues through market sources. Most investments were undertaken to meet shorter-term capacity adequacy by replacing older plants and building new peaking generation (Finon and Perez 2008). Newer technologies such as combined cycle gas turbines (CCGTs) that were fuel efficient, had low capital costs and took a short term to build were the engine of this model, because they could enter the market quickly and take advantage of high electricity prices (Finon and Perez 2008; Sansom et al. 2002). This model was thought to be viable because CCGTs had a high degree of operational flexibility; their output could follow load patterns and they produced electricity only when prices were high enough to cover operating costs. In comparison, more capital intensive technologies such as coal or nuclear plants that need longer lead times and incur significant costs before any revenues are realized were risky (Glachant 2006). CCGTs thus appeared to be the least risky option for independent power producers that were new entrants in wholesale markets, in the absence of assured long-term revenue streams.

The comparison of builds between 1960 and 2008 indicates the bias towards investments in gas technologies after restructuring. Figure 10 shows that most of the capacity addition between 1960 – 1998 was in coal and nuclear plants, and to a lesser extent in natural gas plants.

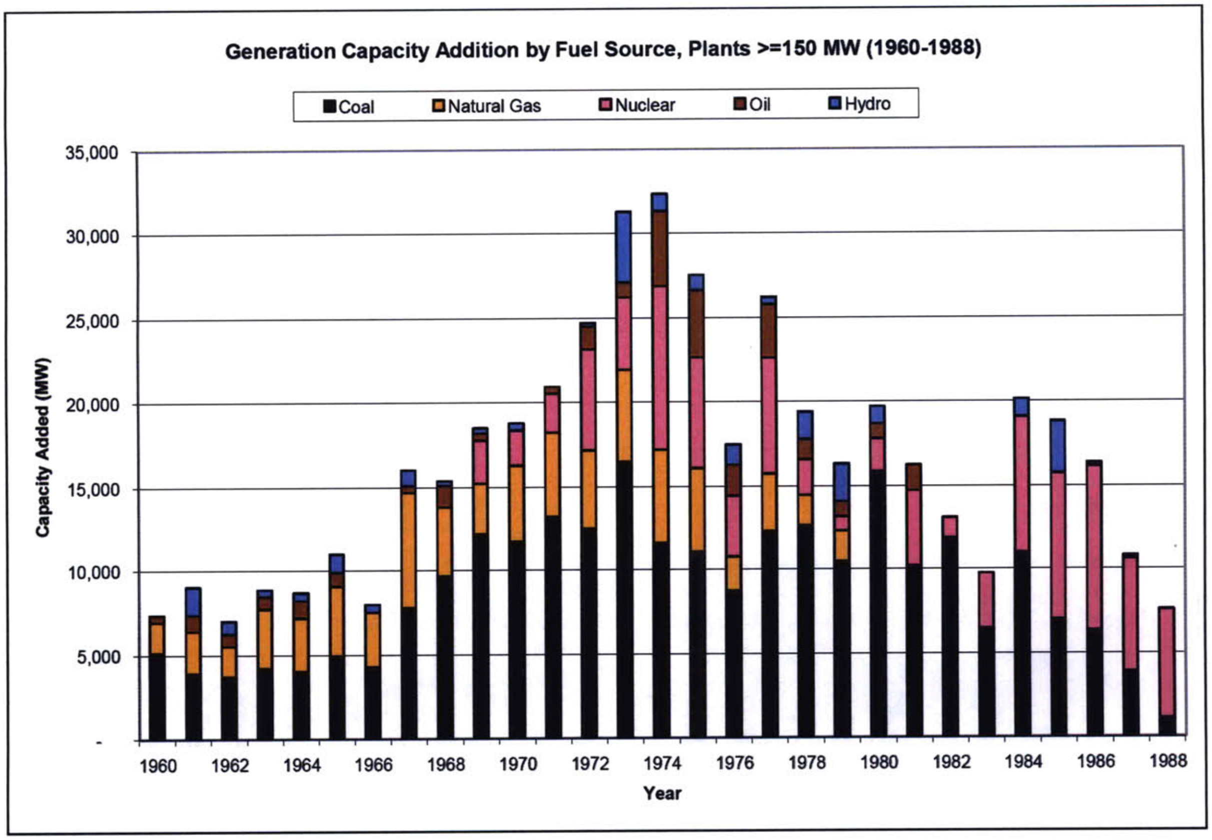


Figure 10. U.S. Capacity Addition for Baseload and Mid-merit Generators, 1960 – 1988

Data source: (Energy Information Administration Form EIA-860 2008)

Between 1988 and 1998, there was relatively little capacity addition as utilities and independent power producers waited for restructuring to be completed in various states. After new regulations were established and wholesale markets were formed, almost all of the new investment has been in natural gas plants (Figure 11).

In the long term, there is an optimal mix of generation technologies and capacity that provides electricity at least cost (Chao, Oren, and Wilson 2008). Merchant projects weren't designed with a view to providing base load generation that operated at high capacity factors and were capable of providing electricity at low levelized costs. A mix of generation technologies with lower fractions of base load capacity leads to higher marginal prices, thereby reducing the social surplus available (Green 2006). A long-run bias in the generation mix in favor of low capital cost technologies such as CCGTs whose perceived risk is low may distort the generation mix leading to lower social welfare.

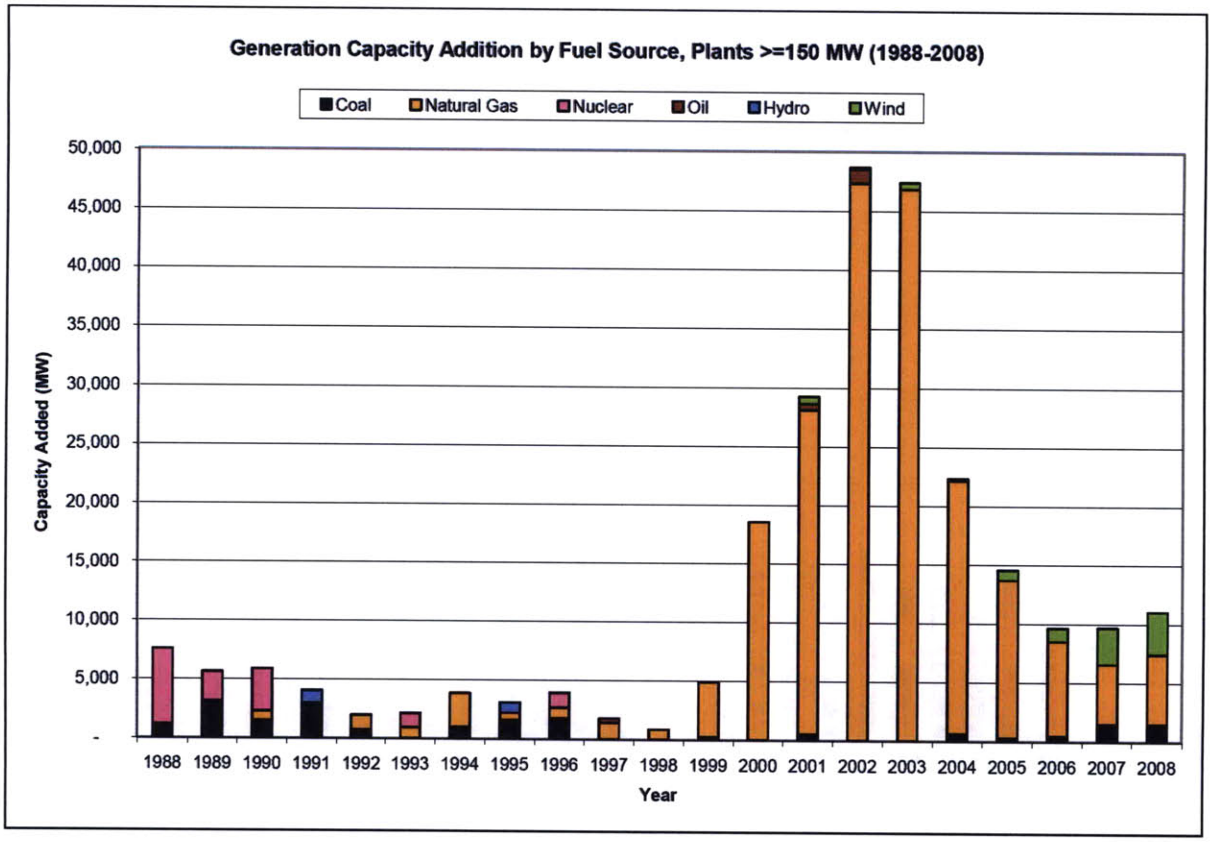


Figure 11. U.S. Capacity Addition for Baseload and Mid-merit Generators, 1988 – 2008
Data source: (Energy Information Administration Form EIA-860 2008)

Under the cost-of-service model, the ability to manage the risk of base load projects with large entry costs is attributed to the regulatory compact that exists between the vertically integrated utility and society (Chao, Oren, and Wilson 2008). The compact is reflected in the assurance of revenues through regulated rates set by the utility commissions, whereby the utility is assured of eventual cost recovery even though the lag between investments and cash flows may be long. Risk is *de facto* borne by end-use customers by passing through the costs to regulated rates. However, the perception of risk is much lower because of costs are amortized over a long period of time. Rate fluctuations are drastically mitigated by inter-temporal smoothing of rates; consumers don't see prices spikes in any single rate cycle because revenues can be reconciled in future cycles. The regulatory compact thus implicitly provides investors with a long-term assurance of demand for their output and a stream of stable revenues (Chao, Oren, and Wilson 2008; Finon and Perez 2008).

Restructuring significantly diminished the ability of a similar compact in the presence of wholesale markets. For one, utilities no longer own generation assets and the investment decision is decentralized. Further, end-use customers are no longer captive to the incumbent distribution utility to the same extent because of competitive retail supply. When retail suppliers' prices reflect generation costs that are higher than the basic service prices offered by a utility, customers can remain on the utility's service. However, if prices fall and retail suppliers offer lower rates, customers may leave. The utility faces the "volume" risk of decreased load and inability to recover procurement costs. The hybrid model of utilities providing regulated basic service in the same environment as competitive retail suppliers does not allow for efficient risk sharing between end-users and generators. The systematic risks associated with the contract are borne by the generator and the utility, and not the generator and the end-use customers. Because they are not locked-in customers can behave opportunistically and find a better deal when the existing one becomes unfavorable to them. Long-term contractual agreements that are called for by project financing are therefore difficult for the utility to justify. When faced by volume risk, the creditworthiness of utilities declines and it is no longer a relatively riskless party to contract with (National Council on Electricity Policy 2007; Chao, Oren, and Wilson 2008). This explains the reluctance of utilities to sign long-term contracts in restructured states.

Much of the capacity addition between 1990 and 2008 has occurred in restructured states such as Texas, California, Pennsylvania and Illinois. Fully regulated states have exhibited capacity additions in this time period comparable to those observed before restructuring. Florida is an exception to this general observation. Total capacity additions by state and time period are depicted in Figure 12.

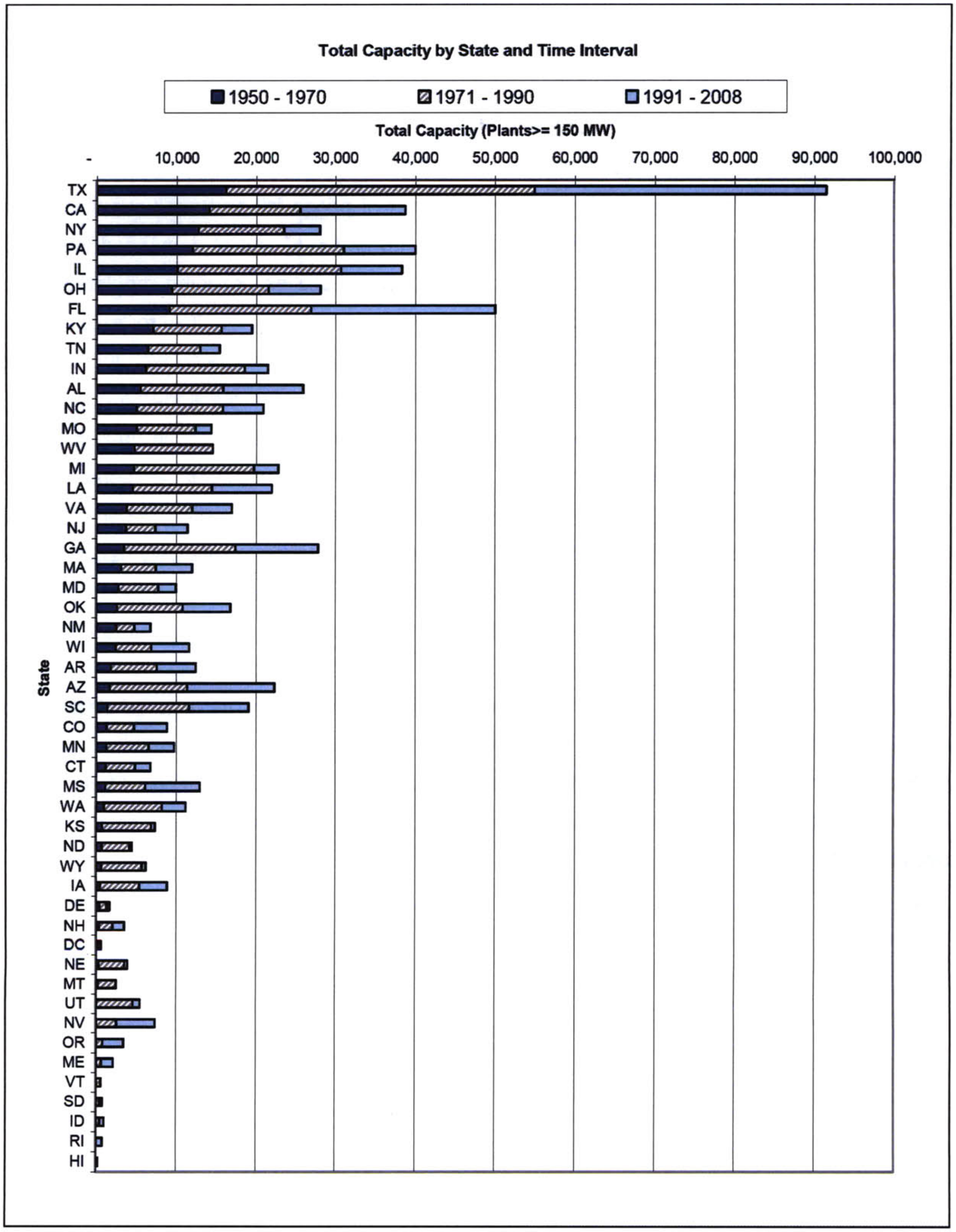


Figure 12. **Total Baseload and Mid-merit Capacity by State and Time Interval, 1950 - 2008**
Data source: (Energy Information Administration Form EIA-860 2008)

4.5 Ex Post Regret

Although long-term contracts have value in terms of hedging against short-term uncertainty in prices and supply quantities, the inability to write complete contracts can result in ex post regret and opportunism as described earlier. Long term contracts as a policy mechanism for investments in specific generation technologies are not new to the US electricity industry. They have a somewhat dubious reputation, and are associated with the "stranded costs" aftermath of the Public Utilities Regulatory Policy Act (PURPA) of 1978 (Public Law 95-617).

4.5.1 Long-term Contracting under PURPA 1978

PURPA was one of five statutes that were signed into law as part of the National Energy Act in 1978, in the wake of the energy crisis of the early 1970s (Edison Electric Institute 2006). PURPA's explicit objectives were to (1) to increase the efficiency and conservation of electric energy, and provide equitable retail rates for electric customers; (2) improve the wholesale distribution, reliability of electricity, wholesale rate making processes and other regulatory mechanisms. More implicitly, PURPA was intended to support the reduction of the U.S.'s energy dependence on fossil fuels. To this end, PURPA required electric utilities to interconnect with and buy any and all capacity and energy that was offered by a special class of generators known as Qualifying Facilities (QFs) (Public Law 95-617). QFs were energy efficient cogenerators and small renewable generators with a generating capacity of 80 MW or less, that met FERC's prescribed standards. Many states implemented the statutory requirements in the form of long-term contracts with fixed pricing, because this made it easier for QFs to obtain project financing. QFs were heavily debt-leveraged and needed a stable, long-term revenue stream to back their loans (Edison Electric Institute 2006).

Under Section 210 of PURPA, utilities were required to procure electricity from non-utility Qualifying Facilities (QFs), which were predominantly cogeneration facilities and small power producers. Rates were required to be no greater than the "incremental cost of alternative electric energy," as determined by state regulatory commissions. The "incremental cost" was defined as:

"...the cost to the electric utility of the electric energy which, but for the purchase from a cogenerator or small power producer, such utility would generate or purchase from another source."

In interpreting the statute, FERC determined that the "incremental cost" is the "full avoided cost" (18 CFR 292.101). As can be expected from this definition, the counterfactual avoided cost of the electricity determined the price of the electricity stipulated in the long-term contracts. Many long-term contracts enabled by PURPA 1978 used high avoided cost estimates as a basis for calculating the costs of power to utilities. Consequently, the contract rates used were often above market, and were reflected in regulated retail prices as a cost pass-through. Moreover, each state had different regulations for the terms and rates of such contracts, because the federal law granted states discretion in designing their respective regulations. The specific method for calculating the incremental cost was left to each state to determine. States used a host of mechanisms to determine the incremental cost - forecasts of oil prices, average electricity costs, bidding processes, etc. PURPA-based long-term contracts therefore varied considerably in their structure and economic value to utilities and the generating facilities. By fiat, the PURPA provisions created a market in which Qualifying Facilities could unilaterally sell electricity to utilities at a guaranteed price equal to the utilities' avoided costs. It is estimated that PURPA led to over 20,000 MW of QF capacity addition in the early 1980s, and the contracts with QFs became the primary mode of generation capacity addition in many states (Edison Electric Institute 2006; Energy Information Administration 1996). Figure 13 shows that a large share of the utility connected generation capacity in the late 1980's and early 1990's were non-utility qualifying facilities. Some eligible non-utility generators that were installed before 1978 were also able to retroactively obtain QF status.

Qualifying facility investments were largely concentrated in a few North East and Mid-Atlantic States, Texas and California. Figure 14 depicts the total non-utility generation capacity in each state in 1992. There appears to be a high correlation between the states that witnessed a large share of QF capacity addition prior to 1992, the states that were among the first to restructure, and those that subsequently invested heavily in merchant power capacity after restructuring. Texas, California, New York, Massachusetts and Pennsylvania appear to be notable among these. However, there are many regulated states such as Florida and Louisiana that had a large share of QFs by 1992.

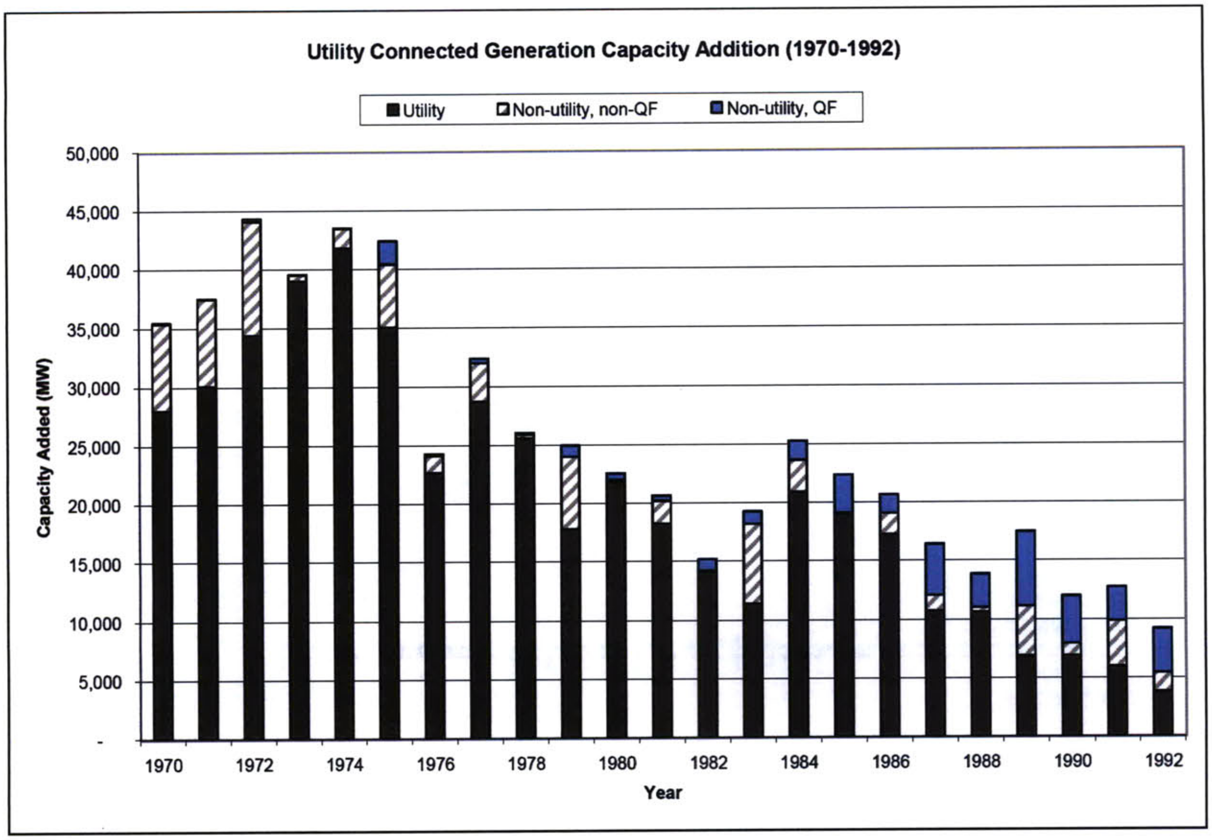


Figure 13. Utility Connected Generation Capacity Addition by Ownership, 1970 – 1992

Data source: (Energy Information Administration Form EIA-860B 2000; Energy Information Administration Form EIA-860A 2000)

The Energy Policy Act of 1992 paved the way for electricity industry restructuring in many states, where generation was legally separated or unbundled from transmission and distribution. The wholesale generation cost of electricity was no longer regulated by state utility commissions in a move to creating competitive wholesale markets for electricity. The mismatch between long-term contracts based on utilities' avoided costs and the utilities' new ability to procure electricity in a market environment led to the problem of contractual "stranded costs."

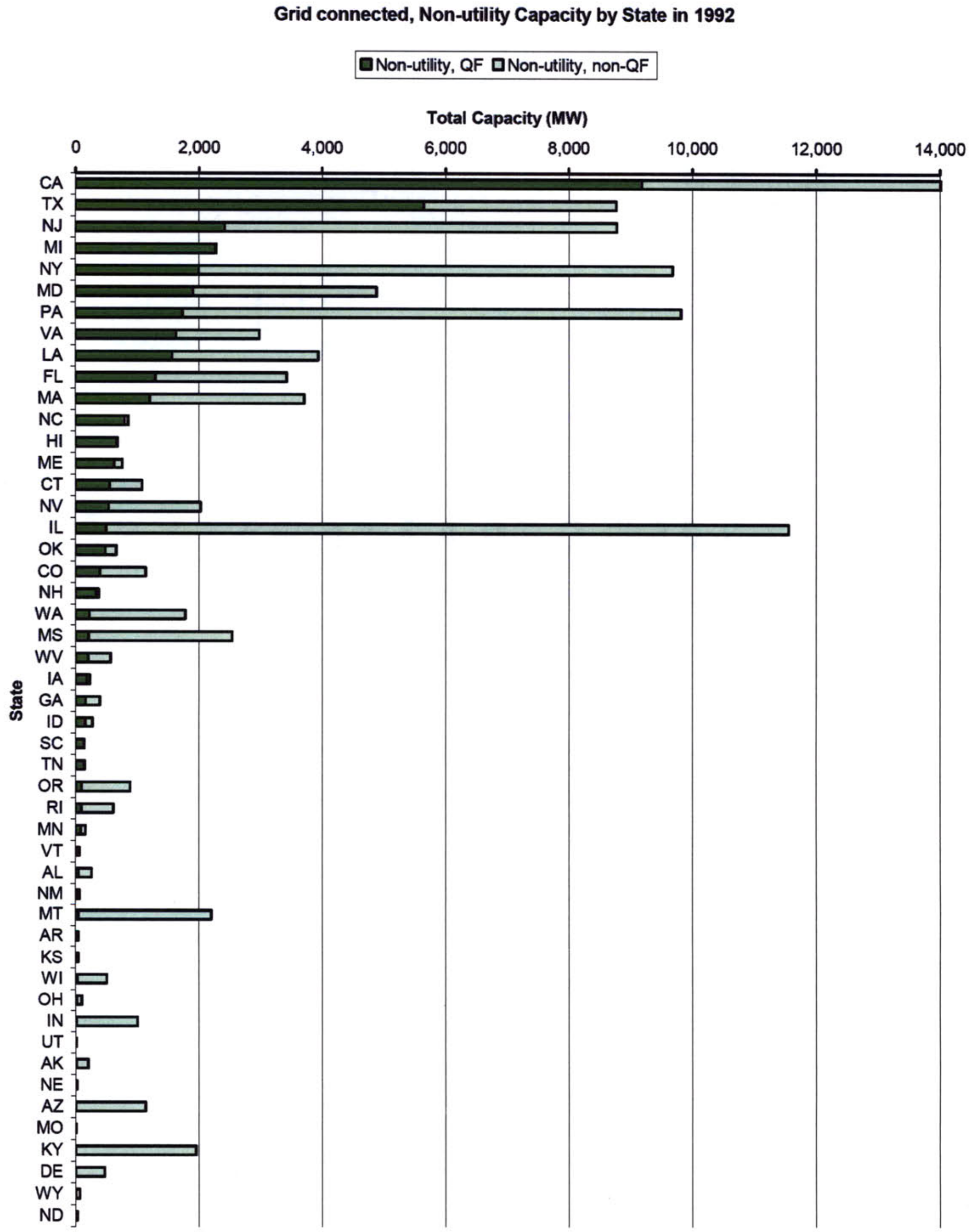


Figure 14. Non-utility Generation Capacity as of 1992 by State
Data source: (Energy Information Administration Form EIA-860B 2000)

4.5.2 Stranded Costs of Long-term Contracts

In general, electric utility stranded costs are the historical financial obligations of utilities in a regulated environment that become unrecoverable after transition to a competitive market. Such costs were assumed to be recoverable in the regulated environment because cost recovery was guaranteed by state authorities through ex ante regulated rates for electricity sales. Of the various types of costs that can become "stranded," this analysis focuses only on long-term contract liabilities. For contractual obligations, stranded costs are characterized by:

> "...the difference between the present value of the contractual payment obligations and the net present value of the competitive market value of the electricity delivered under the contracts."

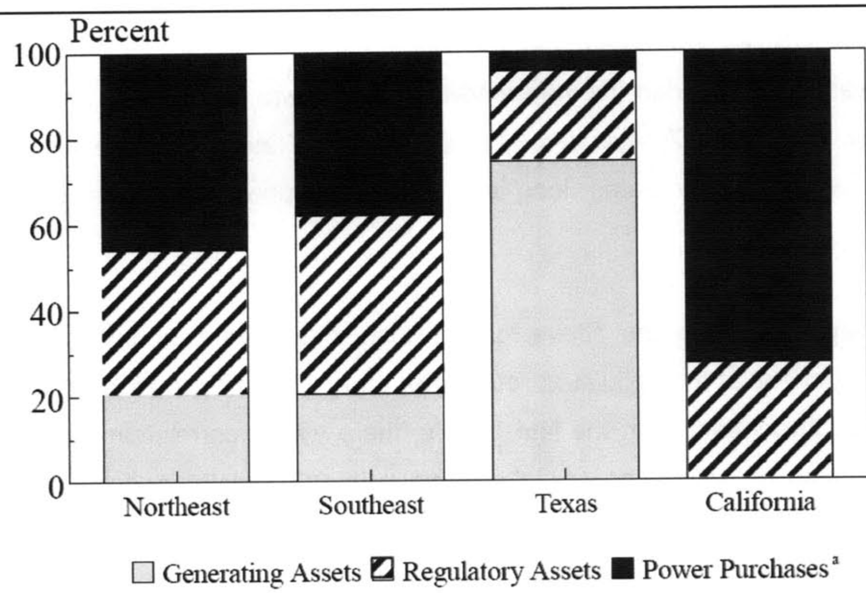
In a sense that is broadly applicable to this analysis, a definition that focuses on capital outlays identifies stranded costs as (Hovenkamp 1999):

> "investments in specialized durable assets that may seem necessary, or at least justifiable, when constructed and placed into service under a regime of prices and entry controls but have become underutilized or useless under deregulation."

Stranded costs can also be distinguished from "strandable" costs, or those that have the potential for becoming stranded pursuant to a change in regulatory regime (Joskow 2000). The distinction is important because the potential for becoming stranded does not imply the certainty, but acknowledges the risk of costs becoming stranded once the new regulatory scheme is implemented. Thus, solutions may be devised to mitigate the risk of costs becoming stranded.

There appear to be two main reasons for PURPA-related contracts becoming strandable (Congressional Budget Office 1998; Edison Electric Institute 2006; Energy Information Administration 1996). Firstly, the contract designs as mandated by state regulation were not very flexible in the face of uncertainty. Most contracts imposed durations of 20 – 30 years on the contracting parties. The fixed price terms were often based on forecasts of oil, coal and gas prices that were developed in the 1970s amidst concerns of energy independence that did not foresee technological, economic or regulatory changes in the industry. For example, the Energy Information Administration projected in the early 1980s that oil prices would rise to $100 per barrel by 1995, but the average prices were below $20 in that year (Cain and Lesser 2008). By the time of restructuring, many utilities were still locked into high avoided cost payments to QFs. Secondly, the dynamics of power procurement were dramatically changed with the passing of the Energy Policy Act (EPAct) of 1992. EPAct reformed previous legislation to create a new class of nonutility power producers known as exempt wholesale generators (EWGs). EWGs were not limited by the PURPA requirements for cogeneration and renewable Qualifying Facilities. Utilities were also not mandated to purchase electricity from generators that wanted to interconnect with them. Subsequent FERC regulations for "open access" to networks allowed EWGs to market power to utilities to which they were not directly connected. Utilities were thus able to shop for wholesale power in a market framework that was formalized later through restructuring laws. Moreover, QFs could also now market their power to buyers other than the incumbent monopoly utility (Energy Information Administration 1996). Established bidding processes for the sale of electricity from QFs and other generators resulted in market prices that were often lower than the administratively determined than avoided cost rates. Lower power prices exerted pressure on utilities and regulatory authorities in states with a large share of QF contracts to reevaluate their decisions to enter into such contracts (Edison Electric Institute 2006). In sum, inflexible and administratively determined long-term contract agreements became imprudent as the uncertain future evolved. Devising the transition of the utility industry from a regulated environment into a competitive market necessitated that states address the potential of long-term contracts becoming stranded, and whether and how utilities would recover the cost of their obligations to QFs.

Estimates of the total potential above market stranded costs that could be attributed to PURPA-related and other utility long-term contracts are quite large and have significant variations. A 1994 study that focused on the assessment of 7300 long-term contracts estimated that the contracts presented a potential above market stranded cost of $15 billion annually. Over 80% of the above market contracts were concentrated in the Southeast, Northeast and Western U.S. (Feiler et al. 1994). Another study estimated that long-term contracts accounted for $37 billion (30%) of total national strandable costs of approximately $122 billion in 1996 (Resource Data International 1996). Further studies also estimated the range of stranded costs to be similarly large (Congressional Budget Office 1998; Baxter and Hirst 1995). Much of the variation in estimates is driven by differences in the methodology used for estimating stranded costs and the underlying assumptions and forecasts. The contribution of long-term contracts to stranded costs also varies regionally, depending on factors such as utility generating portfolios, contracts signed, state regulations, etc. Figure 15 illustrates this regional variation in percentage terms. In spite of variations in estimation methodology and assumptions, these large estimates suggest that above market long-term contracts in aggregate have been known to create significant economic distortions.



SOURCE: Congressional Budget Office based on data from Resource Data International.

NOTE: These numbers reflect net stranded costs after subtracting the costs of below-market generation facilities or power purchases.

a. Includes contracts mandated by the Public Utilities Regulatory Policies Act of 1978 (PURPA) as well as other power purchases by utilities.

Figure 15. Categories of Stranded Costs by Region
Source: (Congressional Budget Office 1998)

To avoid the pitfalls of interpreting aggregate regional or national estimates of the above market portion, long-term contracts could be examined individually or within states or regional markets. Such an approach enables an understanding of how a single contract or few contracts can result in large distortions or lost economic value. For example, the Potomac Edison Company (Allegheny Power) in the restructured state of Maryland sells electricity from its Warrior Run QF 30-year contract into the PJM wholesale market. For the year 2008 alone, Allegheny Power estimated that its Warrior Run contract-related costs amounted to $111 million, whereas its revenues from sales into PJM were estimated at $71 million. As per its 1999 settlement agreement, Allegheny Power could recover approximately $40 million in lost revenue for 2008 from regulated tariffs set by the Maryland Public Service Commission, the state regulatory authority (Cain and Lesser 2008; Maryland PSC Case No. 8797 1999; Maryland PSC Case No. 8797 2007). New Jersey is another restructured state where utilities have contracts with non-utility generators for durations as long as 30 years, some until 2024. In 1998, the New Jersey Board of Public Utilities estimated that the net present value of the cost of these power purchase agreements exceeded the market value of the power by $3.5 – 5.3 billion (New Jersey Board of Public Utilities 1997; New Jersey Division of the Ratepayer Advocate 1998). Even if the estimates are limited to states, long-term contracts appeared to have significant above-market costs.

Yet another way to examine the above market costs of long-term contracts is to look at the generation component of the regulated retail rate, that is in part driven by the prices paid for energy under such contracts. In the late 1990's, there was a correlation between states with high average costs of generation (ex. California with 6-7 c/kWh) and the large number of PURPA contracts that they had executed. States with low average costs of generation (ex Indiana and Oregon with 2- 3 c/kWh) did not require utilities to sign above market PURPA contracts. Around the same time, the short-run unregulated price of electricity in the wholesale market was about 2.5 c/kWh and the long-run marginal cost was in the 3 -4 c/kWh range. States with the largest price gaps such as California and the New England states were more anxious to find a solution to mitigating the possibility of contractual obligations becoming stranded (Joskow 1997).

The main thrust of this discussion is to highlight the possibility of becoming locked into long-term contracts with price terms that are based on a very limited ability to forecast the future. Such contracts have provided certain types of power generators with the stable revenue streams that made it easier to secure financing, but at the expense of the regulated pass through of high costs to retail rates. As a policy mechanism, long-term contracts encouraged the development of cogeneration and small renewable generators by effectively providing them a subsidy. It could be argued that PURPA was successful in its objective of supporting this development, but the same argument should also acknowledge that the support came at a very high cost. It is not clear that the long-term contract requirement adopted by many states was a good policy mechanism to achieve the objective of energy efficiency and conservation and improving electricity supply and distribution.

4.6 Some Recent Claims regarding Contracts

In its evaluation of generation investment in competitive wholesale markets for electricity the Electric Energy Market Competition Task Force reports that (Electric Energy Market Competition task Force 2007):

> Long-term contracts are a critical pre-requisite in obtaining financing for new generators. Both generators and consumers [have been] unable to arrange long-term contracts.

The statement is comprised of two main claims. The first claim is that investment in new generation capacity will not occur if generators have not secured a long-term purchase agreement. The second claim is that neither generators nor load-serving entities have been able to sign such contracts, because none of the parties is willing to enter into a long-term agreement, or in other words that long-term contracts are just not "available." The circumstances which allowed the Task Force to make this statement were investigated as discussed below, but the results of the investigation were ambiguous. If these claims do hold weight, then a logical extension would imply that no new generation capacity must have been added in parts of the country where long-term contracts were not "available."

The Task Force analyzed FERC Electric Quarterly Reports for the year 2004-2005 in three regions of the country to investigate the basis of the aforementioned claims. The analysis found that short-term contracts for a period of less than one year were the predominant form of bilateral transaction in each of the regional markets examined. This finding is expected based on the short-term basic service procurement requirements in restructured states. Short-term sales in the New York Independent System Operator (NYISO) region accounted for 91 % of the transactions by the MWh volume of electricity sold. The corresponding number for the Midwest Independent System Operator (MISO) region was 77%, and 60% for the Southeastern Reliability Corporation (SERC) region. Active long-term contracts (10 years or more) accounted for 0% of the bilateral transactions by volume in NYISO, and only 2% in MISO. In contrast, 16% of the sales by volume in SERC were through active contracts of 10 years or more. Thus, there was at least one wholesale market, NYISO, in which no long-term contracts were active during the time frame of the analysis (2004-2005). There was also at least one non market region, SERC, where long-term contracts were used for a significant fraction of the load. The results of the Task Force analysis are shown in Figure 16 through Figure 18.

The Task Force acknowledges that using EQR data introduces a number of limitations, because of the data reporting requirements. EQR data does not require reporting by entities that do not hold FERC's Market-based Rate Authorizations (MBRAs) (federal power administrations, municipal plants, etc), or reports of retail sales to native load. Consequently, the EQR data provides a partial view of transactions, which may not be representative of all the bilateral activity, including some long-term contracts.

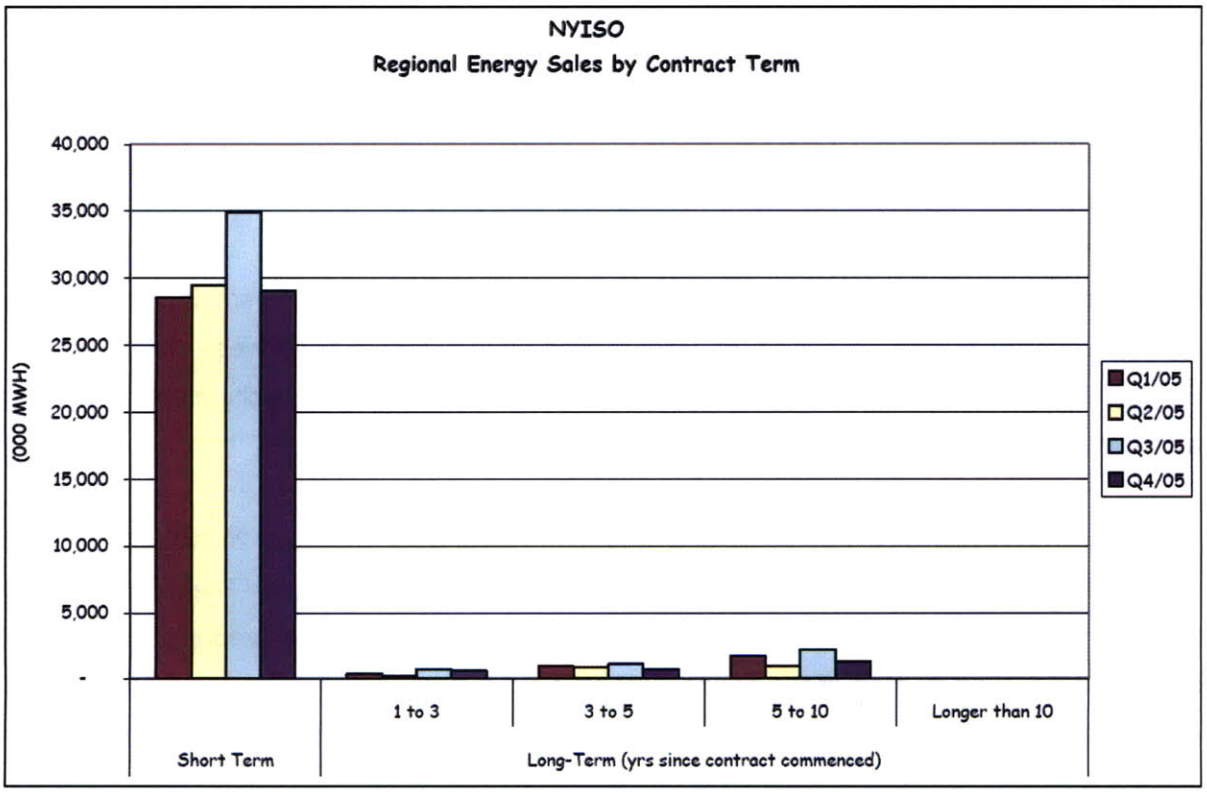


Figure 16. Sales by Contract Term in New York ISO (2005)
Source: (Electric Energy Market Competition task Force 2007)

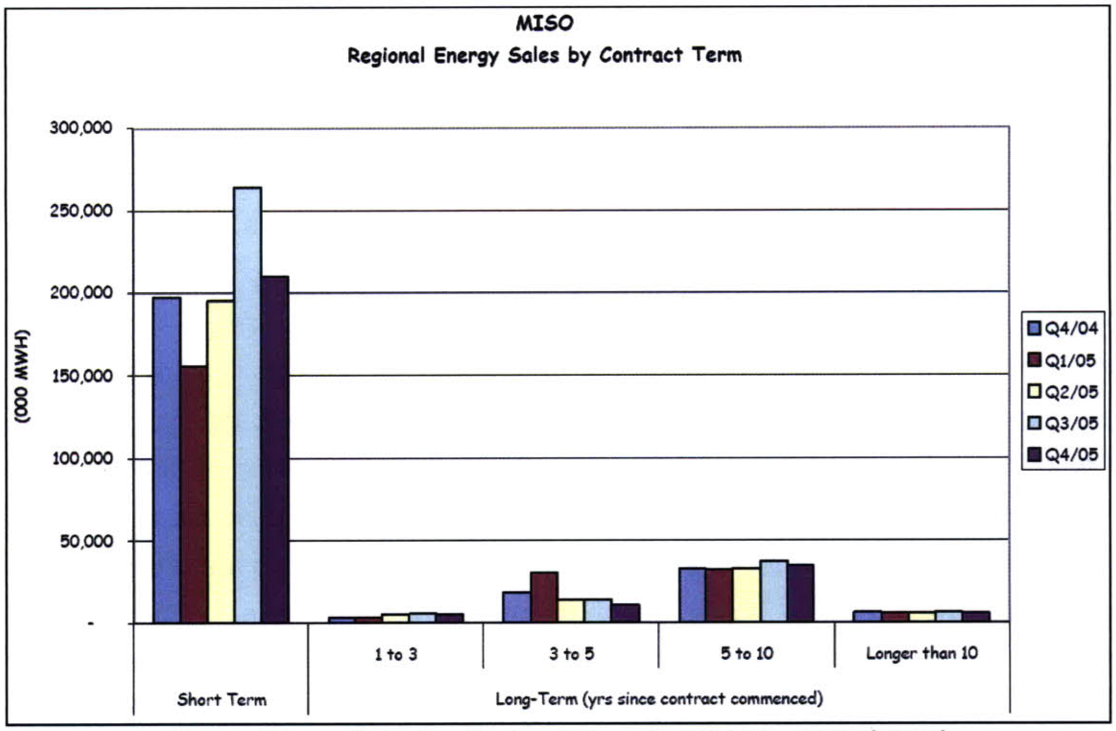


Figure 17. Sales by Contract Term in Mid-West ISO (2005)

Source: (Electric Energy Market Competition task Force 2007)

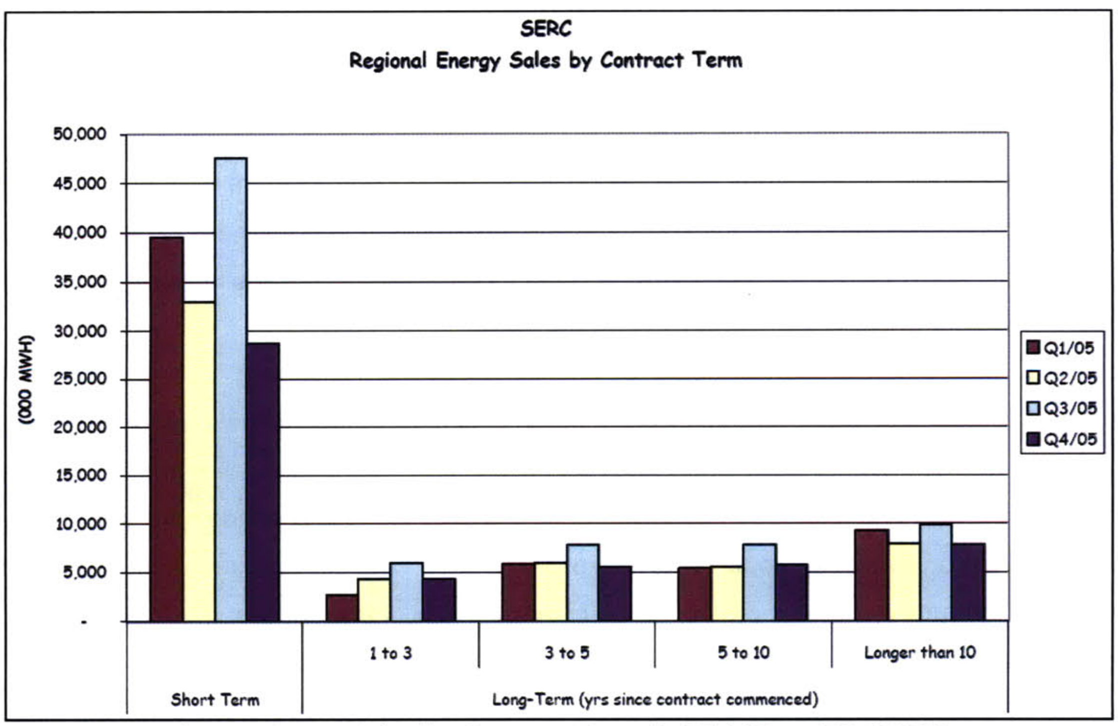


Figure 18. Sales by Contract Term in Mid-West ISO (2005)

Source: (Electric Energy Market Competition task Force 2007)

The analysis also looks only at a short duration of four quarters (in the year 2004-2005), which is hardly indicative of any trends regarding the use of long-term contracts. Additionally, the analysis recognizes that many of the long-term contracts in SERC are legacy contracts and were entered into before competitive markets were introduced. The Task Force therefore tentatively concludes that the predominance of short term activity is due to the fact that organized wholesale markets like NYISO and MISO were designed to produce reliable spot prices for short-term activity, with market agents fulfilling longer term needs through bilateral transactions. It also suggests that capacity or reliability pricing products in markets may offer a long-term price signal for investment, and such markets do not have to rely only on contracts. The report doesn't distinguish between recurring contracts with existing plants and contracts with new plants. The Task Force's limited analysis and tentative conclusions are not very convincing in light of our discussion above, because long-term contracts are simply not allowed or approved in these regions. NYISO operates primarily within the bounds of the state of New York, which is a restructured state. On the other hand, states in the SERC region are still fully regulated. SERC's market is purely a bilateral market with a relatively small number of market agents, thereby reducing the choice available for trading partners (Electric Energy Market Competition task Force 2007). The limited choice may make the relationships between the few agents more important, and they may be more willing to sign long-term contracts to reflect the importance of those relationships. SERC-area contracts may also be looked upon favorably by regulators because they bring the benefits of vertical integration among the small number of trading partners. It is therefore plausible that long-term contracts are still predominant in regions without functioning spot markets, and this possibility merits further investigation. The difficulty in obtaining private contract data from the vast number of entities in the U.S., however, limits the scope of an analysis of contracts in this thesis.

The Task Force's first claim that long-term contracts are essential for new investments is not valid because many plants have been added in wholesale market regions without resorting to long-term contracts under the merchant model of generation. The second claim that long-term contracts are not available appears to have some justification because utility procurement practices in restructured states prohibit or discourage them. Furthermore, the hybrid regulatory model of basic service provided by utilities in the same market as competitive electricity suppliers makes them less able to bear the "volume" risk of the long-term contract, because utilities cannot pass the risk through to end-use customers who are no longer captive.

The possibility of ex-post regret and stranded costs has previously been the cause of much concern in the U.S. electricity industry as evidenced by the PURPA long-term contracts. Even today, the potential for economic distortions continues to observed in the case of recent contracts (United Press International 2010). Some regulators have been very careful to disapprove of such contracts, given the possibility of significant losses (Wood 2010). This discussion emphasizes that ploicymakers should be conscious of the disadvantages of long-term contracts while considering their use.

Having evaluated recent trends in procurement, financing and recent investments, the analysis now returns to the topic of the thesis question – identifying the economic gain that may in fact justify the use of a long-term contract in a relationship-specific situation. The next chapter develops a theoretical model to explore possible results to the central thesis question.

Chapter 5 The Analytic Investment Model

This chapter develops an analytic investment model to identify situations in which the use of a long-term contract may be beneficial and to quantify the gain to the economy in those situations. An competitive equilibrium investment strategy is developed in three steps beginning with an strategy under conditions of demand uncertainty, and successively including construction time-to-build and technology competition. The resulting investment strategy suggests that when a low-cost technology with time-to-build competes with a high cost-technology without time-to-build, the value of the economy is reduced because of rapid entry by the high-cost technology. This result presents the opportunity to identify relationship-specific circumstances in which the reduction in economic value can be eliminated.

5.1 Motivation for Developing an Investment Strategy Model

In previous chapters, the aspects of relationship specificity discussed provided the general framework for understanding why a long-term contract may be valuable in certain circumstances. The general framework was based on a synthesis of the literature, which does not provide much insight into how the value of a long-term contract may be quantified. If the long-term contract is to be a meaningful policy mechanism for securing investments in new power generation, the ability to identify that the contract enables a gain and quantification of that value is critical. In cases where the relationship-specific gain has been identified as significant, the contracts could be selectively allowed. When the gain is negligible or absent, the contracts could be disallowed. The measurement of the economic gain of the contract is therefore an indicator of its value to policymakers. This model demonstrates the quantification of the economic gain available in certain situations in a competitive market.

Recent experiences discussed showed that a reliance on spot markets and the merchant model of generation led to excessive investments in a low capital cost, high operating cost technology with a short time-to-build that could quickly enter the market and capture profits during times of higher prices. But when prices collapsed and a capacity glut was realized, investors had no way of recurring the costs of their investment. Had investors been able to secure long-term contracts in a high capital cost, long time-to-build technology with an assurance of revenues, their dependence on high and volatile spot market prices would have been reduced. This could have led to an increase in social surplus. The model developed here demonstrates how a technology bias is visible through a dependence on spot prices, and its potential negative effect on the value of the economy. It also demonstrates how value reductions can be avoided by strategic interventions at certain times.

In wholesale markets, investment decisions are expected to be efficient because power producers can observe market prices and invest when they are high. If market prices are high and firms move quickly, the "early birds" are able to capture profits from quick and low cost market entry. However, this strategy brings down prices, reducing the incentive for further investments by others. In the short-term, it is possible that there will be times of high prices followed by rapid investment in low overnight cost, high operating cost technologies, after which capacity will be in excess and prices will be low. In the long-run, this strategy will cause the consumer surplus to be lower because of higher average electricity costs. Firms are following a strategy that is optimal for them at the time of making the investment, but is not socially optimal in the long-run. This model can be used to observe the investment process when different firms competing in the same market are following individually optimal strategies to understand the value of influencing the investment strategy.

5.2 Investment in Competitive Equilibrium – The Deterministic Case

This section shows how an equilibrium investment strategy is computed for firms considering irreversible investments, such as power generation capacity. The model described here is adapted from Leahy (1993). The Leahy model is useful for the purpose of this study, because it identifies an investment strategy under uncertainty and in the presence of competition between firms all investing in the same technology (Leahy 1993). Both these conditions bear on the issues underlying the use of a long-term contract.

A principal motivation of Leahy's model is to improve upon the simplistic Net Present Value investment criterion such that the option value of deferring or refusing the investment is factored in to the investment decision. The net present value (NPV) rule does not adequately capture the effect of deferring the investment on the value of the investment, because it is only concerned with whether the sum of the present values of all assumed future cash flows is positive or negative. According to Leahy (1993), an irreversible investment involves a commitment in which the firm gives up the option value of postponing the investment until market conditions change, or refraining from it entirely and the option value should be included in the investment decision rule. Importantly, the Leahy model also demonstrates that competition does not affect the investment decision. 'Observant' firms that are aware of their competitors' action will pursue the same investment strategy as firms that are 'myopic' - firms that have static expectations of the amount of capacity installed or the actions of other firms. This result is useful because for policies that consider intervening in the actions of an individual firm, because its investment strategy is independent of the actions of its competitors.

In the Leahy model, output is produced from capital at constants returns to scale – one unit of capital produces one unit of output. Also, capital is infinitely divisible. Each infinitesimal unit of capital can therefore be thought of as a separate firm. If capital cost is k, firms can add capacity at k per unit. The operating cost of a unit of capital is c per annum. Firms are assumed to be risk-neutral and future cash flows are discounted at the risk free rate r. Furthermore, capacity is considered to have an infinite life and is never retired. Therefore, the capital costs are incurred perpetually and payments are equal to rk. Total annual payments are therefore $rk+c$.

To show why myopic firms would follow the identical investment strategy as the non-myopic firms, first consider a simple deterministic case where price depends only on installed capacity and time:

$$p(q,t) = -\alpha q + \beta t$$

$$\begin{aligned} \text{where } p&: \text{price} \\ q&: \text{installed capacity} \\ \alpha, \beta&: \text{positive constants} \\ t&: \text{time} \end{aligned}$$

In this industry, price will continue to rise in the absence of entry by firms, until $p_c = rk+c$. In other words, firms will enter when the price is sufficient to cover the total costs. A competitive equilibrium is reached when firms enter in sufficient quantities to maintain the price level at $p_c = rk+c$. At this price level, profits earned by each firm are zero. Investment will not occur earlier or later. Thus, the price level p_c acts as a price trigger; investment is triggered whenever price reaches that level.

The investment process does not depend on the visibility of the actions of other firms. Whether firms are myopic or observant, they will both wait until the price reaches the trigger level. Thus, the timing of the investment by both types of firms is identical. However, this says nothing about the quantities invested by the two types of firms. Myopic firms will tend to invest infinitely until price is brought down (Leahy 1993; Caballero 1991; Abel 1983).

In a more general case, consider the inverse demand curve,

$$p_t = D(q_t, x_t)\ ,\ \ D_1 < 0,\ D_2 > 0$$

where x_t is the arbitrary determinisitic demand shock. Under the assumption of myopia the firm will treat the installed capacity q_t as constant $\bar{q}$, assuming that capacity will never be added by other firms. The investment strategy is such that entry will be chosen at the time T to maximize the present value of the profits earned by the firm:

$$\max_T \left\{ \int_T^{\infty} e^{-rt}\left[D(\bar{q}, x_t) - c\right]dt - e^{-rT}k \right\} \Rightarrow \max_T \left\{ \int_T^{\infty} e^{-rt} D(\bar{q}, x_t)\,dt - e^{-rT}\left(\frac{c}{r} + k\right) \right\}$$

Solving for the first condition gives $p_T = rk + c$. Thus, investment occurs when the price is equal to the annuity value of capital plus the operating cost. The second order condition for this result states that the price must approach this trigger value from below. For all possible values of T that satisfy the conditions, the firm will choose the one that maximizes profits.

It must be noted that firms in this model are only myopic in their expectations of installed capacity, and not other factors. As firms invest, the value of q_t changes and therefore the value $\bar{q}$ assumed constant by myopic firms changes. At every instant, the investment strategy is updated with the prevailing value of $\bar{q}$. Meanwhile, the price process is driven by the arbitrary demand shock which is visible to the firm. As a result, the investment strategy can be said to be myopic in capacity, but rational in demand.

Leahy (1993) subsequently proves that the general deterministic results discussed above yield a competitive equilibrium, by showing that the present discounted value of profits at any time of entry is equal to the discounted present value of the cost of entry $k+\frac{c}{r}$. In other words, myopic behavior gives the optimal result in competitive equilibrium.

An important assumption of this model is that firms employ all invested capacity in production. Capital does not depreciate, and firms cannot exit. Therefore, to clear the market, price must fall.

Another assumption of the model is that capacity is instantaneously available and becomes active immediately after the investment decision is made. However, this assumption is not realistic for most types of irreversible investments, and will ultimately be relaxed in my model.

The discussion thus far has neglected the motivation of incorporating uncertainty into the decision rule. Having demonstrated the general deterministic result under competitive equilibrium, the discussion will now focus on the effect of uncertainty.

5.3 Investment in Competitive Equilibrium – Including Uncertainty

Uncertainty alters the investment strategy of the firms in the Leahy model. In competitive equilibrium, price is capped at the trigger value because firms invest in new capacity only at that price level. They do not have an incentive to invest earlier. However, the price process could easily fall below the trigger value as it is driven by the demand shock. Since price declines after investment, firms must invest at a trigger value that is higher than the $p_T = rk+c$, the annuity value of capital plus the operating costs, in order to cover costs. This expectation is intuitive. From the perspective of the myopic firm, it must consider the value of remaining uncommitted. It will therefore wait to see if the price rises sufficiently above p_T before it invests. This section describes the solution for the modified investment strategy.

The inverse demand function is as follows, and depends on capacity and the demand shock:

$$p_t = D(q_t,x_t) \ \geq \ 0 = x_t q_t^{\frac{-1}{\lambda}}$$

In the deterministic case, the price process was driven by deterministic demand shocks. Leahy (1993) incorporates uncertainty by treating the demand as a diffusion process of the form:

$$dx = \mu(x)dt + \sigma(x)dw$$

where dw is an increment of a standard Wiener process. If μ and σ are constant, then x is a Brownian motion or a continuous time random walk. For implementing the model in my analysis, I use a discrete random walk. The stochastic demand x_t follows a random walk process with drift μ and volatility sigma σ, given by:

$$\frac{\Delta x_t}{x_t} = \left(\mu - \frac{1}{2}\right)^2 \Delta t + \sigma\sqrt{\Delta t}\,\tilde{\varepsilon}_t$$

where $\tilde{\varepsilon}_t$ is a standard random variable.

Following Dixit (1989) and Dixit and Pindyck (1994), the optimal entry trigger is given by

$$P^* = \frac{\alpha}{(\alpha-1)}(r-\mu)K$$

where $K = \left(k + \frac{c}{r}\right)$, the present value of lifetime costs of the investment at the time of entry and $\alpha > 1$ is the positive root of the polynomial $r - \left(\mu - \frac{1}{2}\sigma^2\right)\Phi - \frac{1}{2}\sigma^2\Phi^2$. The root is given by $\alpha = \frac{1}{2} - \frac{\mu}{\sigma^2} + \sqrt{\left(\frac{\mu}{\sigma^2} - \frac{1}{2}\right)^2 + \frac{2r}{\sigma^2}}$.

Note that setting $\sigma = 0$ in the polynomial brings us back to the certainty case, where the root $\alpha = \frac{r}{\mu}$. As $\sigma \to \infty$, $\alpha \to 1$ and the value of P^* increases in comparison with K . The difference between P^* and K is the option value, or the value of remaining uncommitted, for the specific values of σ and α. Both these variables can therefore influence the timing of the investment (Dixit 1989; Dixit and Pindyck 1994).

In this formulation, $r > \mu$ and $r - \mu > 0$, i.e. the discount rate is larger than the growth rate of demand. If this were not true, demand would always grow faster than the rate at which the cash flows from the investment could be discounted. Thus, waiting longer would always be a better policy and firms would maximize profits by choosing a larger T.

Because $\alpha > 1$ is a root of $r - \left(\mu - \frac{1}{2}\sigma^2\right)\Phi - \frac{1}{2}\sigma^2\Phi^2$,

$$r - \left(\mu - \frac{1}{2}\sigma^2\right)\alpha - \frac{1}{2}\sigma^2\alpha^2 = 0$$

$$\Rightarrow \text{-}r + \mu\alpha - \frac{1}{2}\sigma^2\alpha + \frac{1}{2}\sigma^2\alpha^2 = 0$$

$$\Rightarrow r\alpha - r - r\alpha + \mu\alpha + \frac{1}{2}\sigma^2\alpha(\alpha - 1) = 0$$

$$\Rightarrow r(\alpha - 1) - \alpha(r - \mu) + \frac{1}{2}\sigma^2\alpha(\alpha - 1) = 0$$

$$\Rightarrow \frac{\alpha}{(\alpha - 1)}(r - \mu) = r + \frac{1}{2}\sigma^2\alpha = 1 + \frac{1}{2}\frac{\sigma^2}{r}\alpha$$

Therefore, the price trigger P^* can be re-written as

$$P^* = \frac{\alpha}{(\alpha - 1)}(r - \mu)K = \left(1 + \frac{1}{2}\frac{\sigma^2}{r}\alpha\right)K$$

Since α, σ and r are positive, $\left(1 + \frac{1}{2}\frac{\sigma^2}{r}\alpha\right) > 1$. Thus, the price trigger P^* is always greater than or equal to K, and uncertainty adds a positive cost to the investment (Berger 2008). This uncertainty premium was earlier referred to as the option value of waiting to invest.

Again, Leahy (1993) demonstrates that the myopic policy yields the identical result as competitive equilibrium. The main implication in this section is the decision rule P^* that can be used in a simulation that analyzes the investment process in the presence of uncertainty and competition.

5.4 Investment in Competitive Equilibrium – Including Uncertainty and Time-to-Build

So far, we have identified an investment strategy that holds under conditions of demand uncertainty and in the presence of competition. The next step is to identify how the strategy would be altered if some uncertainty related to a particular characteristic of the production capacity is introduced. This section will study the effect of time-to-build (TTB) for capacity on the investment strategy. The solution adopted here is based on the dynamic competitive equilibrium derived for a market with time-to-build using a real options approach (Grenadier 2000).

Time-to-build introduces a special kind of uncertainty in the context of irreversible investments. In a market with TTB, investments will be made based on expectations of prices that will prevail once construction is completed. However, the actions of competitors between investment and project completion will affect the prices and asset values. Since we are ultimately interested in power generation capacity which is sometimes affected by long construction times, the effect of TTB on the value of an investment in this industry must be understood. In the preceding sections, the model based on Leahy (1993) assumed that all the physical characteristics of the capital investment were captured in terms of its capital and operating costs, k and c . The task in this section is to explicitly introduce TTB, which is a physical characteristic of the capital investment and influences the dynamics of competition, but is not captured in the purely cost-based investment strategy.

As before, capital is invested at a cost of k per unit with operating costs of c per year. Additionally, if the investment occurs at time T and if the construction takes δ periods, i.e. the TTB = δ, production capacity comes online at time $T+\delta$. Capacity cannot be retired and does not depreciate. The market clears by ensuring that the price adjusts to meet uncertain demand. The investment decision is analogous to exercising a call option on an asset δ years from completion, and the cost of construction is the exercise price (Grenadier 2000).

In this extension with TTB, the inverse demand function is again of the constant-elasticity form:

$$p_t = x_t q_t^{\frac{-1}{\lambda}}$$

The stochastic demand x_t follows a random walk process with drift μ and volatility sigma σ, given by:

$$\frac{\Delta x_t}{x_t} = \left(\mu - \frac{1}{2}\right)^2 \Delta t + \sigma\sqrt{\Delta t}\,\tilde{\varepsilon}_t$$

where $\tilde{\varepsilon}_t$ is a standard random variable.

At any instant, there may be capacity in construction, C_t, in addition to active capacity q_t, such that the committed capacity at that instant is $Q_t = q_t + C_t$. Also, $Q_t = q_{t+\delta}$ or $Q_{t-\delta} = q_t$. Thus, when investment occurs and an increment of capacity ∂Q_t is committed, $\partial C_t = \partial Q_t$ is the increment of capacity that enters into construction. For times when $\partial Q_t = 0$, capacity becoming active is $\partial q_t = -\partial C_t$.

As Grenadier (2000) explains, the challenge with deriving a competitive equilibrium with TTB is that the state space of this market can be of infinite dimension. Although firms observe the current level of demand and active capacity that determine current prices, this information is not sufficient to formulate a rational investment strategy. Firms must also anticipate the amount of committed capacity in the pipeline that is currently under construction and know when those units will be completed, because this information will impact the equilibrium prices during the subsequent δ periods. Firms must have this information for the previous δ periods. Consequently, the model must be converted to one of finite dimensionality for a closed-form solution to be derived.

Grenadier's solution to this issue is to assume that all units currently under construction are already completed. This solution is acceptable because a firm entering construction today will not receive any cash flows until it is completed in δ periods. At that future time, all firms committed today will be active and can be treated the same as units that are already completed today. There are then only two state variables that must be considered: the current level of demand x_t and the committed capacity Q_t . The investment would be based not on the current price p_t, but on the expectation of price δ periods in the future, $p_{t+\delta}$.

Similar to Leahy (1993), the investment strategy must maximize the expected present value of profits for the individual firms and in doing so, maximize the expected present value of social welfare for the economy as a whole. This objective is the same as the social planner's objective of maximizing consumer surplus. The total flow rate of social surplus at any time is equal to the area under the demand curve and is given by:

$$S(x_t,q_t) = \int_0^{q_t} \left(x_t q_t^{-1/\lambda} \right) dq = \frac{\lambda}{\lambda-1} x_t q_t^{(\lambda-1)/\lambda}$$

The optimal control problem that needs to be solved is represented by the Bellman value function:

$$J(x_t,q_t,C_t,\Lambda_t) = \max_{Q(s):s>0} E\left[\int_0^{\infty} e^{-rt} S(x_t,Q_{t-\delta})dt - \sum_t K e^{-rt} \Delta Q_t \right]$$

where $K = \left(k + \frac{c}{r} \right)$, the present value of lifetime costs of the investment at the time of entry and ΔQ_t is the increment of capacity committed at time t.

Using option pricing, Grenadier (2000) derives the equilibrium investment strategy to the dynamic programming problem described here, in the form of a trigger function X^* expressed as:

$$X^*(Q_t) = \frac{\alpha}{(\alpha-1)}(r-\mu)Ke^{(r-\mu)\delta}Q_t^{1/\lambda}$$

Note that the trigger function is of a similar form as the price trigger P^* derived in the Leahy model, with the addition of the term $e^{(r-\mu)\delta}Q_t^{1/\lambda}$. Whereas P^* was independent of any capacity terms and investment depended only on the price level, X^* depends on committed capacity as well as the time-to-build and investment is triggered by the value of demand. Thus, the solution explicitly includes time-to-build. Moreover, when $\delta = 0$, $Q_t = q_t$ always and $X^*(Q_t) = P^*$.

Investment is triggered when x_t rises to the level $X^*(Q_t)$, but the value of $X^*(Q_t)$ changes as Q_t changes. That is, the trigger value increases as investment continues and more capacity is committed. In contrast, P^* always remains constant because it is independent of capacity.

To see that the trigger function follows the same intuition as in Leahy (1993) while converting the model to finite dimensionality, consider the expectation of prices at time $t+\delta$:

$$E\left[p_{t+\delta}\right] = E\left[x_{t+\delta} q_{t+\delta}^{-1/\lambda}\right]$$

$$\Rightarrow E\left[p_{t+\delta}\right] = x_t e^{\mu\delta} Q_t^{-1/\lambda}$$

From the trigger function, when x_t rises to the trigger value $X^*(Q_t)$

$$X^*(Q_t) Q_t^{-1/\lambda} = P^* e^{(r-\mu)\delta}$$

$$\Rightarrow E\left[p_{t+\delta}\right] = P^* e^{(r-\mu)\delta} e^{\mu\delta}$$

$$\Rightarrow P^* = e^{-r\delta} E\left[p_{t+\delta}\right]$$

This result demonstrates that in the market with time-to-build, the investment strategy is modified by replacing the price trigger strategy P^* by the discounted expected equilibrium price that will prevail as a result of market clearing once construction is completed (Grenadier 2000). In other words, firms will not invest when $p_t = P^*$ but when $e^{-r\delta} E\left[p_{t+\delta}\right] = P^*$. The implication of this is that firms will wait until prices rise higher than P^*, and the difference in the price level represents the uncertainty premium of what competitors might do while capacity is under construction. Consequently, there will be times at which a firm will not invest in a market with TTB, when it otherwise would have invested in the same market without TTB for identical values of demand and price.

Although we now have an investment strategy based on a closed-form solution, the strategy cannot be used in the form of prices because the value $x_{t+\delta}$ is not observed by firms at time t and consequently, the value of $E\left[p_{t+\delta}\right]$ is not known by firms. The investment strategy is therefore implemented in the form of the trigger function X^*.

5.5 Competition with Myopia, Time-to-Build, and Two Technologies

The optimal investment strategy derived above is informative about the decisions of firms in an environment of demand uncertainty, where capacity has time-to-build. However, this "world" is still unrealistic because only one technology type is assumed, and all firms invest in the same technology. How would the investment strategy change if firms could choose from different technologies, based on their expectations of the profitability of the respective technologies, given demand uncertainty and different values of cost and time-to-build? This section incorporates the impact of technology choice into the investment strategy.

In the context of the model above, representing different technologies is simplified. I assume that the values of capital and operating cost, k and c, and time-to-build δ are sufficient to distinguish between technologies. Also, it is possible to think of the technology choice as separate investments by firms that are constrained to invest in only one technology, because a firm is represented by a unit of capacity. For example, any investment in plants with characteristics $\{k_1, c_1, \delta_1\}$ would be labeled as "Type 1" firms entering the market, and so on for other technology types. By allowing different types of firms to enter the market, various technology types can "compete" with each other. The investment decision for a single firm is therefore not which technology to select, but when to invest in its particular technology type.

Modeling technology competition presents a significant challenge because firms must now not only evaluate information about the existing capacity and prices, but also the effect of other firms' entry on installed capacity and prices. Different values of time-to-build make the problem more complicated because expectations will have to be formed of when capacity committed in various "pipelines" will become active. To make this problem tractable, I first limit the technology competition to only two types of firms: gas and nuclear. Later on, I will discuss how this approach does not result in a loss of generality even with a larger number of technologies.

The task therefore reduces to identifying the separate investment strategies for gas and nuclear firms. To distinguish between the gas and nuclear, I use the notation 'g' and 'n'. Thus, the main variables are:

Gas: $\{k_g, c_g, \delta_g, K_g, q_g, Q_g\}$

Nuclear: $\{k_n, c_n, \delta_n, K_n, q_n, Q_n\}$

The main architectural assumptions of the model are adopted from the Grenadier case. As before, the inverse demand function is given by:

$$p_t = x_t q_t^{\frac{-1}{\lambda}}$$

Capacities have to be denoted individually such that $Q_{g_t} = q_{g_{t+\delta}}$ and $Q_{n_t} = q_{n_{t+\delta}}$. Committed capacity is related to capacity under construction and current capacity as $Q_t = q_t + C_t$. That is,

$$Q_t = \left(q_{g_t} + q_{n_t}\right) + \left(C_{g_t} + C_{n_t}\right) = \left(q_{g_t} + C_{g_t}\right) + \left(q_{n_t} + C_{n_t}\right) = Q_{n_t} + Q_{g_t}$$

As before, the social planner's optimal control problem is

$$J\left(x_t, q_t, C_t, \Lambda_t\right) = \max_{Q(s):s>0} E\left[\int_0^\infty e^{-rt} S\left(x_t, Q_{t-\delta}\right) dt \ -\sum_t K e^{-rt} \Delta Q_t\right]$$

but must be solved for the two separate streams of gas and nuclear.

$$J\left(x_t, q_t, C_t, \Lambda_t\right) = \max_{Q(s):s>0} E\left[\int_0^\infty e^{-rt} S\left(x_t, \left(Q_{g_{t-\delta}} + Q_{n_{t-\delta}}\right)\right) dt \ -\sum_t K e^{-rt} \left(\Delta Q_{g_t} + \Delta Q_{n_t}\right)\right]$$

This problem is also an infinite dimensional problem as in Grenadier (2000) because information about committed capacity in pipeline, $Q_{g_{t-\delta}}$ and $Q_{n_{t-\delta}}$, and the times at which the units will be completed must be known to calculate the optimal ΔQ_{g_t} and ΔQ_{n_t}. To make the problem finite-dimensional and derive a closed form solution, Grenadier relied on the fact that cash flows to capacity entering construction were realized after δ periods and treating committed capacity as active capacity. That solution cannot be used in the technology competition context because of different values of time-to-build between technologies. For example, if $\delta_g < \delta_n$, then gas capacity that becomes active will affect the cash flows to already committed nuclear plants as and when they come online. As a result, finding a closed form solution to this problem is extremely difficult.

I address this issue by relying on Leahy's and Grenadier's findings that using the myopic investment strategy results in the competitive equilibrium solution. In Leahy's case, a firm was ignorant about the actions of other firms and was able to achieve the individually and socially optimal outcome by pursuing the dominant strategy of using the price trigger function. In Grenadier's case, the firm was fully observant and treated committed capacity as active, thereby achieving the individually and socially optimal outcome by using the demand trigger function. In the current situation of competition between two technologies, Leahy's myopic firms will over invest, assuming that no other firms are investing. Grenadier's fully observant firms would under invest, assuming that all installed capacity is already active. The optimal amount of investment would in reality be bounded by the two extremes of complete myopia or full observance of the actions of competitors.

I therefore assume that allowing firms to always pursue the dominant strategy, first under myopic conditions and then under conditions of observance, bounds the optimal added capacity. Uncertainty and time-to-build is preserved as before; myopia therefore assumes no committed capacity while observance assumes knowledge of all installed capacity. Myopia gives the lower bound to the optimal investment strategy for each period in time, whereas the upper bound is given by full observance. I therefore rewrite Grenadier's demand triggers for the two types of firms as:

Gas:

$$X^*\left(q_{g_t}\right)\Big|_{\phi=0} = \frac{\alpha}{(\alpha-1)}(r-\mu)K_g e^{(r-\mu)\delta_g} q_t^{1/\lambda}$$

$$X^*\left(Q_{g_t}\right)\Big|_{\phi=1} = \frac{\alpha}{(\alpha-1)}(r-\mu)K_g e^{(r-\mu)\delta_g} Q_t^{1/\lambda}$$

and

Nuclear:
$$X^*\left(q_{n_t}\right)\Big|_{\phi=0} = \frac{\alpha}{(\alpha-1)}(r-\mu)K_n e^{(r-\mu)\delta_n} q_t^{1/\lambda}$$
$$X^*\left(Q_{n_t}\right)\Big|_{\phi=1} = \frac{\alpha}{(\alpha-1)}(r-\mu)K_n e^{(r-\mu)\delta_n} Q_t^{1/\lambda}$$

where $\phi=0$ denotes myopia and $\phi=1$ denotes observance. Note that firms observe the total current and committed capacities. By this construction, the upper bound for capacity added at each period in time is $\Delta Q_{g_t}\Big|_{\phi=0}$ and $\Delta Q_{n_t}\Big|_{\phi=0}$, and the lower bound is $\Delta Q_{g_t}\Big|_{\phi=1}$ and $\Delta Q_{n_t}\Big|_{\phi=1}$ respectively. This approach is slightly different from Berger (2008), where the investment triggers are based on a similar logic but the specific terms in the resulting trigger function are different.

The ultimate indicator of the optimality of the investment strategy is the present discounted value of the economy, J, given by the Bellman value function. Because of the investment strategy used above, the value of the economy will correspondingly be bounded such that $J\Big|_{\phi=0} \leq J \leq J\Big|_{\phi=1}$. That is, the value of the economy is highest in the case of full observance and lowest in the case of complete myopia.

The investment strategy is derived here for two technology competition with demand uncertainty and time-to-build. The approach holds for developing the investment strategy for any number of technologies, because of the result that the optimal strategy for the individual firm results in the competitive equilibrium for the economy. Thus, the decision rule can be extended to more technology types if necessary.

5.6 Implications of the Three Step Model

The significance of modeling the investment strategies in three distinct steps is that this approach allows us to calculate the value of the economy in the three separate scenarios:

(1) An economy with uncertainty and instantaneous capacity addition where only one technology is available ("One Technology model")

(2) An economy with uncertainty and time-to-build for capacity addition where only one technology is available ("One Technology model with Time-to-Build")

(3) An economy with uncertainty and time-to-build for capacity addition where two technologies are allowed to compete ("Two Technology model")

The value of the economy J is given by the social surplus realized by meeting electricity demand less the total cost of producing electricity in a particular time period. The net present value of the economy is the sum of the discounted values of J for every time period. That is,

$$NPV(J) = \sum_t \left[\frac{S_t - (rk + c) * q_t}{(1+r)^t} \right]$$

In (1), we can calculate the value of the economy given uncertain demand for a particular technology type using the derived equilibrium investment strategy. By using the modified strategy obtained in (2), we can quantify the effect of time-to-build on the value of the economy for the identical conditions of uncertainty. Finally, the introduction of a second competing technology in (3), allows us to identify the change in the value of economy in the presence of competition.

The next task is to implement the investment strategies in a simulation to calculate the values of a hypothetical economy, using some parameterized technology types. Since (3) calls for two different technologies, I will incorporate scenarios (1) and (2) separately for the two technology types that will ultimately be used in (3). Gas and nuclear technologies will be evaluated with different capital and operating costs and values of time-to-build. Gas is assumed as a low capital cost, high variable cost technology with no time-to-build. Nuclear is considered to be a high capital cost, low operating cost technology with a non-zero time-to-build. These assumptions are explained in more detail along with the simulation results in the following chapter. In present value terms, the cost values are chosen such that nuclear has lower present value of lifetime costs ("low cost technology") than gas ("high cost technology"). The results expected of the simulation exercise are as follows:

a. In a comparison of two one-technology economies where neither have time-to-build, the value of the economy is higher for the economy with the low cost technology (nuclear).

b. For any one-technology economy, introducing time-to-build decreases the value of the economy

c. Whether the value of the low cost one-technology economy with time-to-build (nuclear) is higher than the high cost one-technology economy with no time-to-build (gas) depends on the time-to-build chosen for the former.

d. Introducing the high cost technology (gas) as the competitor in an economy with the low cost technology with time-to-build (nuclear) reduces the value of the economy.

Of the results expected, (d) is the one of interest for the purposes of this thesis, because it suggests that allowing firms to pursue their dominant individually optimal strategy in a competitive environment reduces the value of the economy as a whole. The non-zero sum economic gain that this analysis has been in search of is precisely an amount equivalent to the value reduction. If this result holds true, a mechanism that allows the firm to pursue a non-dominant strategy could be implemented, thereby increasing the value of the economy. A credible commitment to pursuing the non-dominant strategy could be obtained from the firm through a long-term contract, whereby it would have the assurance of cost recovery and the economy would realize the gain which is non-zero sum.

Chapter 6 Analysis of the Investment Strategy Model

The investment strategy developed in previous chapter is simulated. This chapter summarizes the results in the case of the "One Technology" and "Two Technology" scenarios. The One Technology model first demonstrates that there exists a dominant strategy while selecting the technology in the face of uncertain stochastic demand: always invest in the low cost technology. The One Technology model with Time to Build (TTB) then shows that TTB reduces the value of the economy obtained by following the dominant strategy. Finally, the Two Technology model demonstrates that under competition, following the dominant strategy often results in the optimal outcome. However, it also identifies the existence of cases when following the dominant strategy might result in a sub-optimal outcome. These cases are of interest for the purpose of identifying the value of a long-term contract in relationship-specific situations.

6.1 One Technology Model

The one technology model analyzes the investment decision by comparing the investments in two types of technology for the identical stochastic demand. The model assumes a "world" in which a firm can invest in only one type of technology; it cannot pick and choose between various technologies. Based on the underlying Monte Carlo simulation for electricity demand, the model produces the amount of capacity, prices, total costs, social surplus and net value of the economy (social surplus less total costs). The model is then run assuming a second technology type for the same realizations of demand. The technologies in the two sets of runs are identical in every respect, except for their differing costs. Actual differences in technology characteristics such as heat rates, capacity factors, fuel costs, etc are assumed to be reflected in the single cost difference number. Thus, the investment decision analysis reduces to a comparison between a low-cost and a high-cost technology. The main finding of the analysis is that in a world where a fim can invest in only one type of power generation technology, it will invest only if that technology is cheapest. In other words, only firms that can invest in the cheaper power generation technology will be active. The cheaper technology will always dominate and more expensive capacity will never be installed. To demonstrate the result, this section lays out the assumptions in the one technology model and describes the supporting analysis.

Given the objective of this thesis, the results of the model are useful if the underlying economy is structured so that relationship-specific circumstances are realized from time to time. A low overnight cost, high operating cost technology that can quickly enter the market, is in competition with a high overnight cost, low operating cost technology that takes a long time-to-build. The values are parameterized such that the low overnight cost technology has a higher present value of lifetime costs, whereas the higher overnight cost technology has a lower present value of lifetime costs. The latter is therefore "cheaper" in the long run, but its time-to-build creates the possibility of incomplete cost recovery, in the event of low prices upon completion. A relationship-specific circumstance is therefore realized if the competitive market is in a state where a particular firm would invest in the high overnight cost technology to sell "cheaper electricity," but for the time-to-build of the technology. At the same time, a buyer wants electricity at lower prices than available in the market and is willing to sign a contract with the firm to alter its strategy and commit to investing in the cheaper technology. The gain enabled that is non-zero sum is the cost savings associated with purchasing cheaper electricity.

The technology cost assumptions are presented in Table 5. Based on the values selected, the total annual costs for gas are higher than those for nuclear, making it the low-cost technology (Column 9 in Table 5). Other parameters such as plant life, weighted average cost of capital (WACC), and the risk free discount rate are identical for the two technologies. The difference in costs is reflected in the price triggers for each technology – the trigger for nuclear is less than that of gas (Column 9 in Table 6). The price trigger values are used as the investment decision rule in the One Technology model.

Table 5. Technology Cost Assumptions for Simulation

	Capital Cost [1] ($ millions / 1000 MW)	O&M Cost [2] ($ millions / 1000 MW / year)	Plant Life [3] (years)	Weighted Average Cost of Capital [4] (% / year)	Risk free Discount Rate [5] (% / year)	Annuitized Capital Cost [6] ($ millions / 1000 MW / year)	PV (Perpetuized Capital Cost) [7] ($ millions / 1000 MW)	PV (Lifetime Costs) [8] ($ millions / 1000 MW)	Total Annual Costs [9] ($ millions / 1000 MW / year)
Gas	609	350	40	7.8%	5.0%	50	1,000	8,000	400
Nuclear	3,046	100	40	7.8%	5.0%	250	5,000	7,000	350

[1], [2], [3], [4] based on analysis in Du, Parsons (2009)

[6] Annuity value of [1] = [1]*[4]/(1-1/(1+[4])^[3])

[7] Assume reinvestment at end of plant life, s.t. capacity is never retired. [7]=[6]/[5]

[8] = [7] + ([2]/[4])

[9] Lifetime costs as a perpetuity, = [8]*[5]

Table 6. Levelized Cost of Electricity and Price Trigger Comparison

	Capital Cost [1] ($ thousands / MW)	O&M Cost [2] ($ thousands / MW / year)	Risk free Discount Rate [3] (% / year)	PV (Lifetime costs) [4] ($ thousands / MW)	Capacity Factor [5] (%)	Annual Production [6] (hrs/year)	Annualized Cost of Electricity [7] ($ thousands / MW / year)	Levelized Cost of Electricity [8] ($ / MWh)	Price Trigger [9] ($ / MWh)	Equivalent Annual Revenue [10] ($ thousands / MW / year)
Gas	1,000	350	5.0%	8,000	85.0%	7,446	400	53.72	56.37	420
Nuclear	5,000	100	5.0%	7,000	85.0%	7,446	350	47.01	49.33	367

[1] Present value of lifetime capital costs, i.e. assumes 100% reinvestment at the end of plant life, s.t. capacity is never retired

[2] Annual Operations & Maintenance cost including fuel, incurred perpetually

[4] Present Value (lifetime costs) = [1] + ([2]/[3])

[6] Annual production per unit of capacity = 1*0.85*8760 MW-hours/year

[7] = [4]*[3]

[8] = ([7]/[6])*1000

[9] = ([10]/[6])*1000

[10] from simulation

Uncertainty is introduced through a stochastic demand process. The demand is generated using a Monte Carlo simulation based on a random walk process, as described in Chapter 5. Figure 19 shows sample paths of the random walk for the duration of the study period of 200 years, superimposed on the expected demand for the Monte Carlo process. Sample path 1 will be used throughout the model for a comparison of the results in different cases of the simulation. Figure 20 is a log representation of the sample paths and expected demand, along with the realized upper and lower 95% confidence interval (CI) for the simulation. The analysis therefore presents results for a deterministic case, for the purpose of illustration, as well as a more robust probabilistic assessment based on the full Monte Carlo simulation.

The decision rule for investments is dictated by the price trigger, as discussed while developing the solution of Leahy (1993). Investment occurs if and only if the price exceeds the price trigger, because the trigger value is the price that makes $E\left[NPV\right]=0$ for the investment. Figure 21 shows that the price line is horizontal at these times, indicating that capacity is being added. Price never exceeds the price trigger for either technology, as new capacity will instantly be added until price is brought down to the level of the price trigger. Figure 21 also demonstrates that nuclear capacity will be added at lower price levels than gas because the price trigger for nuclear is lower than gas. This also causes the price of electricity from gas to always be higher than that of nuclear.

The capacity addition process is another way to represent the how the same dominant investment strategy is exercised, and is shown in Figure 22. When price is below the trigger value, capacity is held constant. Capacity is instantaneously added when price exceeds the trigger value. For identical values of demand, the total nuclear capacity is always higher than that of gas because of lower costs for nuclear.

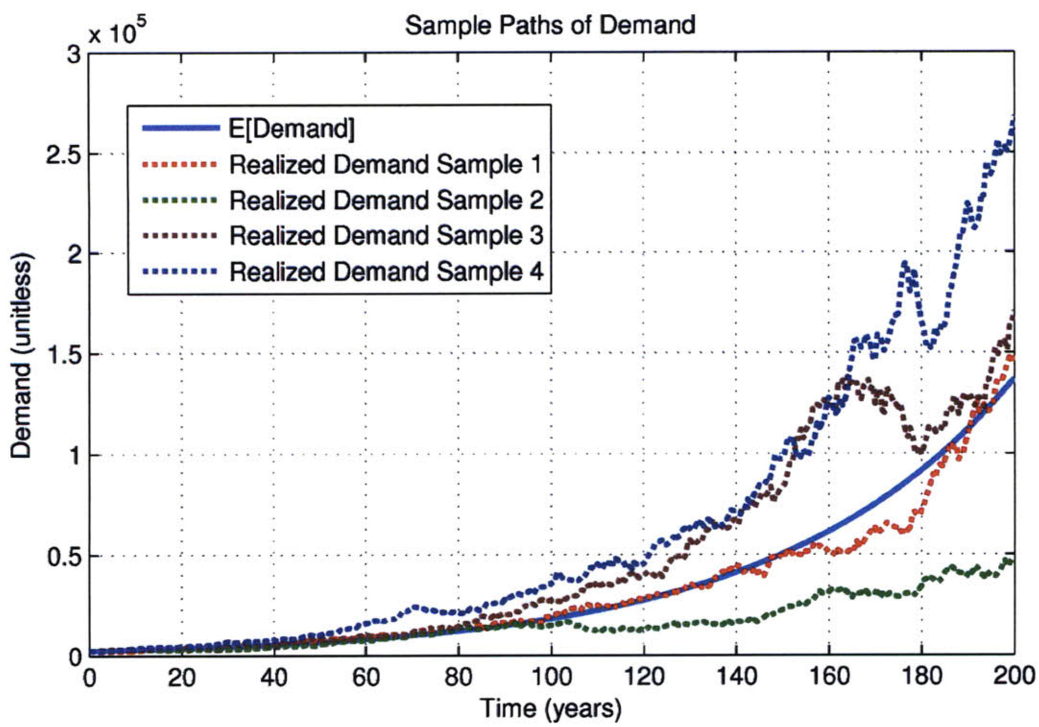


Figure 19. Sample Paths of the Random Walk in the Monte Carlo Simulation

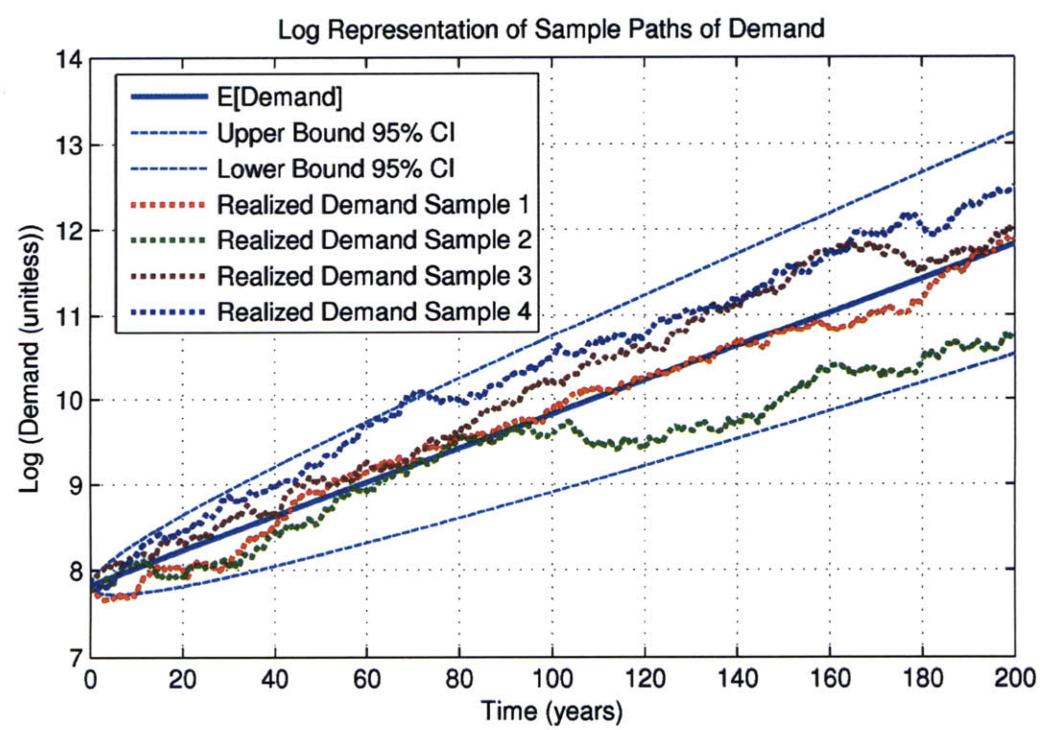


Figure 20. Log Representation of Sample Paths of the Random Walk

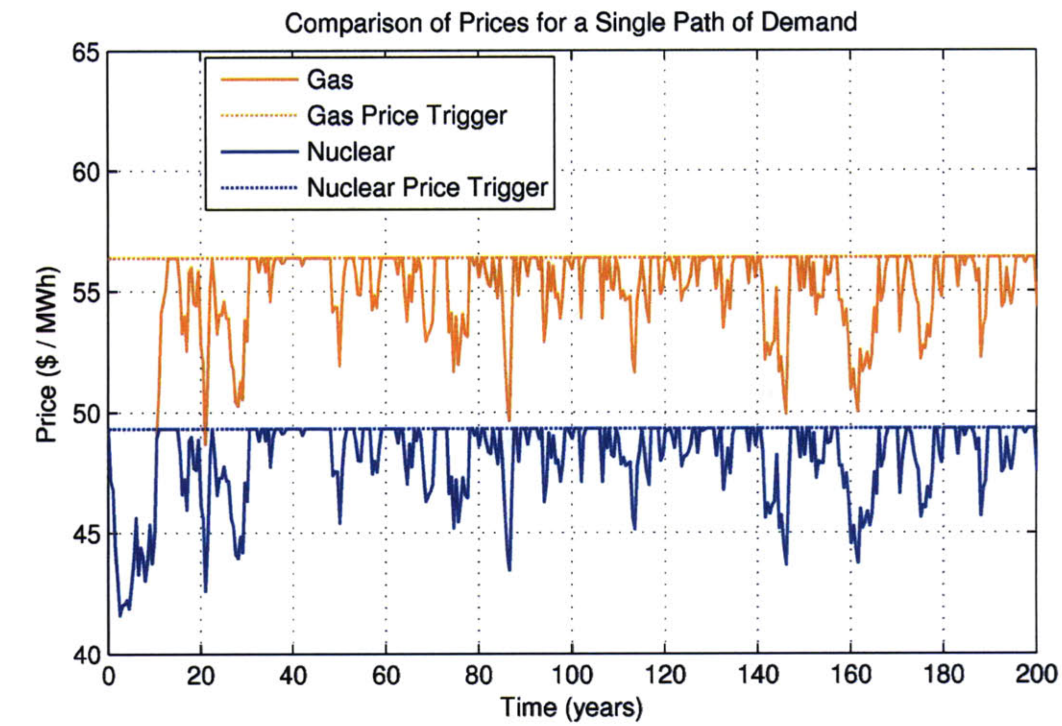


Figure 21. Price Comparison for the One Technology Simulation

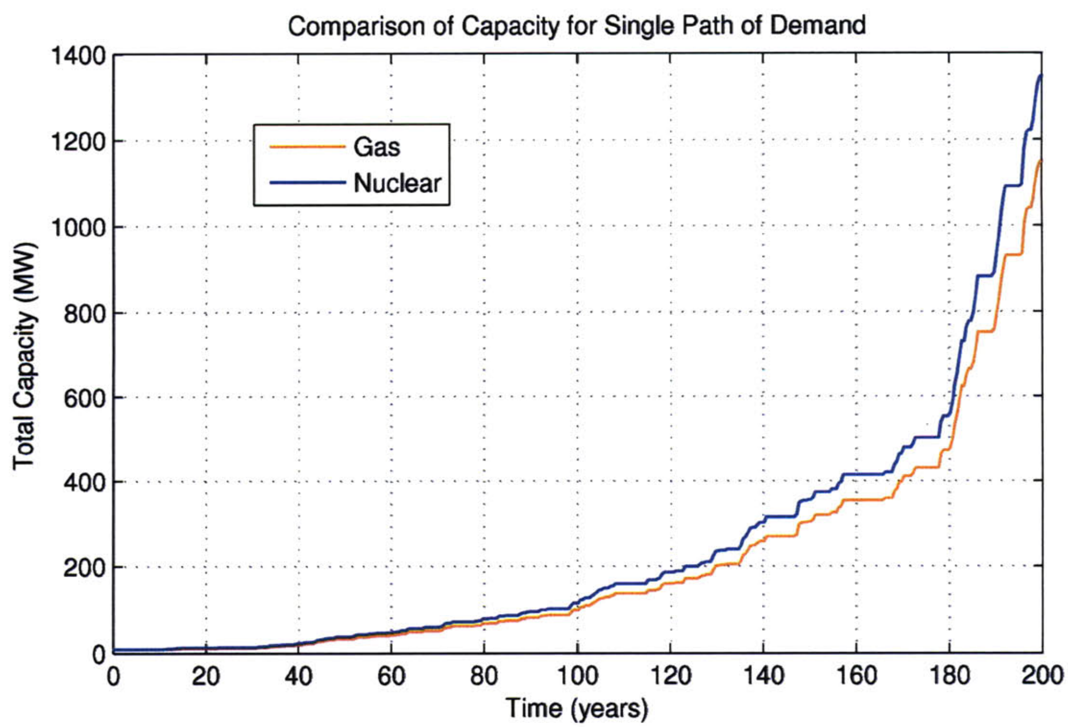


Figure 22. Capacity Comparison for the One Technology Simulation

The price and capacity relationships are illustrative of the strategy exercised, but do not provide a measure of the value or economic impact of the strategy. To ascertain this, the value of the economy must be calculated at each time period during the course of the study. Figure 23 and Figure 24 depict the social surplus, the total costs of all the installed capacity, and the value of the economy (the difference of the two, denoted by J) at each time period for each technology. J is found to closely track the value of demand served.

A comparison of J for the two technologies (Figure 25) shows the value of the economy for nuclear J_{nuc}, is always greater than or equal to J_{gas}. The sum of the present values of J for every time period in the study gives the NPV of the economy. The NPV number is a good single measure of the effect of the investment strategy. $NPV\left(J_{nuc}\right)$ is found to be higher than $NPV\left(J_{gas}\right)$, indicating that the economy is more valuable if the dominant strategy of only investing in the cheaper technology is used.

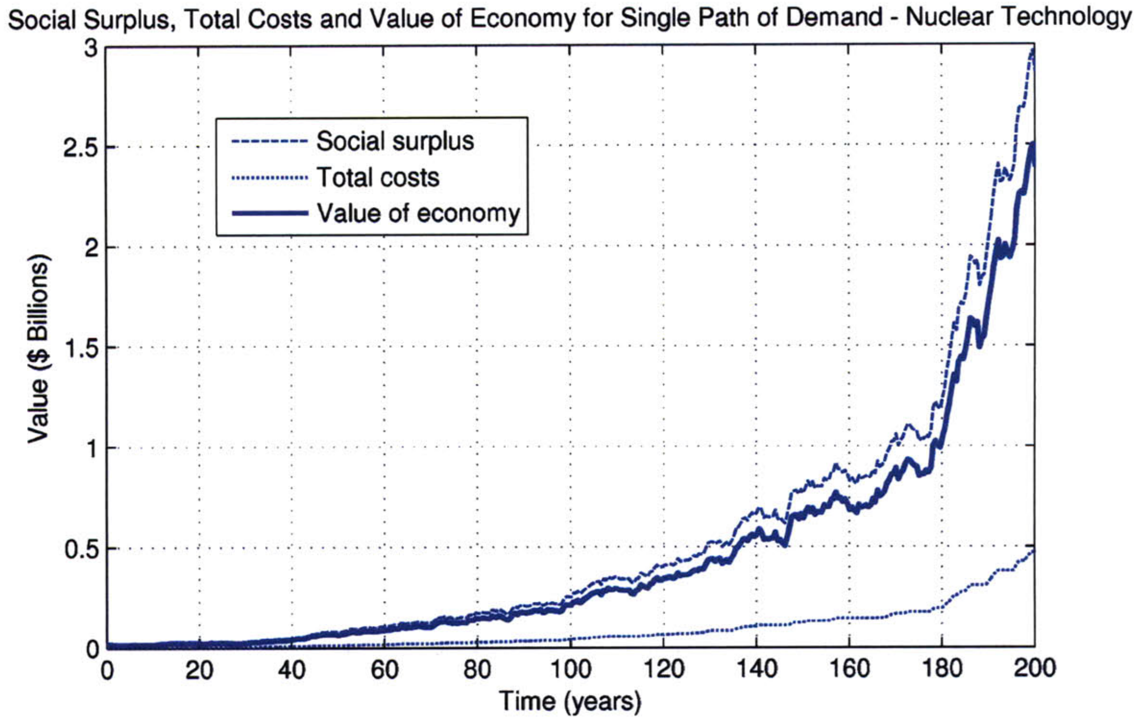


Figure 23. **Representation of J_{nuc} for a Single Path of Demand**

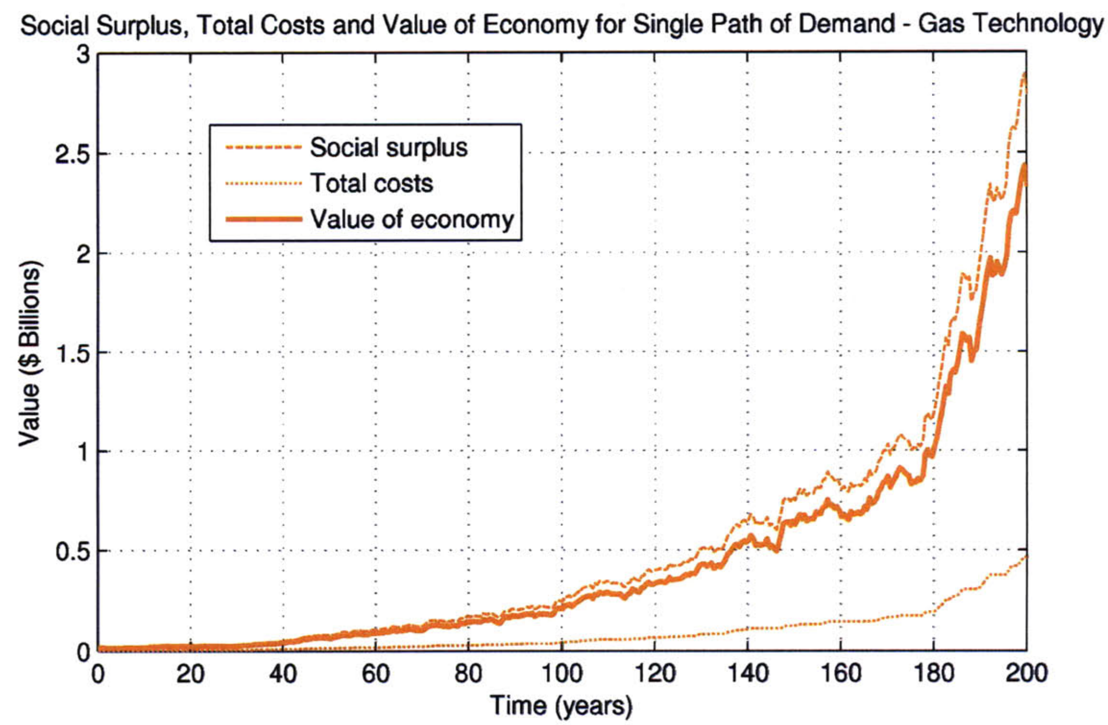


Figure 24. **Representation of J_{gas} for a Single Path of Demand**

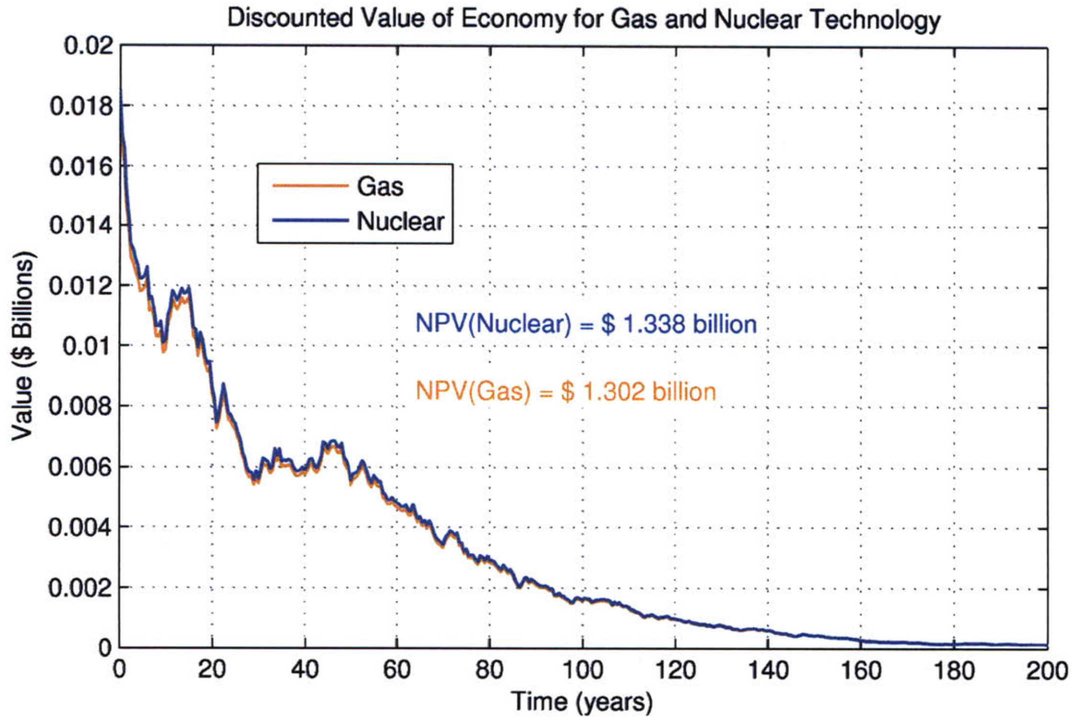
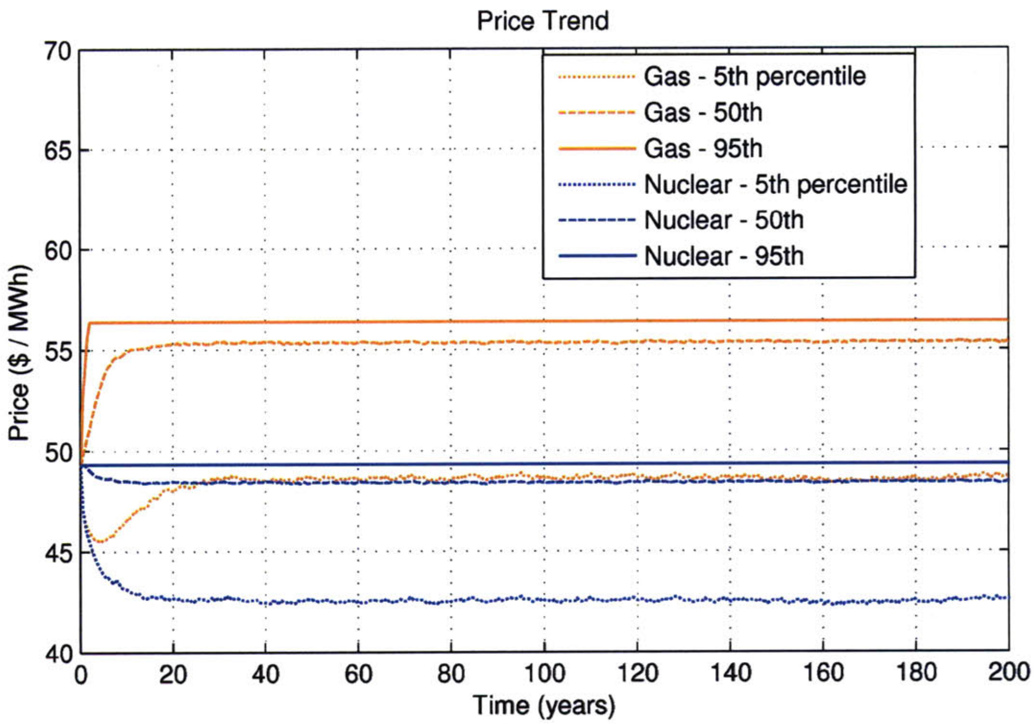


Figure 25. Comparison of Discounted Value of J_{nuc} and J_{gas}

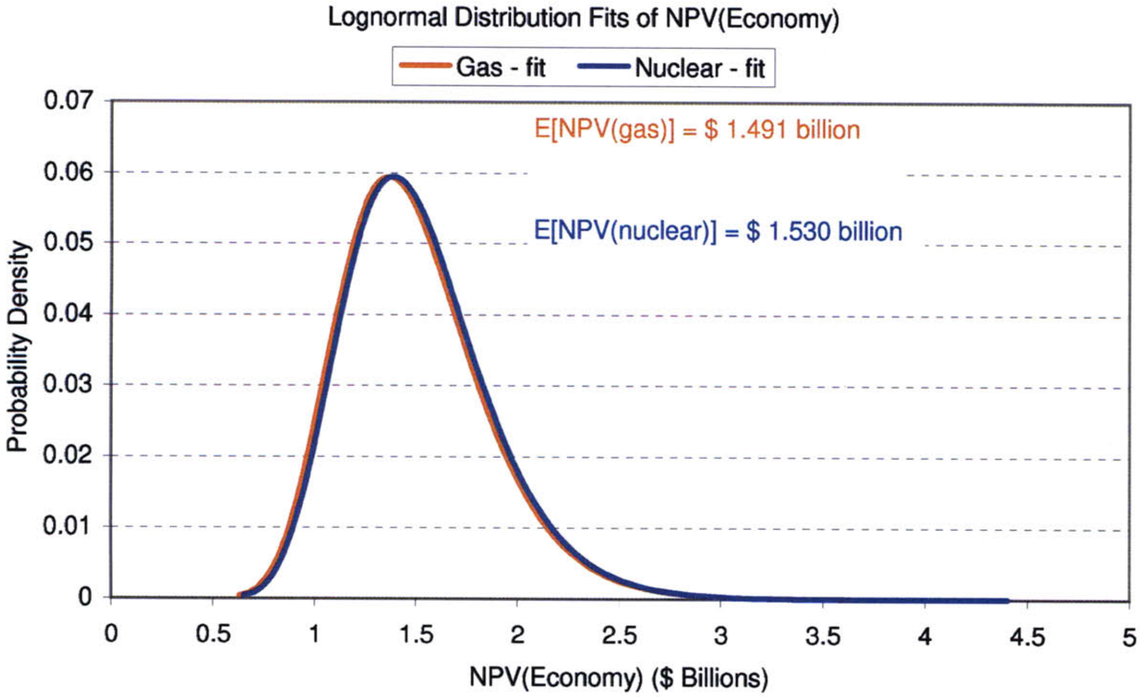
The results that have been compared hitherto are those realized for a single random path of demand. As such, they do not provide a representative view of the range of outcomes in the face of uncertainty. A probabilistic assessment of the effects of the strategy is obtained by looking at the prices, capacity and value of the economy across all possible outcomes of the Monte Carlo simulation (10,000 possible paths of demand). The objective is to assess whether the dominant strategy still holds in the face of uncertainty, i.e. in a probabilistic setting.

Different percentile values of prices over the duration of the study indicate that the price process quickly reaches steady state for both technologies. The main implication is that the results are not very sensitive to the initial conditions in the economy. Prices are always higher for the more expensive technology at a given percentile value, as shown in Figure 26. The trends also reflect the price trigger as the upper bound for prices, with the steady state 50th percentile values being very close to price trigger for both technologies. In the absence of the price trigger decision rule, the 95th percentile of prices may have been much higher. Thus, the instantaneous capacity addition process reveals a price suppression effect.



	Mean Steady State Price ($ / MWh)		Time to 1st Capacity Addition (years)		Approximate Time to Steady State (years)	
	Gas	Nuclear	Gas	Nuclear	Gas	Nuclear
p(5)	48.62	42.54	22.5	5.5	28.5	24
p(50)	55.34	48.43	7.5	0.5	22.5	13.5
p(95)	56.37	49.33	2	0.5	2	0.5

Figure 26. Percentile Values of Prices in One Technology Cases



	Log Likelihood	Mean	Variance	Mu	Sigma
Gas	-3545.34	1.46455	0.12999	0.35213	0.24257
Nuclear	-3807.51	1.50435	0.13697	0.37898	0.24241

Figure 27. Comparison of NPV Distributions in the Monte Carlo Simulation

The distribution of NPVs across the 10,000 paths of the simulation indicate that the economy is more valuable for nuclear, the cheaper technology, in terms of expected value. Figure 27 depicts the lognormal distribution fit for the two technologies, with the fit for nuclear slightly shifted to the right of the fit for gas. For the assumed cost values however, the shift is not very large.

The results described in this section suggest that in the absence of competition, the dominant strategy is to invest in the cheaper technology, given that the two technologies differ only in costs. The subsequent sections will first explore the effects of allowing the technology to differ in one other characteristic, viz. time-to-build, and then of introducing competition.

6.2 One Technology with Time-to-Build

To understand the effect of differentiating between technologies in another parameter, time-to-build (TTB) is introduced for nuclear, the low cost technology. TTB is assumed to be $\delta = 4$ years. The TTB implies that when price exceeds the price trigger, nuclear capacity is committed but is not immediately active. It comes online and produces electricity 4 years after being committed. Thus, although the nuclear technology is cheaper, it now has a disadvantage in that it cannot meet the demand for electricity instantaneously, whereas gas capacity can enter and is immediately active as before. The purpose of this section is to identify the impact of the TTB disadvantage on the value of the economy, compared to the case where neither technology had a TTB. It is plausible that the effect of TTB erodes the dominance of the strategy of only investing in the cheaper technology.

In the case of TTB, the firm will invest only if $e^{-r\delta} E\left[p_{t+\delta}\right] = P^*$, as discussed while developing the solution of Grenadier (2000). The price trigger obtained from the Leahy (1993) solution can no longer be used as a decision rule, because the firm has no way of calculating $E\left[p_{t+\delta}\right]$. The trigger is therefore expressed in terms of demand as X^*, and committed capacity is factored in while deciding whether to invest.

The delayed activation of nuclear capacity is shown in Figure 28. Capacity committed at time t, $Q_t = q_{t+4}$, the current capacity at time $t+4$. That is, capacity comes online after a lag of exactly 4 years. This time lag is factored in to the investment decision, and produces the effect of reducing the total amount of nuclear capacity. Q_{n,TTB_t} is always lower than Q_{n_t}. The general effect of TTB is that the firm will now withhold investment at some times when it would have other wise have invested in the scenario without TTB. Except in a few instances, Q_{g_t} is also higher than Q_{n,TTB_t}, indicating that there are times when gas could be meeting demand, as shown in Figure 29.

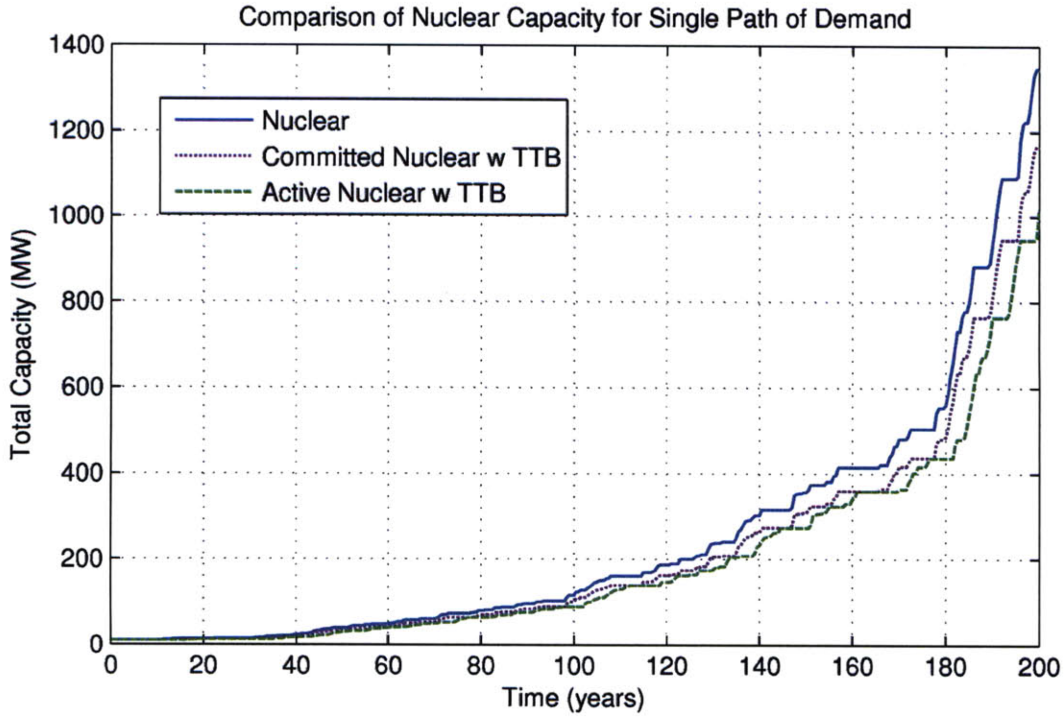


Figure 28. Comparison of Nuclear Capacity without and with TTB

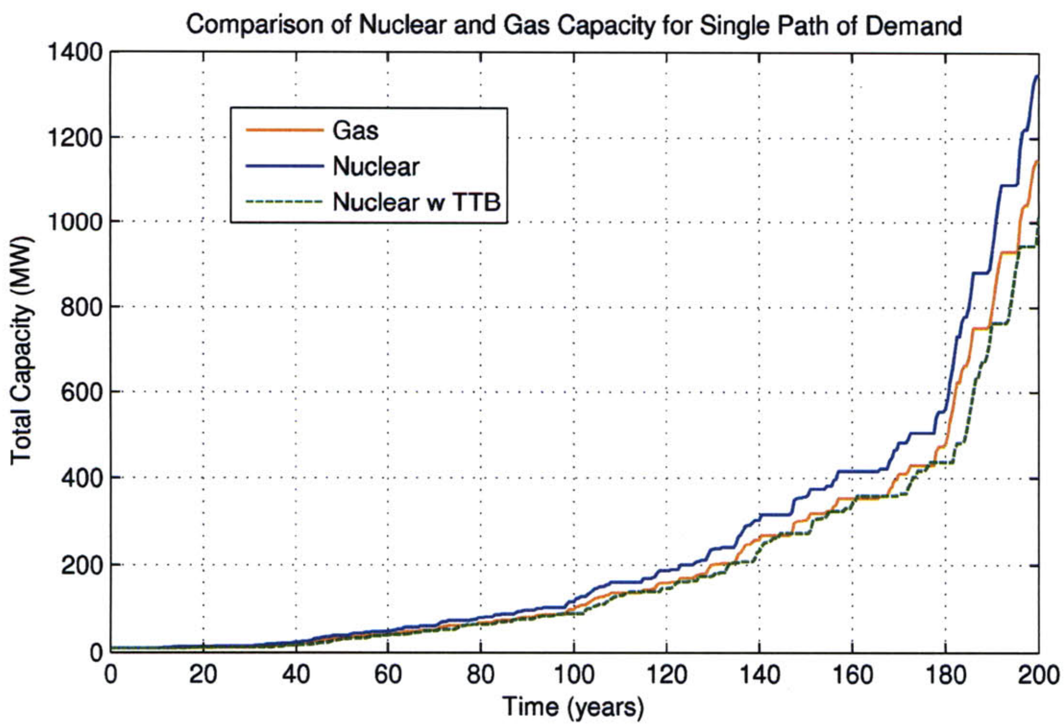


Figure 29. Comparison of Gas, Nuclear, and Nuclear with TTB Capacities

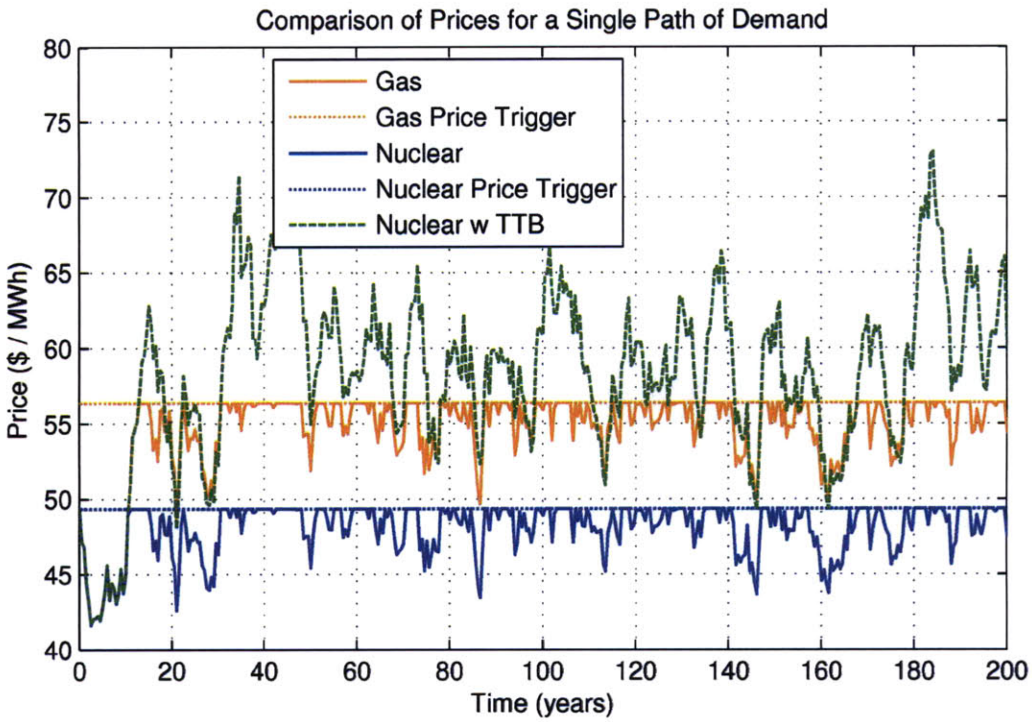


Figure 30. Comparison of Prices, including the case of Nuclear with TTB

As capacity is not activated instantaneously, the price is not capped at the trigger value; it continues to evolve with X. Price is brought down as and when capacity under construction comes online, as depicted in Figure 30. For the assumed values of cost and TTB, P_{n,TTB_t} is always higher than P_{n_t}. There are times when P_{n,TTB_t} falls below P_{g_t}; active nuclear capacity q_{n,TTB_t} is higher than gas capacity q_g at those times.

The value of the economy in the case of nuclear with TTB, J_{n,TTB_t}, is always equal to or lower than in the case without TTB, J_{n_t} , as show in Figure 31. However, J_{n,TTB_t} is sometimes lower than J_{g_t} indicating that investing in gas is a better strategy at those times (years 33 -35 and 44 – 48 in Figure 31). $NPV\left(J_{n,TTB_t}\right)$ is found to be lower than $NPV\left(J_{n_t}\right)$, but higher than $NPV\left(J_{g_t}\right)$.

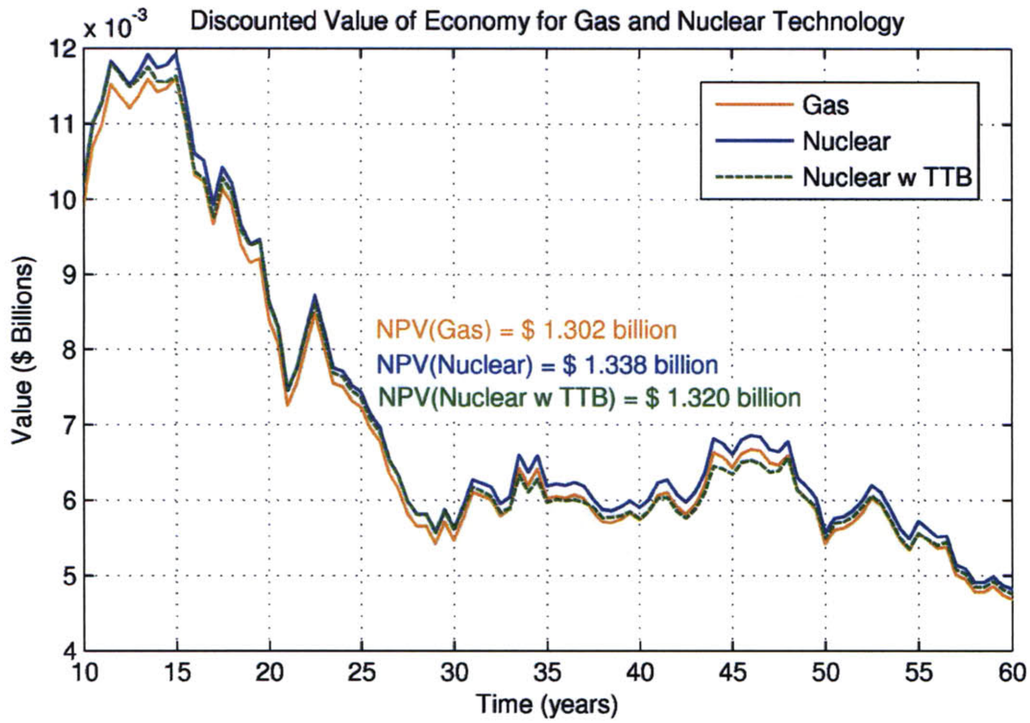
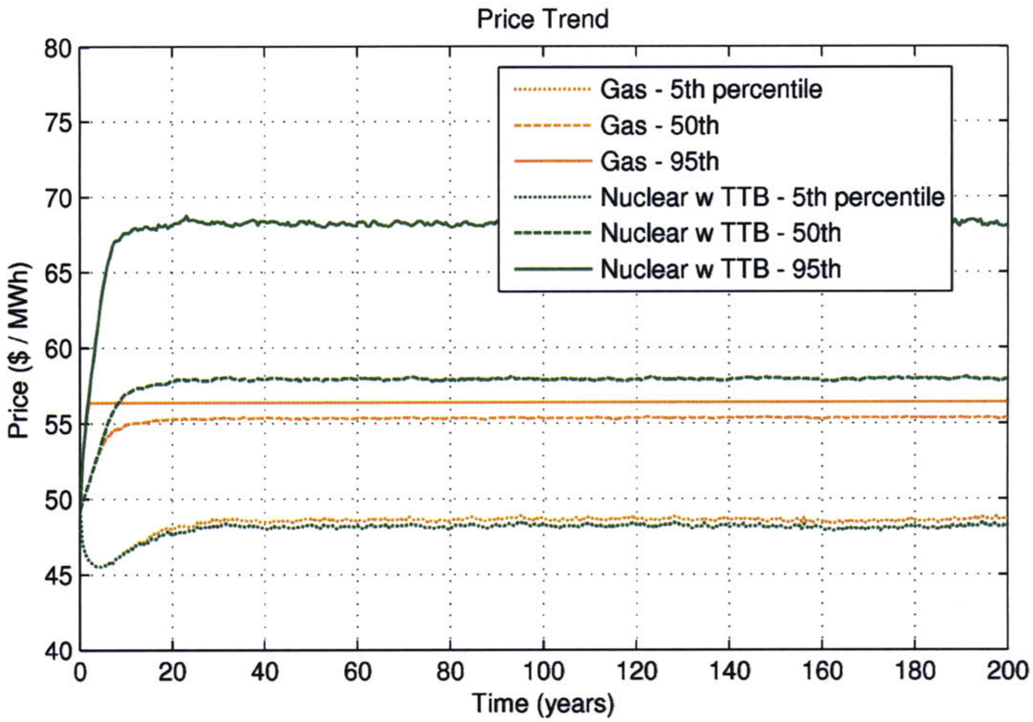


Figure 31. Discounted value of the economy J_{n_t}, J_{g_t} and J_{n,TTB_t}, Years 10 - 60

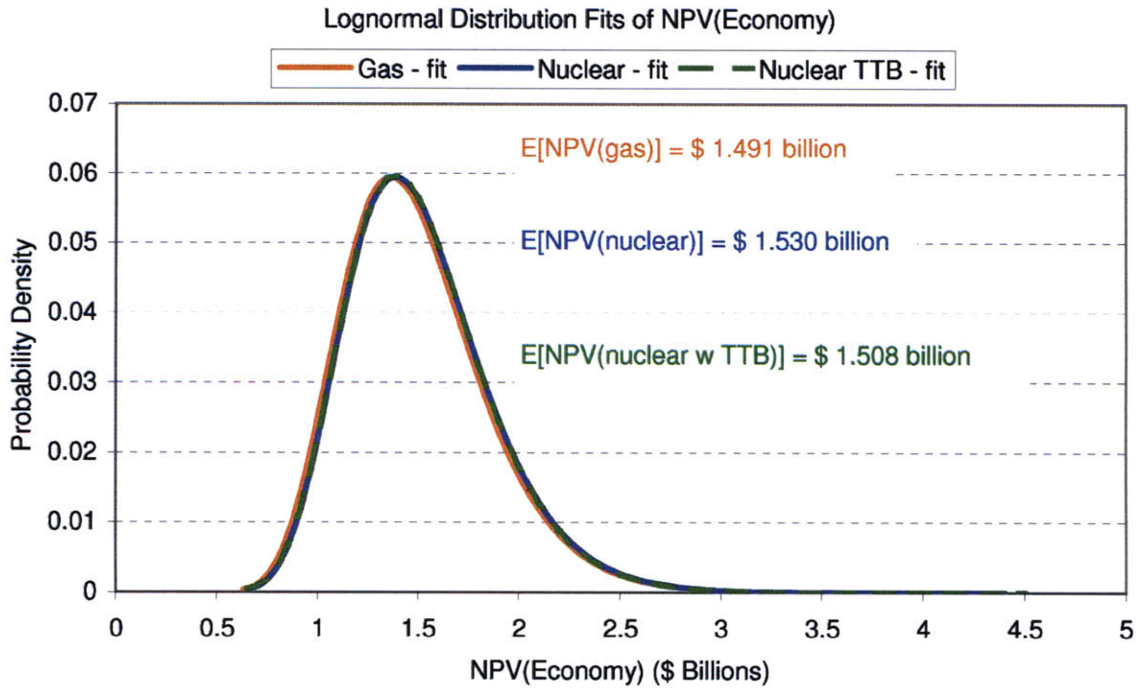
In a probabilistic assessment using the full Monte Carlo simulation, percentile values of P_{n,TTB_t} are always found to be much higher than P_{n_t}, because price is no longer effectively capped at the trigger value for nuclear with TTB. P_{n,TTB_t} is also higher than P_{g_t}, except for low percentile values where they are comparable. The steady state characteristic of prices is observed, similar to the case without TTB (Figure 32). The high steady state 95th percentile values for P_{n,TTB_t} suggest that there are instances when demand is high, but nuclear capacity that was previously committed is still under construction, leading to price spikes until new capacity becomes active. As a result, investment in new capacity is withheld and demand is not served at such times. It is possible gas capacity can serve high demand in these instances and bring down the price of electricity. The value of the economy would thereby increase, because of the surplus gains of meeting the high demand for electricity.



	Mean Steady State Price ($ / MWh)			Time to 1st Capacity Addition (years)			Approximate Time to Steady State (years)		
	Gas	Nuclear	Nuclear w TTB	Gas	Nuclear	Nuclear w TTB	Gas	Nuclear	Nuclear w TTB
p(5)	48.62	42.54	48.18	22.5	5.5	21	28.5	24	29.5
p(50)	55.34	48.43	57.92	7.5	0.5	6	22.5	13.5	24
p(95)	56.37	49.33	68.18	2	0.5	2	2	0.5	20.5

Figure 32. Comparison of Percentiles Values of Prices for One Technology Gas and Nuclear with TTB

Investing in nuclear with TTB is probabilistically still more valuable than investing in gas, as shown in Figure 33. The distribution fits for NPV values of the economy for the three technologies shows that the fit for $NPV\left(J_{n,TTB_t}\right)$ is shifted to the right of that of $NPV\left(J_{g_t}\right)$ and significantly overlaps the fit for $NPV\left(J_{n_t}\right)$. Again, the shift is small but measurable.



	Log Likelihood	Mean	Variance	Mu	Sigma
Gas	-3545.34	1.46455	0.12999	0.35213	0.24257
Nuclear	-3807.51	1.50435	0.13697	0.37898	0.24241
Nuclear w TTB	-3499.15	1.48196	0.12840	0.36496	0.23837

Figure 33. Comparison of NPV Distribution in the Monte Carlo Simulation

In terms of expected values, $E\left[NPV\left(J_{n,TTB_t}\right)\right]$ is higher than $E\left[NPV\left(J_{g_t}\right)\right]$, but lower than $E\left[NPV\left(J_{n_t}\right)\right]$. Thus, investing in the cheaper technology is expected to be more profitable, for the assumed value of time-to-build.

It could be argued that these results hold only for the assumed value of TTB = 4 years. To understand if the observations above apply more generally, the simulation was executed for varying values of TTB from 0 to 10 years. In terms of expected value, nuclear with TTB is always less valuable than nuclear without TTB, as shown in Table 7. However, gas is better than nuclear with TTB for very high values of TTB. Thus, determining whether investing in nuclear is the dominant strategy depends on how long the construction of nuclear capacity is expected to take. The attractiveness of nuclear as the cheaper technology decreases as its time-to-build increases.

Table 7. Expected NPV(J) of Nuclear w TTB for Varying TTB

	E[NPV(J)] ($ billions)					
Time to Build (TTB) (years)	0	2	4	6	8	10
Gas	1,491	-	-	-	-	-
Nuclear	1,530	-	-	-	-	-
Nuclear w TTB	1,530	1,519	1,508	1,498	1,489	1,481

The main point here is that although investing in the cheaper technology with TTB does not make the economy as valuable as in the case without TTB, the economy is still better off than investing in the more expensive technology for many values of TTB. However, there are certain realizations of demand and values of TTB when investing in the more expensive technology may in fact be better than investing in the cheaper technology with TTB. As a result, it is not clear that investing in the cheaper technology with TTB is the dominant strategy in the face of uncertainty.

The analysis in this section explores the effect of TTB and shows that TTB undermines the dominance of the cheaper technology. However, the results of the simulation would be more realistic if the two technologies were allowed to compete against each other. In a scenario of nuclear and gas competition, the value of allowing a firm to invest in gas at times when demand is very high and nuclear capacity is under construction could be studied.

6.3 Two Technology Model

In the previous section, the dominance of the cheaper technology in the absence of time-to-build and competition was demonstrated. In this section, the effect of competition is studied. The main general result is the value of the economy is reduced when the high cost, no TTB technology is introduced in an economy that ordinarily invests in a low cost technology with time-to-build. The outcome is a result of the fact that firms investing in both types of technologies each pursue their respective dominant strategies at all times, which is sub-optimal.

In a 'world' with competition, firms of both types simultaneously observe stochastic demand and the resulting prices. Firms can invest in their respective technologies at any point in time, as long as their respective decision rules are met. Gas firms use the same price trigger strategy as in the one technology case, i.e. they invest when price exceeds P_g *. The strategy for nuclear firms incorporates TTB. The main distinction between the one and two technology simulations is that firms observe total capacity across both technologies, and not just the capacities of the individual technologies. Because of TTB, firms will have to consider any capacity in the pipeline and its effect on prices upon becoming active, creating the issue of infinite dimensionality as described earlier. The issue is addressed in two ways – firms are "myopic" in one case and "observant" in the other. In the "myopic" case, firms are only allowed to observe the total active capacity. Any committed capacity that is under construction is therefore ignored. In the "observant" case, firms assume that any committed capacity is already active, irrespective of when it is expected to come online. The implication is that the value of the economy under competition is now bounded – the upper bound is derived from the observance case, while the lower bound is derived from the myopia case.

The first step in the two technology analysis is to verify that the results of the One Technology analysis hold when TTB = 0. As shown in Figure 34 and Figure 35, the prices and total capacity are identical to the nuclear case with TTB = 0. No gas capacity is added under the modified competitive decision rules, demonstrating that the cheaper nuclear technology dominates as expected. Thus, the two technology simulation reduces to the one technology case when TTB = 0. The one technology economies can therefore be thought of as special cases of the more general competitive two technology simulation with nuclear TTB greater than 0.

Next, a TTB of δ = 4 years is introduced for the nuclear technology. The effect on prices, capacity and the value of the economy for the Two Technology simulation is studied. For the rest of the discussion, $\phi = 0$ denotes the case where committed capacity is ignored in the decision rule, whereas $\phi = 1$ denotes the case where it is included.

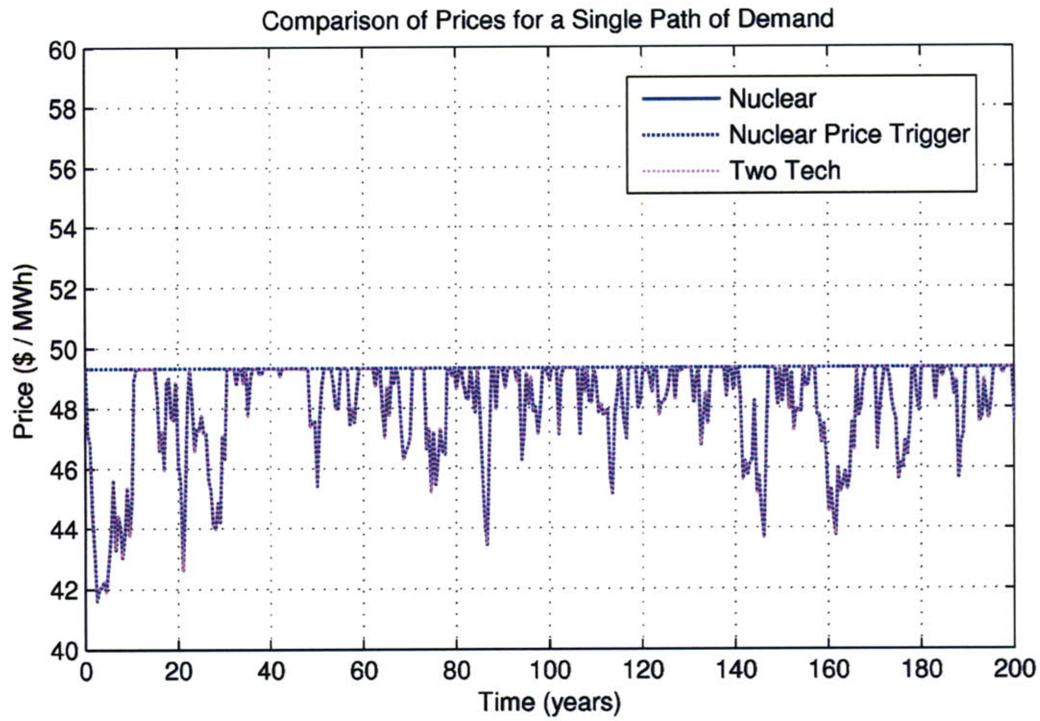


Figure 34. Comparison of Prices for One and Two Technology Cases w TTB=0

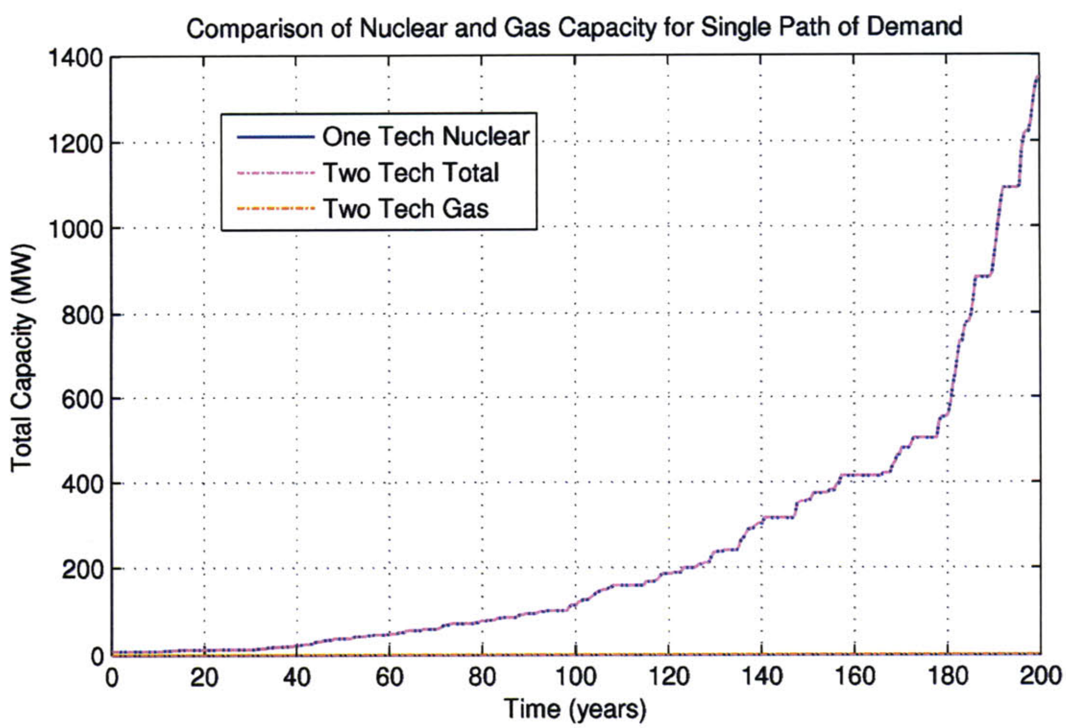


Figure 35. Comparison of Capacity for One and Two Technology Cases w TTB=0

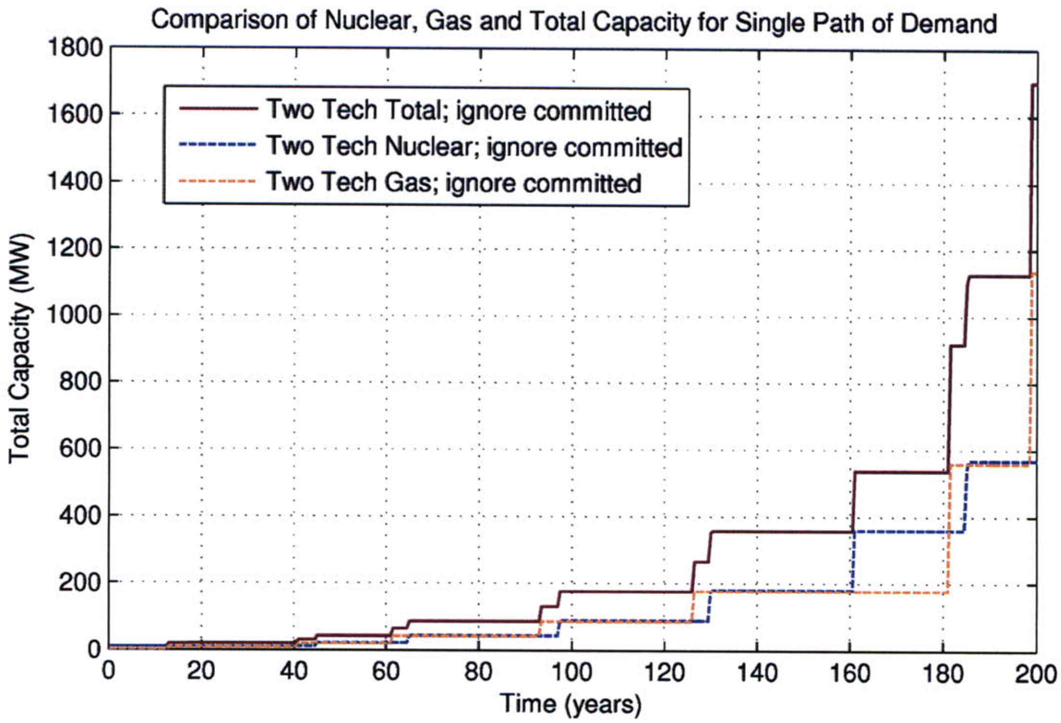


Figure 36. Nuclear, Gas and Total Capacity in Two Technology Case, $\phi = 0$

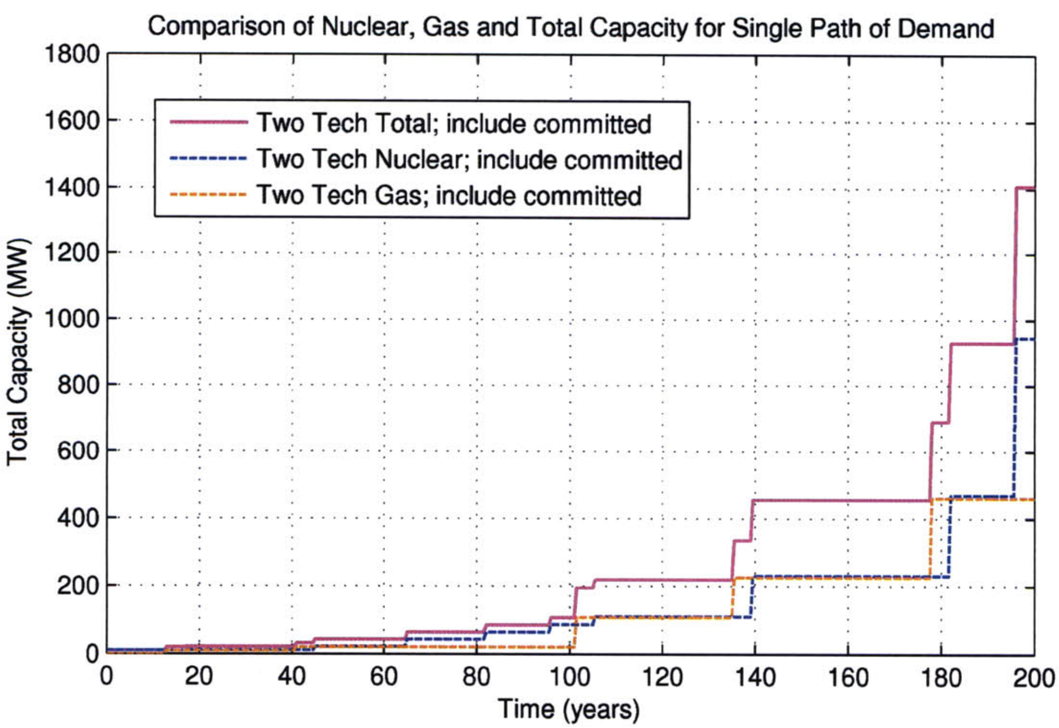


Figure 37. Nuclear, Gas and Total Capacity in Two Technology Case, $\phi = 1$

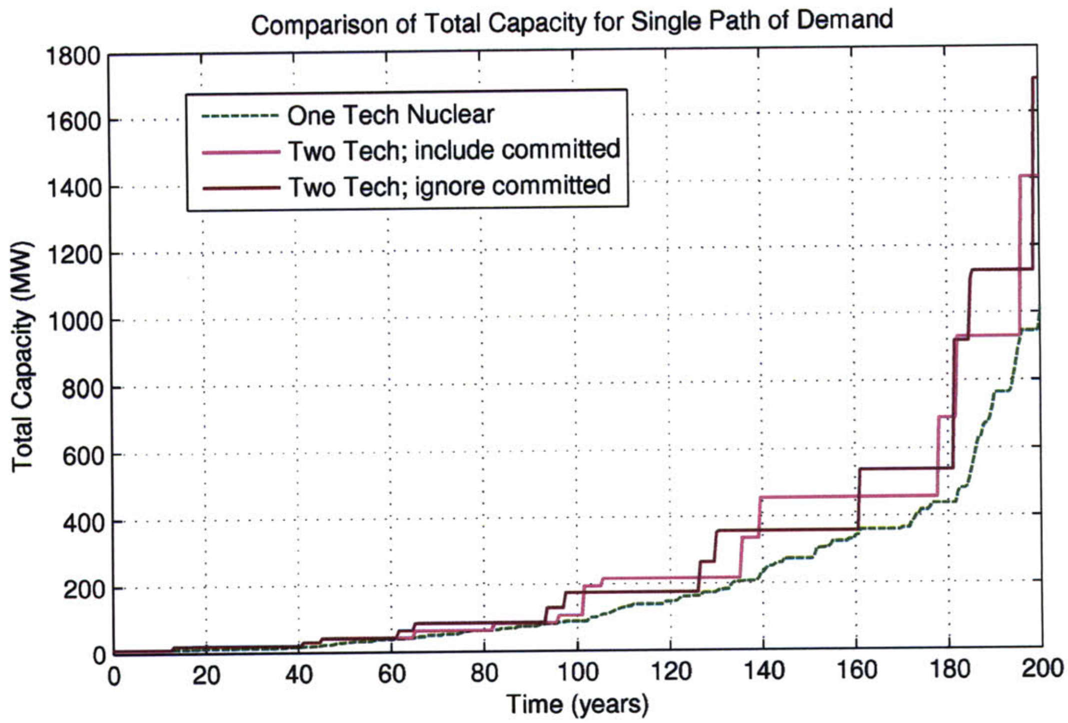


Figure 38. Comparison of Total Capacity in Nuclear w TTB and Two Technology Cases

Ignoring committed capacity results in overinvestment, as is expected. Figure 36 and Figure 37 depict capacity values observed for the two cases respectively. $Q_{n_t}\big|_{\phi=0}$ and $Q_{g_t}\big|_{\phi=0}$ are higher than $Q_{n_t}\big|_{\phi=1}$ and $Q_{g_t}\big|_{\phi=1}$, leading to a higher value for $Q_t\big|_{\phi=0}$ than for $Q_t\big|_{\phi=1}$. Figure 38 compares total capacities in the two simulations. Q_{n,TTB_t} is always found to be the lowest, while $Q_t\big|_{\phi=0}$ is the highest. There are times when $Q_t\big|_{\phi=1}$ is very close or equal to Q_{n,TTB_t} and other times when $Q_t\big|_{\phi=1}$ is higher, typically after a large amount of gas capacity is added. During the latter, it might be possible to withhold gas capacity even further to ensure that total capacity is lower and closer to Q_{n,TTB_t}.

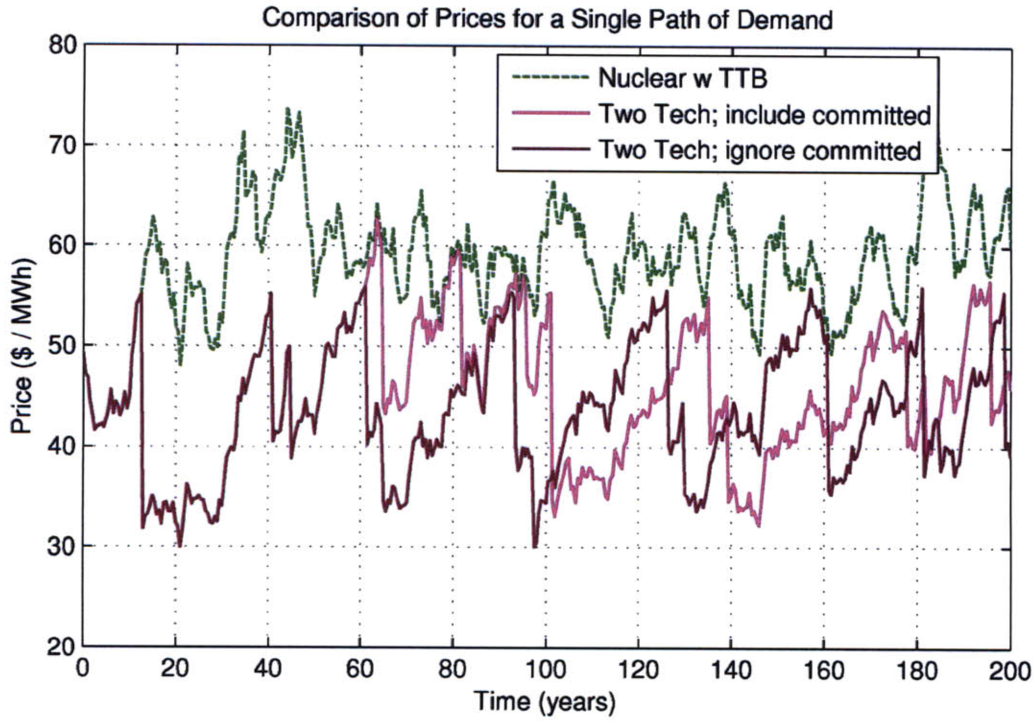


Figure 39. Price Comparison for Nuclear w TTB and Two Technology Cases

The observations for the addition of capacity are also reflected in the price processes. Figure 39 compares prices in the two cases of the Two Technology simulation, $P_t\big|_{\phi=0}$ and $P_t\big|_{\phi=1}$ with the earlier One Technology with TTB, P_{n,TTB_t}. The value of P_{n,TTB_t} is always observed to be highest. When committed capacity is included, $P_t\big|_{\phi=1}$ sometimes rises to the level of P_{n,TTB_t}, because investment in gas is withheld (around years 63-65 and 78-82 in Figure 39). Values of $P_t\big|_{\phi=0}$ fall to the lowest levels, because investment in gas is not withheld, thereby leading to overinvestment.

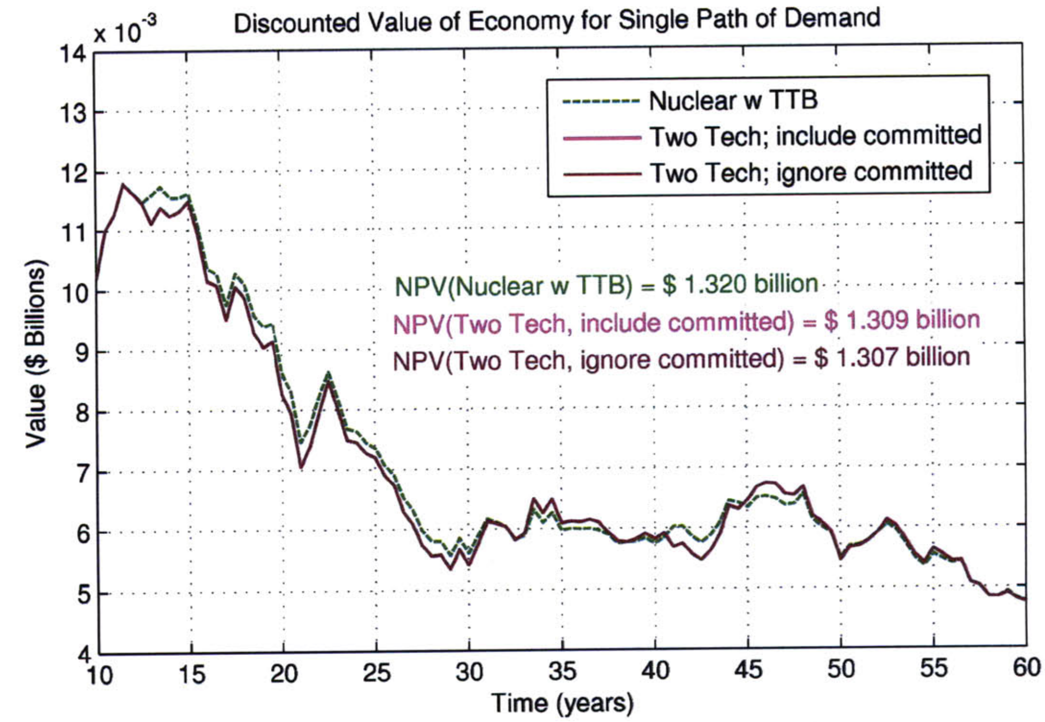
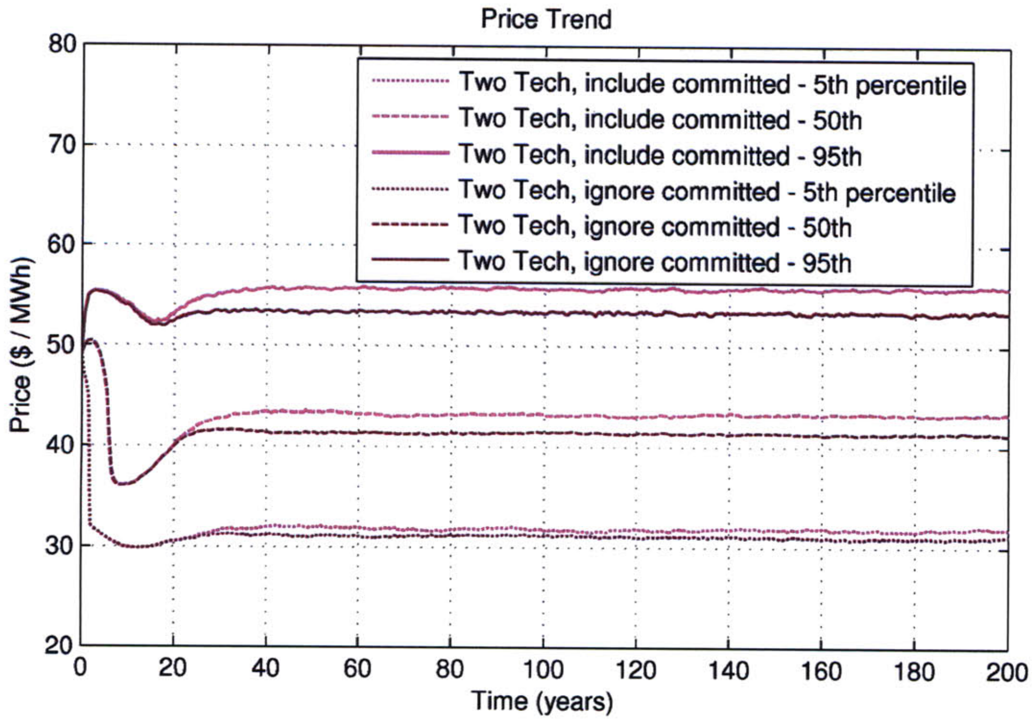


Figure 40. **Discounted value of J for One Technology w TTB and Two Technology Cases**

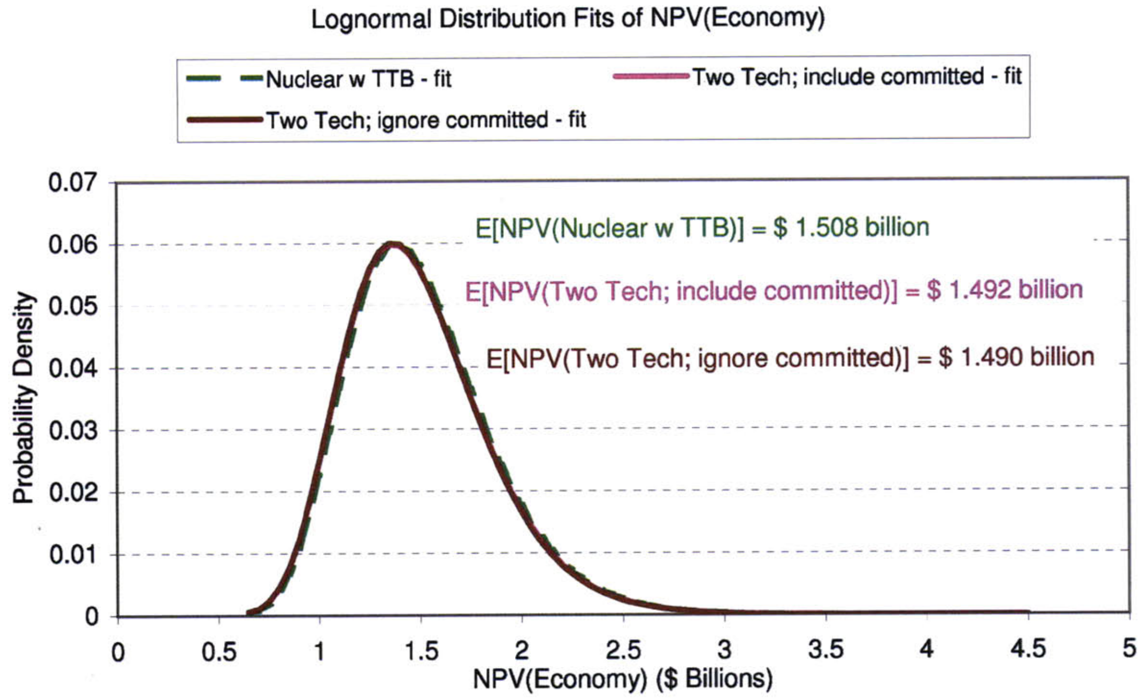
Investment in gas capacity in the competitive Two Technology simulation reduces the value of the economy, i.e. $NPV\left(J_{n,TTB_t}\right)$ is higher than $NPV\left(J_t \middle| \phi=0\right)$ or $NPV\left(J_t \middle| \phi=1\right)$. However, there are times when $J_t|\phi=1$ is higher than J_{n,TTB_t} because gas capacity enters immediately to meet high demand (years 33-35 and 44-48 in Figure 40). This is expected based on the results of the One Technology simulation.



	Mean Steady State Price ($ / MWh)			Time to 1st Capacity Addition (years)			Approximate Time to Steady State (years)		
	Nuclear w TTB	Two Tech, include committed	Two Tech, ignore committed	Nuclear w TTB	Two Tech, include committed	Two Tech, ignore committed	Nuclear w TTB	Two Tech, include committed	Two Tech, ignore committed
p(5)	48.18	31.78	31.04	21	21.5	22	29.5	30.5	26.5
p(50)	57.92	43.10	41.31	6	6.5	6.5	24	33	25
p(95)	68.18	55.62	55.34	2	2	2	20.5	35.5	3

Figure 41. Comparison of Percentiles Values of Prices in Two Technology Cases

The results obtained for the single path of demand in the illustrations above also hold for the Monte Carlo assessment. Figure 41 compares percentile values of prices for the Two Technology simulations. For every percentile comparison, P_{n,TTB_t} is higher than $P_t\big|_{\phi=1}$, and $P_t\big|_{\phi=0}$, the case with the lowest prices. Prices reach steady state early in the course of the study, indicating that the investment strategy results in a competitive equilibrium.



	Log Likelihood	Mean	Variance	Mu	Sigma
One Tech Nuclear	-3499.15	1.48196	0.12840	0.36496	0.23837
Two Tech; include committed	-3471.30	1.46601	0.12788	0.35365	0.24041
Two Tech; ignore committed	-3447.42	1.46402	0.12724	0.35235	0.24015

Figure 42. Comparison of NPV Distribution for One Tech with TTB and Two Tech Cases in the Monte Carlo Simulation

Two Technology competition reduces the value of the economy. As shown in Figure 42, the distribution for $NPV\left(J_{n,TTB_t}\right)$ is shifted slightly to the right of the distributions for $NPV\left(J_t|\phi=0\right)$ and $NPV\left(J_t|\phi=1\right)$, which overlap significantly. $E\left[NPV\left(J_t|\phi=0\right)\right]$ and $E\left[NPV\left(J_t|\phi=1\right)\right]$ for the Two Technology cases are almost identical. This suggests that the 'myopic' strategy (phi=0) makes the economy only slightly worse off than the 'observant' strategy on an expected value basis. If firms are neither completely myopic nor completely observant, i.e. $\phi = (0,1)$, the value of the economy will lie within the range $NPV\left(J_t \middle| \phi = 0\right)$ and $NPV\left(J_t \middle| \phi = 1\right)$. Since the range is quite small, the lack of 'observance' of committed capacity appears to be insignificant for the assumed values of costs and TTB.

A comparison of the expected values of the economy finally gives some indication of the available economic gain. This number is the difference between $E\left[NPV\left(J_{n,TTB_t}\right)\right]$ and $E\left[NPV\left(J_t \middle| \phi = 0\right)\right]$ or $E\left[NPV\left(J_t \middle| \phi = 1\right)\right]$. For the particular cost and time-to-build values, the available gain is \$ 16 – 18 million, which is approximately 1% of the value of the economy. It has already been established that this value difference is attributable to competition between the two types of technology. Thus, upto 1% of the value of the economy is available to be gained in a non-zero sum fashion, by being selective about the technology chosen for investment.

Of course, the results are dependent on the assumed cost values and TTB selected. To understand whether the results hold for other values of cost and TTB, a sensitivity analysis was conducted by varying TTB for different values of gas technology cost. The range of costs includes values that are much lower as well as much higher than the cost of nuclear. The results are summarized in Table 8.

In general, $E\left[NPV\left(J_t \middle| \phi = 0 \text{ or } 1\right)\right]$ first decreases and then increases as gas becomes more expensive for a given value of TTB. $E\left[NPV\left(J_t \middle| \phi = 0 \text{ or } 1\right)\right]$ also first decreases and then increases as TTB becomes larger for a given value of gas costs. The most useful comparison is between $E\left[NPV\left(J_t \middle| \phi = 0 \text{ or } 1\right)\right]$ for a given value of TTB and the corresponding $E\left[NPV\left(J_{n,TTB_t}\right)\right]$. As the costs for gas increase, the value reduction due to myopia also increases, until nuclear starts to dominate again.

When gas is cheaper than nuclear, the gas technology dominates irrespective of the value of TTB for nuclear, as expected. When gas is significantly more expensive than nuclear, nuclear dominates and $E\left[NPV\left(J_t|\phi=1\right)\right]$ is identical to the One Technology nuclear with TTB case. For very low and very high values of gas costs ($ 0.25, 0.30 and 0.50 millions/MW/year), the dominant strategy of investing in the cheaper technology holds true. The results are not so straightforward when the costs of gas are the same or slightly higher as the costs for nuclear ($ 0.35, 0.40 and 0.45 millions/MW/year).

Table 8. Expected NPV(J) for Varying Costs and TTB in Two Technology Competition

		E[NPV(J)] ($ Billions)					
Nuclear TTB (years)		0	2	4	6	8	10
One Technology Nuclear w TTB		1,530	1,519	1,508	1,498	1,489	1,481
Annual Gas Costs ($ millions/MW)							
0.25	phi = 0	1,585	1,585	1,585	1,585	1,585	1,585
	phi = 1	1,585	1,585	1,585	1,585	1,585	1,585
0.30	phi = 0	1,546	1,546	1,546	1,546	1,546	1,546
	phi = 1	1,546	1,546	1,546	1,546	1,546	1,546
0.35	phi = 0	-	1,510	1,515	1,516	1,516	1,516
	phi = 1	-	1,515	1,517	1,517	1,517	1,517
0.40	phi = 0	1,530	1,492	1,490	1,493	1,498	1,499
	phi = 1	1,530	1,507	1,492	1,497	1,500	1,500
0.45	phi = 0	1,530	1,498	1,483	1,479	1,479	1,484
	phi = 1	1,530	1,519	1,508	1,491	1,481	1,485
0.50	phi = 0	1,530	1,514	1,486	1,475	1,472	1,471
	phi = 1	1,530	1,519	1,508	1,498	1,489	1,481

(green) = optimal competitive outcome
(yellow) = sub-optimal competitive outcome

For certain values of gas costs and TTB, Two Technology competition gives a higher value of the economy than in the One Technology w TTB case (highlighted in green). These situations arise when the cost of gas technology is the same or slightly higher than that of nuclear and TTB is high enough to create significant disadvantage for nuclear. As a result, TTB heavily influences the investment strategy such that firms avoid nuclear and invest in gas. Demand is met immediately by new gas capacity and this increases the value of the economy. Competition thus results in the optimal outcome.

There are instances when $E\left[NPV\left(J_t \middle| \phi = 0 \text{ or } 1\right)\right]$ is lower than $E\left[NPV\left(J_{n,TTB_t}\right)\right]$. A combination of slightly different technology costs, TTB and myopia act together to create a disadvantage for nuclear such that it is not the preferred technology (highlighted in yellow). Firms default to their individually optimal strategy of investing in gas, but competition reduces the value of the economy. The maximum reduction in value is \$ 27 million, or slightly less than 2% of the value of the economy. This situation is observed under the assumptions of gas costs of \$ 0.40 million/MW/year, complete myopia and a TTB = 2 years. Firms investing in a world where these assumptions hold may benefit from altering their investment strategy.

The states of the world highlighted in yellow can be thought of as relationship-specific circumstances where firms could attempt to achieve the optimal outcome that would have been observed in the absence of competition. If in such situations, firms could withhold investment in gas or choose to invest in nuclear technology with a small value of TTB instead of more expensive gas capacity, the value of the economy could increase. Such situations could merit a long-term contract, where firms have the necessary commitment to avoid their dominant strategy and the economy obtains a more favorable outcome. To justify this, firms first have to identify that they are in fact in a relationship-specific situation, i.e. that they are in a state of the world where the usual investment will not result in the optimal outcome. The policy that considers the use of the long-term contract in these situations should also be careful to ensure that a "green" state is not being observed where the market outcome would in fact be the optimal outcome.

To summarize, an analysis of the simulation results has demonstrated that competition between two technologies under conditions of uncertainty often results in the individually and socially optimal outcome. This depends on the state of the world that is observed. However, there are some states of the world where competition reduces the value of the economy. Based on the range of assumptions, this value is found to be on the order of 1 – 2% for the hypothetical economy simulated. This lost value is available to be regained in a non-zero sum way by altering the investment strategy. The next chapter will synthesize these findings in the context of the literature discussed earlier and in conclusion will offer some recommendations for the policy issue under consideration.

Chapter 7 Synthesis and Conclusions

This chapter will summarize the lessons learned in the course of the analysis. It will reflect on the original thesis question in light of the prior understanding of long-term contracts, issues in financing and procurement, and the findings of the model. The central message for policy is that long-term contracts have the potential for adding value to the economy in non-zero sum situations by avoiding ex post opportunism. If they are used indiscriminately or as a device for offering subsidies, they can result in significant economic distortions. Policy should therefore consider the selective use of long-term contracts.

7.1 Re-statement of the Thesis Question

The thesis began with a description of the debate between project developers, distribution utilities, regulatory agencies and others on the role of long-term contracts for new investments in power generation. The analysis was motivated by the fact that long-term contracts presented some up side opportunities, but also raised the specter of significant downside risks. Concern was expressed about the fact that some fundamental questions were left unanswered, viz. are long-term power purchase agreements essential for securing adequate investments in generation capacity, renewable or otherwise, in the presence of functioning wholesale spot markets for generation? Will necessary investments in generation capacity not occur in the absence of such contracts? Will the resulting mix of generation technologies be undesirable in the long run? Are such contracts valuable in realizing some measurable economic gain? What do these contracts enable and should policymakers intervene and require their use? The analysis laid out here has provided some useful insights for answering these questions.

At the outset, this study posited that electricity policymakers should be concerned if long-term contracts are being used indiscriminately and present the possibility of significant economic losses because of ex post regret or opportunism. Policymakers should also be concerned if parties in relationship-specific situations are able to identify clear economic gains, but are unable to realize them because the existing framework of statutes and regulations does not support the use of long-term contracts. The main questions of interest for the formulation of a policy on long-term contracts were described as (1) whether parties encounter obstacles to their beneficial use and (2) in what situations should policy encourage or compel market entities to enter into such agreements? The hypothesis advanced was that long-term contracts should only be used when they allow contracting parties to secure measurable economic gains in relationship-specific circumstances. The gains must be identified and quantified before the decision to execute the contract can be made. The central question was therefore:

> "how can the gain available through the use of a long-term contract in a relationship-specific investment be identified?"

The analysis has revealed some obstacles to the beneficial use of long-term contracts. It has also demonstrated the use of an investment strategy model based on real options literature to identify and measure non-zero sum economic gains in a competitive market for electricity under conditions of demand uncertainty. After summarizing the lessons learned, conclusions are drawn to inform policymaking on the use of long-term contracts.

7.2 Lessons Learned

7.2.1 Relationship-specificity is the Foundation

Contract theory indicates that the length of the contract is heavily influenced by the relationship-specificity of the transactions between the contracting parties. Such transactions can be characterized by the specificity of the site of the investment, the design of the physical assets involved or the dedicated nature of the assets. Specific assets are beneficial because they generally lower the cost of production. The producer is therefore able to supply the customer with a product or service at a lower price. The gains from lower costs are available to be shared by both parties.

Extending this reasoning to the electricity industry suggests that power producers would sign a long-term contract with a customer if the investment was characterized by a high degree of one or more types of specificity. A distribution utility that wants to procure electricity for a significant fraction of its load at below market prices could look for a independent power producer that is willing to invest in a new base load plant to supply most or all of its output to the utility. The utility would then be able to obtain electricity at lower prices than usual and this would give it a reason to contract with the power producer so that the producer invests in the specific asset. Absent the specificity of the relationship, neither the power generator nor the customer has a compelling reason to sign a long-term contract. The choice of the contract assumes that the utility cannot invest in the plant itself and must look to another entity to make the investment.

The economic gain in the relationship is enabled by the fact that specific investments are undertaken because the product can be supplied on terms that are favorable to both the buyer and seller. If one or more specificities are important to a buyer-seller relationship, then the parties will rely less on repeated negotiations over time and tend to enter into longer-term commitments to avoid ex post haggling over the benefits of the contract. Both parties are able to agree to the terms ex ante, before any investments are undertaken. They are forced to decide how the risk of the contract will be shared between them and to formulate their respective performance incentives in advance.

Specificity also implies that the relationship is subject to the possibility of ex post opportunism. Even the most complex contracts are incomplete and a situation may later arise where the contract terms are unfavorable to one or both of the parties. By terminating or reneging on the contract, one of the parties could leave the other with stranded assets or high costs of procuring a substitute product in an imperfect market. In relationship specific-circumstances, many firms therefore choose to be vertically integrated with the entity with which they are transacting. By internalizing the relationship within the firm, they avoid the risk of ex post opportunism. Where vertical integration is not feasible, long-term contracts are the next best option. In restructured states however, vertical integration is no longer allowed, and distribution utilities are typically prohibited from owning generation. A long-term contract for investments in highly specific generation assets is therefore the solution that is most likely to bring the benefits of vertical integration in a restructured electricity industry.

7.2.2 Non-zero Sum Economic Gains can be Identified

The investment model demonstrates that firms in competitive markets follow their dominant strategies under conditions of uncertainty. In many cases, the dominant strategy results in an individually as well as socially optimal outcome. Some cases were identified where following the dominant strategy was not socially optimal and the value of the economy was reduced. The value reduction is attributed to competition between technologies under conditions of uncertainty. In the hypothetical world represented by the model, these cases present the opportunity where lost value can be regained by influencing the investment strategy.

The non-zero sum gain was identified only in certain states of the world, and was quite small as a share of the total value of the economy. The states of the world can be thought of as relationship-specific circumstances where firms could attempt to achieve the optimal outcome that would have been observed in the absence of competition. If in such situations, firms could be persuaded or required to alter their investment strategy, the value of the economy could increase. To justify altering the investment strategy, firms first have to identify that they are in fact in a relationship-specific situation, i.e. that they are in a state of the world where the usual investment will not result in the optimal outcome. This task can be left to firms because they are best able to make the business decisions. Any subsequent policy attempt to influence the strategy must also ensure that the economy is not in a state where the usual practice will result in the most favorable outcome.

7.2.3 Economic Gain is secured through Credible Commitments

Game theory suggests that contracts are often useful when an economic gain is available in a non-zero sum situation, but the opponents are ordinarily unable to secure it. In following their dominant strategy, opponents end up obtaining sub-optimal payoffs. To reach the state of higher payoffs, they have to commit to a non-dominant strategy. Transacting parties can use a long-term contract as a sign of credible commitment to the non–dominant strategies they have decided to follow. They assure each other that they will forego other attractive opportunities that may arise later, and include performance incentives in the terms of the contract to ensure fulfillment of the obligations. However, the parties do this because they know that the non-zero sum gain is available and they are looking for a credible way to realize it.

The economic benefits available to a power producer and customer that are made possible by an investment in a specific asset may be difficult to secure because power producers do not ordinarily invest in very specific assets, and customers do not ordinarily enter into long-term purchase agreements. In wholesale markets for electricity, which is a homogenous product, power producers and customers have many transacting parties to choose from and their transactions are not asset specific. Power producers follow a strategy of maximizing their revenues, and will invest in plants that allow them to do that. Recent evidence has shown that merchant power producers tend to invest in plants that are mostly likely to recover their costs from available market revenue sources, and these investments are limited to low overnight cost, high operating cost technologies that can quickly enter the market at times of high prices.

Wholesale customers and distribution utilities follow a cost minimizing strategy, and procure electricity from the lowest-cost producers. For the power producer to commit to investing in an asset that is beneficial to a particular customer but is risky and ordinarily decreases its ability to maximize revenues, the power producer needs long-term assurance of revenues from that customer. The customer must also be willing to forego other low cost procurement options that may become available in the future and commit to the decision of purchasing from the producer. Each party has a dominant strategy that will ordinarily be followed, unless a credible commitment is obtained to pursue a different strategy. The long-term contract can be used as a sign of this commitment, if clear economic gains in the non-zero sum situation have been identified.

7.3 Conclusions for Policy

Existing wholesale markets for generation call for many different types of generation investments such as base load plants, peaking units or ancillary service generators and offer power producers with a number of different revenue sources. In general, new plant investments in restructured markets are not relationship-specific assets. Their output can be supplied to a large number of customers, either through bilateral transactions or spot market sales. Many generators have undertaken investments without using long-term contracts, and long-term contracts do not appear to be "essential" for securing new investments in generation capacity.

Long-term contracts are desirable in cases where the investments are highly specific to the relationship. Because relationship-specificity is not a general feature of the industry, power producers or customers that find themselves in relationship-specific situations can identify the gain available through the use of specific assets and choose to use a long-term contract. However, this is a voluntary business decision and does not call for explicit policy guidance.

Contracts are inherently "incomplete" and create the possibility of ex post regret and stranded costs. The electricity industry in the U.S. is familiar with the potential for significant economic distortions as in the aftermath of long-term contracts for qualifying facilities pursuant to PURPA 1978. Utilities were locked into long-term contracts with price terms that were based on a very limited ability to forecast the future. Such contracts have provided certain types of power generators with the stable revenue streams that made it easier to secure financing, but at the expense of the regulated pass through of high costs to retail rates. As a policy mechanism, long-term contracts encouraged the development of cogeneration and small renewable generators by effectively providing them a subsidy, but subsequently resulted in distortions. Policymakers should avoid mandating their use, and be careful to disapprove contracts that present the risk of ex post regret.

Obstacles appear to exist for the beneficial selective use of long-term contracts. If transacting parties were to find themselves in a relationship specific situation and want to use a long-term contract, it is not clear that they would be able to do so. Rules for distribution utility procurement in restructured states explicitly prohibit or discourage long-term commitments. Exceptions to this observation are cases when the contracts have been signed with renewable generators. Policy makers should be concerned with why the option to sign a long-term contract is not available to all generators, especially if particular situations exhibit relationship specificity and the potential to realize non-zero sum gains. Current rules in restructured markets preclude the consideration of long-term contracts and make it unfeasible for the economy to benefit from relationship specific circumstances.

The hybrid regulatory model of basic service provided by traditional distribution utilities and competitive retail supply is not conducive for utilities to bear the risk of long-term contracts, because its ultimate customers are not required to share any of this risk. Although relevant to the use of long-term contracts, the issue of competitive retail supply needs holistic evaluation that is beyond the scope of this thesis. This issue is recommended as a topic for future work.

Finally, policies should encourage or require the selective use of long-term contracts only in relationship-specific situations where identified non-zero sum gains are not being realized under dominant practices. In cases where these gains are not observable or are insignificant, the long-term contracts are more likely to cause pain than gain.

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Appendix

A. MATLAB Code for Two Technology Model

```
% Define input variables

    paths   =   10000 ;              %number of sample paths in the simulation
    periods =   400 ;                %number of time periods in each path
    years   =   200  ;               %length of study (years)
    delta   =  years/periods;        %length of each period (in years, ex. 40
                                     years/100 periods = 0.4 years/period)
    time    =  [0:delta:years];

    r       =   0.05;      %risk free rate(%/year)
    mu      =   0.02;      %drift for Geometric Brownian Monte Carlo (%/year)
    sigma   =   0.0460;    %volatility for Geometric Brownian Monte Carlo
                                                                  (%/year)

    opcn      =   100;     %op cost  ($ thousands /MW/year)
    opcg      =   450;
    capcn     =   250;     %PV lifetime cap cost  ($ thousands /MW)
    capcg     =   50;

    Kg    =    (capcg+opcg)/r;   %present value of total cost ($ thousands/ MW)
    Kn    =    (capcn+opcn)/r;


    gamma    =   1.2;             %elasticity

    build_g    =   0;             %gas build time in years
    build_n    =   4;             %nuclear build time in years

    x_init = 2500;        %initial value of exogenous demand shock (arbitrary)

    Q_g_init=0;           %initial value of installed gas capacity  (MW)
    Q_n_init=10;          %initial value of installed nuclear capacity  (MW)

    Q_init=Q_g_init+Q_n_init;   %initial value of installed capacity  (MW)

    prctvector=[5 25 50 75 95]; % percentile values


%Discount Factor Calculation

    for i=1:paths
        for j=1:(periods+1)
             dsctfactor(i,j)=(1/((1+r)^time(j)));
        end
    end
```

```
% Random Array Generation

    randn('state',300);          %set the random generator to the same state in
                                each run to make random array reproducible
    rn=randn(paths,periods);     %create array of random numbers in a matrix
                                with "paths" rows and "periods" columns

% Exogenous Demand Evolution

    returns=rn;
    cumul_returns=rn;
    X=rn;                   %X(paths,periods) is the array of demand shock values

    X(:,1)=x_init;

    for i=1:paths
       for j=1:periods
 returns(i,j)=((mu-0.5.*(sigma.^2)).*delta)+(sigma.*(delta.^(1/2)).*rn(i,j));
            X(i,j+1)=exp(log(X(i,j))+ returns(i,j));
            cumul_returns(i,j)=log(X(i,j+1)/X(i,1));
       end
    end

% Leahy Price Triggers-Gas & Nuclear

    %Gas
    beta_g=((1/2)-(mu/(sigma.^2))+((((mu/sigma.^2)-
(1/2)).^2)+(2*r/sigma.^2)).^(1/2));

    Pstar_g=(beta_g/(beta_g-1))*(r-mu)*Kg;

    %Nuclear
    beta_n=((1/2)-(mu/(sigma.^2))+((((mu/sigma.^2)-
(1/2)).^2)+(2*r/sigma.^2)).^(1/2));

    Pstar_n=(beta_n/(beta_n-1))*(r-mu)*Kn;


% Two firms: one nuclear and one gas. Demand shock is exogenous as before.
% Prices are based on total active capacity.


% Grenadier Price Trigger for technology with build time - Nuclear

    Qcurr_g=rn;
    Qcurr_n=rn;

    Qcomm_g=rn;
    Qcomm_n=rn;
```

```
    Qcurr_g(:,1)=Q_g_init;   %current capacity, same as initial capacity
                                    in no time to build case
    Qcurr_n(:,1)=Q_n_init;
    Qcurr=Qcurr_g+Qcurr_n;

    Qcomm_g(:,1)=Q_g_init;   %committed capacity, at t=0, Qcomm_g=Qcurr_g
                                    because no capacity is under construction
    Qcomm_n(:,1)=Q_n_init;
    Qcomm=Qcomm_g+Qcomm_n;

    Qconst_g=0;              %initially, capacity under construction is zero
    Qconst_n=0;

    Qcompl_g=rn;             %initially, capacity being completed is zero
    Qcompl_n=rn;

    Qcompl_g(:,1)=0;
    Qcompl_n(:,1)=0;

    D=0;                     %initial Value of Demand being served is zero


    Qcurr=Qcurr_g+Qcurr_n;

    price=(X(:,1).*(Q_init.^(-1/gamma)));


% Grenadier Capacity Addition - Gas and Nuclear

    Xstar_g=Pstar_g.*exp((r-mu).*build_g).*(Qcurr.^(1/gamma));
    Xstar_n=Pstar_n.*exp((r-mu).*build_n).*(Qcurr.^(1/gamma));

%Grenadier "demand trigger" as a function of price trigger and committed
capacity


    for i=1:paths

        for j=1:periods

            if (X(i,j+1)>Xstar_g(i,j))
                if (((X(i,j+1)./(Pstar_g.*exp((r-
mu).*build_g))).^gamma)>Qcurr(i,j));
                    Qcomm_g(i,j+1)=((X(i,j+1)./(Pstar_g.*exp((r-
mu).*build_g))).^gamma);
                else
                    Qcomm_g(i,j+1)=Qcomm_g(i,j);
                end
            else
                Qcomm_g(i,j+1)=Qcomm_g(i,j);
            end

            if (X(i,j+1)>Xstar_n(i,j))
```

```
                if (((X(i,j+1)./(Pstar_n.*exp((r-
mu).*build_n))).^gamma)>Qcurr(i,j));
                    Qcomm_n(i,j+1)=((X(i,j+1)./(Pstar_n.*exp((r-
mu).*build_n))).^gamma);
                else
                    Qcomm_n(i,j+1)=Qcomm_n(i,j);
                end
            else
                Qcomm_n(i,j+1)=Qcomm_n(i,j);
            end


            Qconst_g(i,j+1)=Qcomm_g(i,j+1)-Qcomm_g(i,j);

            Qconst_n(i,j+1)=Qcomm_n(i,j+1)-Qcomm_n(i,j);




            if(j>=(2*build_g+1))
                Qcompl_g(i,j+1)=Qconst_g(i,j-2*build_g+1);
            else
                Qcompl_g(i,j+1)=0;
            end


            if(j>=(2*build_n+1))
                Qcompl_n(i,j+1)=Qconst_n(i,j-2*build_n+1);
            else
                Qcompl_n(i,j+1)=0;
            end

            Qcurr_g(i,j+1)=Qcurr_g(i,j)+Qcompl_g(i,j+1);
            Qcurr_n(i,j+1)=Qcurr_n(i,j)+Qcompl_n(i,j+1);

            Qcurr(i,j+1)=Qcurr_g(i,j+1)+Qcurr_n(i,j+1);


            Qcomm(i,j+1)=Qcomm_g(i,j+1)+Qcomm_n(i,j+1);

            price(i,j+1)=X(i,j+1).*(Qcurr(i,j+1).^(-1/gamma));

            Xstar_g(i,j+1)=Pstar_g.*exp((r-
mu).*build_g).*(Qcurr(i,j+1).^(1/gamma));
            Xstar_n(i,j+1)=Pstar_n.*exp((r-
mu).*build_n).*(Qcurr(i,j+1).^(1/gamma));

        end
    end

    D=(gamma/(gamma-1)).*X.*((Qcurr).^((gamma-1)/gamma))./1000000;
                                                % in $ billions
```

```
capcost_g=capcg.*Qcomm_g./1000000;
capcost_n=capcn.*Qcomm_n./1000000;  %because Capital Costs are annualized,
                                            Qcurr_n is used not Qconst_n

opcost_g=opcg.*Qcurr_g./1000000;
opcost_n=opcn.*Qcurr_n./1000000;

capcost=capcost_g+capcost_n;
opcost=opcost_g+opcost_n;

total_cost=capcost+opcost;


%Welfare Analysis


S=D-total_cost;


% PV Analysis

dsct_S=S.*dsctfactor;

PV=dsct_S;

NPV=sum(PV,2);
```