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Robust Decisions and Deep Uncertainty

An Application of Real Options to Public and Private Investment in Hydrogen and Fuel Cell Technologies

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ABSTRACT

This dissertation assesses the prospects for private sector investment in hydrogen and fuel cell technologies using an innovative application of real options analysis. Specifically, the dissertation considers the decision faced by natural gas utilities over whether, how and to what extent they should invest in projects that could be of value if a hydrogen energy market develops in the future. This is a problem of investment under uncertainty when there is little prior information available and where the investment itself could affect the future development of this market. The ultimate goal of the dissertation is to identify investment strategies that are robust against alternative futures and assess the tradeoffs of various policy instruments.

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ACRONYMS AND ABBREVIATIONS

Bcm	Billion cubic meters
CNG	Compressed natural gas
DCF	Discounted Cash Flow
DOE	Department of Energy
GBM	Geometric Brownian Motion
GTI	Gas Technology Institute
LDC	Local distribution company
LNG	Liquified natural gas
NPV	Net Present Value
PUC	Public Utilities Commission
RPS	Renewable Portfolio Standard
ROV	Real Options Valuation
SFC	Synthetic Fuels Corporation

CHAPTER 1: INTRODUCTION

SIGNIFICANCE OF THE RESEARCH

In 2002, President Bush announced the 5-year, $1.7 billion *FreedomCAR and Fuel Cell Initiative* to accelerate the research and development of hydrogen and fuel cell technologies in order to meet the nation's long-term energy goals. The research portfolio of the federal government includes both nearer-term technologies that convert fossil-fuels (and nuclear power) to hydrogen, and longer-term efforts to generate hydrogen from biomass, waste, and renewable electricity.   However, the issue of early commercialization and infrastructure development has largely been left to state-level initiatives and the private sector.

There is increasing recognition among policy makers that the private sector will play a major role in any effort to build a hydrogen infrastructure. For example, California's *Hydrogen Highways* initiative envisions public-private partnerships that would facilitate the construction of a hydrogen refueling infrastructure. Likewise, other states such as Florida, Illinois, and New Mexico have proposed pilot projects in order to attract private sector interest in hydrogen.

However, the existing research on investment in hydrogen technologies has not articulated a convincing framework for private industry to make near-term investment decisions, nor how such decisions would shape the options available to them in the future. Those studies that have made serious attempts to tackle the difficult issue of infrastructure development have focused primarily on the transportation sector, including recent innovative efforts at spatial analysis and static optimization of potential hydrogen production and distribution networks that might provide "gasoline-like" convenience to fuel cell vehicle owners at the lowest cost.

Until recently, the prevailing wisdom has been that government-sponsored pilot programs would need to be followed by a very rapid ramp-up period – sometimes characterized as a "Big Bang" –requiring billions of dollars in capital investment for an infrastructure that would be underutilized, and therefore unprofitable, for many years, as fuel cell vehicles gradually penetrate the market. This traditional approach emphasizes the fact that a hydrogen infrastructure would be an extraordinary cost borne by society, rather than a potential business opportunity for certain industries.

A National Academies (2004) report on the Hydrogen Economy points out that the linkage between the stationary power and transportation sectors may be important in the development of a hydrogen infrastructure, but that a comprehensive study has not been conducted and that the Department of Energy (DOE) has not considered this adequately in its research portfolio (2004). Initial efforts at the Institutes for Transportation Studies at UC Berkeley and UC Davis have demonstrated promising links between advanced power technologies and hydrogen infrastructure (Lipman, Kammen et al. 2004; Lipman 2004).

Currently, policymakers are struggling with defining the role that the public and private sectors should take in building a hydrogen infrastructure. There is still a significant degree of controversy over hydrogen's role in the nation's energy portfolio. Proposals in California and Illinois for the construction of "Hydrogen Highways" through public-private partnerships have articulated the importance of engaging the private sector in this regard. However, the policy framework and financial commitments for these programs have not yet been determined.

Although significant technical hurdles remain, the perspective of this dissertation is that developments in the energy markets—and particularly the electric power sector—may change the way that the private sector values fuel cell technologies and hydrogen, and that policymakers need to acknowledge how private capital valuation of these technologies will be affected by the perception of changing market, technical and policy risks. For example, the trend toward electricity deregulation of the electric power sector since the 1990s and legislation regarding renewable electricity, and potentially carbon dioxide emissions, may play an important role in the development of hydrogen. This dissertation argues that such changes in technologies, markets and public policies merit attention to new analytic approaches—or in fact, new approaches to traditional analytic methods.

RESEARCH QUESTIONS

This dissertation attempts to answer the following research questions:

1. What should energy companies consider in their strategic decision making regarding fuel cells and hydrogen?

2. What are the conditions for which early investment is the best option?

3. Where is the early investment option vulnerable?

4. What is the role of government policy in shaping private sector investment?

APPROACH

This dissertation develops a multi-dimensional real options valuation technique to model investment decisions made by a generic natural gas distribution utility.[1] A model natural gas distribution utility is used as the decisionmaker, facing public policy, market, and technical uncertainties. The natural gas industry was chosen because it will likely play a major role in early hydrogen infrastructure, but has not yet actively participated in the development of a national hydrogen energy strategy. Also, the data collection and modeling in this dissertation have benefited from a highly interactive process with stakeholders in private industry and government.[2]

This analysis does not attempt to address the question of whether hydrogen *should* be a significant part of U.S. energy policy, nor does it necessarily advocate focusing public policies solely on the natural gas sector. Rather, this dissertation attempts to develop a modeling technique that could be useful to both private and public stakeholders in valuing infrastructure investments where uncertainties regarding markets and technologies are ill-defined, and where acquisition of new information may be crucial over time. As a result, the model focuses on strategic-level decision making, rather than technological detail.

The dissertation considers the decision faced by natural gas utilities over whether, how and to what extent they should invest in projects that could be of value if a hydrogen energy market develops in the future. This is a problem of investment under uncertainty when there is little prior information available and where the investment itself could affect the future development of this market. The ultimate goal of the dissertation is to offer insights on how government policies can shape private sector investment decisions in this market.

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[1] The term "utility" is used in the dissertation to denote the primary business activities of gas distribution companies, which are regulated at multiple levels. However, unregulated business activities outside of natural gas distribution are also considered in the model (as described in Chapters 4 through 6), since many gas distribution companies have entered into other unregulated lines of business.

[2] Portions of this analysis serve as a basis not only for this dissertation, but also a project under the auspices of the Department of Energy, conducted jointly by RAND, Gas Technology Institute, and ARES, as described in Appendices A.1-A.6.

CHAPTER 2: LITERATURE REVIEW ON REAL OPTIONS AND INVESTMENT UNDER UNCERTAINTY

This chapter reviews the theory and practice of real options valuation, and its place within the discipline of investment under uncertainty. The focus is on the application of real options to situations governed by multiple uncertainties, and their implications for public policies. Chapter 3 will review the literature more specifically related to investment in the energy sector and alternative fuels.

LIMITATIONS OF TRADITIONAL DISCOUNTED CASH FLOW METHODS

Several characteristics of risky product development and R&D are often cumbersome or even impossible to capture with traditional tools such as discounted cash flow or Monte Carlo models. First, during the stages of product development or R&D, a firm is often able to get a better sense about costs (and other product characteristics such as quality), and so review its decision based on new information. Second, a firm has the potential to expand the scope of the project to new markets or abandon it as it acquires new information over time.

Traditional corporate decision analysis models focus on "detail complexity" associated with cash flows from a single scenario or a group of narrative scenarios, rather than "dynamic complexity" of downstream decision making (Smith 1999).[3] The neoclassical investment model suggests that a firm should invest to the point at which the marginal cost of capital equals the marginal return to capital. In practice, the variants of the neoclassical model, such as the "user cost of capital" approach and "Tobin's q", rely on the net present value (NPV) rule, which contains two subtle assumptions (Dixit and Pindyck 1994; Hubbard 1994). The first is that invested capital is reversible, because it can be sold to others. The second is that an investment requires a now-or-never investment decision. However, these assumptions begin to break down for capital investments in industries where technical or market risks are substantial, where investments are firm or industry specific, or where management has the flexibility to delay or stage

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[3] In this context, a cash flow simulation with "detail complexity" typically focuses on resolving high-resolution technical or financial information for a single scenario or small group of scenarios, while "dynamic complexity" typically refers to the evaluation of multiple downstream decision points and multiple scenarios.

investment decisions. As a result, application of the classic net present value rule to such investment decisions would not maximize a firm's value.

The most basic application of real options valuation can be understood in a two-period decision problem where a firm has the ability to decide whether to make an immediate investment at t_0, or whether to wait until the next time period, t_1. The following treatment assumes that an investment entitles a firm to annual cash flows that continue forever. However, the value of these cash flows is not certain at t_0, and is only revealed at time t_1. The market will either yield a favorable stream of cash flows, $CF_{up}=CF+u$, with probabililty p_{up}, or unfavorable cash flows, $CF_{down}=CF-d$ with probability $p_{down}=1-p_{up}$. Cash flows are discounted annually at a constant discount rate ρ.

According to a traditional NPV approach, an investor would make a now-or-never investment decision at t_0, reaping expected net cash flows minus the upfront investment cost:

$$NPV_{\text{Invest Now}} = - \text{ Investment Cost} + p_{up} \sum_{t=0}^{\infty} \frac{CF_{up}}{(1+\rho)^t} + p_{down} \sum_{t=0}^{\infty} \frac{CF_{down}}{(1+\rho)^t}$$

However, if an investor has an opportunity to delay the investment until t_1, when uncertainties in cash flows are fully resolved, then the payoff structure is different. The investor can now choose not to invest if market conditions prove unfavorable:

$$NPV_{\text{Wait}} = p_{up} * Max\left\{ \underbrace{-\frac{\text{Investment Cost}}{1+\rho}}_{\substack{\text{Investment in period 1}}} + \underbrace{\sum_{t=1}^{\infty} \frac{CF_{up}}{(1+\rho)^t}}_{\substack{\text{Cash flows from} \\ t_1 \text{ to } t_\infty}}, 0 \right\} + p_{down} * Max\left\{ -\frac{\text{Investment Cost}}{1+\rho} + \sum_{t=1}^{\infty} \frac{CF_{down}}{(1+\rho)^t}, 0 \right\}$$

Assuming that cash flows are insufficient to cover investment costs in the down state, the investor wisely forgoes investment, and this expression can be simplified to the following:

$$NPV_{Wait} = p_{up} \left[-\frac{\text{Investment Cost}}{1+\rho} + \sum_{t=1}^{\infty} \frac{CF_{up}}{(1+\rho)^t} \right]$$

The real option value of the flexibility to delay investment until uncertainty is resolved as the difference between these two NPVs. Substituting the formula for the present value of a perpetuity and combining terms, we get the following:

$$\text{Real Options Value} = \text{NPV}_{\text{Wait}} - \text{NPV}_{\text{Invest Now}}$$

$$= \underbrace{\text{Investment Cost} \cdot \left[1 - \frac{p_{up}}{1+\rho} \right]}_{\substack{\text{I} \\ \text{Incur investment cost} \\ \text{only if outcome is good}}} - \underbrace{\frac{(1 - p_{up})(\overline{CF} - d)}{\rho}}_{\substack{\text{II} \\ \text{Avoid cash flows from} \\ \text{bad outcome}}} - \underbrace{p_{up}(\overline{CF} + u)}_{\substack{\text{III} \\ \text{Lose cash flows} \\ \text{from first period}}}$$

Although the opportunity cost of investing in a particular project is accounted for by the discount rate in a classic NPV, the intertemporal opportunity cost associated with making an immediate irreversible investment or waiting is not, as demonstrated in the first two terms of the preceding equation. The first term shows that the ability to delay or forgo an investment can defray expected investment costs, since they are only incurred when cash flows are favorable. In particular, if the initial investment outlay is large, not recoverable in a secondary market (and therefore irreversible), and can be delayed, the real options value can diverge significantly from the classic NPV.

The second term illustrates the importance of the variability of future cash flows on the real options value. If the volatility of the underlying project cash flows is high (e.g. resulting in a large negative cash flow in the down state, $\overline{CF} - d$), the value of flexibility in avoiding these cash flows increases the real options value. By holding onto an option, an investor is able to monitor the market value of a project and decide to invest when conditions are favorable, thus creating a beneficial asymmetric payoff profile, akin to managing a financial portfolio, enabling the up-side while limiting downside losses, for the price of an option premium.[4] This would imply that, in the presence of embedded options (in this case, the ability to defer an investment until later), a greater variability in project outcome values may increase project value.

The third term in this equation represents the downside to delaying investment. If foregone cash flows from delaying investment at t_0 are significant, they reduce the benefits of waiting and thus the real options value. This is magnified if the discount rate is high, such that the other real options benefits of delaying investment are diminished and first period cash flows become relatively more important.

Although this example is highly stylized, it illustrates the classic tradeoff in a real options valuation between holding onto an option and exercising it, which is instructive when constructing more complex

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[4] This example assumes that the investor already owns the rights to an option to invest, so the option premium is free (or sunk).

and higher dimensional models. The real options approach has been referred to in the management literature as an "expanded NPV" (McKinsey, etc.). This type of analysis can be extended to more sophisticated approaches that include multiple time periods, where cash flows can be associated with traded commodities, and uncertainties include future costs, discount rate, and structural and parametric behavior of cash flows.

In a formal real options application, a firm must hold the rights to make an investment at some point in the future. The previous example assumes that the investor already owns the rights to investment, and thus does not have to pay an option premium to exercise this right. A firm can acquire investment opportunities through the ownership of intellectual property, physical assets, or take advantage of regulatory protection. Developing firm capabilities may also be regarded as real options (Kogut and Kulatilaka 2001). Option rights that are not entirely proprietary, such as temporary economic barriers to entry, can be considered "shared" rights to an investment, and are described later in this chapter.

The real options approach can be traced back to Myers (1977), who asserted that the value of a firm was not only the present value of its existing assets, but the present value of the options to make further investments if conditions are favorable at some time in the future. This proposition meant that if a firm had a choice of whether to invest or wait, that immediate investment led to the irreversible exercise of an option, forgoing the opportunity to invest at a later date (McDonald and Siegel 1986; Dixit and Pindyck 1994). The seminal works on financial option pricing by Black and Scholes (1973) and Merton (Merton 1973) provided a mathematical foundation for the first applications of real options. Some practitioners of real options have taken this analogy quite literally and applied Black-Scholes options pricing directly. Others have preferred to use discrete approximations to the underlying stochastic process of interest (Margrabe 1978) (Carr 1988). Cos, Ross and Rubinstein (1979) showed that a binomial lattice[5] could approximate the lognormal diffusion of stock prices. Improved computational methods and techniques have allowed analysts to approach realistic investment problems with a variety of real options techniques. Real options valuation today refers to a whole set of techniques that are used to value management flexibility on the use of physical assets and intellectual property.

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[5] A binomial lattice is essentially a recombining probability tree.

R&D AND INTANGIBLE ASSETS

The valuation of R&D and intangible assets such as intellectual property is a classic case where traditional analytic methods are problematic. An R&D manager, for example, typically reevaluates an R&D portfolio as technologies reach certain milestones within the regulatory process or are reevaluated by benchmarks established by the firm. In a typical R&D real options problem, private uncertainty regarding the technology is resolved through investment, while market uncertainty is resolved through waiting. For example, Childs and Triantis (1999) look at the optimal dynamic investment policy for an R&D program, where uncertainty is resolved through investment, rather than by waiting. In the presence of competition, a firm would tend to invest in parallel R&D investments in the early development stages of projects, less parallel investments in the latter stages, and lower overall investment.

Davis and Owens (2003) employ real options to find the value of federal investment in research and development in renewable electricity under uncertain fossil fuel prices. Using a similar technique, Considine and Kervitsky (2004) build a preliminary framework for calculating the options value of federal investment in hydrogen research and development. Tsui (2005) identifies the option value of GM's fuel cell R&D based on the benefits of being able to meet potentially more stringent CAFE requirements in the future. Tsui finds the option value of $3.21 billion dollars, compared with a traditional discounted cash flow value of negative $1.27 billion.

COMPETITION, GAME THEORY, AND OTHER EXTENSIONS

The early real options literature focused primarily on applications that are analogous to financial options and thus analytically tractable with the mathematical tools available, such as Black-Scholes option pricing. One of the critical assumptions was the presence of a real option afforded an investor a proprietary right to invest during a specific time period (American call) or at a predetermined date (European call). Such proprietary rights to investments can exist when there are legal or regulatory barriers to entry for other potential market participants, such as the decision by the owner of an oil field whether or not to start oil production on that field.

In recent years, the real options literature has considered the effect of competition and game theoretic interactions among market participants. If the firm's ability to delay an investment is affected by strategic interactions with other firms, a real option becomes a "shared" right to investment, where delay

can result in competitive erosion of project payoff. In these cases, the "rights" to the option often involve temporary economic barriers to entry and are thus necessarily weaker than explicit legal rights.

The payoffs associated with holding onto or exercising an option can be understood in a game theoretic context. Since an option by definition cannot be "de-exercised", two players with shared rights to an investment can engage in classic game-theoretic situations, as demonstrated by Smit and Trigeorgis (2004).

For example, a classic prisoner's dilemma has a direct options analogy. If two investors share a right to an investment, they will both have a motive to pre-empt competitive entry in order to gain first-mover advantage by exercising their option to invest. However, both would be better off if they held onto the option and waited to invest at a later time when uncertainties are resolved.

Other games can also be played, some of which may be more relevant to real investment opportunities. For example, a market may not currently exist, and can only emerge if one or more investors enter the market. However, there is only room for one investor to make profits, and simultaneous investment results in battle with negative payoff.[6] Investors may also have a choice of high irreversible investment or flexible, low-effort investment. A large commitment signals research quality to competing firms and reduced profitability to potential entrants. Alternatively, large commitment results in establishment of a technology standard.[7] If a firm can take advantage of a first-mover advantage, such as creating an early technology standard or convincing regulators to allow cost recovery, the decision between exercising and holding onto the option can become complicated. For example, Kulatilaka and Lin (2004) use real options to consider a single firm with a temporary monopoly position over an investment opportunity, finding that there exists a unique optimal licensing fee that results in a single technology standard.

Alternatively, network externalities may suggest that participants are better off if they both invest, depending on the shift in demand as a result of the establishment of a new infrastructure. Smit (2003), for example, examines the case of European airport expansion.

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[6] Also known as an asymmetric innovation race or "Grab the Dollar" game.

[7] Signaling games and product standardization or pre-emption.

REAL OPTIONS AND PUBLIC POLICY

The presence of real options in an industry can have important implications for public policy, particularly in capital intensive industries such as telecommunications and energy, where policy changes such as deregulation can have significant implications for market uncertainty and the potential for sunk investments. A better understanding of private sector capital valuation methods can help policymakers understand the likely effect of public policies on the timing and level of private sector investment. Of particular concern is the evidence of perverse outcomes in U.S. electricity, refining, telecommunications sectors over the last decade. Real options methods have been used to show how some policy incentives can inadvertently lead to underinvestment in these industries.

The existence of embedded real options can influence industry equilibrium and innovation. If firms benefit from other firms making initial investments, this can lead to a market failure situation. Once a sunk cost is incurred, the delay option is no longer available to an incumbent. For example, Pindyck (2005) showed that higher sunk costs lead to a smaller number of firms in a market in equilibrium, and lead to an amplification effect of the direct sunk cost of entering a market. Studies have shown the importance of entry and exit on innovation and productivity growth (Foster, Krizan et al. 1998). To the extent that real options and policy uncertainty raise entry and exit thresholds, it is important for policymakers to acknowledge them.

The richest literature on real options as applied to regulatory policy is in the telecommunications industry, where traditional regulation based on marginal cost pricing has been shown to fail to account for the presence of real options and has led regulators to mandate inefficiently low regulated lease rates. Hausman (1998) found that telecommunication regulations which gave competitors access to infrastructure did not price adequately to account for sunk cost, which essentially subsidized entrants at the expense of incumbents. Similarly, Hausman and Myers (2002) found that regulators failed to account for sunk costs in railroad regulations.

The relevance of sunk costs and uncertainty is of particular importance in capital intensive industries, such as the energy sector. In recent years, the literature on the investment in the electric power sector has helped explain the behavior of utilities and energy companies which face policy uncertainty. Teisberg (1993) presented a real options model that explained why regulated utilities would make rational decisions to delay or abandon investments when faced with uncertain PUC reviews, particularly in relation

to uncertain profit restrictions. Teisberg (1994) also demonstrated why utilities facing policy uncertainty would prefer smaller, shorter-lead time technologies, which would result in less aggregate but more immediate investment.

More recently, the California energy crisis of 2000-2001 spurred a literature on the effects of deregulation and related policies on investment in electricity generation. At issue were unexpected delays in power generation investments and the fact that regulations were leading to perverse outcomes in the market.[8] Ishii and Yan (2004) found empirical evidence that uncertainty regarding electricity restructuring led to delays in nonutility investments in new generating capacity nationwide.[9] The authors found that investors would tend to take a "wait and see" approach consistent with real options valuation, in order to get better information regarding a state's level of commitment, design and performance of a restructured market. This was consistent with the seminal works on "information gathering" investment models of Cukierman (1980) and Bernanke (1983), who demonstrated that firms would prefer to wait to gather more information if they believe that policies are uncertain.

In an overview of global trends in electricity deregulation, the International Energy Agency (2003) found that the uncertainty in electricity prices and the lack of liquid markets in long-term financial instruments in the electricity sector had led deregulated utilities to favor smaller powerplants with lower capital costs and thus less exposure to electricity price fluctuations, but higher fuel price risk. Traditional technologies that exhibit economies of scale and longer-lead times, such as coal and nuclear power plants are more exposed to electricity price risk. As a result, the IEA recommended that real options analysis be used increasingly in the power sector to capture these changes in technologies and the electricity market. Similar analogies have been drawn by advocates of distributed power (Lovins, Datta et al. 2002).

Although the U.S. petroleum refining industry is not a regulated utility, it has frequently been the subject of Congressional scrutiny and consumer concerns due to price spikes of refined products. As a result, policy uncertainty (particularly environmental) has played a major role in the industry's investment decisions. A RAND study (Peterson and Mahnovski 2003) found that refining executives responded to policy uncertainty in recent years by making incremental investments which led to tight markets and price

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[8] Other types of analysis have also been employed, such as the system dynamics approach to boom and bust cycles in power plant construction by A. Ford (2001).

spikes in the industry. In particular, the industry was more averse to making technology-rich investments than they were in the 1980s.[10] Industry executives cited not only the sunk costs incurred during the 1980s, but the increasing use of regulatory phase-ins and ad hoc changes in policy as particularly onerous. This led to a change in investment philosophy favoring "cheapskate investments" which lead to tight supplies and resulting price spikes.

Pindyck (2000) uses a real options approach to illustrate flaws in standard analytical frameworks that are applied to environmental policy. In particular, environmental policies can often be characterized by the presence of timing flexibility, and both *sunk costs* and *sunk benefits* (Pindyck 2002). In theory, the presence of sunk benefits should lower the threshold for policy adoption, if policymakers are interested in addressing environmental externalities. In practice, environmental sunk benefits may often be more difficult to characterize than investment costs, for which plausible bounds can be characterized more easily. This is of particular interest to global warming abatement policies (Baranzini, Chesney et al. 2003), where environmental damages can be characterized by discontinues and jump-diffusion processes (Dotsis, Makropoulou et al. 2005), or specific events such as the damages to the ice shelf of Antarctica (Guillerminet and Tol 2005).

Energy efficiency investments have also been evaluated with real options techniques. Hassett and Metcalf (1993) postulate that underinvestment in energy-efficiency can be explained by a high implicit discount rate, since there is always a positive option value of waiting to make such an investment in order to acquire more information about energy prices. However, Sanstad, et al (1995) argue that the option value only accounts for a small portion of the revealed hurdle rate.

THEORY VERSUS PRACTICE: SOME PRECAUTIONS

Real options methods are used regularly in several industries, such as energy, pharmaceuticals, and telecommunications. The energy industry, for example, is able to utilize publicly available historical and near real-time information on energy prices to make short-term operational decisions to capture value

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[9] This was consistent with the Averch-Johnson (AJ) Effect, where companies have a reduced incentive to control costs under regulation because shareholder profits are protected by regulation, resulting in overcapitalization.

[10] This trend in the 1980s may be consistent with studies that have shown that firms sometime appear to over-comply with environmental regulations, such as purchasing pollution abatement capital, when they anticipate changes in current regulations. Lee, A. (1998). Environmental Compliance under Uncertain Regulation. Boulder, Center for Economic Analysis, Department of Economics, University of Colorado at Boulder.

(Ronn 2002). The pharmaceutical industry has also used real options to capture well-defined staged R&D decisions and changing risk profiles.

However, one of the biggest obstacles in adoption of real options is the lack of transparency of models, which can lead to potential overvaluation and a lack of trust by upper management (Thurner 2003). In particular, the overvaluation of technology stocks in the late 1990s based on specious arguments on future cash flows has helped contribute to this skepticism. In theory, a basic real options perspective would imply that uncertainty is good, and that the most uncertain projects could perhaps be the ones with the greatest payoff. This begs the question whether the real options technique is useful, and if so, under what circumstances. One response in the management literature has been that real options should be construed as a complement, not a substitute to classic NPV (Copeland and Keenan 1998; Copeland and Keenan 1998; Copeland and Trufano 2004).

Another criticism of real options in practice is that it can lead to an escalation of commitment to a larger number of initial-stage or low-budget projects, which poses two potential problems. The first is that it can raise the cost of monitoring and managing projects. The second is that it may be difficult to define an ex ante timetable for the exercise of options or abandonment of investments, and perhaps even more difficult to execute if such a timetable could be constructed.

Some have criticized the drifting of the real options paradigm away from its original financial options analogy. In a financial option, an investor is assumed to have no influence on the stock market and is a price taker for the underlying commodity. Adner and Levinthal (2004), for example, argue that many problems construed as real options are in fact better described by other path-dependent processes. Others argue that the main contribution from real options is the intuition that leads to the discovery of embedded real options in project valuation, and relating such options to the market, where possible.

Zardhooki (2004) outlines the conditions under which real options could lead to an escalation of commitment, citing (1) tragedy of the commons, where benefits accrue to the investor but costs are diffused, (2) psychological and social justifications, and (3) prospect theory, where firms overweight certain outcomes relative to outcomes which are probable. Adner and Levinthal (2004) argue, however, that a firm's ability to influence the outcomes of a project in a real options context makes efficient abandonment of projects very difficult even for rational organizations. In practice, an embedded principal-agent problem can exist in real options approaches. Traditional portfolio theory suggests that an individual

investor holds a diversified portfolio of assets to manage risk. This strategy by investors means that if managers of individual firms were acting solely in the interests of the shareholders, the managers should simply try to maximize their firms' NPVs. Such management "agents" would not need to worry about firm-specific risk (although they would pay attention to risk in their choice of discount rates for evaluations of particular projects) because the investors (the "principals") can handle risk by holding stock in a portfolio of firms. Most of the options model considered in the text assume that the managers of the firm are the sole decision-makers without reference to the behavior of investors because managers have a large degree of autonomy and do in fact have a "proprietary" interest in the success or failure of their firms.

Much of the research in real options over the past decade concerns the use of uncertainties in increasingly more realistic investment problems, where strict analogies with financial options begin to break down. These have included analogies to exotic derivative securities, such as compound or rainbow options. In particular, the link between real options and decision analysis has been debated in recent years. Nau and McCardle (1995) and Smith and Nau (1995) found that the two methods can give identical results if risks are treated analogously. They distinguished between market risks, which can be hedged with financial securities, and private (or project-specific) risks, which cannot be hedged in the market. Copeland and Antikarov (2003) proposed using the assumption that the present value of the project without options is the best unbiased estimator of the market value of the project, otherwise known as the MAD (Market Asset Disclaimer) assumption. This assumption allows that value of the project to be used as the underlying asset in a replicating portfolio.

Ng and Bjornsson (2003) offer a comparison of real options analysis and more traditional decision analysis techniques. On balance, the main differences between real options and decision analysis involve 1) the treatment of risks, and 2) the thought process that underlies the choice of options or decision points. A classic decision tree approach would model the options available to management, but use a constant discount rate throughout the tree structure. This would be the same risk-adjusted discount rate as would be used in an NPV calculation for the original project without options. However, the problem is that the risk characteristics of a project with options are different, as reflected by the expected future cash flows calculated at the decision nodes. Several methods have been proposed to handle this problem.

Another, equivalent method which is more convenient to implement in a decision-tree formalism, is the method of risk-neutral probabilities. This method allows the use of a constant risk-free discount rate

throughout the tree, but with cash flows which are adjusted by modifying the objective probabilities to risk-neutral probabilities. The replicating portfolio approach discounts expected cash flows at the risk adjusted discount rate, r, while the risk-neutral probability approach discounts at the risk neutral rate, k. Since the risk-free rate will be less than the risk-adjusted discount rate, the derived risk-neutral probability p will be less than the objective, or "true" probability, q, according to the following formula:

$$V_0 = \underbrace{\frac{qV_u + (1-q)V_d}{1+k}}_{risk-adjusted} = \underbrace{\frac{pV_u + (1-p)V_d}{1+r}}_{risk-neutral}$$

UNCERTAINTIES AND ROBUST DECISIONMAKING

The management literature is quite clear that despite the value of real options valuation, the methodology should rarely serve as the sole basis for an investment decision.[11] This begs the question of how to actually implement real options valuation and what other supplemental methods are necessary. For example, some have conceded that the true value of a project with options is somewhere between the base NPV value at one extreme, and the real options value at the other extreme (Copeland and Trufano 2004). As uncertainty is resolved, the ratio of the total project value that is derived from the option value relative the NPV decreases. Managers should then apply their judgment as to how risky the real option portion of the cash value really is. This argument concedes that there are unresolved methodological gaps that constrain the application of real options to major investment decisions, particularly for stakeholders involved in major policy or investment decisions.

One major question is how to capture multiple uncertainties in a real options model. One of the strengths of real options analysis is that it describes "dynamic" complexity much better than classic NPV analyses, which focus on "detail" complexity (Smith 1999). A typical NPV problem is highly detailed in its treatment of taxes, depreciation, and other aspects of expected cash flows, for a single scenario. A

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[11] The exceptions may be short-term operational decisions involving facilities that produce or consume publicly traded commodities (such as electric power), where uncertainties are well-defined through substantial historical data, and where operational decisions can be agile enough to capture arbitrage opportunities.

classic real options approach, on the other hand, is richer in its treatment of dynamics, but parsimonious with respect to underlying uncertainties in order to avoid a "curse of dimensionality" problem.

Smith (2005), in an analysis of the state of real options, points out recent innovations in higher dimensional real options problems, suggesting Monte Carlo techniques (described in Glasserman (2004)) from financial engineering and regression analysis.

This dissertation will argue that investment decisions based on a single optimization, classic sensitivity analysis, or Monte Carlo techniques are insufficient when uncertainties are difficult to characterize and when stakeholders disagree on fundamental assumptions in the model. In particular, this analysis will draw on both the traditional techniques developed by practitioners of real options and also methods for generating robust strategies under conditions of deep uncertainty (Lempert, Popper et al. 2003; Groves 2005; Lempert, Groves et al. 2005). In policy contexts where there is deep uncertainty and stakeholders with divergent opinions, traditional scenarios and optimization approaches have important limitations. The methodology section of Chapter 5 will describe exploratory modeling methods that use low-dimensional models to evaluate a large set of futures, which defer the assignment of probabilities and present the most relevant uncertainties to decisionmakers.

CHAPTER 3: THE ROLE OF PUBLIC AND PRIVATE SECTORS IN HYDROGEN

INVESTMENT

OVERVIEW

The United States is at the crossroads of a debate regarding the future direction of its energy economy. In the wake of the terrorist attacks of 9-11, the electricity blackouts of August 2003, concern about climate change and increased volatility in all major energy commodity prices, there is a growing consensus that substantial investments will be needed to modernize the U.S. energy infrastructure, which was once characterized as the most technically advanced in the world, in order to meet the unique environmental, economic, and security challenges of the future. This debate involves a wide range of stakeholders at all levels of government, private industry, and civil society.

One fundamental question is whether society should invest in mature technologies for centralized energy production, transmission and distribution in order to shield the economy from major supply shocks and to create value from trillions of dollars of sunk investment in a heavily fossil fuel dependent infrastructure premised on economies of scale. It is this energy infrastructure that has provided enormous benefits to the U.S. economy and unprecedented increases in the standard of living of its citizens since the 19th century. Others have argued in favor of a more modular, "smarter" infrastructure, with less catastrophic (but perhaps more frequent) failure modes, where power is generated and consumed locally, and the price paid by consumers reflects the true cost of production in time and location.

To the extent that hydrogen (and other innovative energy concepts, such as "smart grids", distributed generation technologies, etc) fit within the latter vision, traditional policy instruments in the energy sector may be insufficient. The role of hydrogen in public policy is still at an early stage. Although serious technical obstacles still remain, the greater difficulty for policymakers today is understanding where these advanced technologies fit within energy policy, particularly with the deregulation in the electricity sector, emergence of renewables, and possible regulation regarding climate change.

Since its formation in 1977, the U.S. Department of Energy has provided financial assistance for the construction of energy facilities in support of national energy policy. However, the nature of federal

energy project financing has changed significantly over the past three decades to encourage the participation of private capital markets in order to bridge the gap between social and private returns in the energy sector (Herrick 2002). This follows a broader trend in the United States, where focus has shifted from the internal workings of government to the network of actors that implement and are affected by policies (Salamon 2002).

Currently, several states have announced initiatives related to hydrogen, including innovative approaches to public-private partnerships. However, the existing policy documents related to these initiatives have left many questions unanswered and merit a closer look at where previous government efforts have succeeded or failed. This chapter draws lessons for the financing of a hydrogen infrastructure from previous experiences in alternative fuels.

PREVIOUS ALTERNATIVE FUELS EFFORTS

The United States has made several attempts since World War II to introduce alternative fuels and vehicles into the transportation energy portfolio, with mixed success. These efforts have included synthetic fuels from coal and oil shale (1920s, 1940s, and early 1980s), diesel (1980s), compressed natural gas (1980s and 1990s), oxygenated additives (1990s), electric vehicles (mid-late 1990s) and hybrid gasoline-electric vehicles (late 1990s, 2000s), as shown in Table 3.1. In light of these historical efforts, policymakers and the business community have been reluctant to "pick" technologies which might lead to a stranded investment. Table 3.1 demonstrates the role of stakeholders in these previous efforts. Some of these can be regarded as attempts to build an entirely new refueling infrastructure, while others are more simply attempts to develop fuel substitutes compatible with existing infrastructure and vehicles.

Experience has shown that the construction of a new energy or transportation infrastructure is a rare, difficult, and uncertain proposition because investments in infrastructure and end-use technologies must be synchronized in order to make either of them worthwhile, and consumer preferences are difficult to predict. Grubler (1999) analyzed the structural evolution of transportation infrastructures and showed that transitions typically occur on the order of 50-100 years, as technologies reach saturation and are eventually displaced.[12] Some auto manufacturers have acknowledged that fundamental changes in the

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[12] The federal investment in roads was approximately $25 billion in 1956, which was equivalent to 5.7 percent of GDP at the time.

refueling infrastructure should only occur once a century, thus disqualifying many "intermediate"

solutions, such as methanol-powered vehicles.[13]

Table 3.1: The Role of Stakeholders in U.S. Alternative Fuel Efforts

Alternative Fuel	Year	Government	Private Industry	Consumers
Synthetic Fuels	1920s, 1940s, early 1980s	Primarily effort to increase energy independence. Germany and South Africa pioneered technology during WW2 and Apartheid isolation. U.S. advocates syn fuel from coal, but periods of low oil prices slow efforts	**Auto:** No significant changes needed in conventional auto. Syn fuels similar to diesel or gasoline. **Fuel:** Petrochemical industry sees an opportunity, but very capital intensive. More profitable uses of natural gas exist. Syn fuels are ultra-clean (e.g. no sulfur), however there is no market for this at the time.	Fuel never reaches market in early years. Ultra-clean diesel too expensive. Other potential benefits (environment, energy security) do not resonate with public until OPEC crisis.
Diesel	1980s	Greater fuel efficiency, but unwilling to create European-style tax differential between gasoline-diesel.	**Auto:** Diesel engine technologies static at the time and market weak for light-duty vehicle class. **Fuel:** Refiners reluctant to re-tool infrastructure to create more diesel unless market is proven	Diesel engines loud and emit black particulates and fuel infrastructure not as pervasive as gasoline. Although $/gallon similar to gasoline, consumers do not calculate $/mile driven.
Compressed Natural Gas (CNG)	1980s, 1990s	CNG promoted for federal and state fleets. However, light duty vehicle class not targeted directly.	**Auto:** Compressed gases more difficult to store, and no market in light duty. Heavy duty, however. **Fuel:** Natural gas utilities promote.	Consumers not ready for gaseous fueling. Infrastructure weak and performance not as good. Little incentive to purchase.
Oxygenates (e.g. methanol, MTBE)	1980s, 1990s	Efforts to promote cleaner vehicle exhaust through additives in conventional gasoline (MTBE), but found later to pollute water. Methanol infrastructure never seriously considered.	**Auto:** No significant changes needed in conventional auto for additives (would for methanol, however) **Fuel:** Oxygenates raise cost to refiners (e.g. logistics, blends) with little, if any, return on investment. However, oxygenate manufacturers (e.g. corn lobby) support it.	Consumers generally do not follow what is added to conventional fuel. However, MTBE found to be polluting underground water resources. Methanol can cause blindness if ingested.
Electric Vehicles	1990s	Primarily California-based attempt to decrease vehicle emissions. Auto industry lobby effectively limits regulation of California Air Resources Board (CARB) and threatens to exit CA market or take $ penalty.	**Auto:** U.S. manufacturers reluctant to invest. Battery technology is not ready and vehicles are of inferior quality. **Electricity:** Some utilities see an opportunity to increase "base load" by accessing vehicle refueling market. Recharging stations built in some locations.	Niche markets among environmentally conscious. However, performance and infrastructure are deficient. Movement in 1990s for heavier vehicles with more horsepower inconsistent with goals of electric vehicle policy. Refueling slow.
Hybrid gasoline-electric vehicles	2000+	No new infrastructure needed. Hybrids seen as transition strategy. Some R&D and tax rebates offered, but left to free market mostly.	**Auto:** Japanese manufacturers (e.g. Honda, Toyota) dominate market. **Fuel:** Refineries see this as viable threat to gasoline demand within decade because of greater efficiency.	Existing infrastructure can be utilized, and performance is better than electric vehicles. "Hybridization" of heavier vehicles may be popular.
Fuel Cell Vehicles	2010+ (?)	Federal funding for R&D. However, infrastructure efforts mostly state-level, particularly California.	**Auto:** Still in R&D phase. Industry attempting to create high-end vehicles with new functions, rather than replacing old or low end. **Fuel:** Unresolved who will provide fuel, but natural gas would be the cheapest in short term. Infrastructure issue remains unresolved.	Very popular and controversial concept, but infrastructure scant, first models extremely expensive, safety, regulatory, and insurance issues unresolved and difficult to understand for non-technologists.

Synthetic Fuels

Synthetic fuels have enjoyed mixed success during the twentieth century, with increased public interest during periods of high oil prices, war, or economic sanctions. The premise behind synthetic fuels is the conversion of lower-value (and typically indigenous) hydrocarbons such as coal, tar sands, oil shale, and various "opportunity fuels" into high-value liquid fuels which can be used in the transportation sector without significant conversion of infrastructure or vehicles. The history of government policy on synthetic fuels offers important lessons for energy policy, and hydrogen policy, in particular.

During World War I and World War II, Germany developed "ersatz" gasoline and diesel in order to help supply transportation fuels for its war effort. As a nation poorly endowed with petroleum and natural gas, but rich in coal, German scientists developed several techniques to manufacture synthetic liquid fuels from coal.[14] Likewise, after hostilities commenced with China in 1937, Japan laid out an ambitious seven-year plan to produce synthetic fuels which would be equivalent to half of Japan's 1937 fuel consumption (Yergin 1992). South Africa successfully pursued a synthetic fuels policy, largely based on the German technology, as a result of its international isolation during the apartheid era.

The first phase of synthetic fuels research in the U.S. happened in the 1920s, under the auspices of the U.S. Bureau of Mines, which conducted exploratory research in oil shale extraction (1925-1929) and coal dehydrogenation (1937-1944).[15] The Great Depression and the discovery of oil reserves in Texas led to an oil glut in the early 1930s which reduced federal spending on energy research during that time. However, concerns over fuel supply during World War II led the U.S. Congress to pass the Synthetic Liquid Fuels Act, which authorized more than $80 million in research and development on synthetic fuels during the Truman era. Some, led by the Bureau of Mines, called for the equivalent of a Manhattan project for energy independence, with synthetic fuels playing a lead role. However, the opening of Saudi Arabian oil

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[14] Several discoveries in the German chemical industry in the early twentieth century are still of relevance today. Catalytic synthesis of ammonia directly from hydrogen and nitrogen by the Haber-Bosch process may rank as one of the most important scientific discoveries in the modern era. In addition to allowing large scale production of fertilizers, it revolutionized catalytic and high-pressure chemistry. The Bergius Process was developed by Frederick Bergius in 1912-1913. It is known as a "direct" liquefaction process whereby brown coal (lignite) or heavy oil is dissolved in recycled solvent oil and reacted with hydrogen at pressures between 200-700 atmospheres, in the presence of an iron catalyst. The Fischer-Tropsch process was discovered by Franz Fischer, Hans Tropsch and Helmut Pichler, German coal researchers, in 1923. It is an "indirect" synthesis process, which was used by the Germans during World War II, and is currently the basis of many hydrocarbon-to-liquids processes today. Coal is gasified to synthesis gas, which is a mixture of CO and H_2 gas. This syngas is condensed using Fischer-Tropsch catalysts. Germany produced 16,000 barrels per day of liquid fuels using the F-T process in World War II.

[15] A review of U.S. efforts in coal research is available on the U.S. Department of Energy, Office of Fossil Energy website: http://www.fe.doe.gov/aboutus/history/syntheticfuels_history.html

fields to western investors in the 1950s brought opposition from the petroleum industry, which projected that synthetic fuels would be much more expensive than gasoline. The Eisenhower Administration's philosophical reluctance to continue this effort ultimately led to the demise of this program.[16] A period of low oil prices led to a dormancy of synthetic fuel efforts for more than two decades.

The OPEC oil shocks of the 1970s reawakened interest in synthetic fuels and led to calls for a "Manhattan Project" (or "Apollo Program") for energy independence.[17] In 1979, President Carter announced a policy to manufacture 2.5 million barrels per day of synthetic fuels by 1990. Congress created the Synthetic Fuels Corporation (SFC), a quasi-public entity, authorizing $20 billion in subsidies for synthetic oil production from oil shale, tar sands, and coal. However, the SFC was never able to produce synthetic fuel profitably, and the capital cost of one of the plants exceeded $2 billion.[18] According to energy economist M.A. Adelman (1995), OPEC made an explicit decision in 1978 or 1979 to set prices at just below the cost of synthetic fuels production, which was thought to be around $60/bbl. In 1984, President Reagan significantly reduced funding for the SFC, dismantling the program in 1986.

Since the dismantling of the SFC, synthetic fuels have not featured prominently in U.S. energy policy until the oil price increases in 2000-2005. According to a recent RAND study (Bartis, LaTourrette et al. 2005), the economics of oil shale production have consistently lagged behind crude oil production. Today, the Clean Coal Initiative (CCI) is essentially the last surviving remnant of the synthetic fuels program. The recent revived interests in oil shale and coal gasification essentially share the same underlying technological platform which would technically allow for carbon dioxide sequestration and hydrogen separation (Simbeck, 2001). It is interesting to note that the most intensive implementation of coal technologies and perhaps synthetic fuels may be occurring in China today, partly under the auspices of the U.S. DOE.

In energy policy circles, the SFC has become synonymous with government waste. However, the successes and failures of the program merit closer attention today. According to Herrick (2002), the Department of Energy's loan guarantee mechanism to finance new energy technologies was largely

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[16] By 1953, one of the flagship synthetic fuels plants in the program was decommissioned and refitted for ammonia production.

[17] The overthrow of the Shah of Iran in 1979 and the Iran-Iraq war in 1980 lead to a doubling of oil prices from $14 per barrel in 1978 to $35 by 1981.

[18] http://www.net.org/proactive/newsroom/release.vtml?id=27583.

unsuccessful because the government did not emphasize the financial viability of a technology in the marketplace and instead assumed the burden of the project's risk, rather than transferring it to the private sector. The SFC allocated funds to underwrite loan guarantees for up to 75 percent of the project cost. Furthermore, the SFC relied on "non-recourse" project financing, which was based on the project's expected ability to pay off debt with future cash flows, rather than the creditworthiness of the project sponsors. As a result, many of the projects that utilized this financing mechanism defaulted on the loans.

According to Deutch (2005), U.S. policies regarding synthetic fuels offer important lessons on the development of alternative fuels, including current oil shale, coal and hydrogen policies. In particular, Deutch suggests that the key to public policies concerning risky energy technologies is bringing the discipline of the private capital markets to bear on their development and commercialization. In particular, the government should not be involved in favoring any particular technology, but providing information and credible and reliable public policies. To the extent that funding is needed to bridge the gap between private and social returns, market forces should decide how funds are allocated, rather than government project managers. The record of government-funded demonstration plants is particularly poor, since they are often over –budget, provide little useful information to the private sector, and are subject to congressional pressure to influence R&D policy.

Deutch (2005) suggests the approach of Romer and Griliches (1993) - self-organized industry investment boards, where market forces would be used to decide how funds would be selected. Alternatively, Deutch has proposed the creation of an Energy Technology Corporation (ETC), whose primary purpose would be to collect and disseminate information rather than pick technologies.

Deutch points out that the SFC made the mistake of basing their analysis on energy forecasts, which are notoriously unreliable. In particular, the program set production targets independent of the prevailing market price for oil, by offering price guarantees, with price differentials paid by the SFC. However, the long-term viability of such a policy was put in doubt when OPEC made the specific long-term policy goal of countering Carter's synthetic fuels program by setting the price ceiling at just below synthetic fuels production costs (Adelman 1995).[19]

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[19] According to Adelman, OPEC appointed a Long Term Price Policy Committee of oil ministers in April 1978 who established this policy in secret. This report was leaked in late 1979.

Compressed Natural Gas and Electric Vehicles

The introduction of natural gas and electricity into the transportation energy portfolio in the 1980s and 1990s faced two formidable obstacles – the construction of a new refueling infrastructure, and the production and adoption of new classes of vehicles. This represented a potential shift in the burden of alternative transportation energy programs from the manufacture of synthetic fuels to the distribution and end-use of alternative energy. Despite the daunting tasks of constructing a distribution infrastructure, CNG and electric vehicle technologies promised to offer electric and gas utilities access to a potentially lucrative and stable[20] transportation market. Nonetheless, these programs were greeted with mixed emotions by the utilities.

Today, many natural gas utilities are unenthusiastic about their CNG investments from more than a decade ago and have chosen to maintain such assets because they represents a sunk investment, and in some cases, put them in good stead with regulators.[21] However, many utilities would not have made such investments had they foreseen a weak policy environment and stagnant demand for CNG vehicles in future years. This experience is of particular importance because existing CNG stations have been identified by researchers as cost effective platforms for the introduction of hydrogen in the transportation sector.[22]

In an analysis of CNG vehicle commercialization efforts in the United States and Canada in the 1980s, Flynn (2002) concluded that lessons from this effort need to be revisited for hydrogen and other alternative fuels efforts. Two lessons of are particular importance for the case of hydrogen. First, early profitability of a new infrastructure is critical to maintaining a genuine commitment beyond the minimum regulatory compliance. Second, investors in infrastructure must view this as part of their strategic core business, rather than administer it by middle managers with little attention from senior management.

LESSONS FOR HYDROGEN

Fuel cells may have the potential to address some of the long-term challenges of the heavily fossil fuel dependent U.S. energy sector—such as excessive dependence on foreign oil supplies and the deleterious effects of greenhouse gas and pollutant emissions—by displacing refined crude oil products.

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[20] One of the appeals of the transportation demand is that it represents more of a predictable "base" load, which is typically not as seasonal as residential natural gas or electricity demand.

[21] Interviews with natural gas distribution utility executives, January 2005.

Today, the transportation sector produces approximately one-third of the anthropogenic greenhouse gas emissions in the U.S., and 97 percent of the fuels consumed in this sector are derived from crude oil, most of which is imported. Between 1973 and 1999, the U.S. imported more than $1 trillion (nominal) of crude oil, representing a substantial wealth transfer to the OPEC oil cartel.[23]

Infrastructure – What should it look like?

According to a recent National Academies (2004) report, hydrogen can be produced at a cost similar to gasoline on an "efficiency adjusted" basis with existing technologies.[24] The problem is that the most economical methods involve production from natural gas at large, remote facilities that can benefit from favorable natural gas rates and economies of scale.[25] However, large facilities are much riskier in the early stages of a hydrogen transportation fuel market because of the potential for underutilization, which would drive the unit costs much higher. At low utilization rates, the early capital investment would not be able to recover costs, and so policymakers have focused on smaller-scale distributed units which have higher unit production costs but are less risky to investors.[26]

Estimates of the capital investment necessary to build a nationwide hydrogen infrastructure vary from $4 billion to more than $50 billion, and depend on critical assumptions concerning economies of scale, feedstock prices, technological progress, and consumer refueling behavior. The cost of building or retrofitting a single refueling station for hydrogen applications is typically cited in the $500,000 to $2 million range.

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[22] Researchers such as Ogden have employed Geographic Information Systems (GIS) to evaluate where to introduce hydrogen, and CNG stations have figured prominently in this research.

[23] Cotzlemann, NHA Conference, April 2004.

[24] Hydrogen and gasoline costs are often compared on an "efficiency adjusted" basis which accounts for the difference in efficiency of a representative gasoline internal combustion vehicle and a theoretical hydrogen fuel cell vehicle. Therefore, rather than expressing the price of fuel in terms of volume or mass, they are compared on a dollar per mile basis.

[25] Approximately one-half of the delivered cost of hydrogen from central facilities is from transportation and dispensing costs.

[26] According to Joseph Romm, who helped oversee hydrogen and transportation fuel cell research at the Department of Energy, the existing policy prescriptions are still inadequate:
"Who will spend hundreds of billions of dollars on a wholly new nationwide infrastructure to provide ready access to hydrogen for consumers with fuel cell vehicles until millions of hydrogen vehicles are on the road? Yet who will manufacture and market such vehicles—and who will buy them—until the infrastructure is in place to fuel those vehicles? I fervently hope to see an economically, environmentally, and politically plausible scenario for bridging this classic catch-22 chasm; it does not yet exist." Romm, J. J. (2004). The Hype About Hydrogen: Fact and Fiction in the Race to Save the Climate. Washington, Island Press.

One of the major issues in the cost estimates of a hydrogen infrastructure involves the extent to which consumers will need "gasoline-like" refueling convenience.[27] Since 70 percent of the U.S. population resides in 100 metropolitan statistical areas (MSAs), it is likely that a hydrogen infrastructure would be highly concentrated in certain geographic regions where there are favorable economics or public policy incentives (Melaina, 2003). Based on experiences with CNG and diesel vehicles, various studies have found the critical range between 10 to 20 percent of existing gasoline stations, with significantly diminishing returns to driving time for additional alternative fuel stations (Greene 1998). Ogden (2004) and Melaina (2005) have employed GIS tools to evaluate the tradeoffs between various hydrogen infrastructure configurations, including mean drive time to refueling location from residence and overall cost. Some have suggested "piggybacking" off of the existing CNG infrastructure (Gladstein 2005). Others have maintained the hydrogen should not be introduced for light duty vehicles, but rather heavy duty and marine applications (Farrell, Keith et al. 2003).

Multiple Markets and Early Profitability

In recent years, the literature on hydrogen technologies and policies has grown substantially, and includes a wide range of perspectives, including futuristic studies and advocacy pieces, engineering feasibility studies, cost-benefit calculations of hydrogen infrastructure investments, and long-term climate models, to name a few. Those studies that have made serious attempts to tackle the difficult issue of infrastructure development have preferred strategies that focus solely on the transportation sector, such as recent innovative efforts at spatial analysis and static optimization of potential hydrogen production and distribution networks that might provide "gasoline-like" convenience to fuel cell vehicle owners at the lowest cost.

Until recently, the prevailing wisdom has been that government-sponsored pilot programs would need to be followed by a very rapid ramp-up period – sometimes characterized as a "Big Bang" –requiring billion of dollars in capital investment for an infrastructure that would be underutilized, and therefore unprofitable, for many years, as fuel cell vehicles gradually penetrated the market (Melaina 2003). This traditional approach emphasizes the fact that a hydrogen infrastructure would be an extraordinary cost

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[27] It is notable that the petroleum industry spends about $37 billion per year on the conventional petroleum infrastructure in the United States and about $130 billion per year worldwide. There are approximately 170,000 stations in

borne by society, rather than a potential business opportunity for certain industries. One can conclude that this model has already failed several times in the U.S. experience.

In recent years, the deregulation of the electricity market, the emergence of renewables and possible carbon regulations, and technological developments in distributed power generation and smart grid concepts have opened the possibility of hydrogen being more closely integrated with electricity in addition to transportion markets.

For example, gasification processes have received more attention because of their relatively clean output, the prospects for efficiently sequestering carbon dioxide[28], the economies of scale, and low fuel costs for coal and other opportunity fuels. For example, Simbeck (2001) has suggested that deregulated energy companies will increasingly be able to enjoy multiple value streams, and that the concept of "cogeneration" which is typically applied to combined heat and power, will increasingly give way to "polygeneration". The integrated gasification combined cycle (IGCC), a technology designed to gasify coal (or other fossil fuels) and create electric power, has several advantages in this regard. In addition to economies of scale that can be achieved and cheaper fuel costs, this technology creates hydrogen as an intermediate step which can be separated for other uses, and a carbon dioxide effluent stream that may be amenable to sequestering in a carbon-constrained world (Simbeck 2004).

On a smaller scale, researchers have studied various hydrogen refueling station configurations that generate hydrogen on site, but also have the capability to divert some of the potentially excess hydrogen to a fuel cell to generate electricity that can be sold back to the grid or used locally. A National Academies (2004) report on the Hydrogen Economy points out that the linkage between the stationary power and transportation sectors may be important in the development of a hydrogen infrastructure, but that a comprehensive study has not been conducted and that the DOE has not considered this adequately in its research portfolio. Recent efforts at the Institutes for Transportation Studies at UC Berkeley and UC Davis have demonstrated promising links between advanced power technologies and hydrogen infrastructure.(Lipman, Kammen et al. 2004; Lipman 2004). The development of public policies that allow the selling of distributed electricity to the grid through net metering without significant interconnection fees could play an important role in the development of such technologies.

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the U.S. that sell refined fuels, and 9,500 gasoline stations in California (10 percent of which sell diesel).

However, critics have pointed out that the energy losses associated with the manufacture, storage, and conversion of hydrogen, would be economically prohibitive for small scale energy stations. As a result, some analysts have recommended that policymakers first focus efforts on renewable electricity, reduced demand, and biomass before addressing hydrogen (Bossel 2004; Romm 2004; Bossel, Eliasson et al. 2005).

The role of government in hydrogen

For policymakers, the great challenge concerning the development of a hydrogen infrastructure lies primarily in determining whether government should intervene, and if so, how to structure policy incentives and facilitate its financing, rather than resolving its inherent technical complexity.[29] Some have argued that the hydrogen market will likely evolve from local markets or "technology islands" with immediate needs for the technology, possibly merging over time into a regional or national infrastructure, rather than being managed from a "top-down" approach at a national level.[30] The technologies, standards, and consumer preferences are simply too uncertain, and the regional fossil and renewable energy endowment too heterogeneous, for a top down approach. As a result, state and local policies will play a pivotal role in shaping its development.

Recently, several state governments, most notably California, have proposed pilot programs and public-private partnerships to attract private industry investment in hydrogen infrastructure. For example, the Governor of California signed an executive order in April 2003 to establish a "California Hydrogen Highway Network" which would provide a state-wide infrastructure in support of fuel cell vehicles by 2010. This effort envisions public-private partnerships to spread the risks and benefits of early hydrogen infrastructure investment, which are expected to cost $100M-$10B in California.

A multidisciplinary team representing the Hydrogen Highways initiative recently produced a comprehensive set of documents[31] describing the technical and economic aspects of the program, and an initial scoping of potential public policies. However, the exact nature of the financing mechanisms and

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[28] The high partial pressure of carbon dioxide that can be achieved in an IGCC allows for an efficient separation from other products.

[29] "Formulating and Implementing Public Policy for Hydrogen," Clint Andrews, Rutgers University.

[30] Scott Weiner, "The 'Value Proposition' of Hydrogen," Rutgers University, 2004.

[31] The Hydrogen Highways Initiative has announced that this document will be updated biannually.

policy changes have not yet been defined, and the effort leaves many questions unresolved, including the role of renewables, regulatory issues regarding competitive access, and analytic methods that would be relevant to policy makers and industry stakeholders. The next chapter will analyze the perspectives and potential role of natural gas distribution utilities in investing in hydrogen.

CHAPTER 4: A CASE STUDY OF THREE NATURAL GAS DISTRIBUTION UTILITIES

This chapter develops a case study of the potential role of natural gas distribution utilities in hydrogen and fuel cell investments. This analysis is based on interviews with executives of three major natural gas distribution utilities in the United States and a critical review of the literature. The goal of the case study is to identify investment strategies, uncertainties, and public policies that are relevant to the industry. In Chapter 6, these findings are quantified for a generic natural gas distribution utility, which is the unit of analysis for the real options model.

APPROACH

As an integral part of the analytic effort, representatives from three natural gas distribution utilities—Southern California Gas Company, NiSource, and Keyspan—were consulted in validating the general modeling approach used in this dissertation. Between January and December 2005, a series of on-site discussions and email-based surveys were conducted with senior and mid-level executives.[32] The utilities differed greatly in the size and location of their service territories, the scope of physical assets, perceived risks, and regulatory environment. In terms of customers served, they represent three of the nation's top five natural gas distribution companies. This diversity greatly benefited the model development, but many common themes emerged during the discussions. A more detailed description of the utility discussions and comparisons of their investment philosophies are shown in Appendices A.1-A.6. These results are summarized in Table 4.1.

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[32] This analysis serves as a basis not only for this dissertation, but also a project under the auspices of the Department of Energy, conducted jointly by RAND, Gas Technology Institute, and ARES.

Table 4.1: Summary Characteristics of Three Natural Gas Distribution Utilities Surveyed

Characteristics	Southern California Gas Company[33]	NiSource	KeySpan
Revenues ($ billions)	11.7	7.9	>5
Customers (million)	29	3.6	2.5
Spatial Characteristics	Dispersed urban	Mixed rural, industrial and urban	Dense urban
Assets	Gas distribution. SEMPRA parent company owns LNG and also San Diego Gas and Electric	Primarily gas distribution	$11 Billion. Gas distribution and also electric generation as well as CNG units

The market structure of the U.S. natural gas industry is illustrated in Table 4.2. The focus of this analysis is on the distribution companies, although all of the utilities surveyed owned other types of assets as well.

Table 4.2: Market Structure of U.S. Natural Gas Industry[34]

Market Segment	Market Structure
Production	8,000 producers (24 "majors")
Processing	580 plants
Transmission Pipelines	160 pipeline companies 280,000 miles of pipe (185,000 interstate)
Storage	114 operators, 415 underground facilities
Local Distribution Companies (LDCs)	>1,200 Own 833,000 miles of distribution pipe
Marketers	~260 companies (80% of product sold to end users through them)

Investment philosophies from the natural gas distribution companies are important for two reasons. First, policymakers will most likely need to engage this industry in any serious effort to build a hydrogen infrastructure. The natural gas (and electric utilities), who could be important providers of hydrogen services in the near-term, have not played a major role in developing the national hydrogen energy vision,

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[33] Information on revenues and customers served is for SEMPRA, which also includes San Diego Gas and Electric Company.

and the DOE would like to engage them. For example, the natural gas industry has an existing set of physical assets, knowledge of their customer base and technologies, and ability to finance investments that may be unique. Also, natural gas is used in the lowest cost processes available for manufacturing hydrogen today.[35] It would be important to have an analytic basis for policymakers and private industry to understand the risks and rewards associated with this vision.

Second, the natural gas industry is expected to make substantial investments over the next two decades, and one of the questions facing policymakers and utilities is whether serious consideration should be given to hydrogen during this investment cycle. The U.S. Energy Information Administration estimated (1999) that an investment of $40 to $80 billion will be needed in new pipelines and expansion of existing transmission infrastructure to meet the growth in natural gas demand over the next two decades, primarily from the electric power sector. A National Petroleum Council report (1999) forecasted $781 billion in capital investments by the natural gas industry through 2015, $123 billion of which would be spent on transmission, storage, and distribution infrastructure expansion, with the remainder spent on upstream supply development. Yet, the industry has an incomplete understanding of its potential role in hydrogen and whether it merits attention in their investment portfolio.

INDUSTRY VIEWS ON INVESTMENT

At the beginning of the study, none of the utility executives interviewed saw a current or future business case for hydrogen, at least within their planning horizons, which was typically about three years forward. It is clear that these natural gas utilities look to significant leadership from the state and/or federal level regarding policy implementation. However, they are all interested in hearing whether there is a case

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[34] From http://www.naturalgas.org/business/industry.asp

[35] Currently, about 5-8 percent of U.S. natural gas is used to make industrial hydrogen, mostly via steam methane reforming, which is one of the lowest cost processes available for manufacturing hydrogen The hydrogen atom is the most abundant element on earth, and is found in water and virtually all organic substances. However, molecular hydrogen, which is used in most types of fuel cells, is not found readily in nature, and must be created from other substances. Today, hydrogen is almost exclusively produced from natural gas, although heavier fossil fuels and water can also be used. Natural gas is considered the most favorable fossil fuel feedstock for hydrogen production due to its high hydrogen-carbon ratio, widespread infrastructure, and handling properties. This process typically involves a high pressure, high temperature reaction in the presence of steam and a nickel catalyst (reforming), but can also be produced with oxygen (partial oxidation), or both (autothermal reforming). Hydrogen is also a by-product of several petrochemical manufacturing processes, and is produced to a much lesser extent from coal gasification, partial oxidation of petroleum, and electrolysis.

About 95% of all industrial hydrogen in the U.S. is made via steam methane reforming, about half of which is used in refineries to make gasoline and diesel fuel. The rest of the hydrogen demand comes from the fertilizer, methanol, petrochemical, metal production, and microchip industries. World hydrogen production doubles approximately every decade, mostly due to increasing demands at refineries, with demand growth stagnant in other industries.

to be made, particularly if it would fit within their core business plan. Their investment philosophies are shaped by several major issues.

Core business is the focus

First, gas distribution utilities increasingly must justify investments within their core business plans. All of the utilities have had negative experiences with speculative investments in CNG refueling stations, extensions of distribution infrastructure in promising but uncertain territories[36], and in-house research and development. As a result, the gas utility business has become more conservative than it was in the past. Most of the players in the industry have divested themselves of in-house R&D assets over the past two decades. Some companies prefer equity interests in small technology companies in order to maintain their knowledge base, influence the course of technology development, and occasionally sell equity positions for a profit. Meanwhile, some of the falloff in traditional R&D has been met through the national laboratories and the Gas Technology Institute.

Therefore, the focus is predominantly on serving the customer base and increasing gas throughput, since this constitutes the lion's share of their revenue stream. Thus, investments which may be profitable but not a "platform" for fundamental sources of growth are generally not favored. However, all of the utilities seemed interested, in principle, in innovative ways to look at their investment portfolio. As far as hydrogen is concerned, they are interested in hearing how it might be justified within their core business, even though they are skeptical there is a case for it within their short planning horizon.

However, there has been a trend in recent years on utility expansion in new markets, particularly ones that can increase gas throughput. Unregulated energy service subsidiaries have been the primary vehicle for accessing these markets.

Risk management tools are central element of business

Since the deregulation of the natural gas industry in the 1980s, a variety of risk management strategies have played a crucial role in helping utilities manage gas price risk. The primary revenue source for most distribution utilities is the regulated natural gas pipeline transportation charge, which is usually

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[36] One utility executive described this as the "Build it and they will come" approach, otherwise known as the "Field of Dreams Theory".

based solely on the physical throughput of gas, rather than natural gas wellhead price. As a result, price risk is passed down to consumers. Although most consumers have an inelastic demand profile for short-term price spikes, longer-term price spikes are a concern, particularly on service territories with competing fuels, such as fuel oil in the northeast. Also, sustained price spikes have led to increasing regulatory scrutiny and legislative efforts aimed at greater energy efficiency which would substantially impact their revenue stream. As a result, some utilities have begun to invest in LNG assets in order to manage price spikes.

Geczy, Minton et al. (2000) examined the effectiveness of alternative risk management strategies used by natural gas industry, as a result of deregulation. They found that the industry engaged in two types of strategies. For short-term risk management, they engaged in exchange-traded derivative instruments, larger cash holdings, and physical storage in pipelines and storage facilities. Longer-term risk management strategies included new lines of business and geographic diversification.

One of the questions for utilities today is whether hydrogen or other advanced energy technologies could be part of their slate of risk management tools. They would like a greater understanding of whether the location of hydrogen conversion along the natural gas industry value chain could affect the utility industry's ability to participate in large-scale aggregate markets for technology, financing, and hydrogen services. Would distributed or at-home hydrogen generation supplant or enhance the utility's traditional role of metering/billing for energy services? What kind of relationship would utilities have with end-use consumers? Would they purchase unused hydrogen back from consumers? Would they offer preferential prices or different types of rate structures for natural gas to consumers who converted to hydrogen? However, for most discussants, these were largely long-term, theoretical questions they felt would not be resolved in the near-term.

Executives felt that hydrogen did not represent a risk management tool as a commodity, since hydrogen prices would be highly correlated with natural gas prices. Furthermore, these utilities are not interested in entering a commodity chemical business, but would prefer to make hydrogen investments if they are somehow connected with their energy portfolios. To the extent that it represented a window into another line of business in the energy sector, it was of interest. In particular, it may play a role in reducing the risk of natural gas displacement in the electric power sector if there is a significant growth of renewables.

Non-core investments face very high risk-adjusted hurdle rates

Utility executives had explicit rules or implicit guidelines on investment returns in non-core technologies. Most indicated that positive cash flow needed to be achieved within 3-5 years (with a slightly longer timeframe for R&D, for those pursuing it). Equivalently, others set very high risk-adjusted discount rates for non-traditional investments.[37] These rules of thumb on hurdle rates were the result of years of experience with riskier investments, particularly in the 1980s and 1990s. Of particular note was the mention by one senior executive of the relationship between investment and uncertainty, and how these experiences in the past had shaped their philosophy today.[38]

> *We have been burned in the past when the rate of investment was faster than the rate of resolution of uncertainty.*
>
> -- Natural gas utility senior executive

Rather than being necessarily risk-averse, utilities are interested in understanding how to incorporate new market information over time, and how to incorporate it in decisions that are being contemplated today.[39]

Government policies do not encourage technological risk-taking

Utility executives perceive regulation as establishing both a floor and a ceiling to the economic returns for their business. Their investment philosophy is driven primarily by expectations about future demographics and managing Public Utilities Commission (PUC) rate adjustment cases, rather than potential risks or rewards associated with mitigating or taking advantage of future market or policy outcomes. This is primarily because their investment horizon is short-term, but also because it is very difficult to rationalize taking risks for relatively small returns, in the context of the relatively secure returns expected by stockholders. There is a belief that most risks assumed by the utilities in the core business can

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[37] See also Lempert, R. J., S. W. Popper, et al. (2002). "Capital Cycles and the Timing of Climate Change Policy." The Pew Center on Global Climate Change.

[38] Interview with senior utility executive, January 2005.

[39] It is interesting to note that the real options method can be used to demonstrate how high hurdle rates are consistent with the existence of real options. For example, the classic approach of "Tobin's q" can be modified in such a way that it accounts for the opportunity cost of investment by requiring the q to exceed unity. This would essentially be equivalent to a discount rate that is adjusted above the capital cost. The opportunity cost here would be the opportunity cost of immediate investment versus delay (rather than the opportunity cost of other investments, which would be accounted for in the discount rate).

be managed because of the expectation that they can go to regulators to recover their costs and there are no credible competitors (outside of fuel oil in the Northeast).

Utilities are reluctant to invest in the hydrogen business because they believe that the regulators will take away any profitable business that they build. For example, natural gas distribution utilities may find that they can offer hydrogen at a low cost if they do not charge natural gas distribution markups to their own internal hydrogen production business. However, they fear that if such an enterprise were to become profitable, that regulators would eventually scuttle this advantage. They would then be faced with the prospects of absorbing significant sunk costs and even allowing competitors access to their infrastructure at rates below cost recovery levels.

It is clear that all of the natural gas utilities would require a major commitment at the state and/or federal level in order to make substantial hydrogen investments of any type. Government action is clearly central here. The utilities would need a credible, stable, long-term policy that would allow them to pass down costs to ratepayers, or tax incentives or subsidies. For example, utilities are worried about what they characterized as a "free-rider problem" from their experience in building CNG stations for government and private fleets that later rescinded contracts with them. For distributed generation applications, the main barrier mentioned was capital cost, followed by myriad regulatory and electric utility constraints.

Typically, traditional hydrogen markets do exist on their service territories, but these are already saturated and the utilities are not interested in becoming dual-commodity suppliers. However, they were open to the possibility of an unregulated spin-off hydrogen business if the opportunity arose.

Policy uncertainty was cited by many utility executives as a source of concern, particularly for gas operations related to the electric power sector. One discussant described a situation where deregulation would be more accurately described as a process of "re-regulation", which has led to long-term underinvestment in the power sector and problems with blackouts. Regulatory risks are a larger consideration in their sales of gas to the electric power sector than in their core business.

Utility executives were generally reluctant to make large strategic decisions based on uncertain policies. However, several discussants cited the fact that there seemed to be a "policy window" available for the industry to get involved in the distributed generation and hydrogen business, and perhaps show proof of principle to regulators. Discussants were particularly interested in policies that they felt would be sustainable—namely that they should make sense for both industry and government. For example, several

executives felt that a policy that would allow utilities to partially recover sunk costs for speculative investments (rather than upfront cost sharing with government) that met higher policy goals would meet such a criteria. This way, the utility would decide if the investment made sense for its core business, and only petition for sunk cost recovery if it is expressly unprofitable. Likewise, it if were partial recovery rather than full recovery, there would be less incentive to game the system.

The role of gas utility and unregulated subsidiaries not always clear

The electric generation sector is of growing interest to utilities. However, the gas utility's relationship with the incumbent electric utility plays a major role in their perspective on distributed power generation. In fact, one of the main impediments to gas utility participation in distributed generation, as cited consistently by discussants, was the managerial or cultural difference between the electricity and gas side of the business, even if they are part of the same holding company. Some utilities own electric generation assets, others provide gas, and some are joint electric-natural gas utilities owned by a larger holding company. The electric side has generally been regarded as having more gravitas in such arrangements.

This is of particular importance because many of the benefits of distributed generation, as cited in the academic literature, are attributed to the foregone investments in electricity transmission and distribution assets, particularly in dense urban areas or other expensive pockets where an electric utility might prefer to have a third party build a distributed power resource. However, this "global optimization" approach suffers from practical obstacles, even when power and gas companies are jointly owned, because the regulations on the returns on investment in transmission and distribution may not offer the right incentives for companies to choose expanding DG assets in lieu of traditional infrastructure upgrades.

CRITERIA FOR MODEL DEVELOPMENT

Based on the results of the interviews with these natural gas distribution utilities, a modeling approach was constructed that would incorporate these concerns and therefore be relevant to a real-world problem facing utilities, regulators and the DOE. The following criteria were used in developing the model:

1. **Transparency.** The utilities and the DOE are interested in a methodology that is transparent and at least consistent with or comparable to traditional analytic methods. An emphasis on discrete math, for example, would be preferable to partial differential equations. Also, there is a need to establish clarity on parametric assumptions used in the model.

2. **Core Business**. The utilities are interested in strategies that address their core business and generate near-term revenues. Also, policy tools should be ones that are considered credible to the industry and ones that would impact their core perspective.

3. **Dynamic Complexity rather than Detail Complexity**. The model should focus on the relationship between investment strategies and how they relate to the dynamics of new information that a utility might acquire over time. The utilities understand the technical and geographic details very well, but are interested in getting a better handle on the tradeoffs between making early risky commitments and waiting until uncertainties are resolved.

These criteria were incorporated in the analysis in the following chapters.

CHAPTER 5: POTENTIAL HYDROGEN MARKETS AND PUBLIC POLICIES

Based on a review of the literature and interviews with utility discussants, potential hydrogen markets were identified and analyzed. The following discussion describes the various markets considered and reasons for their inclusion or exclusion in the model.

HYDROGEN VEHICLE REFUELING

Among the various uses of hydrogen, the hydrogen vehicle refueling market is of greatest interest to policymakers, but is regarded by utilities as an investment option that would be driven almost exclusively by government policy rather than business fundamentals, at least within their investment horizons. Some analysts and policymakers have identified existing CNG refueling stations as a cost-effective platform for hydrogen.[40] Currently, there are about 110,000 natural gas vehicles and 1,300 natural gas stations in the U.S. Many CNG stations are still owned and operated by natural gas distribution utilities, which have reluctantly maintained their operations because they generated modest, but steady revenues, and represented a sunk investment with very limited opportunities for redeployment. Utilities would consider retrofitting some CNG stations for on-site hydrogen production and dispensing only with substantial policy incentives or sustained penetration of fuel cell vehicle fleets. However, utilities are reluctant to be first movers in the fuel cell vehicle market because of the risks of free-ridership. Some utilities have experienced this problem with their CNG stations when private fleet owners have cancelled contracts with them after the utility had already allocated significant resources.

From an analytic standpoint, it was determined that the vehicle refueling market would not be modeled directly, because it did not meet the criteria set out earlier in this chapter—namely, that it was part of a larger strategy that addressed core business issues and had the potential for early revenues. Although some utilities have bid for hydrogen stations or stationary fuel cells, they serve primarily as small demonstration projects in partnership with government, rather than a concerted business strategy.

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[40] This is generally considered a near to medium-term strategy. Currently, the transportation sector accounts for only 3 percent of natural gas consumption in the United States, most of it to fuel pipeline transportation of hydrocarbons, rather than CNG vehicles. There have been few studies that seriously consider the implications of a significant market penetration of natural gas for new hydrogen markets in transportation.

As described in a National Academies Report (2004), there are unresolved questions regarding the links between the electric power and transportation sector for fuel cell investments. The approach taken in this dissertation is that a utility would have a greater interest in the existing distributed generation market (described in the next section), with the option to redeploy assets to the fuel cell vehicle refueling market at some point in the future. Different engineering concepts, such as the "Energy Station", as mentioned in Chapter 3, might in theory allow fuel cell vehicle refueling stations to be profitable in the early years by selling electricity to the grid, and diverting hydrogen at a later point to serve the vehicle refueling market.

However, there are serious engineering and economic questions surrounding these concepts. For example, some have argued that incorporating a fuel cell within any hydrogen refueling station configuration would be inherently unprofitable with foreseeable technologies (Simonnet 2005). This dissertation does not dispute this work. However, if existing sunk assets, such as CNG stations, are available for retrofitting, it may change this cash flow valuation. Issues regarding the sizing of steam methane reformers, fuel cells and hydrogen storage are critical, but from the perspective of this analysis, are too detailed and too uncertain to model an investment strategy. Rather, the perspective taken here is that the emergence of a fuel cell vehicle market may or may not generate a secondary market for this capital, which may lower the risk of investment in stationary fuel cells for distributed generation. This would be equivalent to creating a salvage value which would represent selling or redeploying assets to a more favorable market.

DISTRIBUTED POWER GENERATION MARKET

The distributed power generation market is of growing interest to many natural gas utilities, because it represents an opportunity to increase natural gas sales to natural gas-consuming technologies such as microturbines and fuel cells. Future power generation applications may emerge for hydrogen, but primarily for small-scale distributed generation or combined heat and power (CHP) generation with certain types of stationary fuel cells. In fact, fuel cells will be part of a larger set of technological options, which currently include micro-turbines, diesel backup generators, and renewable resources. It is estimated by the EIA (2000) that the technical market potential for distributed generation in the commercial and institutional sectors is more than 77 GW. However, these investments would depend critically on local energy prices

and policies. Other niche applications for hydrogen are theoretically possible in the electric power sector, but were not considered in this analysis.[41]

In the absence of government intervention, major technological innovation, or increased demand for power quality and reliability from distributed power, it is unlikely that fuel cells will play more than a niche role in the electric power sector in the 2005-2020 timeframe. According to the U.S. Energy Information Administration (2005), solar and wind technologies will likely dominate the distributed generation market due to federal and state-level renewables legislation.[42]

Demand for power quality and reliability were once cited as an important driver of fuel cell market growth. However, the technology downturn in recent years has changed this valuation, particularly for internet servers and semiconductor facilities requiring highly reliable and premium power (Baer, 2004). The implications of power reliability on distributed generation are not clear, and whether its growth in recent years represents an anomaly rather than a trend. Some have argued that tight markets in recent years will require DG in order to avoid blackouts. However, blackouts may also increase investments in central generation and traditional transmission and distribution infrastructure, obviating the need for DG. Others have cited the potential emergence of smart grids, which would allow a greater integration of distributed assets with the grid. In addition to capital costs of fuel cells, one of the main barriers is interconnection standards imposed by electric utilities in order to ensure grid stability and electric utility control over load growth.

Emerging distributed power generation and "smart" electric grid technologies may change the way electric utilities perceive their infrastructure investments by allowing a more efficient use of assets over time and space. Since the marginal costs of electricity service can vary widely throughout a utility service territory and by time, distributed generation assets, in some cases, can be more cost effective than traditional distribution upgrades to meet load growth (Woo 1995). To the extent that smart grid technologies allow the electric utility to charge rates that reflect deferred costs in an economically efficient

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[41] For example, as a blend with natural gas for low-NOx applications, as an energy storage mechanism where peak-shaving is important or remote wind or solar power are prevalent (Synapse study on Dakota wind and hydrogen, Bartholomy study). Some have argued that the addition of a small fraction (< 5% molar mixture) of hydrogen in natural gas applications can improve emissions, but the life-cycle implications are less clear. If hydrogen is manufactured from natural gas, there are inherent inefficiencies in converting a small amount of natural gas to hydrogen to then using it as an admixture to natural gas. This dissertation does not aim to answer this question. For example, see Ulf Bossel, Baldur Eliasson, and Gordon Taylor critique on hydrogen energy.

way, rather than averaged over time and space (Ianucci and Eyer 1999), and to enable real-time dispatch of distributed resources, end-users (or the utilities themselves or other energy service providers) may be increasingly able to internalize those benefits by investing in smaller scale assets nearer the point of use in lieu of traditional utility infrastructure upgrades.

Distributed power generation technologies have typically been looked upon with caution by electric utilities due to the high cost of interconnection to the grid, potential complications with grid stability, and prospects for market share loss to the natural gas industry and non-traditional power producers such as renewables. As a result, the electric power industry today has the leverage to charge a prohibitively large interconnection fee for end-users desiring to sell electricity to the grid, effectively rendering unprofitable some types of distributed energy resources by limiting their access to the grid. However, a slate of new electric power grid technologies are expected to lower the cost of interconnection and dispatching of DER assets (Kannberg 2003), and will likely be deployed in some form in the United States during the timeframe of the hydrogen investment scenarios developed in this analysis. The natural gas industry may serve an important role in the distributed power generation market, due to its widespread infrastructure, access to consumers, and expertise in operations with compressed gas processing, transport, and storage.

The greatest opportunity for stationary fuel cells may arise from renewables legislation. Although fuel cells are technically not a renewable energy source, their high efficiencies, low emissions profile, ability to use "green" hydrogen and base load capabilities have generated interest in their inclusion in renewables regulations in the electricity sector.

Figure 5.1: Role for Fuels Cells within RPS in 2020?
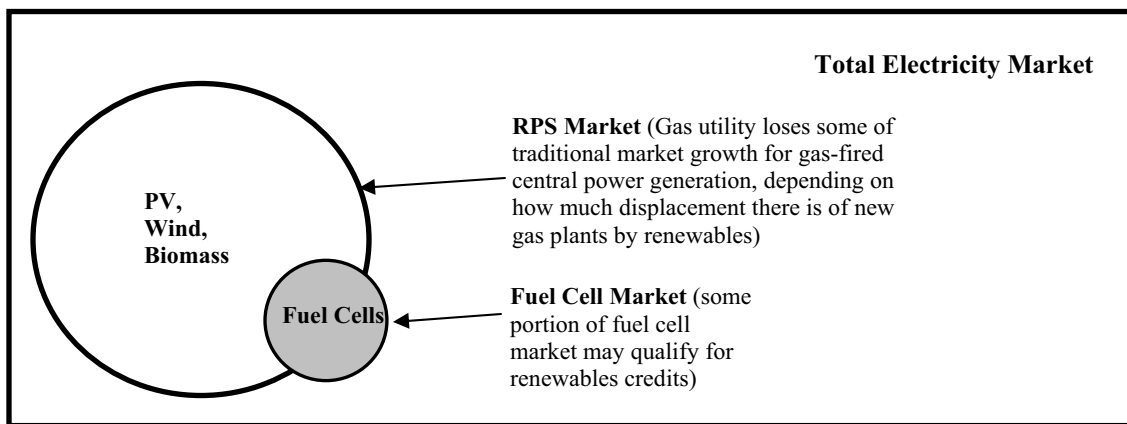
The penetration of renewables would eventually take away from natural gas demand growth in the electricity sector, as shown in Figure 5.1. To the extent that fuel cells can capture some of this market share, it would be an important risk management tool for gas utilities. A recent Lawrence Berkeley National Lab report (2004) calculated the potential impact of natural gas displacement from renewables.

At present, 18 states have enacted legislation establishing Renewable Portfolio Standards (RPS), which either mandate purchases of renewable electricity by electric utilities or establish markets[43] for tradable credits. Thus far a federal RPS has been blocked in energy legislation but may happen in the future. Nearly all of the 18 states are currently in the early phases of implementation and may depart significantly from initial legislation. For example, proposals have been made in several states to accelerate the introduction of renewables beyond the established RPS policy. Most state RPS legislation includes fuel cells as a qualifying renewable energy source, but in several states, non-renewable-fueled fuel cells receive either partial or no credit. Several states, such as New York, currently include natural gas powered fuel cells.

CENTRALIZED HYDROGEN PRODUCTION AND TRANSPORTATION

Centralized hydrogen production and transportation is of interest to policymakers because hydrogen can be produced at a cost similar to gasoline at this scale, as mentioned in Chapter 2. However, it would represent a risky investment for the gas industry, unless it wanted to get involved directly in the traditional hydrogen business.

Centralized hydrogen production and transportation is a mature industry located primarily in parts of the U.S. Gulf Coast and western Europe to serve traditional industrial consumers of hydrogen. Hydrogen is a common industrial chemical which is primarily used to produce ammoniaand methanol, and to upgrade and desulfurize petroleum products at refineries. Other applications include semiconductor manufacturing, food processing, and ammonia-based fertilizers. The United States represents more than 50 percent of the 220 bcm/yr worldwide hydrogen market, which doubles approximately every decade, mostly due to increasing demands at refineries for hydrotreatment to create high-octane, low-sulfur gasoline. Otherwise, demand growth for hydrogen has been stagnant in other industries. Since existing hydrogen technologies exhibit significant economies of scale and high transportation costs, most hydrogen is

produced at large centralized facilities and is consumed on-site or in proximity to existing hydrogen pipeline networks near the U.S. Gulf Coast.

Traditional hydrogen markets have been contemplated by natural gas utilities, but they have generally ruled this out in favor of providing natural gas for specialty chemical companies who typically use steam methane reforming techniques to create hydrogen, and transport via tube trailers and even pipelines. This additional capital is quite expensive. In principle, gas utilities are interested in accessing traditional markets insofar as these stable sources of demand would allow them to hedge against more speculative investments in the energy sector. However, they did not envision a role in this market, except perhaps as a niche player.

Some have argued that there may be benefits to generating hydrogen at a more efficient scale somewhere further upstream in a distribution network. These concepts include (1) dedicated hydrogen transmission or distribution pipelines, (2) dual-use hydrogen-natural gas pipelines, and (3) traditional natural gas pipelines "doped" with small amount of hydrogen.[44,45] Hydrogen pipelines could also be used to transport hydrogen from other suppliers, including hydrogen generated from renewable resources or fossil fuel processes with sequestered CO_2. Finally, a hydrogen network could theoretically facilitate the emergence of a hydrogen spot and derivatives market, which would offer risk management benefits to both producers and consumers. One question has centered on the location of hydrogen conversion along the natural gas industry value chain and how it might affect the utility industry's ability to participate in large-scale aggregate markets for technology, financing, and hydrogen services. These ideas were considered but ultimately rejected for this analysis.

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[43] For example, Texas has an RPS market with tradable Renewable Energy Credit (REC) permits.

[44] Pipeline owners could also carry small amount of hydrogen in the existing natural gas backbone. This hydrogen could be separated at the end-of-pipe, or used as hythane in combustion applications. With some retrofitting of seals and fittings (to avoid corrosion and leaking), the amount of hydrogen injected into a natural gas pipeline could be ramped up to 10-15 percent before the pipeline would encounter compression problems. However, residential burners and other end-use technologies receiving this mixture would have to be retrofitted to accommodate different flame characteristics of hydrogen-rich gases. Also, this strategy is very complicated, since it involves the coordination of every segment along the natural gas industry chain in addition to idled pipeline capacity, and is thus highly unlikely. Also, safety concerns regarding hydrogen embrittlement of pipelines may be prohibitive.

[45] Small amounts of hydrogen added to natural gas have been shown to reduce nitrogen oxide (NOx) emissions during combustion in laboratory conditions. As a result, natural gas-fired power plants could, in some cases, forgo investments in NOx mitigation equipment if natural gas is "doped" with small amounts of hydrogen. This approach is currently described in the European Union's energy portfolio. However, critics have maintained that it makes little sense to do this if hydrogen is made from natural gas.

The forecasted rate of growth of distributed power generation capacity over the next 20 years is very modest[46] and geographically unpredictable, presenting a very poor target for upstream hydrogen investment in the absence of significant efforts to coordinate this market.[47] For example, an emerging concept that could provide a focal point for targeted DER growth is that of "neighborhood clusters" of distributed energy and telecommunications for critical infrastructures, such as financial institutions and server farms (Balkovich and Anderson 2003).   Also, in service territories where natural gas and electricity distribution are within the purview of the same utility (e.g. such as SDG&E and PG&E in California), the utility could theoretically perform a "global" optimization to facilitate distributed generation adoption where it would be most beneficial to the system – namely, to alleviate congestion in electricity infrastructure or to balance natural gas load geographically. These types of coordination would facilitate investment in distributed generation and perhaps an associated hydrogen infrastructure. However, they were not considered relevant for this analysis. Although hydrogen pipeline investments were not considered in this model, it is notable that recent developments in coal and petroleum coke-powered IGCC power plants have spurred interest in transporting sequestering carbon dioxide by pipeline to geological carbon sinks, and piping hydrogen possibly to emerging hydrogen markets (Ogden, 2003).

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46 The EIA predicts a 3.4 percent annual growth rate from 2001 to 2025 (reference case scenario) in natural gas consumption for distributed generation purposes, compared with a 5.0 percent annual growth rate in natural gas consumption in the traditional power sector. (Table A8, p. 131, AEO2003)

47 The demand for hydrogen for non-traditional applications in new, geographically dispersed markets would be very low and highly uncertain for a number of years. Thus, smaller-scale, distributed production would likely emerge in order to address nascent markets outside of the traditional petrochemical and refinery applications. Distributed hydrogen would be produced primarily through natural gas reforming and electrolysis in regions where it is economically favorable. The hydrogen produced in such a way would have a higher unit cost, but would be a much less risky investment. Thus, the initial hydrogen supply chain would be highly regionally heterogeneous, and would depend on local energy infrastructure endowments, energy commodity prices, and regulations.

CHAPTER 6: REAL OPTIONS MODEL

MODEL OVERVIEW

This dissertation uses an adaptation of a real options valuation to model capital investment decisions facing a generic natural gas distribution utility under different assumptions about market, technology, and policy uncertainties. The goal is to identify investment strategies that are robust across a wide range of futures, to discover where they are vulnerable, and to evaluate the impact of government policies on the level and timing of such investments. The ultimate goal is to reduce the dimensionality of the problem, in order to provide guidance to policymakers and private sector investors.

Based on the case study developed in Chapter 4, it was determined that a real options approach would be the most appropriate for modeling the types of decisions a utility would make. Of greatest interest to decisionmakers are how uncertainties might evolve, and how to structure investment decisions to incorporate new information over time. As a result, the approach emphasized dynamic rather than technical complexity, focusing on strategic-level issues evaluated at multiple decision points, allowing for staged investments and the possibility of abandonment or redeployment of technologies to different markets.

A discrete-time approach was chosen in order to allow a richer treatment of investment strategies, uncertainties and policies. The real options problem is solved as a decision tree with annual time steps, where probabilities and states are defined by a separate spreadsheet-based module that feeds into the decision tree. This relationship is shown in Figure 6.1. The next section will describe components of the real options model and the analytic techniques used to sample the parameter space.

Figure 6.1: Overall Model Structure

Stuctural Uncertainties in State Variables

Define probabilities

Electricity Market Model

Define cash flows for each state

Payoff

120 Possible Final States

Strategies (4 Core)

15 Time Periods

Real Options Decision Model

Tree Solver

Optimal Investment Strategy *s* **

Real Options Model Outputs

Real Options Model Inputs

Construct Database (Scenarios ensemble)

Consider improved hedging options

Identify Candidate Strategy

Identify Vulnerabilities

Exploratory Simulation and Robust Decision Making

INVESTMENT STRATEGIES

This section describes the specific investment rules that were developed for the model, based on the discussion in Chapter 4. The fundamental question a utility faces is whether it should (1) totally ignore the fuel cell market and maintain a business-as-usual strategy, (2) make some type of early commitments related to fuel cells, or (3) wait until a later date to make hydrogen investments should specific market or policy signals occur. These decisions depend intimately on what the utility assumes to be the main driving forces behind a nascent distributed power and fuel cell market. These include uncertainties about the energy market, public policies, technologies, and whether the investor has any influence in the market or public policy as a first mover. Some of these uncertainties can be partially resolved through investment, while others can only be resolved over time. The optimal investment pathway depends critically on what assumptions are made about the relationship between uncertainties, cash flows in each state, and decision points for each strategy.

A recurring theme in the discussions with utilities was the ambiguity or uncertainty concerning public policy on fuel cells, renewables, and hydrogen. In particular, it was not clear to utilities whether or not there was a near term "window" of opportunity to make early investments, and if so, whether subsequent legislation would render such investments unprofitable or whether early investment might actually lead to the establishment of a technology standard or proof of principle to regulators. In this regard, a real options model is well suited to emphasize the tradeoffs between immediate investment and waiting. Table 6.1 illustrates the investment choices considered, and the justification for their inclusion or exclusion from the model.

A stylized characterization of these relationships is shown in Figure 6.2, where the investment regime is divided between an early period and a late period. Specific assumptions about uncertainties will be described later in this chapter. The model assumes that market and policy uncertainties attenuate over time and disappear after 2010, so that a utility investing in the late period does not encounter any market or regulatory risks, but may face greater barriers to entry in the business. Under certain assumptions, a delay in utility investment can lead to market share erosion from competition (competition in this case emerging not only from other fuel cell distributors but also other technologies that fulfill the RPS mandate or serve as

competitive distributed generation technologies). For most reasonable assumptions regarding discount

rates, there is negligible loss of generality by locking-in decisions for these last 10 years. The model

assumes that the Energy Services Company and R&D strategies cannot be pursued simultaneously, since

the budget constraint can only support one early investment strategy.

Table 6.1: Natural Gas Distribution Utility Assets and Potential Investment Strategies

Strategy	Leveraging Which Asset?	Relevant Uncertainty	Pro	Con	Model
Distributed Power Generation (Stationary Fuel Cells)	Knowledge of customer base and incumbent electric utility in service territory	Government policies, Gas and Electricity prices, Demand, Electric reliability	1) Potential Early Cash Flows 2) First-mover market influence over tech adoption or regulation?	Risk of policy or technical surprise leading to abandonment	Early investment in ramping up energy services subsidiary allows utility to enter DG business
Fuel Cell Vehicle Refueling Station	Existing CNG stations	Rate of introduction of fuel cell vehicles Government policy on sunk investment and cost sharing	May get a higher capacity utilization from CNG stations, more lucrative market, or potential platform for future investment in central hydrogen production	Free rider problem. Risk of FCV fleet timing and sunk investment	Addressed indirectly in model. Salvage value in secondary market, which is fuel cell vehicle refueling market.
Centralized Hydrogen Production and Transportation	Natural Gas Transmission and Distribution Pipelines	Rate of introduction of fuel cell vehicles Government policy on dual use infrastructure	Create cheaper hydrogen. Potentially transport hydrogen generated by other hydrogen producers. Network economies and economies of scale possible.	Significant sunk investment if no market emerges or no cost recovery allowed by PUC.	Not modeled.
Research, Development, and Demonstration	Existing knowledge and R&D relationships	Where to invest research $$$? What impact on core business?	Resolution of technical uncertainties, potential lower capital costs, competitiveness, allows better market capture	The scale of R&D that is funded by any single utility may be insufficient to make major advancements. Also, may be better to use third-party technology	Early investment in R&D allows utility to enter into hydrogen business in 2010-2020 timeframe at lower cost or higher market share
Wait-and-See		Government, market, technology	Allows resolution of critical uncertainties before capital is allocated to risky investment	Potentially losing early cash flows (if they exist), or if not, losing the ability to capture market share or influence market	Utility has option to invest in 2010-2020 timeframe, but with potential market erosion
Business-as-Usual		Natural Gas demand, prices, PUC rate decisions	Core business is stable and less risky than alternatives	Potentially not capturing emerging market opportunity which may simultaneously pose a risk to growth in gas demand for electric generation	Utility continues to sell natural gas to whomever demands it.

Figure 6.2: Investment Rules in the model

Early Period ←———————————————————————→ Late Period

Timeline (Years): 0 — 1 — 2 — 3 — 4 — 5 ... 15

	Year 0	Year 1	Year 2		Period 4	Year 5	Late Period
Energy Services Company	**Market Study:** Predicts Demand with Imperfect Accuracy	**Invest?** If Yes, make 1st payment.. Demand revealed at end of period	**Continue or Abandon?** If Continue, keep receiving early cash flows, otherwise BAU		Policy and Market Uncertainty Resolved at end of period 4	**Continue or Abandon?** If Continue, must make 2nd payment	If Continue, receive late cash flows / If Abandon, same as BAU strategy + Salvage Value
R&D	**Invest** Pay R&D Costs	No early cash flows as R&D progresses. Evaluation on whether R&D has Succeeded or Failed is made by the end of Year 4.			Policy and Market Uncertainty Resolved at end of period 4	**Enter Market or Do Nothing?** If Enter Market, make payment	If Enter Market, receive late cash flows / If Do Nothing, same as BAU strategy
Wait and See	**Pay cost to monitor market ?** (e.g. market study)	No early cash flows			Policy and Market Uncertainty Resolved at end of period 4	**Invest or Do Nothing?** If Invest, must make payment to enter market	If Invest, receive late cash flows / If Do Nothing, same as BAU strategy
Business-as-Usual (BAU)	No action in this market						

▨ **Decision Point**

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Business-as-Usual ("BAU")

In a business-as-usual strategy[48], the utility does not enter directly in the hydrogen or fuel cell markets, but may benefit from some increased demand for natural gas from producers of hydrogen (including fuel cell owners), depending on the emergence of a market that is exogenously determined. A utility may believe that avoiding the hydrogen market entirely is the least risky option, and that any benefits would materialize as increased demand for natural gas.

This strategy is associated with the lowest risks, since gas sales to residential, commercial and industrial consumers are usually very predictable. However, gas sales to the power sector may be more uncertain in the future, as described in Chapter 4. In particular, the increasing entry of renewable technologies into the electric power sector due to state-level renewable portfolio standards will likely replace a portion of currently anticipated natural gas (and coal) demand by reducing the growth rate in conventional power plants. For example, states where new additions are almost exclusively natural gas-fired plants, such as California, have higher "gas displacements rates" than others, such as New York (Wiser, Bolinger et al. 2005). As a result, a do-nothing option may entail new risks not accounted for in historic measures of market value for a gas distribution company.

In this model, the Business-as-Usual strategy assumes that no additional investments are needed, and that profit margins are equivalent to the gas utility's core line of business. Revenues are simply based on the regulated distribution charge for volumes of natural gas transported. The focus of the model is on gas demand in the power sector.

Create or Expand an Unregulated Energy Services Company ("Early DG")

Based on conversations with the three utilities, it was determined that an unregulated energy service subsidiary would be their most likely investment vehicle for the distributed power market. A subsidiary would utilize third-party technologies and have the capability to install and maintain the equipment. Most

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[48] It may not be totally correct to assume that the actual business-as-usual strategy for these companies is to ignore the distributed generation markets, since some of them have already made investments in microturbines, with a small subset actively involved in fuel cells and renewables, as well.

utility executives were not interested in getting involved in the "high-nines" business, where the utility would guarantee an extremely high standard of power reliability for a consumer.

Some gas distribution utilities already own such unregulated subsidiaries, but are typically small and only peripherally involved in non-traditional technologies. It was assumed that a utility that already owns such a subsidiary would require substantial additional capital expenditures (human and physical) to access the markets at the scale that is considered in this modeling effort. For example, one utility was contemplating its role not only in fuel cells and gas microturbines, but also in renewables, which would require substantial financial commitments and technical expertise.[49] Risk-sharing through partnerships was also identified by the three utilities as an attractive way to enter this market. Partnerships can potentially allow investors to share risks and reduce overall investment costs.[50] Since utilities had several prospective business models to choose from, the only constraints the model imposes is that revenues are equal to the value of the electricity generated by the utility's distributed generation assets, which presupposed that the utility sells electricity, rather than gas, for this line of business.

In the model, this strategy assumes that a utility chooses to make an immediate investment, which the model assumes to be in the "early period" (in the 2006-2010 timeframe). Depending on the other parametric assumptions, this choice offers the utility several potential advantages and disadvantages. Immediate investment may allow the utility to benefit from early cash flows if a market exists. It may also pre-empt competitive entry by other parties by establishing technology standards or raising the economic and non-economic barriers to entry in the market.[51] Alternatively, an early investment can result in expenditures that cannot be recovered fully (if at all) if the utility's bet on the future is wrong.

It is assumed that the utility makes a "learning investment" in the first period of the model, prior to any substantial physical investment, in order to reduce uncertainty about the market and technologies. The learning investment would constitute a market study, a pilot study, or any other type of endeavor which gives the utility a better sense of demand in this market. In the model, a learning investment offers

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[49] Private discussions with a natural gas distribution company, September 2005.

[50] Kogut, 1991.

[51] It may also encourage future demand by establishing a nascent infrastructure, although this was not considered in the model. One of the original approaches for this dissertation was to test the impact of network externalities on investment decisions and related public policies. However, as described in Chapter 4, it was not considered realistic for the timeframe used in this model.

imperfect information about the market at a relatively low cost (e.g. at least an order of magnitude less expensive than the physical investment itself). This model assumes that a utility follows an early investment strategy only if a market study demonstrates that the market for fuel cells is favorable (either because of government intervention, blackouts or the emergence of fuel cell vehicles). However, this demand is only revealed after an actual investment is made, and there is some likelihood that the market study was inaccurate and overestimated demand, so that the actual cash flows cannot support the initial investment cost. A utility can choose to abandon this investment strategy the following time period, recovering some of the investment cost in a secondary market, if such a market exists. This is treated stylistically in the model as some fraction of the original investment cost, which can vary parametrically between 0 and 1, depending on the assumptions about the salvage value. The baseline assumption is that the salvage value is zero.

The model assumes that the fixed investment costs of the energy services company are incurred in 2 time periods, representing a nested, or compound option. The first installment occurs in the first year of ramp-up, giving the investor an option to expand the investment in year 5 with a larger capital outlay. The second investment was assumed to be twice as large as the first investment.[52] The total cost of these two stages was assumed to be in the range of $5 million to $50 million. The model allows for a probability that the RPS schedule will either accelerate or decline after 2010, and for partial credits to be available (or not) for natural gas fuel cells, resulting in the capture of a fraction of the RPS market.

Invest in Research, Development and Demonstration

What constituted R&D, or RD&D, in the minds of utility executives differed greatly. Although natural gas utilities divested themselves of formal in-house research and development departments over the past two decades, they all play some role in investing in third-party technologies or at least tailoring technologies and services for their customer base.

There was a fundamental disagreement on the role of the utility in developing technologies in the DG market. Some felt that technologies for distributed power generation were generic, and that the competitiveness of any particular DG technology would be determined primarily by its capital costs, which

could be described best by a learning curve determined by aggregate industry investment. In this context, any single utility would have almost no effect, in a large pool of industry and government investment. Others emphasized the importance of "location, location, location" in the DG market. Although a utility would not make any contributions to the fundamental science associated with any technology, it could play a role in the "development" and "demonstration" part of RD&D. For example, issues concerning the integration of heat and power (e.g. proper sizing and configuration of technologies) is often crucial to the success or failure of distributed generation units, but can hardly be considered basic science. According to some utilities, the acquisition of new technologies can have a contagion effect with other technology providers and electric utilities, and can serve as a proof of principle to regulators.

Some utilities made equity R&D investments in order to keep up to speed on technologies, and perhaps influence the course of technology development. Others felt that technologies would potentially be used in their core business or energy services company. In this model, the R&D choice essentially represents a decision to place a bet on the development of the market in later years, and the ability to be a competitive player in those years by having better technologies. If a utility believes that a fuel cell market might exist in the future, but that existing technologies are immature, it may choose to make investments in R&D, rather than deferring an investment or making immediate commitments through an energy service company. The model assumes that R&D will result in no early cash flows, and that the R&D effort is evaluated at the end of year 5. If R&D is a success, the investor can receive late cash flows. The nature of these cash flows is determined by three important parametric assumptions, which were added to allow flexibility in what R&D meant to each organization.

The first assumption concerns the impact of R&D on the company's market share once it enters into the market. A conservative assumption is that successful R&D confers no advantage on market share compared with investing late with third-party technology, which is analogous to the Wait-and-See strategy. Alternatively, R&D might be an integral part of a company's strategic planning, and a successful technology offers competitive advantages despite the fact that the company enters the market late. The competitive position might then be similar to a first-mover advantage of an Early DG investment.

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[52] This cost structure was vetted with several industry executives.

A second set of parameters describes the impact of R&D on the fuel cell market itself. Successful R&D can have an impact on the viability of the fuel cell market. This can vary between no impact and a significant impact. The model assumes that this influence is a function of investment costs. A baseline assumption is that R&D and Early DG have the same impact on the fuel cell market itself, as described in the previous section.

A third assumption concerns the general business model that successful R&D products fit into. Successful R&D may or may not incur additional investments in order to generate cash flows. For example, a company could make profits from successful R&D if it sells its equity share in a technology company. Alternatively, it may incorporate a successful technology in its own operations, possibly requiring additional investments. These additional costs were assumed to be less than or equal to the "Early DG" investment cost.

Wait-and-See

There was particular interest among utilities in developing a strategy that would capitalize on "targets of opportunity" rather than commit to a large initial capital outlay or forgo the market opportunity altogether. Several utility representatives felt that their utility would favor investing a modest amount of money to be capable of quickly ramping up to address such targets of opportunity or generally respond to changing market or policy signals. From a modeling standpoint, certain assumptions needed to be made to accommodate this investment strategy, as described in more detail later in this chapter.

For simplicity, the Wait-and-See strategy assumes that the utility makes a decision whether to invest or not only when policy uncertainties are resolved, which is assumed to occur in Year 5. There is a general consensus that future government policies related to hydrogen are highly uncertain today, but that this will decrease significantly in the next several years.

The Wait-and-See strategy differs from the Business-as-Usual strategy in the first five years in that the utility must pay for the capability to be able to monitor and quickly respond to a market signal. The baseline assumption was that this cost in the range of $2 to 5 million, spread out over 5 years.[53] It is

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[53] This range corresponded roughly to the costs paid by utilities to support staff who attended training sessions, conferences, etc.

assumed that if the utility decides to invest in Year 5, it would be investing in an energy services subsidiary with total nominal investment costs similar to the Early Investment strategy, but discounted at year 5. As described later in the chapter, the model allows for 2 potential barriers facing utilities that choose a Wait-and-Strategy: 1) potential policy retrenchment regarding fuel cells due to lack of investment, and 2) potential difficulties in penetrating the market as a late-mover.

DEFINING THE STATES OF THE REAL OPTIONS MODEL

The cash flows associated with the states in the real options model are represented by a reduced form model of the electricity market, which will be referred to as the Electricity Market Model (EMM). The EMM is a spreadsheet-based model that defines the cash flows of every branch of the real options decision tree, as shown in Figure 6.1. As described in previous chapters, the hydrogen "market" is not modeled here directly, since there are currently no spot markets for hydrogen.[54] The approach taken here is to model the demand for fuel cells in the electricity market, under the assumption that natural gas would be used as the primary feedstock to create hydrogen on site.

Government policies play a central role in the model, and define many of the states of the decision tree. In the absence of policy intervention in this market, major technological innovations which lower their capital cost, or increased demand for distributed power, it is assumed that capital costs of fuel cells are a chief barrier to their adoption and result in only a niche market for fuel cells in 2006-2020, in accordance with Energy Information Administration forecasts.[55]

Several side cases were also run which did not rely on RPS policy, but focused rather on the market for distributed power generation in the event of increased demand for power reliability and also different interconnection policies.

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[54] Outside of several major petrochemical complexes in the Gulf of Mexico and northwest Europe, there are generally no significant hydrogen transportation pipeline networks. Transportation costs are commensurate with the costs of hydrogen synthesis, depending on the purity of the hydrogen.

[55] Annual Energy Outlook, Energy Information Administration, 2005.

Figure 6.3: Influence Diagram

Energy Market

-Demand for Electric Reliability
-Electricity Growth Rate
-Natural Gas Price
-Secondary Market (e.g. fuel cell vehicle refueling)

Government Policies

-Renewable Portfolio Standard
-Fuel Cell Partial REC Credit/ Cap
-Regulation of Other Combustion DG
-Interconnection and Net Metering
-Cost Sharing or Sunk Cost Recovery

Electricity Price

Incentives for fuel cell market

Displacement of natural gas in traditional power sector

Investment Strategies

1) Early Investment
2) Late Investment
3) Invest in RD&D
4) Business-as-Usual

Any influence over technology adoption or regulation?

Is there an early mover advantage?

Fuel Cell Market Size (kWh)

Revenues

Net Cash Flows

Market Share Captured (%)

Costs

Competition for Market Share

Profit Margin Assumption

Investment Costs

Other Annual Fixed Costs and Variable Costs

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The cash flows associated with each investment strategy are determined by the 1) Investment Costs,

2) Annual Cash Flows, and 3) Salvage Value, and are discounted on an annual basis with a discount rate ρ.

Table 6.2: Cash Flows Associated with Each Investment Strategy

Strategy	Investment Costs	Annual Cash Flows	Salvage Value
Business-as-Usual	None	Gas sales only	None
Early Investment	Investment staged in two time periods. The first stage is ½ as expensive as second stage, which can occur in period 5. The total nominal cost is treated as an adjustable parameter that can vary between $5M-$50M.	$\dfrac{p_{elec,t}\,q_{elec,t}\,m}{(1+\rho)^t}$	$\alpha\,\dfrac{Investment\ Costs}{(1+\rho)^{t_{Abandonment}}}$
Research and Development	R&D costs spread out over first 5 years. Range of total nominal cost can vary parametrically between $5M-$20M.	Early Period: Gas sales only Late Period: If R&D is successful, then same as Early Investment Strategy. If failure, then only gas sales.	None
Wait-and-See	If utility decides not to invest, then no costs incurred, except for maintaining "Wait-and-See" readiness, which is assumed to be $2-5M spread out over the first 5 years. If the utility invests, then the costs are the same as Early Investment strategy, except all occur in Year 5	Early Period: Gas sales only Late Period: if no investment, then same as BAU. If investment, then same as Early Investment	$\alpha\,\dfrac{Investment\ Costs}{(1+\rho)^{t_{Abandonment}}}$

<u>Investment Costs</u>

Investments costs for each strategy are described in Table 6.2. From a real options standpoint, if

one assumes that there is no competition in this market, then the natural gas distribution utility can be

assumed to have already exercised its option and essentially "owns" the right to make an investment at any

point in the future. The Early Investment cost would represent that "strike price" associated with capturing

cash flows from this market. Under the assumption that there is significant competitive erosion from

deferring investment, the utility does not have such a proprietary right to the market, but may capture

greater market share if it can capture a first-mover advantage through early investment.

Salvage Value

The salvage value is the value of the option to abandon a project if there is a secondary market for

sunk capital that can be recommitted elsewhere. This term serves two main purposes in the model. First, it

is a convenient way to implement the government policy scenario related to the partial recovery of sunk

costs, as described later in this chapter. Also, to the extent that utilities believe that they can redeploy

assets (e.g. fuel cells, steam methane reformers, hydrogen storage, land) to serve an emerging fuel cell

vehicle refueling market, it lowers the risk of initial investment. The stylized treatment of abandonment

value was simply:

$$Salvage\ Value = \alpha \frac{Investment\ Costs}{(1+\rho)^{t_{Abandonment}}}$$

where α is a parameter that can very between 0 and 1, which described the degree of sunken-ness of the

assets. The reference value was set at 0.

Annual Cash Flows

Annual cash flows associated with any strategy are represented by the following general form,

with profit margin m:

$$Annual\ Cash\ Flow = \frac{\pi_t}{(1+\rho)^t} = \frac{R_t - C_t}{(1+\rho)^t}$$
$$= \frac{R_t \cdot m}{(1+\rho)^t}$$
$$= \frac{p_{elec,t} q_{elec,t} m}{(1+\rho)^t}$$

Two major assumptions were made in the cash flow calculation. On the cost side, it was assumed

that annual fixed costs and variable costs could be described by a profit margin assumption, rather than a

detailed description of the cost structure of the particular line of business.

The profit margin assumption was utilized for two reasons. First, I did not want to assume a cost structure associated with a very specific business model. Rather, a profit margin was treated as an adjustable parameter that could readily be compared with the utility's other lines of business. For simplicity, it was assumed that profit margins were not a function of time[56], and therefore cash flows focused more closely on the revenue stream.

On the revenue side, an assumption was made that the business model was based on the energy service company owning and operating the units, and therefore selling power rather than just gas. It is assumed that they are price takers because they do not influence the electricity market. It is assumed that distributed generation units can sell electricity back to the grid through "net metering" or other mechanisms.[57] Thus, the value of electricity produced was equal to the electricity sold to the grid and any foregone electricity costs through self-generation. The quantity of electricity sold was further defined by the product of the market size for fuel cells and the market share captured by the energy company:

$$q_t = Market\ Share_t \cdot Market\ Size_t$$

Where the market size (in kWh) is determined by the total electricity demand, the share of this demand met by a Renewable Portfolio Standard (as a percent of total electricity demand), and the share of fuel cells within the RPS (as a percent of RPS):

$$Market\ Size_t = Fuel\ Cell\ Share\ of\ RPS_t \cdot RPS\ Size_t \cdot Total\ Electricity\ Demand_t$$

Total electricity demand is described by a base demand at t_0 and a constant annual growth rate, which varies for the different regions considered in the model:

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[56] This is a reasonable assumption for most mature businesses, but less so for new businesses that have developed innovative products. However, this assumption could be consistent with the energy service subsidiary that is part of a larger organization.

[57] Different policies regarding net metering or distributed generation interconnection can be handled through assumptions about the electricity price, such as whether DG units can sell electricity at wholesale or retail prices.

$$Total\ Electricity\ Demand_t = Elec\ Demand_{t_0} \cdot (1 + Elec\ Growth\ Rate)^t$$

Market share represents the portion of electricity generated by fuel cells owned and operated by the natural gas distribution utility.

A basic levelized cost of electricity calculation shows that stationary fuel cells do not compete favorably with mature power generation technologies. However, an RPS market would essentially create two separate markets – one for conventional technologies and a separate one for qualifying renewables, as described in Chapter 4. Thus, fuel cells would compete with wind, solar, and biomass technologies, rather than other fossil fuel technologies. However, little insight can be gained from a traditional levelized cost calculation in modeling this competition, for several reasons. An electric utility must rationalize its adherence to RPS legislation and the deployment of technologies across its service territory. Issues such as grid stability, base load versus peak load capability, and renewable resource endowment are important considerations. Sophisticated technical models can help estimate these tradeoffs for specific locations, but offer less insight on the strategic-level issues considered here.

Various mechanisms have been proposed for RPS legislation, as described in Chapter 4. Typically, states have proposed to mandate the percentage of renewable electricity an electric utility must purchase (or otherwise meet with a permit). As described in previous chapters, many states have not determined the final portfolio of technologies that qualify for renewable energy credits within RPS. Some have allowed fuel cells that run off of natural gas, others do not include fuel cells, and several allow fuel cells that consume only "green" hydrogen. Modeling a state-level RPS market would be a significant undertaking in its own right, and several simplifying assumptions were made. Of particular interest was the fact that federal RPS policy might take over in the near to medium-term, and specific state-level policies today may be regarded as temporary. As a result, an assumption was made that public policies regarding fuel cells may follow the policy framework used to allocate "partial" zero emission vehicle credits for automotive technologies. Fuel cells could either get such a partial credit, or would simply be capped at some percentage of the RPS mix.

Table 6.3 summarizes the states used in the cash flow model. For simplicity, it was assumed that the potential market for fuel cells would be in one of two states: 1) up to the market cap (assumed to be 20

percent of RPS), or 2) niche technology (assumed to be equivalent to approximately 5 percent of RPS).

The potential market share that the utility could capture was also assumed to be in one of two states—a

utility could either be 1) a niche player (capturing 20 percent of the local fuel cell market) or 2) a dominant

player (capturing 80 percent). RPS policy was assumed to be certain until 2010, following a linear

increase of 1 percent renewables per year. After 2010, RPS policy would be in three possible states 1)

standard, 2) accelerated, or 3) declining.

Table 6.3: States and Associated Structural Uncertainties in the Model

Policies	Description	States in Model
1.Renewable Portfolio Standard	RPS Penetration Rate	RPS fixed at 1% percent increase per year until 2010. After 2010: 1.) Standard: Increase in increments of 1% until 2010, then flat. 2.) Accelerated: Increase in increments of 1% until end period. 3.) Decline: 1% linear increase until 2010, then equivalent decrease from 2010-2020.
	Fuel Cell inclusion within RPS	1.) 20% of RPS can be met with Fuel Cells. 2.) No Fuel Cell provision within RPS. Policy reversal can lead to switching from State 1 to State 2 in 2010.
2.Cost Sharing	Sunk Cost Recovery	Abandonment leads to partial recovery (represented by adjustable parameter between 0-100% of nominal investment cost) of investment costs if Early DG is abandoned.
3.Distributed Generation Regulations	Environmental restrictions on fuels	1.) No restrictions 2.) Partial restrictions 3.) Diesel prohibited
	Interconnection Standards and Net Metering Market value of DG-produced electricity	Electricity Price facing DG owner can be adjusted to correspond to different policies regarding DG interconnection.
Market		
Competition	Early investment may or may not help in capturing market. Competitors include other renewable and DG investments as well.	1.)Utility is a Dominant player 2.)Utility is a Niche player
Natural Gas Prices	Wholesale natural gas price	NG price embedded within profit margin assumption

UNCERTAINTIES

One of the great challenges in implementing the real options model described in this chapter is the fact that many uncertainties are poorly understood and difficult to benchmark from historical data. As a result, an optimal investment pathway for any particular set of assumptions is not likely to be robust in the face of deep uncertainty. The functional forms for the various sources of uncertainty, and their relationships between strategic investment decisions and uncertainty resolution, are at the center of the real options problem in this model. Certain tradeoffs in describing these uncertainties are necessary.

This dissertation differentiates between two types of uncertainties. *Parametric uncertainties* refer to the uncertainties regarding the constants in the Electricity Market Module, such as annual electricity growth rate, as shown in Table 6.2. *Structural uncertainties* are associated with the evolution of "state" variables over time. A classic approach to the latter is the construction of a binomial lattice or event tree for which an underlying commodity price evolves by geometric Brownian motion or other stochastic process, often chosen for convenient mathematical properties. As shown in Table 6.3 and 6.4, some of the structural uncertainties were conveniently resolved into parametric relationships, while others were associated with classic state variables in the decision tree.

The Electricity Market Model and Real Options Decision Model contain more than 30 adjustable parameters that describe probabilities, states, payoffs, and relationships between them. These values are either (1) difficult or cumbersome to describe, (2) unknown, or possibly (3) unknowable. Applying a statistical distribution to these parameters (e.g. Monte Carlo approach) offers two main problems to analysts and decisionmakers. The first is that reference values and distributions are not known with any degree of confidence, in many cases. The other is that it is impossible for the analyst to track specific inputs and ouputs. A parametric analysis allows the analyst to track the underlying assumptions behind a result with specificity and aids in analysis and discussion. This is implemented in software developed to visualize and analyze the solution space of complex models.[58]

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[58] The exploratory modeling in this dissertation relied heavily on Computer Assisted Reasoning® (CARs™) software developed by Steven C. Bankes, Steven W. Popper, and Robert J. Lempert at Evolving Logic.

Parametric Uncertainties in the EMM

One of the goals of the model was to create a structure that described a generic utility, but that could be tailored to suit specific regional or utility service territory situations more accurately. An interactive process with utilities was undertaken in order to narrow the plausible bounds of this parameter space and identify which regions were of particular relevance, as described in Appendices A.1-A.6 and the Robust Decision Making section. Table 6.4 illustrates the range of selected parameters used in the model.

Table 6.4: Selected Parametric Assumptions in Model

Parameter	Units	Reference Case	Min	Max	Included in RDM Analysis?
Energy Market					
NG Distribution Charge	% Wholesale Price	0.35	0.3	0.4	Yes
NG Price	$/MMBtu	7.0	-	-	Range embedded in Profit Margin Assumption
Wholesale Electricity Price	cents/KWh	8	6	12	
Electricity Growth Rate	%	1.5	0	5	Yes
Prob increased demand for power reliability	-	0	0	1	No
Business Fundamentals					
Discount Rate	%	8	12	1	Yes
Profit Margin of Fuel Cell Business	%	5	0	10	Yes
Proft Margin of Traditional Gas Dist	%	5	0	10	Yes
Cost of Energy Service Subsidiary	$ million	20	5	50	Yes
Cost of R&D	$ million	5	5	20	Yes
Cost of Market Study	$ million	2	2	5	Yes
Abandonment Value	% of initial investment	0	0	0.5	Yes
Fuel Cell and DG Market					
Fuel cell market size in the absence of government policies	% RPS	5	2	7	Yes
Market Share if "Dominant" player in FC	% Fuel Cell Market	75	70	80	Yes
Market Share if "Niche" player in FC	% Fuel Cell Market	25	20	30	Yes
Probability that gas utility has a dominant share if it makes an early investment	-	0.5	0	1	Yes
Probability the gas utility has a dominant share if R&D is successful	-	0.25	0	1	Yes
Probability the gas utility has a dominant share if it defers investment	-	Function of Market Erosion if Defer			Not exogenous
Market erosion from competition if Defer		0	0	1	Yes
Impact of Early Investment on Policy		0	0	1	Yes
prob R&D Success	-	0.25	0	1	Yes
prob Market Study Accurate	-	0.75	0	1	Yes
Maximum DG penetration allowed by Grid	% Electricity Load	10	5	15	No
Public Policy					
RPS cap for Fuel Cells	% RPS market	20	10	35	Yes
prob RPS Standard	-	0.5	0.5	1	Yes
prob RPS Accelerated	-	0.25	0	0.25	Yes
prob RPS Decline	-	0.25	0	0.25	Yes
prob fuel cells not longer included in RPS policies post-2010	-	Function of Impact of Early Investment on Policy			Not exogenous
prob fuel restrictions on DG	-	0	0	1	No

Structural Uncertainties of State Variables

"State variables" determine the precise state of the system as a function of time. The literature on real options, as described in Chapter 2, generally distinguishes between two types of uncertainties regarding state variables. The first are market uncertainties, which can be quantified through information available in the market and therefore can be hedged by trading securities. Market uncertainties are typically handled by risk-adjusting the discount rate (e.g. replicating portfolio technique) or alternatively, risk-adjusting the probabilities of cash flows, but applying a risk-neutral discount rate (e.g. "risk-neutral" approach). These adjustments are made by finding information about a traded asset, or by assuming that the present value of the project without options is the market price, as if the project were traded ("Market Asset Disclaimer" assumption).

The second group are private uncertainties, and correspond to project-specific risks. Private uncertainties are handled by assuming a risk-neutral discount rate. In some cases, uncertainties may fall somewhere in between these two definitions, and practitioners have proposed methods for correlating the two (Smith 2005). Many realistic problems also involve a combination of uncertainties (e.g. "rainbow options") which can be separated into market and private, such as the decision when to drill for oil on a reserve of unknown size (private, technical uncertainty) and unknown oil prices (market uncertainty).

Real options techniques used in the energy industry benefit from the richness and public availability of historic and near real time prices for many energy commodities, which allow statistical methods to be used to calculate the structural form of uncertainty, degree of volatility, and correlations among commodities (e.g. spark-spread). In practice, practitioners typically assume that the price of a commodity obeys geometric Brownian motion (GBM), which has convenient mathematical properties. However, uncertainties often do not get resolved smoothly over time as assumed by GBM, but rather when the information becomes available. Other structural forms of uncertainty, such as mean-reverting and jump-diffusion processes are also used, but predominantly for academic analysis involving only one uncertainty. Policy uncertainties, which play a very important role in this analysis, generally fall into this second category (Copeland and Antikarov 2003).

Policy uncertainties play a central role in this dissertation. It is assumed that the main uncertainties that investors face in the early years of technology adoption are related to government policy. One of the

goals of this study was to test how investment decisions depend on assumptions about the likelihood and level of government intervention in the market. As described in the literature review of Chapter 2, this is in the spirit of "information gathering" models (Cukierman 1980; Bernanke 1983; Ishii and Yan 2004) where firms facing policy uncertainty are faced with the decision whether to invest or wait until a credible policy change has been enacted.

One of the goals of the model was to allow for different assumptions concerning 1) the timing and likelihood of policy changes in the market and 2) whether utility investments had an effect on the structure of policy uncertainty—namely, whether increasing funds allocated to early investment had any influence on policy uncertainty resolution, rather than just waiting. Several assumptions were made in the model:

Assumption 1

Corporate decisions on whether to commit capital to the lines of business described in this model will not be determined by fluctuations in commodity prices, but rather broader, longer-term trends. In this context, the chief uncertainties relate to government policy and larger developments in the energy market.

In real options problems, policy interventions are generally treated as discontinuities modeled by jump-diffusion processes. Based on a review of the existing legislation, and the views from industry, I felt that there would be only a negligible loss of generality if future policy uncertainties were treated as being completely resolved at a predetermined point in the future, rather than a random function of time. Since the response time of corporate-level decisions is generally much longer (e.g. months or years, in this case, 1-year time steps) than short-term operational decisions, and since the inertia of the legislative process would likely not result in a random distribution of policy enactments and reversals over time, a formal Poisson process was considered inappropriate for this model.

Therefore, the structure of policy uncertainty was greatly simplified by dividing the timeline into two periods. During the early years, future policies are not known, but it is known that these uncertainties will be fully resolved at the end of Year 5. This resulted in two investment regimes, as shown in Figure 6.2. This roughly approximates the assumption that many of the utility discussants had concerning the RPS market – that there was a window of policy experimentation over the next 4-5 years which would eventually result in a long term policy being set in place.

Assumption 2

Risk-neutral probabilities (and thus a risk-neutral discount rate) were used in the model. A risk-neutral approach is well-suited to evaluating real options in a decision-tree context, because discount rates do not need to be re-adjusted at each node. Thus, the risk-neutral probabilities used in the analysis are essentially shifted by a risk-premium from the real probabilities. It is assumed that the robust decisionmaking process, described later in this chapter, would identify which structural and parametric assumptions in the model are critical. Risk-neutral probabilities that are identified as critical uncertainties in the RDM analysis can then be risk-adjusted to real probabilities if necessary.

There are several problems with identifying risks in this model. For example, one could argue that a Business-as-Usual strategy is not necessarily the least risky, if that line of business is affected by legislation that may limit expected growth rates for natural gas in the electric power sector. Thus, market betas based on historical data may be misleading for the future. Another is that the risk perspective depends intimately on the unit of analysis, whether it is the subsidiary, utility, or holding company.

Assumption 3

This dissertation argues that multiple uncertainties can be included in a real options problem if data mining techniques are used to reduce the dimensionality of the parameter space. This shifts the focus from finding the exact structural and parametric form for uncertainty to finding where such assumptions matter and further inquiry is needed. In recent years, several methods have been proposed to handle multi-dimensional options problems, primarily related to applying Monte Carlo methods used in the financial options community to real options (Smith, Longstaff and Schwartz). Smith (2005) has also identified recent research on finding "near-optimal" exercise policies and regression methods for identifying response surfaces. The approach taken here will be developed further in the section on Robust Decisionmaking.

RPS Market Size and Policy Uncertainty

One of the fundamental tradeoffs in this real options model is whether the investor has enough confidence in the technology to make early investments that may accelerate or standardize the market (or at

least make early profits), or whether there is a high likelihood that the technology will be supplanted by a superior one within the investment timeframe. It is assumed that even if government allows fuel cells within the RPS portfolio in the early investment time frame, it may reconsider the mix of technologies included in this policy at some point in the future. For example, technological surprises or issues regarding natural gas supply could lead to a reversal of policy in 2010.

The model allows the probability of this policy reversal to be affected by the level of early commitment on the part of the utility. One can either assume that public policy is entirely exogenous, or that the utility's investment strategy has some degree of influence on fuel cell policy.

Market Share and Competition

A real option represents a right, but not an obligation to commit to an investment at some time in the future. Here, an option can be an opportunity to invest, as a result of regulatory or economic barriers to entry. A natural gas distribution company may or may not have some type of regulatory protection (or barrier) for hydrogen-related investments. It is more likely that any advantages it compared with potential competitors would be weaker, and related to greater knowledge of its customer base and ability to finance such investments. The model will test the optimal investment pathway for a utility under both assumptions: a proprietary right, and one in which there is market erosion from competition. The sources of competition might be other fuel cell providers, or more likely, other renewable technologies that would saturate the RPS market if the natural gas utility does not make an early investment.

ROBUST DECISION MAKING

Investment decisions based on a single optimization, classic sensitivity analysis, or Monte Carlo techniques have important limitations when uncertainties are difficult to characterize and when stakeholders disagree on fundamental assumptions in the model. To overcome these obstacles, this analysis will draw on both the traditional techniques developed by practitioners of real options and also on methods for generating robust strategies under conditions of deep uncertainty.

Robust Decision Making (RDM) is an iterative and analytic process that 1) identifies strategies whose performance is largely insensitive to poorly characterized uncertainties, and 2) characterizes a small number of scenarios representing uncertainties that are relevant to the choice of strategies (Lempert, Popper et al. 2003; Groves 2005; Lempert, Groves et al. 2005). In particular, RDM utilizes exploratory modeling methods to evaluate a large set of plausible futures for low-dimensional policy models. The goal is to seek robust, rather than optimal policies, to help focus decision makers on a subset of uncertainties and the likelihoods of key scenarios.

The approach taken here applies the principles of RDM in order to overcome the obstacles posed by the parametric and structural uncertainties in the real options model, as illustrated in Tables 6.3 and 6.4. As developed in Chapter 2 and Chapter 5 of this dissertation, the real options technique offers an analyst the benefit of capturing dynamic complexity in order to more accurately assess the value of an investment by acknowledging and identifying the managerial flexibility inherent in a project. The crux of this approach is the identification of embedded options that can serve as hedging strategies similar to financial options. As with financial options, embedded real options can create an asymmetric payoff profile that lowers the risk of a downside without eliminating the benefits of an upside, for the price of an options premium.

It is interesting to note that RDM and real options both recognize the tradeoffs between strategies that involve pre-commitment, and those that are staged. Thus, the identification of embedded options is in many ways analogous to the search for hedging options and milestones in an RDM methodology.

However, several important distinctions merit attention.. Whereas RDM often uses data mining techniques to carefully identify new hedging strategies, a real options valuation typically begins with the

identification of such strategies outright.[59] Theoretically, an iterative RDM process could be used to identify improved real options strategies, rather than specifying a priori a fixed subset of options. However, in a realistic options problem, there are likely to be a limited number of hedging strategies that are dictated by practical constraints, such as the response time of corporate actors to new information. Perhaps more important is the fact that investment choices and uncertainties can be highly stylized, and since the relationship between the two is critical, a technique may lead to spurious relationships as a result of data mining. For example, one must be careful in arbitrarily adding choice nodes to a decision tree. In a backward induction calculation, preferentially expanding the set of strategies for any particular choice node rather than another will tend to increase the payoff at that node since the maximum of all possibilities is necessarily chosen rather than the expected value.

As a result, this dissertation uses the tools of RDM in order to identify low-dimensional spaces where the candidate strategy is particularly vulnerable. In particular, the methodology is used to help avoid the problem of specification of uncertainty regarding state variables in the model by identifying which uncertainties are most critical, allowing attention to be focused on those uncertainties that matter. The following procedure was used in this dissertation.

Step 1: Exploratory Modeling

The first step in RDM involves the construction of a virtual ensemble of futures, where a "future" is defined as the outcome of a single strategy played out in one plausible state of the world. A scenario ensemble can be described by the matrix, $M = L \times X$, where L represents the set of alternative investment strategies and X is a set of plausible future states of the world. As described previously in this chapter, this model contains 33 exogenous parameters and 4 core strategy choices.   As shown in Figure 6.3, 22 parameters were chosen for inclusion within the RDM portion of the study, while the remainder were kept constant at the reference values.

A futures ensemble was created by evaluating the results of the core real options model for each strategy (l_i) across a sample of the exogenous factors (x_j) defining the states. At this point, different

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[59] However, the differences between these approaches attenuate when several clear, plausible choices are

sampling procedures can be used, depending on the size of the virtual ensemble and the functionality of the model. In order to avoid systematic sampling bias, a Latin Hypercube[60] sampling procedure was chosen. Four, independent, 500-point Latin Hypercube experimental designs generated a sample over the 22-dimensional space of input parameters for each investment strategy. The parameters were randomly sampled within the ranges specified in Table 6.3.[61] This procedure created a database with 11,500 records. Each record had 23 entries: 22 listing the parameter values for each of the 500 futures, and one reporting the output metric ("regret"—described in the next section).

Step 2: Ranking and Selecting a Candidate Strategy

An integral aspect of the RDM strategy is that optimality cannot be used as a criterion for selecting policies (or investment strategies in the case of this dissertation) if probabilities are ill-specified and no single policy dominates across all states. Lempert et al. (2003) argue that "robustness"—the relative insensitivity of a strategy to the unknown probabilities of any state—is the most appropriate criterion in a public policy setting. One such measure of robustness is "regret", which is based on the assumption that decisionmakers are sensitive to the relative outcome of their choices compared to what the best outcome would have been. Regret is defined as the difference between the performance of a strategy in a future state of the world and the best performing strategy for that same future. For example, a strategy that performs poorly relative to the best strategy for a particular scenario can be described as having high *regret*.

$$R(l_i, x_j) = \underset{i'}{Max}(m_{i'j}) - m_{ij}$$

Following the work of Lempert et al. (2003) and Groves (2006), this dissertation uses regret as the robustness measure. It should be noted that private sector actors are considered the decisionmakers in the real options model in this dissertation, rather than policymakers, who are typically the focus of RDM studies (policies are treated as exogenous events while investment strategies are the levers in this model)

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identified by the modeler.

[60] A Latin hypercube sample is created by dividing each of the parameters into segments that are randomly sampled. The sizes of each segment are inversely proportional to the number of samples taken.

[61] Initially, a 5,000–point Latin Hypercube was used. However, since the model is not highly non-linear, the sample size was reduced to 500 without any noticeable differences in RDM results and interpretability. Each sample took approximately 2 seconds to run on a Windows PC with an Intel Pentium M 1.80 GHz.

However, the case studies of the gas utilities suggest that managers responsible for the fuel cell programs in these type of energy companies often pursue "satisficing" strategies that aim to achieve satisfactory performance across most plausible scenarios, rather than choosing the strategy with the highest performance in one possible state ("maxi-best" criterion), avoidance of the worst outcome by minimizing the maximum loss ("mini-max" criterion), or other metric. Thus, the regret criterion seems to be appropriate for considering the decisions made by managers of partially regulated utilities, but may be inappropriate if applied in other situations, such as a start-up fuel cell company funded by venture capital.

Next, the analyst must choose among procedures for ranking investment strategies according to regret. One goal of RDM is to choose policies that are not overly sensitive to individual scenarios. This dissertation compares investment strategies according to median performance across futures. The four core strategies are compared according to median regret and interquartile range of regret. This process is aided by visualization of the distribution of regret with a box-and-whisker plot. Although other ranking strategies are also possible, this method was chosen primarily to avoid a probabilistic weighting of states and also to avoid discarding policies that perform exceedingly poorly in a very limited number of states (which may not be of policy relevance). Next, a candidate strategy is chosen as a reference in order to identify vulnerabilities.

Step 3: Identify Vulnerabilities of Candidate Strategy

Once a candidate strategy is chosen, the goal is to identify regions where it is vulnerable. One such method is to search for low-dimensional regions where there is a high probability of an adverse outcome, measured by regret in this dissertation. The construction of such low-dimensional regions also aids in scenario development that has both narrative simplicity and a quantitative underpinning.

This dissertation employs the Patient Rule Induction Method (PRIM), as developed by Friedman and Fisher (Friedman and Fisher 1999) and implemented by Lempert, Groves, Popper, and Bankes (2005) and Groves (2006).[62] The goal of PRIM is to partition a solution space into box-shaped regions in order to identify boxes with particularly higher (or lower) averages of the output variable. These low-dimensional

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62 A detailed description of the PRIM algorithm, limitations, and applicability to RDM is available in Groves (2006). A special thanks to David Groves for his assistance with the PRIM procedure.

regions in the input space would identify high concentrations of poor performance for a particular strategy, in this case measured by regret. For example, a threshold level of regret can be chosen by the analyst in order to make a binary transformation of regret and facilitate the interpretation of the parameter space. The mean value within a cluster identified by the PRIM algorithm would then represent the percentage of high-regret futures within that parameter space. The choice of clusters is determined by the tradeoff between the mean value of high regret futures desired in the cluster, and the size of the cluster. Clusters with a higher percentage of high-regret futures are typically associated with a larger number of dimensions and smaller ranges within each of those dimensions.

CHAPTER 7: RESULTS

OVERVIEW

This chapter illustrates several techniques that were used to characterize the performance of the four main investment strategies developed in this dissertation, to identify a candidate strategy that is robust across a wide variety of futures, and to evaluate where such a strategy is vulnerable. As described in the case studies in Chapter 4, the three energy companies had different perspectives on the potential business fundamentals for hydrogen and fuel cells, as a result of the differences in state (and utility service territory) policy environment, energy market fundamentals, as well as the companies' perspectives on risk and existing asset base. One of the challenges was to incorporate views of a variety of stakeholders in a single model.

SENSITIVITY ANALYSIS AND VISUALIZATION

The model developed in this dissertation was the result of an interactive process with the three energy companies described in the case study in Chapter 4. First, a traditional parametric sensitivity analysis was performed over selected dimensions which were of particular interest to discussants in order to construct graphical response surfaces, as shown in Figures 7.1-7.6. These are a subset of the graphs that were used in an iterative process with utilities in order to develop more plausible parameter ranges and realistic definitions of investment strategies, in preparation for the robust decisionmaking techniques illustrated later in the chapter. In particular, the utilities were interested in seeing how sensitive investment strategies were to parameters of interest. Of course, these graphical representations of the solution space in multiple dimensions are somewhat arbitrarily chosen because the remaining parameters are held fixed at their reference values. However, several questions emerged during this process which helped focus attention on specific issues and elicit insightful responses from utilities.

Cost of Knowledge and Market Entry

One of the major questions facing energy companies considering expansion into the distributed generation market is whether they can reliably estimate the demand for these technologies on their service territory, and whether they would be willing to commit to a large investment based on this knowledge. For example, many utilities periodically conduct proprietary market studies of industrial demand for combined heat and power, but generally have only anecdotal information for residential and commercial customers. Although the utilities felt that they had a good sense of their own customer base, they were reluctant to commit to a significant investment without a better sense of the real market size, and wanted to know how sensitive investment decisions were to this estimate. In this highly stylized model, Figure 7.1 shows that an early commitment strategy can be very sensitive to assumptions about market size. These charts plots regions where the indicated strategy is dominant within the span of the chosen parameters. Note that R&D costs are fixed at $5 million in this figure.

Figure 7.1: Cost of Knowledge and Market Entry
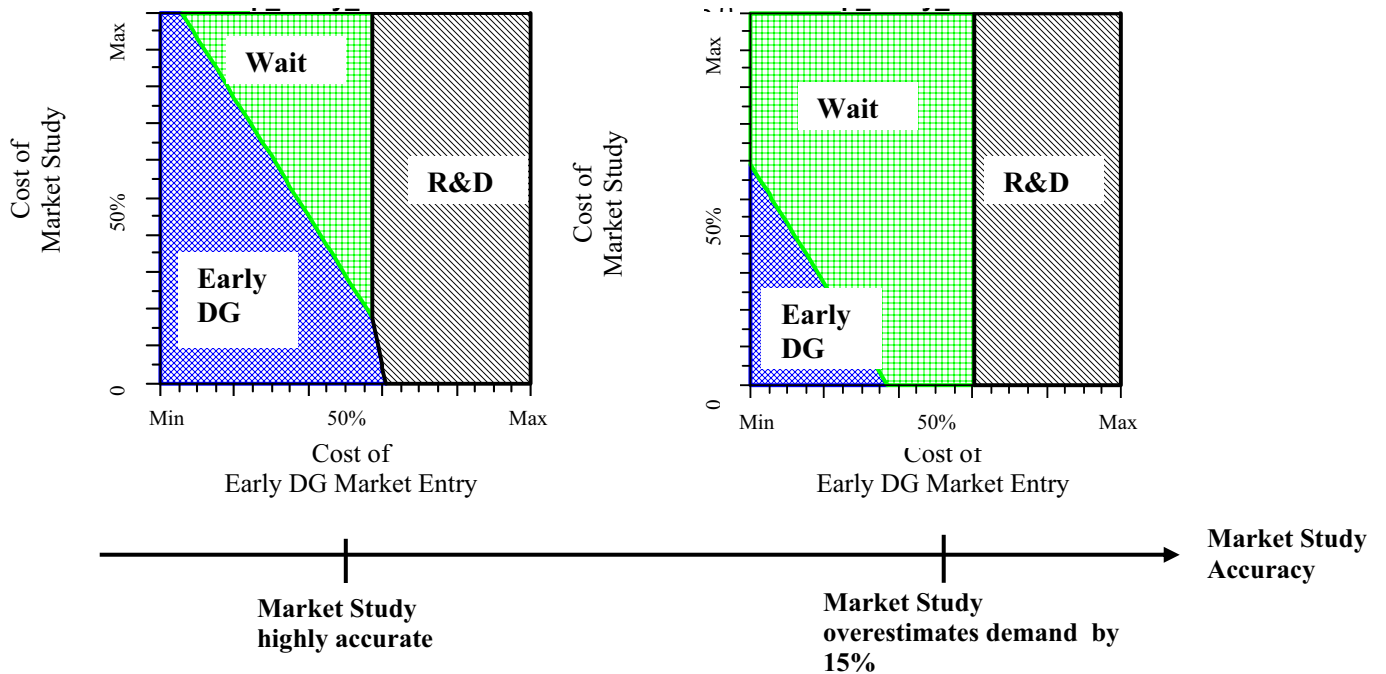
What is the Role of Research, Development, and Demonstration?

RD&D was purposely defined as a strategy with a wide range of possible business models and potential interactions with the market. As mentioned previously, four parametric assumptions allowed for this flexibility, in part to accommodate differing utility viewpoints on the relative merits and definitions of RD&D. As described previously, these relationships involved the 1)cost of R&D, 2) subsequent costs associated with introducing R&D into the market, and R&D's potential influence on the 3) size of the fuel market and 4) utility's market share.

The six plots in Figure 7.2 each represent the results of 100 simulation runs where the strategy that results in the maximum NPV is identified. The main x-axis represents the costs of market entry associated with an R&D strategy. These represent additional costs that a utility would incur in order to capitalize off of successful R&D. Utility companies differed in their potential approaches—some would simply sell equity positions in companies performing R&D, while others preferred to build an energy services company to deliver these products within their service territory. The main y-axis represents the influence of R&D investment on the utility's future market share. Some utilities felt that R&D could be part of its larger strategic planning and an integral its competitiveness, while others saw R&D as entirely external to the company. Within each of these plots, the minor x-axes represent the cost of early market entry via an energy service subsidiary. The y-axes represent the market erosion associated with competition if an investor waits to invest until the late period.

Several utilities felt strongly about their position within this set of assumptions.[63] For example, Utility B sees itself as a late-mover in technology. Although it already owns an energy services company, it feels that additional investments would be needed to enter the fuel cell market. On the other hand, Utility A is interested in R&D and makes equity plays in it, but has no existing energy service subsidiary. However, since it tends to make investments primarily for the purpose of selling an equity position, it does not believe that major additional investments would be needed.

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[63] The red circles in Figure 7.2 roughly represent the portion of the parameter space considered relevant by several discussants. However, the exact range and the "optimal" solutions within these regions are not necessarily instructive at this point, and served primarily to motivate successive revisions of the model, as well as the analytic section on choosing a robust strategy that follows further in this chapter.

Figure 7.2: What is the Role of RD&D?

Utility A: Has a stake in technology development and a business platform to deliver technologies: BAU is not the best option

Utility B: Is passive on new technologies and lacks a distribution platform: WAIT

RD&D's Impact on Market Share

Technology Offers Competitive Advantage (e.g. market share same as same as Early DG)

Late Mover (e.g. market share same as Wait-and-See)

Market Erosion from Competition if Wait

Cost of Early DG

Cost of Market Entry via RD&D

No Additional Market Entry Costs

Some additional investment needed (e.g. Cost is 50% of Early DG Cost)

Need full ESC platform to sell technologies (Cost is identical to Early DG)

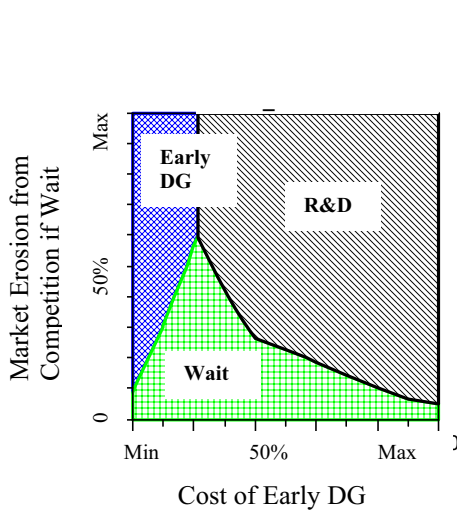**Does the utility play a role in shaping the market?**

Policy uncertainty plays a critical role in the investment outlook in the industry, and is a central theme of the model. One question is whether the policy outcomes are exogenous to utility actions, or whether the utility plays a role in influencing government policy. The model assumes that even if policies favor fuel cells in the early period, that technological or market surprises could result in policy reversal in the late period. For example, natural gas shortages or improvements in renewables technologies could result in the elimination of a fuel cell provision within RPS. The base assumption is that there is a possibility that fuel cell policies may collapse in the post-2010 timeframe. In Figure 7.3, the main x-axis represents the ability of an early investor to lock-in fuel cell policies.

An early investor may be able to help establish a technology standard among consumers or electric utilities, or influence regulators on grid interconnect or RPS policy. Alternatively, if the utility believes that it has little influence over the establishment of the market, then it may make sense to make early investments only if the initial cost of DG market entry is low enough that early cash flows compensate for the risk of future market constraints. If the cost of DG entry is very high, then it may make sense to wait until uncertainties are resolved by engaging in R&D or pursuing a BAU strategy.
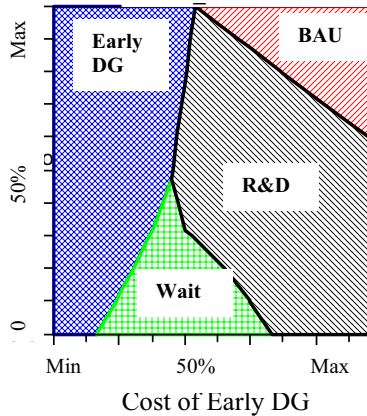
Figure 7.3: Policy Uncertainty and Utility Investment

Renewable Portfolio Standard and Fuel Cells

The baseline assumption in this model has been that if fuel cells qualify within RPS, they are capped at 20% of the total RPS electricity mix. Figure 7.4 illustrates the tradeoff between the investment costs associated with creating an energy services company and the likelihood of government policy favoring fuel cells. As costs begin to increase, early investment requires greater certainty regarding government policy. Note that the costs of the R&D strategy in this figure are set at a fixed $10 million, which results in it being the preferred strategy as the costs of an energy service company become large.

Figure 7.4: Effect of Renewable Portfolio Standard
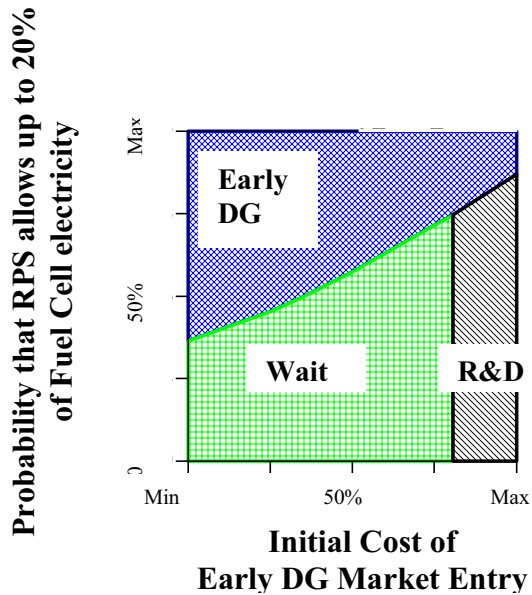
Cost Sharing and Secondary Markets

Various public-private cost sharing policies are part of the slate of policy tools that are currently being considered by the California Hydrogen Highways Initiative and other state-level hydrogen programs. In particular, one tool mentioned by utility discussants was the attractiveness of partial sunk cost recovery for stranded hydrogen investments in the event of a failure of that market. What level of sunk cost recover would be necessary to induce utilities to make an early investment?

This model assumes that under a sunk cost recovery policy, the utility is able to recover a portion of the capital costs associated with early investment if it decides to abandon this investment due to adverse market conditions. The model assumes that R&D expenditures cannot be recovered. Sunk cost recovery is modeled as a payoff associated with abandoning an Early Investment strategy. This was equivalent to allowing the salvage value for the abandonment option to be a percentage of the original sunk cost, discounted at the time of abandonment.

It is interesting to note that a government policy on sunk investment would resemble, from a modeling standpoint, the emergence of a secondary market, such as a refueling market for fuel cell vehicles. If the utility believes that some of the capital associated with the fuel cell investment can be redeployed (such as steam methane reformers, hydrogen storage, land, etc.) to a hydrogen vehicle market, this perspective merits additional attention. The default setting for the abandonment parameter in the model is zero, which could be a very conservative assumption if this redeployment is possible. The degree of sunkeness of investment can be critical - note how increasing the sunk cost recovery parameter widens the Early Investment solution space at the cost of R&D and Wait-and-See.

For each of the three plots in Figure 7.5, the minor x-axis represents the cost of building an energy services company, and the y-axis represents the degree to which a company has a first-mover advantage in the market.

Figure 7.5: Impact of Partial Sunk Cost Recovery on Utility Investment

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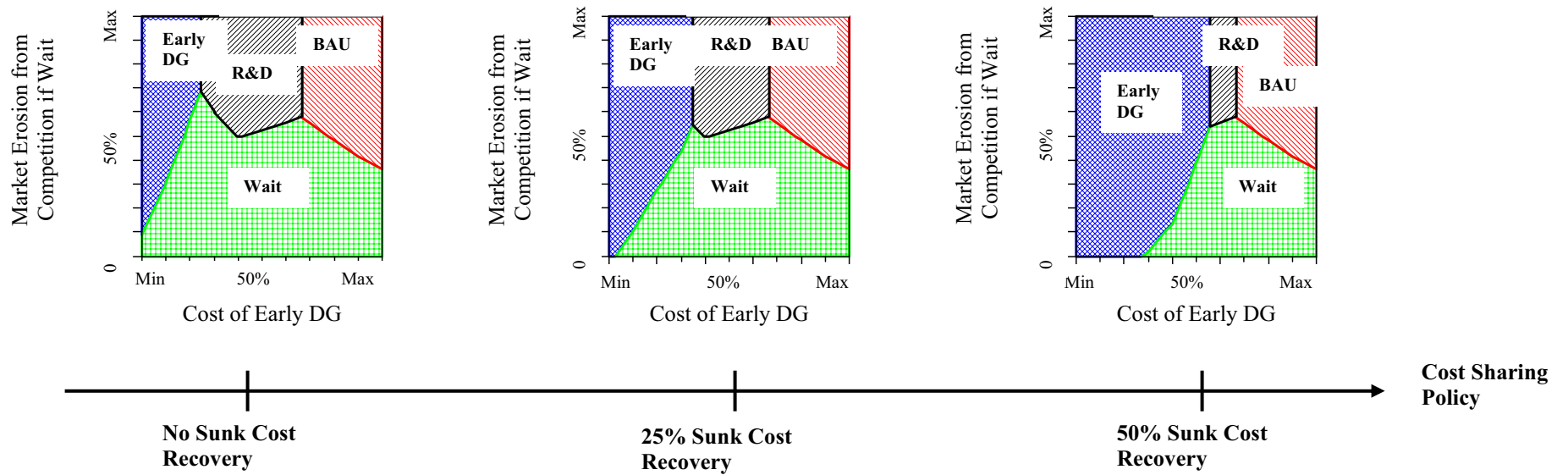
CHOOSING A ROBUST STRATEGY

The sensitivity analysis plots earlier in this chapter were important visualization tools that were used to elicit utility executives' opinions on their business operations and define relevant ranges for parameters used in the model. However, the choice of investment strategy is less clear from these plots—at least 30 other parameters are held constant at arbitrary reference values for any single two or three-dimensional visualization.

A central aspect of Robust Decision Making (RDM) is the identification of key scenarios where a candidate strategy performs poorly compared to others. Such scenarios preferably encompass most of the parameter space where a strategy fails, but also limit the number of dimensions used to describe this space in order to aid the creation of narrative, policy-relevant scenarios. This dissertation utilizes the data-mining procedure PRIM to identify such compact and easily defined sub-regions, as described in Chapter 6.

Comparing Candidate Strategies

The first step in RDM is to identify a candidate strategy to test against. A Latin Hypercube simulation was performed for all four strategies, with 500 samples randomly taken over the entire parameter space (all of the possible futures) for each strategy. As described in Chapter 6, regret was chosen as the metric for robustness, so the output measure—present value of cash flows for each strategy—was transformed accordingly. The box-and-stem plot in Figure 7.6 shows the distribution of regret for each strategy. The first thing to notice is that all four strategies have a significant number of outliers where such strategies perform very poorly.[64] So, despite the fact that the Early DG strategy is the best strategy for more than 50 percent of futures (and thus has a median regret of zero), it performs extremely poorly compared to the optimal strategy in approximately 30 percent of futures.

Of the four possible strategies, Business-as-Usual and R&D have the highest mean regret and also the widest inter-quartile ranges. If we set $10 million as a threshold criterion for identifying a "high regret" future, these two policies perform poorly in more than 8 out of 10 futures (84 percent for R&D and

86% for BAU). Although this would not necessarily disqualify the candidates in terms of robustness (it is possible that they perform poorly for futures that are not policy relevant or realistic), we turn our attention to the remaining two strategies to build a candidate policy.

Although Early Investment has a slight edge compared to Wait-and-See in terms of lower median regret and tighter inter-quartile range, Wait-and-See was chosen as the candidate policy for two reasons. First, the case studies in Chapter 4 showed that energy companies are very much focused on this strategy, making it particularly policy relevant. Second, their performance is comparable in terms of regret.

Figure 7.6: Box-and-stem plots of regret for each investment strategy

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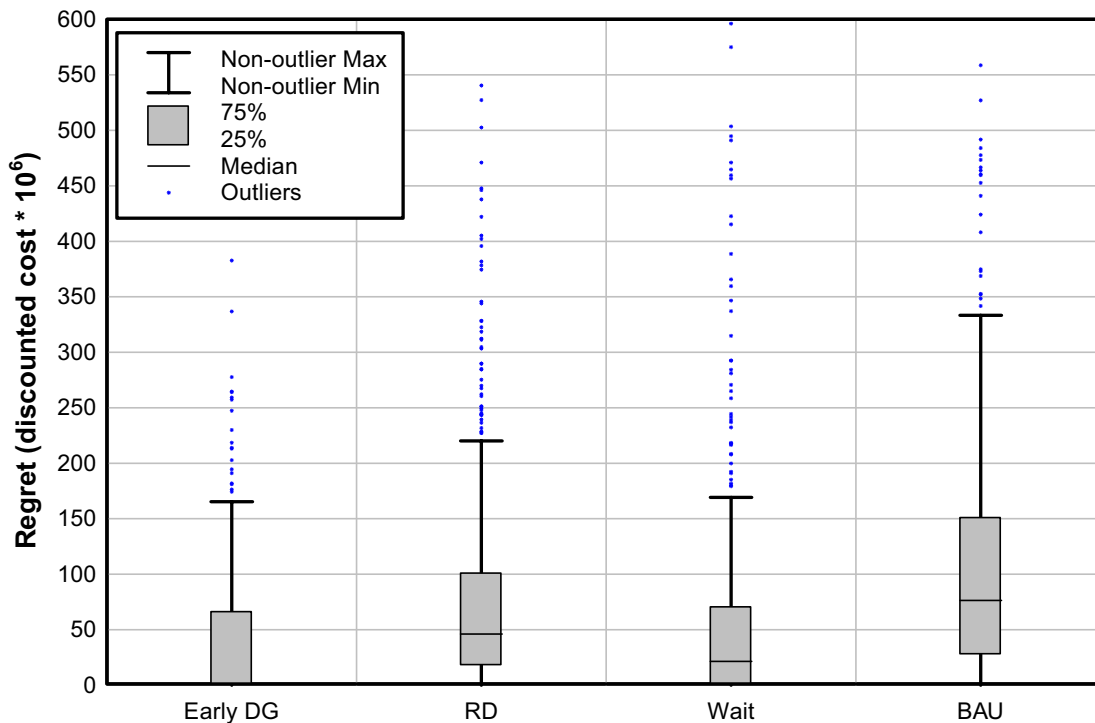
64 In Figure 7.6, the top of each box shows each strategy's upper quartile regret, while the whisker above each box represents observations within 3/2 the interquartile range. The outliers, identified by asterisks above the boxes, represent all other observations.

Identifying Vulnerabilities

One of the key features of RDM is the identification of scenarios, namely low-dimensional regions of the parameter space, where a candidate strategy performs poorly compared with other strategies. Although Early Investment and Wait-and-See have the lowest median regret, further analysis needs to demonstrate whether the regions where a candidate strategy performs poorly are indeed likely or policy relevant.

In order to simplify the interpretation of the PRIM results, the data set was further divided according to whether a regret measure exceeded or fell below a certain threshold, allowing for regret to be transformed into binary output. A satisficing threshold of $10 million was used to define "high regret", which corresponded roughly to the scale of speculative investments currently considered by utility executives in the distributed generation market, as a notional benchmark. For the Wait-and-See strategy, 289 out of 500 futures (58 percent) are classified as high regret.

Scenario 1: "Profitable Early Market"

The PRIM analysis first identified a cluster which spans 27 percent of the parameter space, but captures 44 percent of all high regret cases. The percentage of high-regret cases within the scenario itself was 95 percent. Namely, this scenario represents just under one-half of the futures where the Wait-and-See strategy consistently performs very poorly compared with other alternatives.

Table 7.1: Parameter Ranges Defining the "Early Profits" Scenario

Parameter	Input Ranges
Probability that partial RPS credits are allowed for stationary fuel cells	> 33%
Probability that an energy company can conduct an accurate market study	> 38%
Profit margin for the fuel cell business	> 5.5%
Probability that a utility will take a dominant share of the fuel cell market	> 79%

This first cluster demonstrates that a Wait-and-See strategy is vulnerable if four conditions are met simultaneously: 1) government intervention in the fuel cell market is a possibility, 2) the energy company has a reasonable ability to gauge the size of the market on its service territory through a market study or

other means, and 3) if natural gas prices are below a certain threshold (described here by a profit margin proxy, since the business strategy was not specified in the model) and 4) the company is confident that it can be a dominant player within that market and capture a large market share within the purview of RPS legislation. This would imply that there are conditions where an early action in the fuel cell market could be worthwhile regardless of the prospects for a long-term market.

Scenario 2: "Policy Shaping"

Next, all the futures associated with Scenario 1 are removed from the ensemble in order to identify a second cluster of states where the Wait-and-See strategy is vulnerable. This second scenario was named "Policy Shaping" – 85 percent of futures within this scenario were high-regret.

Table 7.2: Parameter Ranges Defining the "Policy Shaping" Scenario

Parameter	Input Ranges
Probability that partial RPS credits are allowed for fuel cells	> 22%
Probability that fuel cell policies collapse in later years if there is no early investment	> 46%
Probability that an early investment will lead to a permanent RPS policy in favor of fuel cells	> 21%

Whereas the Early Profits scenario focused entirely on short-term profitability, the Policy Shaping scenario reflects the possible longer-term policy environment related to the fuel cell business for utilities. Namely, the Wait-and-See strategy performs poorly compared with an Early Investment strategy if a utility believes it can exert significant influence over policymakers by making early investments in fuel cells. Essentially, the premise of this model is that policies related to renewables and fuel cells are unstable. If a company believes that its actions can influence the adoption of fuel cell technologies within public policies regarding renewables, the underlying investment logic changes.

SUMMARY

The candidate Wait-and-See strategy is a conservative strategy with little downside risk, as described in this model. The two scenarios where this strategy performs poorly are in fact both highly

dependent on government policies which would favor earlier investment. This implies that a greater degree of clarity regarding government policies is critical in this market. However, several other uncertainties merit the attention of energy companies considering operating in this market.

Based on this highly stylized model, we can identify uncertainties that an energy company would need to resolve as part of its due diligence in this market. Some of these are rather obvious, such as profit margins and the variable costs associated with natural gas feedstock for fuel cells. Others may be more subtle. Does a utility fully understand the market in its service territory and the potential competition from other technologies? In an industry that has relinquished its leadership in technology development, what kind of commitment is it willing to make to hire engineers and support staff, purchase facilities in order to simply be able to enter this market when it chooses to do so? Knowledge may be a key component, but it is not free.

From a longer term perspective, an underlying assumption in the model is that government policies are not stable. If an energy company believes that its action can have an influence over state regulators, it would favor earlier commitment to this market. In fact, many utilities are currently in discussions with state regulators and public utilities commissions regarding technology adoption within RPS and some gas utilities have even considered entering the renewables business, which gives some indication that some stakeholders may view the "Policy Shaping" future as a distinct possibility.

Is there a hybrid strategy that would hedge against the adverse outcomes associated with the Wait-and-See strategy? Of the two scenarios where the Wait-and-See strategy fails, the Early Profits future is not likely to be of great concern to most gas distribution companies. As outlined in previous chapters, the possibility of short-term profits outside of the core business is something a gas distribution company faces—and rejects—regularly. However, a hedge on the Policy Shaping scenario would be of greater relevance, since it represents a longer-term market shift. The fundamental question is what type of investment, short of an actual major commitment to an irreversible investment in infrastructure, would be able to give the utility an influence over policy outcomes if it believed that early investment had a great bearing on the future policy environment, but that the market or technology made such an investment, on balance, too risky in the near term. Much of this depends on the definition of "monitoring the market," as described in Chapter 6. As the costs of monitoring the market increase, perhaps beyond the range used in this set of simulations, another strategy becomes evident. The pursuit of a demonstration or "pilot" project

(in partnership with government, rather than proprietary R&D) may be such a hedge.   In fact, utilities have been considering bidding for individual hydrogen refueling stations and stationary fuel cell investments under the auspices of government demonstration projects. Such activities may be understood within this context of hedging against adverse future policy outcomes without committing to a major irreversible investment.

CHAPTER 8: CONCLUSIONS

Policymakers face daunting challenges in formulating energy policies to spur private sector investment in hydrogen and fuel cell technologies, for which near-term markets are idiosyncratic, costs and performance uncertain, and the business propositions for multiple stakeholders ill-defined. This dissertation attempted to address a narrow subset of policy issues related to hydrogen and fuel cell technologies, and several conclusions are worthy of note.

Fuel cells and hydrogen technologies are unlikely to play more than a niche role in distributed power generation within the timeframe of this analysis, unless major technological breakthroughs or government incentives lower the substantial capital costs to investors. However, to the extent that fuel cells are allowed to qualify as "renewables" within the various state-level (and possibly future federal-level) renewable portfolio standard initiatives, these technologies may offer electric utilities an additional tool for meeting these objectives, and natural gas utilities an added source of base-load demand for natural gas, and perhaps more importantly, an opportunity to participate in technological development.

This study did not attempt to address the question of whether hydrogen should be a prominent part of the nation's energy portfolio, nor whether hydrogen fits within renewables policy on the basis of technical or environmental merit. In fact, there are reasons why gas consuming technologies should explicitly be excluded from or limited within a renewable energy portfolio, if one of the objectives of such a policy is to decrease gas demand in the power sector in response to increasing prices and volatility seen throughout North America and Europe in recent years. However, renewables policies typically strive for multiple objectives, and many state-level RPSs do allow natural gas-consuming fuel cells within their portfolios. Here, analogies can be found with the partial zero vehicle emission (PZEV) credits in California as a possible compromise. At a minumum, the relationship between hydrogen and renewables merits clarification by policymakers, particularly as disparate state-level initiatives merge into a federal RPS policy.

One key consideration for regulators is the role that policy uncertainty would play in private sector investment strategies and the costs and benefits to committing to credible long-term policies. Regulatory

risk will be a major consideration for gas companies (or other energy companies) considering speculative investments in hydrogen. At the same time, policymakers are also gathering information over time and they have legitimate reasons not to commit to a policy as well.

Another issue at this early stage is the role of regulation and competition in an emerging hydrogen market. Clearly, with no foreseeable hydrogen "market" for power generation or transportation on the horizon, outside of captive markets for government sponsored pilot programs, this issue remains somewhat theoretical. However, if hydrogen emerges as an important fuel in the power or transportation sectors, regulators will be faced with decisions regarding competitive access to hydrogen distribution networks and also distributed generation access to the electric grid. These would be important considerations for natural gas utilities contemplating speculative investments (not covered by regulated rate recovery) in hydrogen production and distribution.[65]

From a methodological standpoint, a real options approach offers a richer understanding of the dynamics of investment than traditional methods currently used in this sector. Although real options valuation is already used in the energy industry, its applicability as a long-term strategic corporate decision making tool has been somewhat diminished by its mathematical complexity and opacity, often relegating it to purely academic applications. In particular, realistic investment problems often involve multiple dimensions and therefore require cumbersome approaches. An explicit choice was made to limit the representation of technological detail in the model in order to focus on the dynamics of investment. One of the advantages to this approach is the creation and testing of a variety of investment scenarios that would not be readily apparent through traditional techniques, and identifying crucial uncertainties that would require further exploration by stakeholders, perhaps with traditional analytic techniques.

The dissertation showed that a Wait-and-See strategy would be a robust strategy for some natural gas distribution utilities, but that they would be well advised to focus on three different types of uncertainties as they evaluate investment in fuel cell technologies in the future. First, a gas utility should understand the potential market for distributed power generation on its service territory, including the potential impact that legislation in the power sector will have on the demand for renewables and advanced

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[65] The investment decisions chosen in this analysis were constrained by several criteria, including the potential for early profitability, and so were not truly "market transforming." For example, dual-use (natural gas and hydrogen) distribution infrastructure was deemed to be outside the timeline for most utilities in this study. However, it may be worthy of reexamination as long-term hydrogen policies become more clear.

fossil fuel technologies. Second, a gas utility should be able to identify the tradeoffs between an aggressive capital outlay and a more passive strategy that waits for regulatory uncertainties to be resolved, and in particular, their effect on shaping local policies and the competitive landscape. Finally, a gas distribution company should have a clear understanding of its project milestones, and quantify market and policy signals. One of the pitfalls of a real options approach is that the investment pathways suggested by the model can be difficult to execute in real-world managerial situations, particularly when market or policy signals are not readily apparent, which can lead to over-commitment to a project. The real options approach used in this dissertation, though highly stylized, can be a useful tool for structuring and comparing investment strategies in the face of deep uncertainty.

Several comments are in order regarding future applications of the methodology used in this dissertation. Policymakers will increasingly be faced with challenges as new technologies contend to address myriad energy and environmental challenges. In particular, biofuels and power generated with carbon capture technologies, such as IGCCs, both share common characteristics that make traditional analytic techniques difficult to implement. First, both technologies are capital intensive with embedded real options. Second, the viability of both technologies depends to a large extent on the dynamics of multiple markets—agricultural and transportation markets for the former, and power, hydrogen, and carbon markets for the latter. And finally, investments decisions are plagued by multiple uncertainties in technology performance, costs, supply-chain logistics, and government policies. Both of these non-traditional technologies would be good candidates for the real options methodology developed in this dissertation and would underscore the crucial link between private decision making and public policy.

APPENDIX

Appendix A.1: RAND-GTI Study

Appendix A.2: Utility Discussions

Appendix A.3: Utility Email Survey

Appendix A.4: Utility Investment Philosophies

Appendix A.5: Utility Perspectives on Uncertainty

Appendix A.6: Utility Perspectives on Hydrogen

Appendix A.1: RAND-GTI Study

As part of a joint RAND-GTI study commissioned by the Department of Energy, two waves of in-person interviews were conducted with executives, managers and engineers in the offices of the (1) Southern California Gas Company, (2) NiSource, and (3) KeySpan between January 2005 and December 2005. The interviews were loosely structured, and intended to elicit opinions on general investment philosophies, uncertainties, and hydrogen-related investments.

The first set of discussions was held in early 2005 for the purpose of scoping these broad issues and to aid the development of the real options model. A list of interview questions is shown in Appendix A.2. Due to the free-ranging nature of the discussions, which typically lasted 3-5 hours, the exact interview protocol was modified to suit the expertise of available discussants and the areas of particular interest to each gas distribution utility. An additional email-based survey instrument was conducted in mid-2005, and appears in Appendix A.3. The results of the interviews and surveys are summarized in Appendices A.4-A.6

A second round of in-person discussions was held in late 2005 after the basic model was constructed in order to receive feedback from the utilities on the preliminary structure, parametric ranges, and results of the model. Although this feedback is not summarized in the Appendix, it was incorporated into the final model and also more explicitly noted in some parts of the dissertation, such as Figures 7.2 and 7.3. In the interest of confidentiality, utilities were not identified by name when discussing imminent investment opportunities or their views on where they fit within the model.

Appendix A.2: Utility Discussions

Overview

1. How large is your service territory and how many consumers do you serve?

2. How would you describe the growth patterns in your region?

3. What are the main sources of competition to your business, if any?

4. What other lines of unregulated business have you developed recently or are considering deploying in the future?

General Investment Philosophies and Views on Uncertainty

5. What are the timeframe and hurdle rates for your core and non-core investments?

6. What are the risks facing your business and how do you manage with them?

7. What are the uncertainties regarding the energy market, technologies, and public policies are of concern to you? Do you have any influence over them?

Views on Hydrogen

8. Have you made any hydrogen-related investments thus far? If so, what kind?

9. What are the biggest barriers facing the emergence of a hydrogen market on your service territory?

10. What are the prospects for hydrogen refueling stations, dual-use hydrogen-gas pipelines, and stationary fuel cells in your region?

11. What policy or market conditions would make hydrogen technologies legitimate long-term investment candidates for your energy company?

Appendix A.3: Utility Email Survey

1. Have you conducted a study of the market for distributed power within your service territory? …………………………………………………… | Yes | No |

   a. If so, when was the last time? …………………………………………………… | Year |

   b. Was it outsourced or internal? …………………………………………………… | Internal | Outsourced |

   c. Was it limited to your service territory, broader within "striking distance", or national?..............................

   d. Can you share the results with us? ………………………………………………… | Yes | No |

   e. Do you do these with any frequency? If so, when is the next one? …………………………………………...

   f. What types of technologies were considered? (check all that apply)……..………………………………… | Gas | PV/Wind |
      | Diesel | Fuel |

   g. What role does marketing/advertising play in shaping consumer demand? …………………………………… | Low | Med | High |

   h. What are the main barriers to consumer adoption of DG technologies?
      (Rank top three in order, 1=Most Important)

      i. Technology Risk (e.g. obsolescence, maintenance issues, safety, etc.) ……………………………

      ii. Uncertainty in electricity or gas prices…………………………………………………….

      iii. Capital Costs ……………………………………………………………………

      iv. Lack of Insurance ………………………………………………………………

      v. Lack of knowledge ……………………………………………………………..

      vi. Other (please state) ………………………………………………………………

   i. Does the utility mitigate consumer risks? (e.g. absorbing part of initial capital costs, offering guaranteed rates, or going so far as to be the owner operator of the equipment, such that you provide an energy service, rather than distribute appliances, etc.) ………………………

2. Do you invest in R&D? …………………………………………………………………………..

        | Yes | | No |

   a.   If so, what is your annual R&D budget? (approximately) ………………….………………………

        | $ |

   b.   If you were thinking of investing (i.e. equity) in R&D in a new technology,
          what is the magnitude of an investment you would consider? ………………….……………….

        | $ |

   c.   Can you break out your R&D portfolio into major topics? …………….………………………………….

   d.   What is your objective? (e.g. always a minority, always with others, majority position?) …..

3. Which of the following arrangements has your utility made to sell DG to customers?
      (check all that apply)

   a.   Created or used existing unregulated energy services subsidiary which purchases
          and installs 3rd party technology for customers ………………………………………………………..

   b.   Partnered with a 3rd party to share risks and benefits
          in providing such a service to customers ………………………………………………………….

   c.   Acquired rights to new technologies through equity investments or internal R&D …………………………

   d.   Other (state) ………………………………………………………………………………………..

4. **If the market for distributed power technologies (fuel cells or otherwise) were to grow substantially because of market forces or public policy, which arrangement would your utility prefer?**
     (Rank in order, 1=Most Likely, 4=Least Likely)

   a. Create/Expand unregulated energy services subsidiary, but continue
       purchasing 3rd-party technology for customers…………………………………………………….

   b. Form partnership with a 3rd party to share risks and benefits
       in providing such a service to customers …………………………………………………..

   c. Acquire rights to new technologies through equity investments or internal R&D…………..........................

   d. Stay uninvolved in market, except for selling gas for potential new source of demand …...........................

   e. Other (state) …………………………………………………………………………………………

Appendix A.4: Investment Philosophies

PHILOSOPHY	Utility 1	Utility 2	Utility 3
General	Core business is key, primarily based on NG throughput. Have been burned by CNG stations and distribution investments that were based on "build it and they will come" philosophy. However, they seem to be open to innovative ideas and ways of looking at investments, particularly with DG	Core business is key, and primarily based on NG throughput. For example, exited E&P business. They only make "platform" and "accretive" (must have customers) investments that create synergies with core business, rather than looking at individual profitable investments in isolation. All investments must pass hurdle rates (lower for regulated than unregulated businesses)	Government is driver. If utility can pass costs onto ratepayer, then will do it, but would rather that tax passed down to citizens more generally than their ratepayers. On R&D side, invest in small companies, rather than in-house R&D capability.
Percieved Risks	They do not perceive any major impending risks. They do site their CNG experiences and the "build pipe and they will come" as examples of the risks associated with reaching outside of the core business.	According to VP, have been burned when they have invested faster than the rate at which critical uncertainties were supposed to be resolved (very similar to Real Options language)	Lawsuits, government policy uncertainty, and potential to get burned by new technologies, such as fuel cells. Want to supply fuel to device, but not deal with device. Don't want to get involved on the other side of the meter.
Timeframe for Investments		Payoff in 3-5 years (essentially dictated by high hurdle rate for non-core investments). They are strictly energy services, and no R&D (although they had R&D in past). As far as staging investments, they like to identify metrics and strict milestones in advance. Many projects are competing for dollars.	For R&D, cash flow in 5-7 years. For an H2 investment, demonstration program might be attractive or spin-off spin-off H2 services company
Expected Rates of Return		Hurdle rates are risk adjusted. Highest for non-core business, such as tech investments, set at 20-25%. It has rarely been met, but there have been some borderline cases, such as. Core business (gas dist) hurdle rate is lowest, electric dist a little higher. Platform investments are heavily favored. However, they calculate return on investment without this beneficial spillover effect.	PUC constraints on R&D returns? Rest of company?
Financing Issues	Low-level investments possible if senior management is convinced. Informal process.	Aiming for 50:50 debt:equity, Wall Street is a driver. They have been decreasing their debt service over the years to reach this mark, and this is where they would like to be.	For new technologies, they have a modest budget to make small scale equity investments in companies developing technologies.
Sources of Market Erosion	Possibly conservation measures by consumers if NG prices escalate, but not major concern	Fuel switching market shrinking over time. Difficult to pass on extra costs to ratepayers, because it makes them less competitive.	Senior executives in company do not see a any credible sources of market erosion.
Gas T&D investment	Some pockets of distribution constraints, but manageable through curtailment		Getting close to distribution constraints. Need to talk to capacity planning group.
Can a utility influence policy?	Anything that increases NG throughput without major downside risk is good	Gas load generated from DG is good, but there are some constraints.	Involved in PUC-authorized DSM programs. In principle would be interested in acquiring load-profile of electric side through DG investment.

Appendix A.5: Perspectives on Uncertainty

UNCERTAINTIES	Utility 1	Utility 3	Utility 3
Energy Market	**Core Business**: If NG prices are high and sustained, this would have mixed results. On one hand, electric generation would shift from coal and nuclear over time to natural gas. In current regulatory regime, NG prices pass thru to customer and they are purely in distribution business. However, high prices would lead to conservation policies which would curb demand. Collection risks from customers goes up, debt risk increases, and public perception becomes negative.	**Core Business**: Most NG price increases are passed down to consumer, so NG prices affect them adversely only in the sense that there is fuel switching. They have invested in LNG capacity for peak shaving, and this is emerging as an important business.. Cannot pass down extra costs to ratepayer, since in competition with fuel oil.	**Core Business**:
	H2: Key for DG is spark-spread. Either NG prices have to go back to what they were several years ago, or electricity prices must go up. However, electricity mix is mostly coal/nuc. Disser sees the possibility of NG prices going down to "normal". Low NG prices would mean that NiSource is more aggressive on DG. For traditional markets, they see the existing industrial gas companies as having a major advantage, although there is one company looking at niche position which will probably be bought out by big players. They don't really want to be dual commodity suppliers. For CNG station, they see a free-rider problem.	**H2:** CNG experience turned out to be stable on account of large volume buses and taxi cabs.	**H2**: Need market driver to convince senior management of H2 investment. They are interested, however, in future scenarios and how H2 and other aspects of the core busines might play out. It is the "ideal time to do this"
Technologies	**Core Business**: No major impact seen on core business. However, since most of generation mix is coal/nuc, if there are developments there, it will affect gas demand.	**Core Business**: Don't envision any major technological impacts on their business, but interested in finding out more about LNG	**Core Business**: Not a major concern, but increasing interest in LNG.
	H2:	**H2**: For DG, fuel cells capital costs are key. Many businesses that are concerned with reliability issues have already purchased diesel generators or made other modifications to business processes, so market is no large for it right now. They have experience with CNG stations, went to firehouses to teach safety issues, possible template for H2 in the future.	**H2**: Fuel cell capital costs needs to get down to 8-10c/kWh.
Policy	**Core Business**: Anything that would impact coal or nuclear would impact their sales for electric generation.	**Core Business**: Company policy is against any new broad-based energy-taxes, regardless of whether it may or may not directly benefit them. However, any policy related to petroleum business or high carbon fuels would benefit them, since they are in competition with fuel oil. LNG policy also has an effect on them.	**Core Business**: Policy uncertainties primarily on legal/regulatory issues
	H2: There would need to be a sustained, robust demand for H2 vehicles for them to build H2 station. Even then, they would not necessarily want to get involved in H2 side, but perhaps provide NG to on-site H2 producers. However, they are currently saddled with unprofitable CNG stations, so they may partner with somebody to develop those for dual-use. Big issue in refueling is free-rider problem, they would need a strong policy and contractual relationship with government or private fleet in addition to credible market.	**H2**: Major regulatory issues related to H2 safety remain unresolved. Currently, LNG in tube trailers cannot currently be transported within the region. For DG, regulatory issues involves interconnect fees, codes, standards, etc. However, major barrier is cost, because consumer doesn't care about technology, just what it does, so fuel cells don't have much of a market currently.	**For H2**: State government is the key for H2 development. If H2 market develops, CNG stations will be first places used to site H2. Also, if PUC allows H2 investments to be passed down to ratepayers, they may make investments. Codes and standards are very important, from a policy perspective, but capital costs of hydrogen/DG units is key, and costs or risks be drawn down through some policy instrument for them to make the invesment.

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Appendix A.6: Perspectives on Hydrogen

HYDROGEN	Utility 1	Utility 2	Utility 3
Biggest barrier to hydrogen	No demand and little link to core business. Free rider problem of H2 refueling station. Capital cost of fuel cells even more then DG interconnect, code and safety issues. Stability in government policy to make credible. Not enough for President to announce plan.	Capital cost of fuel cell unit. Customer doesn't care about technology, only what it does. H2 safety codes and liability. Lack of demand. Stability in government policy.	State-level policy decisions are key. Also, need to be able to pass on investments costs to ratepayers (or taxpayers).
Any hydrogen-related experience?	No (some fuel cell experience, but not H2 directly)	No (some fuel cell experience, but not H2 directly)	No (some fuel cell experience, but not H2 directly)
Interest in dual commodity business?	No. Interested in H2 only as an energy carrier, not commodity chemical. However, there are some scenarios involving partnerships or government sponsorship that would involve them, but mostly on NG side.	No	No interest in H2 commodity business per se, but could spin-off company
"Traditional" hydrogen markets	Yes, "huge" H2 market, but are already served by big industrial gas suppliers. However, may be possible to tap into it marginally, if only to offset risks of producing hydrogen for other reasons. They would really only want to get involved in H2 for energy purposes, though.	Some, but heavy industry is not prevalent. Regional refinies would be able to produce enough hydrogen if needed.	There is a large H2 load on their service territory. However, they are not interested in getting involved directly.
Distributed Power Generation	Tough competition on most of service territory either because of power prices or incumbent electric utility. In general, however, electric utilities do not see or care about T&D benefit from DG, it's just theoretical to them. Have done market studies on DG, and have units installed. Fuel cells only in R&D settings, though. Separation of hydrogen production from fuel cell hasn't really been considered since fuel cell demand doesn't really exist. Idea of power parks intrigues them, but don't see much of market in midwest, or at least they don't see participation beyond providing NG. They don't want to get involved in the "high 9s" reliability business. There are others who do this much better than them.	There is interest, but some practical barriers because of relationship with electric utilities. Also, electric utilities doesn't see T&D benefits to DG. Interest in DG on mostly for economic, rather than security reasons. Have done market studies on DG, and have units installed. Extremely limited fuel cell market.	Currently, there is no big imperative for DG within the utililty, and any future developments depend on highest-level decisions within company. Microturbines have shown some promise, but government incentives will be needed for future growth.Interested in principle, but would need approval at a higher level to more aggressively pursue DG.
H2 or mixed H2/CH4 pipelines?	In theory, would be willing to make infrastructure dual-use during regular replacement/maintenance cycle if the government were to pay the differential. However, they site Air Liquide study on metallurgical problems associated with hydrogen. NG pipes already leak too much.In theory, hydrogen production would best occur along bigger transmission lines, since capacity is much larger and less issues with supply fluctuations. However, currently no reason to do this. Existing H2 markets may serve to mitigate this risk, but those markets are already tapped into by industrial gas suppliers.	Separation of hydrogen production from fuel cell hasn't really been considered since fuel cell demand doesn't really exist. Idea of digging up very old pipes is very daunting.	Issue is whether they can pass costs down to ratepayer or in some other way be compensated by the government. Do not see business case otehwise.
H2 Refueling Stations	CNG experience is a "scary omen" for them. In this sense, H2 policy might be a "hammer looking for a nail." They have unprofitable CNG stations. However, since they are underutilized, they may be a good target to be retrofitted for H2 if and only if strong government policy incentives and strong contractual relationship with gvt/private fleets were achieved. Free rider problem needs to be addressed.	Own a handful of CNG stations, 1/2 on customers property. Spent a lot of time training local firehouses on safety codes. Early policy initiatives died, but were able to maintain steady demand through buses and taxis. Government fleets in have helped. Spent a lot of R&D funds on CNG stations. This experience could serve them well for H2. They would need to have a new franchise to distribute H2. Tipping point for CNG was a big bus programs.	Own some CNG stations, but have also sold a good number. If H2 market emerges, this will be principle location of H2 stations.

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