LBNL-41098
UC-1321

Primer on Electricity Futures and Other Derivatives

S. Stoft, T. Belden[1], C. Goldman, and S. Pickle

Environmental Energy Technologies Division
Ernest Orlando Lawrence Berkeley National Laboratory
University of California
Berkeley, California 94720

January 1998

The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

[1] Tim Belden currently is employed at Portland General Electric.

Contents

List of Figures

List of Tables

Abstract

Increased competition in bulk power and retail electricity markets is likely to lower electricity prices, but will also result in greater price volatility as the industry moves away from administratively determined, cost-based rates and encourages market-driven prices. Price volatility introduces new risks for generators, consumers, and marketers. Electricity futures and other derivatives can help each of these market participants manage, or hedge, price risks in a competitive electricity market. Futures contracts are legally binding and negotiable contracts that call for the future delivery of a commodity. In most cases, physical delivery does not take place, and the futures contract is closed by buying or selling a futures contract on or near the delivery date. Other electric rate derivatives include options, price swaps, basis swaps, and forward contracts. This report is intended as a primer for public utility commissioners and their staff on futures and other financial instruments used to manage price risks. The report also explores some of the difficult choices facing regulators as they attempt to develop policies in this area. Key findings include:

1. Hedging decisions are often made using sophisticated, proprietary computer models, and new hedging strategies and instruments are developed frequently. It is doubtful that state PUCs will have the time and expertise to reconstruct and dissect hedging decisions made by distribution utilities and others. As such, a performance target approach appears to be a much better policy than a reasonableness review.

2. PUCs should guard against speculation on the part of distribution utilities, even though it can be difficult to establish simple rules that can prevent speculative transactions. One possibility, however, is for regulators to require utilities to identify the obligations being hedged and report both the correlation between the obligation and the future contract, and the size of the hedge as a percentage of the purchased commodity being hedged.

3. Some PUCs have established program limitations and other protective measures for hedging instruments used by utilities and telecommunications companies to manage interest and exchange rate fluctuations. These measures, which may provide a guide to regulating utility involvement in electricity derivatives, have included: 1) requirements that utilities only enter into hedging agreement with entities with a credit rating equal to or better than the utility itself; 2) limitations on the amounts that can be hedged; 3) reporting requirements, including both income effects and expenses and the filing of agreement terms and contracts.

Acknowledgments

The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098. The authors would particularly like to thank Diane Pirkey at the U.S. Department of Energy for her support of this work. In addition, the authors are grateful for valuable comments received from Joe Eto (LBNL), Ed Kahn (NERA), Suzie Kito (MRW & Associates), Mike Lee (Montana Public Service Commission), and Ryan Wiser (LBNL).

Acronyms and Abbreviations

CFTC	Commodity Futures Trading Commission
COB	California-Oregon Border
CPUC	California Public Utilities Commission
ESP	Energy Service Provider
FAC	Fuel Adjustment Clause
FERC	Federal Energy Regulatory Commission
MG	Metallgesellschaft
NYMEX	New York Mercantile Exchange
ORA	Office of Ratepayer Advocates (California)
OTC	Over-the-counter
PBR	Performance Based Ratemaking
PG&E	Pacific Gas and Electric
PJM	Pennsylvania New Jersey Maryland Interconnection
PPAC	Purchased Power Adjustment Clause
PUC	Public Utility Commission
PX	Power Exchange
ROR	Rate-of-return
SCE	Southern California Edison
UDC	Utility Distribution Company
WSCC	Western States Coordinating Council

Glossary

Backwardation	A market experiences backwardation if the spot price exceeds the futures price.
Basis	The spot price of a commodity minus the futures price that is being used to hedge that commodity at any given time.
Basis risk	The risk caused by any possibility that the futures price will not converge to the spot price of the commodity being hedged at maturity.
Cash position	Amount of underlying commodity owned.
Close out	To sell a future you are long in or buy a future you are short in.
Contango	A market is in contango if the futures price exceeds the spot price.
Derivative	A financial product whose value is based on (derived from) another product.
Forward	A contract to deliver goods at some future date at some fixed price.
Future	A standardized forward that can be traded on an exchange.
Hedging	Buying a derivative to offset the risk of a cash position.
Option	When a firm buys an option, it has the right, but not the obligation, to purchase or sell the underlying commodity.
Settlement	To take or make delivery at maturity. Physical commodity futures usually require commodity settlement, financial futures usually require cash settlement.
Speculation	Buying a derivative that increases your risk with the hope of profiting.
Swaps	Swaps provide similar risk management opportunities as futures, but never result in delivery.
Variation margin	Daily payments from losers to gainers.

CHAPTER 1

Introduction

1.1 What Is Hedging?

Increased competition in bulk power and retail electricity markets is likely to lower electricity prices, but will also result in greater price volatility as the industry moves away from administratively determined, cost-based rates and towards market-driven prices.[2] Price volatility introduces new risks for generators, consumers, and marketers. In a competitive environment, some generators will sell their power in potentially volatile spot markets and will be at risk if spot prices are insufficient to cover generation costs. Consumers will face greater seasonal, daily, and hourly price variability and, for commercial businesses, this uncertainty could make it more difficult to assess their long-term financial position. Finally, power marketers sell electricity to both wholesale and retail consumers, often at fixed prices. Marketers who buy on the spot market face the risk that the spot market price could substantially exceed fixed prices specified in contracts.

Electricity futures and other electric rate derivatives help electricity generators, consumers, and marketers manage, or hedge, price risks in a competitive electricity market. Futures contracts are legally binding and negotiable contracts that call for the future delivery of a commodity. In most cases, physical delivery does not take place, and the futures contract is closed by buying or selling a futures contract on or near the delivery date. Other electric rate derivatives include options, price swaps, basis swaps, and forward contracts. Futures and options are traded on an exchange where participants are required to post margins to cover potential losses. Other hedging instruments are traded bilaterally in the "over-the-counter" (OTC) market.[3]

The New York Mercantile Exchange (NYMEX) introduced electricity futures on March 29, 1996. While some futures contracts have failed due to lack of interest,[4] initial interest in electricity futures appears to be strong. In the 20 months since NYMEX introduced electricity futures, trading has grown to an average of 2,500 contracts per day, with over 113,000 contracts traded from January to August 1997, well in excess of the 45,000 contracts traded in all of 1996 (McGraw-Hill 1997, NYMEX 1997). Recent moves by NYMEX to issue cheaper electricity futures trading permits have been designed to further boost trading

---

2 The natural gas industry provides an illustrative example. Prior to deregulation, natural gas prices were relatively steady. Since deregulation, natural gas prices have been among the most volatile of any traded commodity (Enron Capital & Trade Resources 1996).

3 Many of the important futures and derivatives related terms are reviewed in the glossary at the end of this document.

4 Since the inception of future markets in the United States, over 128 commodities have been listed on at least one exchange. As of 1986, only 45 commodities were actively traded (Black 1986).

volume for the commodity, as have the introduction of new NYMEX electricity futures contracts with additional delivery points (Dow Jones 1997, McGraw-Hill 1997). Yet while growth in the trading of electricity futures has been strong, the market remains small compared to futures trading in other commodities. For example, natural gas futures, which were launched in 1990, were the fastest growing contracts in Exchange history with over nine million contracts traded in 1996, second only to crude oil contracts.[5]

Futures are not the only way to hedge electricity price risk, however, and NYMEX also offers electricity options contracts, which were introduced in April 1996. Elsewhere, OTC hedging instruments are widely used in natural gas and oil markets and are beginning to be used in electricity markets. While no official data is available on the volume of these OTC transactions, this market may be as large or several times larger than the futures market.

1.2 Why Should Regulators Care?

Although derivatives offer the potential for managing commodity price risk in a competitive electricity market, their use will introduce new risks. Some speculators and hedgers have incurred substantial losses using futures and more complex derivative instruments. Metallgesellschaft (MG), an oil marketer, lost $1 billion dollars attempting to hedge a ten-year risk using a short term futures contract. Orange County lost $2.3 billion using derivatives in order to earn a higher return, a classic case of speculative losses.

When retail competition develops, state regulators may have an interest in protecting customers from the indirect consequences of potentially speculative derivative activities undertaken by marketers, generators, and other retail service providers (ORA 1997). To the extent regulated distribution utilities enter the derivatives market, state regulators will want to ensure that these transactions are in the best interest of retail customers.

Yet futures and derivatives should not be regulated simply because they can produce losses. Not using futures in volatile commodity markets can also produce losses. Instead, policies should be motivated by the effect the use of futures will have on the objectives of utility regulation. The traditional goal of utility regulation has been to ensure that consumers have a reliable supply of electricity that can be purchased at a fair price. This raises the issue of whether large futures losses by firms that play a vital role in maintaining the reliability of the electricity grid could increase the likelihood of a costly electrical outage.

In some situations, state regulators may need to monitor or set limits on derivatives transactions undertaken by utilities because of market power concerns during the transition to competitive electricity markets (ORA 1997, CPUC 1997a). Some parties have argued that,

---

5 Trading in natural gas futures set a daily volume record of 99,866 contracts on April 23, 1997—the third highest daily trading volume in the history of energy trading at NYMEX (NYMEX 1997).

in states such as California where large distribution utilities are required to sell into a power pool or exchange (PX), they may have incentives to manipulate PX prices in order to reap returns on positions taken in futures and other derivatives contracts. A related concern is that, where futures contracts are settled through delivery—a rare event, as we discuss, but one that nonetheless can and does occur—the distribution utility may be required to buy or sell electricity outside the PX, a sale that would violate their requirement to sell only to the PX (CPUC 1997a, 1997b).[6]

1.3 Purpose and Organization of this Report

This report is intended as a primer for public utility commissioners and their staff on futures and other financial instruments being used by market participants to manage price risks in competitive electricity markets. A primary goal is to contribute to the discussion already underway on both the benefits and risks posed by electricity futures and other derivatives. At a minimum, we hope to discourage regulators who may be tempted to take an "easy way out" on this very important issue. One such easy way out might be to simply ban the use of derivatives by regulated utilities because they are not well understood or are seen as too risky. Such a policy would prevent a great deal of socially beneficial hedging. Alternatively, regulators could ignore derivatives until they become a more serious concern. This second path could lead to a situation where regulators are surprised by an Orange County-type financial disaster that significantly impacts ratepayers.

The report is organized as follows:

- In Chapter 2, we explain why a competitive electricity market needs derivatives.
- In Chapter 3, we focus on futures, explain the rationale for using futures and present the "fundamentals" of hedging price risks using futures contracts.
- In Chapter 4, we explain how other electric rate derivatives work, how they can be used by generators, end users, and marketers, and we discuss the risks associated with these instruments.
- Finally, in Chapter 5, we discuss regulatory issues, including the risks primarily associated with futures, but peripherally with other electric rate derivatives, and we highlight potential regulatory policies to address these risks.

---

6 An additional potential question for regulators is whether electricity markets should be structured in a way that supports the development of derivative markets. Although this is an important question, we focus here on other issues that have received considerably less attention by researchers and policy advocates. See Levin (1995) for a discussion of derivatives and electric industry structure.

CHAPTER 2

Price Volatility and Risk in Competitive Electricity Markets

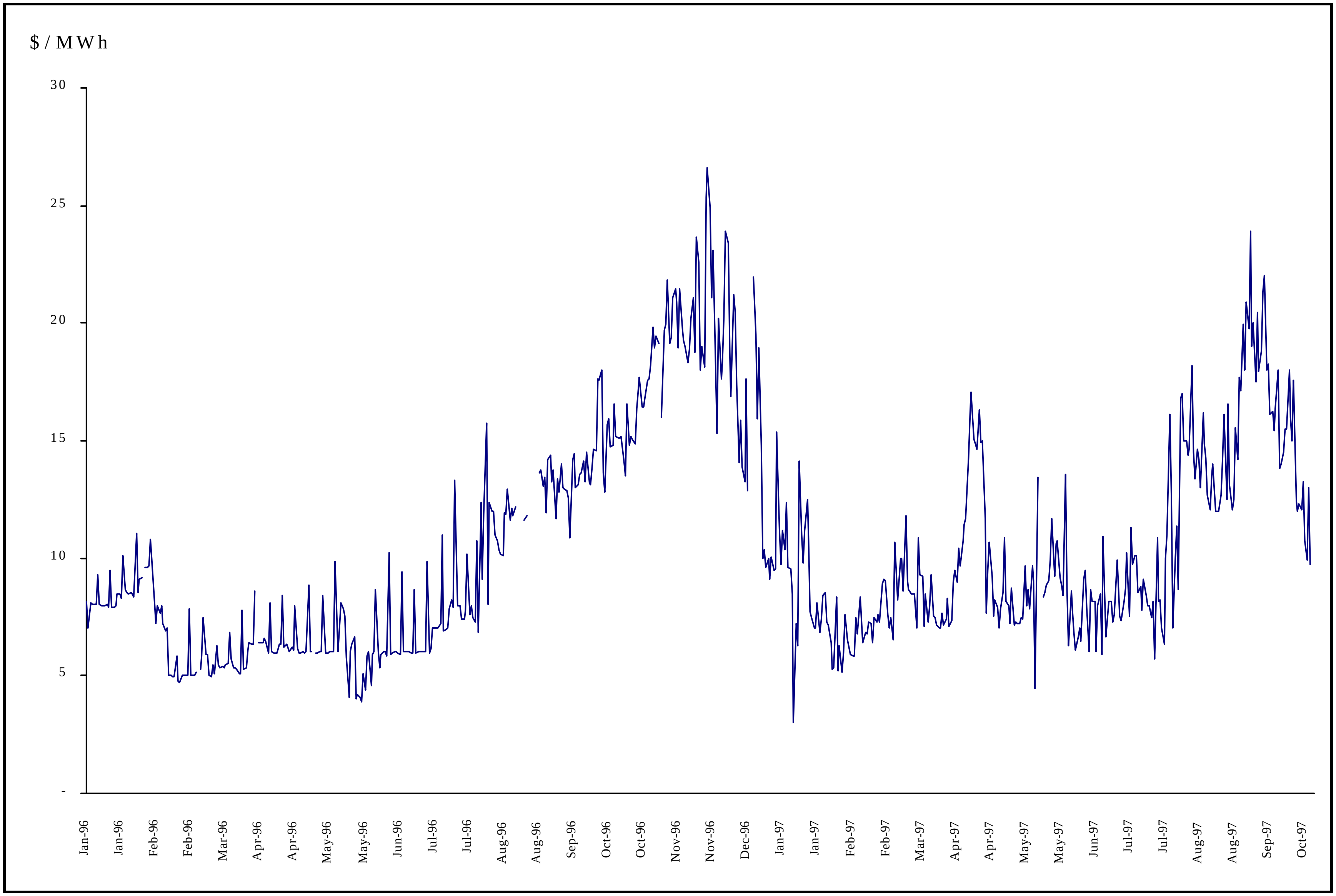
As the U.S. moves towards competitive electricity markets, the expectation is that electricity prices will be lower overall but price volatility will increase. In this section, we describe the link between competition and price volatility, and explain why price volatility will result in new risks for generators, marketers, and end users. Futures and other derivatives can help manage these risks but also introduce risks of their own.

2.1 Determinants of Price Volatility

One can look to the natural gas market to get an indication of the potential price volatility in electricity. Like electricity generation, the wellhead price of natural gas used to be subject to price regulation and was, therefore, quite stable. With deregulation, the price of natural gas decreased but became more volatile. Gas price volatility is driven largely by sensitivity to weather-induced seasonal demand. Electricity is also characterized by seasonal demand and its price can be quite volatile, as illustrated in Figure 2-1.

A traditional and explicit goal of utility regulation has been to stabilize retail prices, even though the underlying costs of producing electricity are quite volatile. Bonbright (1961), in his classic text on rate design, gives two reasons for stable rates. First, regulatory proceedings are "notoriously expensive and cumbersome," making it impractical to frequently change rates. Second, Bonbright argues that consumers need to see prices that reflect long-run costs so that they can make intelligent purchasing decisions for items that use energy. Yet while price stability may promote rational consumer decisions regarding energy using equipment and has a small benefit in reducing consumer risk, it also causes a significant inefficiency in the electricity market by making it impossible for customers to respond to the true cost of electricity. Schnitzer (1995) estimates that peak power costs may approach 50¢/kWh, but because of utility rate designs, consumers treat power even at these times as if it cost only 10¢/kWh. Consequently, customers significantly over-consume during peak hours. However, consumers do pay for these costs during off-peak hours when power is overpriced, in many places by a factor of two or three. At these times, the distortion is towards under-consumption.

Figure 2-1. Non-Firm, Off-Peak Spot Prices at the California-Oregon Border (COB)



As the electricity market becomes more competitive, cost and demand fluctuations will increasingly be translated into price fluctuations. This should make both generation and consumption more efficient. Customers will gain access to cheaper off-peak power, and will receive more accurate price signals during expensive, on-peak power periods. This should result in a flattening of the load-duration curve and an increase in load factors, which will, in turn, reduce reserve margins and the average cost of power.

Price fluctuations occur as companies attempt to maximize profits. For competitive firms, profit is maximized by setting price equal to marginal cost, and for firms with market power, profit is maximized by marking up marginal costs. Either way, the price fluctuations are simply the result of marginal cost fluctuations.[7]

There are four major factors that cause marginal costs to fluctuate (see Table 2-1). On the shortest time scale are demand fluctuations, which affect marginal cost by moving production quantity along an upward sloping marginal supply curve. Most of the amplitude of these fluctuations is experienced on a daily basis, but the height of the peak also varies with the season. As discussed in the next section, derivatives are not typically used to hedge risks associated with daily price fluctuations, but they are used to hedge risks associated with seasonal price fluctuations.

Table 2-1. Marginal Cost Fluctuations

Cause of Fluctuation	Relevant Time Period
1. Demand Fluctuation	Daily, Seasonal
2. Generation Availability (e.g., hydro)	Daily, Yearly
3. Fuel Cost	Seasonal and longer
4. Other Production Costs	Years to Decades

A closely related source of marginal cost fluctuation is shifting of the marginal cost curve as various sources of supply become temporarily unavailable. For example, availability of inexpensive hydroelectric power can shift the short run marginal cost curve. In years with plentiful rainfall, hydroelectric generation typically increases, and the short run marginal cost curve shifts down. Unit outages will also influence which generating unit operates on the margin. If a large baseload plant is being serviced, fossil plants with higher marginal costs will be forced to operate. Derivatives can play a useful role in hedging some of these fluctuations.

Probably the most important source of price volatility from the point of view of understanding futures is volatility in the cost of fuel. This will have a strong seasonal component, but can also be affected by geo-political events and changes in global market conditions.

---

7 Market power fluctuations can also cause price fluctuation, but this is a relatively minor effect and will be ignored.

The final source of marginal cost fluctuations is changes in the production technology itself. Technical progress reduces the cost of production; production costs can also be affected by environmental and labor costs. These cost fluctuations can be very important over the life of a twenty year contract, but are generally beyond the time scope of hedging strategies based on futures and other derivatives.

2.2 The Risks of Price Volatility

In a competitive electricity market, daily fluctuations in electricity commodity prices will be the most dramatic manifestation of price volatility. Those customers on real-time rates will face prices that may increase and decrease by more than 100% over several hours. These fluctuations will not, however, constitute a serious risk because it is easy for customers to time average on a daily basis, and because the amount of money spent on energy in one day is relatively small. For these reasons, electric rate derivatives are not typically designed to mitigate the risks associated with daily price fluctuations.

Price volatility alone does not create serious risk, but when a volatile input price is coupled with a fixed output price, a firm can face significant risks in its financial operations. Consider a marketer that buys power from generators in a spot market and sells power through fixed price contracts. The marketer's markup is likely to be small (e.g., less than 10% above the spot price), and most of the markup goes towards covering marketing overhead, leaving only a small profit. If the spot price jumps 25% in a given year due to a supply shortage, the marketer could lose several years worth of profits. This is an unacceptable risk, and the marketer would be interested in hedging it.

Price volatility becomes price risk when a volatile input price is coupled with a relatively stable output price.

Utilities may find themselves in a similar position if they purchase power in the spot market and are under comprehensive price-cap regulation or otherwise unable to pass costs on to customers. Generators can be placed in a similar bind if they sell in a market that is competitive and dominated by generation from another fuel. If their fuel costs increase more than the fuel costs of other types of generation, then it is likely that spot power prices will not completely cover their increased fuel prices and their profits will suffer.

2.3 Risks Faced by Industry Participants

How will risk be managed in the emerging competitive electricity market? It is useful to compare how traditional regulation managed risk and to specify what risks industry participants will face in the future. Cost of service regulation relies largely on the "prudency" standard. If a utility's investments and expenditures were deemed prudent, regulators would allow the firm to include these investments and expenditures in rates. Some risks (e.g., interest rates, fuel prices, and purchased power prices) were considered beyond the control of utilities and were passed on to customers through automatic adjustment clauses and balancing accounts. Ultimately, the customer received one bundled price for the myriad services provided by the utility.

In a competitive market these different services will be unbundled and priced separately. In many states, regulators are considering or have already required a functional or physical separation of generation, transmission, and distribution assets. It is easier to understand the risks of a competitive market by taking a functional view of the industry. Participants in the electricity market may perform one or more of the following functions: (1) generate power, (2) transmit/distribute power, (3) market power, and (4) consume power. The positions and risks faced by generators, marketers, and end users are described below and summarized in Table 2-2.

Generators

In a restructured electricity industry, generators will include utilities, federal power authorities, qualifying facilities, merchant power plants, and on-site industrial plants. An entity that owns a power plant has a "long" electricity position. That is, the entity's wealth increases and decreases with the price of power. When power prices increase, the value of the plant increases, and when power prices decrease, the value of the plant decreases.

Marketers

A marketer buys and resells power. A marketer can have either a "long" or "short" position. A marketer who buys fixed-price power before finding a market for that power has a "long" position. A marketer who has sold fixed-price power before securing supply has a "short" position. San Diego Gas and Electric and Portland General Electric are examples of utilities who currently serve as marketers for significant portions of their native load. Each of these utilities has greater load than generating resources. Accordingly, they buy power in the wholesale market and resell it at the retail level. Their obligation to serve these retail loads gives them a "short" position, since they must buy power in the wholesale markets in order to meet their obligations to customers.

End Users

Competition will change the choices that customers have for suppliers. An electricity consumer is naturally "short." As is typical with a short position, consumers benefit when prices go down and are hurt when prices increase.

Table 2-2. Industry Participants and Risks

Function	Examples	Natural Position
Generators	Utilities, Independent Power Producers, Qualifying Facilities	Long
Marketers	Utilities, Power Marketers	Long or Short
End Users	Industrial, Commercial, Residential Customers	Short

One firm may perform several of the functions described above, making it difficult to categorize risks as those faced by "utilities" or "marketers" or "end users." A cogenerator may decide to become a power marketer. An investor-owned utility may be long power in its own service territory but may market significant amounts of power in other parts of the country. Firms such as Chevron and Dupont perform all of these functions as they have large electricity loads, own generation on-site, and have established power marketing subsidiaries. As the industry develops, it will be necessary to piece together the different functions that a given firm performs in order to understand the risks that it faces.

2.4 Potential Dangers of Derivatives

If the experience in natural gas markets is replicated in electricity, the use of derivatives could increase rapidly and quickly become a significant market. Although derivatives offer the potential of managing price risk, their use will introduce new risks. Losses have been incurred by both speculators and hedgers, and by both sophisticated and naive investors (see Table 2-3).

Table 2-3. Famous Derivatives Losses

Company	Losses (Millions)
Orange County	$2,300
Showa Shell	$1,500
Barings Bank	$1,400
Metallgesellschaft (MG)	$1,300
Hammersmith & Fulham	$600
Klockner	$380
Merrill Lynch	$350
Allied Lyons	$275
Proctor & Gamble	$157
Societe de bourses Francaises	$125

Source: KCS Energy Risk Management, and Brealey and Myers 1996.

Losses at Orange County and MG should be of particular interest to electricity regulators. Orange County increased the risk of its portfolio by using derivatives to earn a higher return, a classic case of speculative losses. MG's losses highlight the potential pitfalls of hedging. MG, an oil marketer, attempted to hedge a ten-year risk using a short term futures contract. The root of MG's demise is still being debated, but it was either a result of: (1) a hedging strategy with a high chance of succeeding happened to experience extremely uncommon market conditions, or (2) poorly informed managers liquidated a perfectly good long term hedge due to temporary losses (Culp and Miller 1995; Edwards and Canter 1995). Most likely, it was a combination of the two factors.

In considering the development of policies in this area, it will be necessary for regulators to understand the risks associated with common hedging strategies and to be able to distinguish between speculative and hedging activities. These issues are discussed in the next three chapters.

CHAPTER 3

How to Hedge Using Futures Contracts

In this chapter, we describe the pricing of futures contracts, how electricity futures are used by various market participants to hedge price risk, and the types of risks that might arise from these transactions. We also discuss how futures can be used to speculate. An understanding of futures provides a basis for understanding other electric rate derivatives, which are discussed in Chapter 4.

3.1 Description of Electricity Futures Contracts

Commodity futures contracts are legally binding and negotiable contracts that call for the delivery of agricultural, industrial or financial commodities in the future. While agricultural futures have traded since the 1860s (Brown and Errera 1987), energy futures were not introduced until the 1970s. NYMEX initiated trading in heating oil futures in 1978, liquefied propane gas futures in 1987, crude oil futures in 1983, unleaded gasoline in 1984, natural gas in 1990, and electricity futures in 1996.

Futures contracts are traded on a commodity exchange where the delivery date, location, quality, and quantity have been standardized. A future is a standardized contract where all terms associated with the transaction have been defined in advance, leaving price as the only remaining point of negotiation. Standardization helps make the price transparent because no correction for quality is needed to compare different contracts. When the real nature of prices is coupled with the reporting of all transaction prices by the exchange, we have a situation of complete price transparency.

A future is a standardized contract where all terms have been defined in advance, leaving price as the only remaining point of negotiation.

On March 29, 1996 the NYMEX launched two electricity futures contracts. The contract size is 736 MWh per month. The rate is 2 MW per hour for 16 peak hours on 23 peak delivery days (i.e., Monday through Friday). The only difference between the two contracts is the delivery location – one requires delivery at the California-Oregon Border (COB) and the other requires delivery at the Palo Verde switchyard. New contracts introduced by NYMEX will allow delivery at the PJM Interconnection in the mid-Atlantic region, the Cinergy transmission system in Ohio, and the Entergy transmission system in Louisiana (McGraw-Hill 1997). A description of the NYMEX electricity futures and option contract specifications can be found in Appendix A.

Most energy futures in the United States are traded on the NYMEX (the exception is the Kansas City Board of Trade’s western natural gas contract). Each commodity has its own trading area, known as a "pit," where contracts are traded by brokers using the open outcry method. Under this method, brokers yell the prices at which they are willing to buy (the bid price) or sell (the offer price) of a particular month's contract. When a trade takes place, the price is submitted to a recorder who posts the price. Brokers can either trade for their own account or execute orders for customers. Some brokers, known as "locals," trade exclusively for their own account, others only execute customers' orders, while others trade both for themselves and customers.

A futures contract is created when a buyer and seller agree on a price. Because futures contracts are created instruments, and are not limited in quantity the way stocks are, the number of contracts that have been created is a measure of the interest and importance of any particular type of futures contract. This number is termed the "open interest" in the contract. "Open" positions can be closed in two ways. By far, the most common form of liquidation occurs when a party with a long position (someone who previously bought a futures contract) decides to sell, and a party with a short position (someone who previously sold a futures contract) decides to buy a futures contract. More than 98% of all futures positions are closed prior to delivery. The alternative to this financial closing of positions is to hold the contract to maturity and actually take or make physical delivery. The holder of a short position must deliver the commodity while the holder of a long position must receive the quantity.

3.2 The Purpose of Hedging

Most derivatives function like a side bet on commodity prices. They are a zero sum game where there is a loser for every winner. The seller of a future or an option loses one dollar for every dollar that the purchaser earns. But this does not mean that risk is a zero sum game. All parties in a futures market could be hedgers, and all could be successfully using the market to reduce their risk (Stoll and Whaley 1993).

A "short hedger" sells futures to hedge a long position in the underlying commodity (electricity), while a "long hedger" buys futures to hedge a short position in the underlying commodity. A generator is long in electric power and will use a short hedge. A marketer who has sold power to a utility is short that power because he cannot produce it. A marketer will buy futures to hedge its short position in the power market. If these were the only participants in the futures market, then all parties would be hedgers and all would simultaneously reduce their risk.

There is, however, no reason that the amount of short hedging will necessarily equal the amount of long hedging. For this reason, speculators are useful. Hedgers are often willing to pay to reduce their risk. This is analogous to being willing to pay for insurance. If there is an imbalance of hedgers, then speculators can make money by shouldering the risk of hedgers. For example, if the market consisted only of marketers who wished to buy futures, then speculators could sell them futures at a high price. This would, on average, produce a profit for the speculators and it would provide the marketers with insurance at the price of the speculators' profit. Because speculators hold no position in the underlying commodity, their risk is increased by being long or short futures, but this risk is compensated for by the fact that hedgers are willing to pay for the insurance that the speculators provide.

The speculators just described are professionals who would not stay in the market if they did not make a profit. But amateur speculators (including would-be professionals) are also thought to play an important role. A rather dry graduate finance text puts it like this:

> "Amateur speculators consist of two categories—gamblers and fools. Gamblers...know the risks and the fact that there is a house take, but they enjoy the game. Fools...think they know how to make money in futures, but they do not... The supply of fools is replenished by Barnum's Law. (There's a sucker born every minute.)" (Stoll and Whaley 1993)

Because speculators are not tied to any specific underlying commodity, they can and do diversify their portfolios. Modern finance theory tells us that the proper measure of risk is the amount of risk that cannot be diversified away. The risk to a speculator from holding a specific future is given by the variability of that future times its correlation with the speculator's portfolio. This is typically far smaller than the risk that the hedger is laying off.

To sum up, there are three reasons that a futures market can be an inexpensive way for hedgers to reduce their risk. First, short hedgers can trade with long hedgers. Second, professional speculators can diversify away most of the risk inherent in any particular future. And third, amateur speculators bear risk essentially for free.

3.3 The Pricing of Futures

To understand hedging, one must analyze the behavior of the price of futures relative to the price of the commodity being hedged. The most basic point is that the futures price converges at the time of maturity to the spot price of the underlying commodity. This leaves the questions of whether this convergence takes place from above or below, and how the price of the underlying commodity relates to the price of the commodity being hedged.

The futures price converges at the time of maturity to the spot price of the underlying commodity.

A futures contract can be settled either by delivery of the physical commodity or by a cash settlement. In either case, the settlement price should be identical to the spot market price for the same product at the same place. This "convergence to spot prices" is a fundamental feature of futures markets (see Williams 1986).

It requires either a mechanism for determining the appropriate spot price in the case of a cash settlement process, or the location of the delivery point at an active spot market.

Coordinating delivery and receipt of a non-storable commodity, such as electricity, requires careful consideration of the rights and obligations of the delivering and receiving parties. In natural gas, a set of procedures have been worked out to deal with these issues (NYMEX 1992). The exchange takes an active role in matching buyers with sellers for the delivery process (in the terminology of contracts, "longs" with "shorts"). Once a pair is matched they are free to work out mutually acceptable alternative arrangements. In defining these procedures, careful attention must be paid to defining *force majeure* situations so that one party cannot take advantage of another.

One of the paradoxes of futures markets is that the delivery mechanism must be highly reliable and certain, and if this is the case, then no one will use it. The reason for this paradox is that only with a high degree of confidence in the integrity of delivery will market participants accept that the futures price converges to the spot price. Once this confidence is established, it will typically be more convenient for participants to close out positions financially rather than through the delivery mechanism. In typical futures markets, only about 2% of all contracts settle through delivery.

In typical futures markets, only about 2% of all contracts settle through delivery.

To understand and evaluate hedging strategies, one must have a basic understanding of the determinants of futures prices. This fact is underscored by Metallgesellschaft's $1.3 billion in losses in the oil futures market in 1993. MG, an oil and gas marketer, developed a hedging strategy based on historic spot-futures price relationships. When these price relationships did not occur in 1993, the oil marketer experienced huge margin calls. Ultimately, MG was forced to close these positions and realize the losses.

The price of a futures contract is a function of the underlying asset's spot price, interest rates, storage costs, and expectations of future supply and demand conditions. The price of a futures contract is related most importantly to the current price of the underlying cash commodity. Even though actual delivery is quite rare, the possibility of delivery provides the critical link between spot and futures markets, enabling arbitragers to profit when prices get too far out of line.

The determinants of futures prices are most easily understood using a tangible example, in this case one where storage costs are pertinent. Suppose a firm expects to need 1,000 barrels of oil in six months. The firm can either buy the commodity today and store it for six months (the "buy and store" approach) or purchase a futures contract for delivery in six months. The firm will compare the price of the two alternatives and select the cheaper one. Futures prices are reported in the newspaper each day, and for purposes of this example we will assume that the futures price for delivery in six months is $18 per barrel. To calculate the costs of the "buy and store" approach, the firm must know the current spot price, interest rates, and storage costs. Assume that the spot price of oil is $16 per barrel, that annual interest rates are 10%, and that storage costs for six months total $1 per barrel. Accordingly, the total cost of the "buy and store" approach are:

$16.00	Spot Price
$ 0.80	Opportunity cost of money spent on oil ($16.00 × 10% × ½ year)
$ 1.00	Storage costs
$17.80	

Since the futures price equals $18.00 and the "buy and store" approach costs only $17.80, the firm will choose the "buy and store" approach. In fact, these price relationships provide an opportunity to secure a riskless profit today. The firm could sell futures contracts for $18.00 per barrel, buy and store the oil for $17.80 and lock in a profit of $0.20 per barrel by delivering under the terms of the futures contract. This is called riskless arbitrage. As more people take advantage of this riskless profit, the futures price will decline, because people are selling futures, and the spot price will go up, because people are buying on the spot market. In equilibrium, the futures price and the "buy and store" price will be equal.[8] Thus, market forces will tend to make the futures price higher than the spot price by the amount of carrying costs (the time value of money) and storage costs.

An examination of actual futures prices indicates that the futures-spot price relationship posited above does not always hold true. For consumption commodities, the futures price does not always exceed the spot price by carrying and storage costs. In fact, the futures price is sometimes less than the spot price. This indicates that a large number of market participants choose not to take advantage of arbitrage opportunities. When this is the case, "users of the commodity must feel that there are benefits of ownership of the physical commodity that are not obtained by the holder of a futures contract. These benefits may include the ability to profit from temporary local shortages or the ability to keep a production process running. The benefits are sometimes referred to as the *convenience yield* provided by the product" (Hull 1993). We would expect convenience yields to be high when the physical commodity is in short supply and low when the physical commodity is abundant. The following equation summarizes the futures-spot price relationship:

$$\textit{Futures Price} = \textit{Spot Price} + \textit{Carrying Costs} + \textit{Storage Costs} - \textit{Convenience Yield}$$

This equation illustrates another important characteristic of the spot-futures price relationship. As the delivery month for a futures contract approaches, the futures price converges with the spot price of the underlying asset. This is an intuitive result, since carrying costs and storage

8 Similarly, if the futures price is lower than the "buy and store" price, riskless profits can be secured by purchasing a futures contract and selling short in the spot market.

costs will decrease with time. The convenience yield will also diminish with the time to delivery, since the benefits of holding the commodity rather than a futures contract will be less. The possibility of delivery will ensure that the futures price and spot price are the same on the delivery date. Otherwise, it would be possible to arbitrage prices in the spot and futures markets to secure a riskless profit.

3.4 How Generators, End Users, and Marketers Hedge

Hedgers mitigate risk by taking opposite positions in the physical and futures markets.

Futures contracts can be used to hedge or to speculate. An entity with a long (short) position in the electricity market can hedge by selling (buying) a future. A speculator, in contrast, takes an outright long or short position in expectation of a price move. Someone with a long futures position (i.e., has purchased futures) profits when prices increase and loses when prices decline. Someone with a short futures position (i.e., has sold futures) profits when prices decline and loses when prices increase. Table 3-1 shows that hedgers mitigate risk by taking opposite positions in the physical and futures markets. The fact that the hedging arrows oppose the cash-position arrows shows that hedgers are insulated from price changes because gains in the physical position are offset by losses in the futures position, and vice versa. With a perfect hedge, the magnitude of the corresponding gains and losses in the physical and futures positions will be exactly the same.

Table 3-1. Hedging Strategy for End User and Generator

	End User	**Generator**
Cash Position	**Short** the physical commodity (electricity) at a future date.	**Long** the physical commodity (electricity) at a future date.
Risk from Cash (Physical) Position		
• Spot Price Increase • Spot Price Decrease	Profits decrease ↘ Profits increase ↗	Profits increase ↗ Profits decrease ↘
Hedge (Futures Position)	**Long** Electricity Futures. (bought futures)	**Short** Electricity Futures. (sold futures)
Risk from Futures Position		
• Spot Price Increase • Spot Price Decrease	Profits increase ↗ Profits decrease ↘	Profits decrease ↘ Profits increase ↗

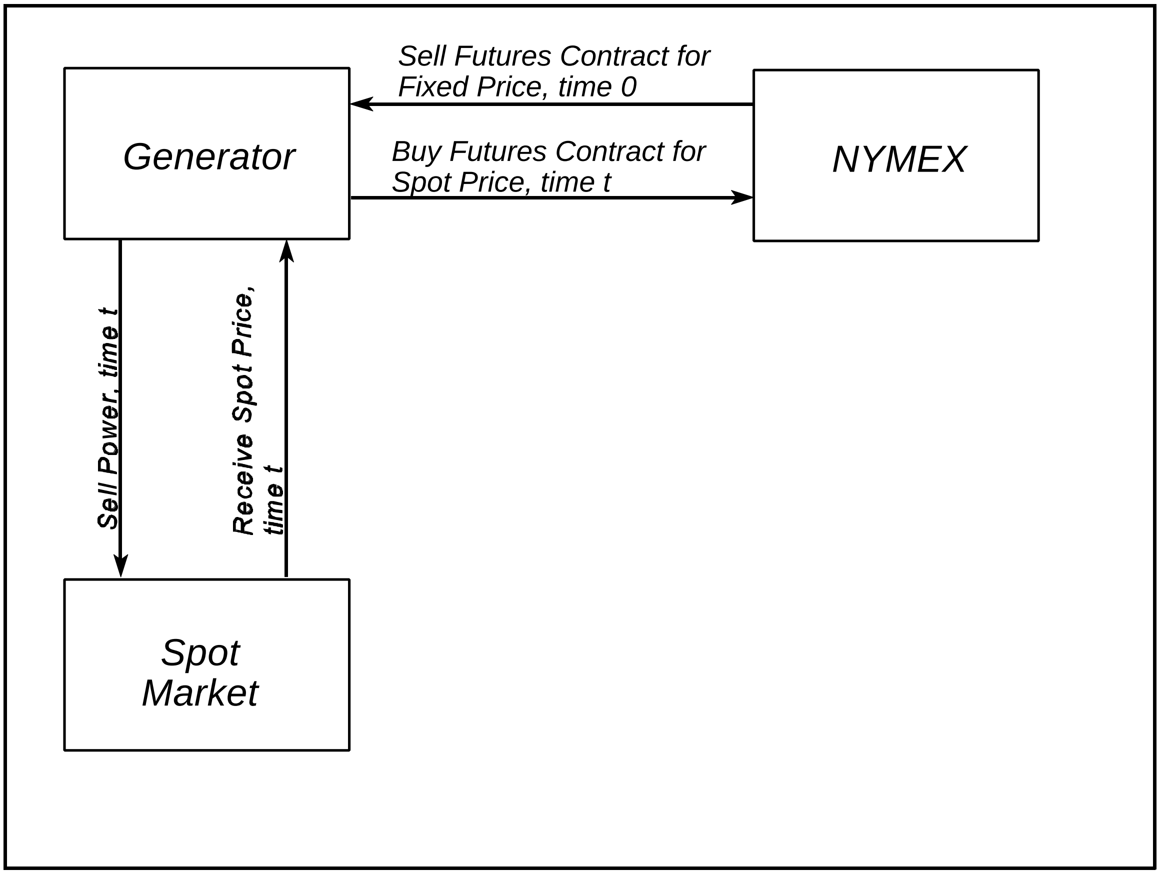
Below we describe how a generator, end user, and marketer hedge using futures.

Generators Sell Futures Contracts

For simplicity, assume that a generator expects to sell electricity into the spot market in six months. The generator's cost of production is $20/MWh, the current spot price is $20/MWh, and the futures price for delivery in six months is $18/MWh. In this instance, the generator is long electricity and will lose money if the spot price falls, will make money if the spot price increases, and will break even if the spot price remains constant.

To mitigate this price risk, the generator could sell futures contracts for $18/MWh. In six months, the generator would then sell electricity for the spot price and buy futures contracts to close out its financial position (see Figure 3-1). For this example, we assume that the futures price converges with the spot price as the delivery date approaches and equals the spot price when the position is closed. In this case, the generator would be perfectly hedged. If the spot price rose to $30/MWh, the generator would receive $30/MWh for its electricity, would pay $30/MWh to close its futures positions, and would receive $18/MWh for its original futures positions. By contrast, if the price fell to $10/MWh, the generator would receive $10/MWh for its electricity, would pay $10/MWh to close out its futures position, and would receive $18/MWh for its original futures position. In both instances, the generator ultimately receives $18/MWh for delivering electricity and is unaffected by price changes and, therefore, price risk.

Figure 3-1. Generator's Hedge



In Figure 3-2, payoff diagrams illustrate the potential outcomes of the generator's hedged positions if the spot price in six months falls to zero or increases to $40/MWh. Figure 3-2a shows the potential profits and losses associated with the generator's physical positions. If the spot price in six months falls to $10/MWh, the generator would lose $10/MWh because its production costs ($20/MWh) would exceed its payment ($10/MWh), but if the spot price rises to $30/MWh, the generators would make $10/MWh. Figure 3-2b shows the potential profits and losses associated with the generators' financial position. If the spot price in six months falls to $10/MWh, the generator would profit by $8/MWh because it sold futures contracts for $18/MWh, but to close out this position, it bought futures contracts for $10/MWh. If the spot prices rises to $30/MWh, by contrast, the generator would lose $12/MWh ($18/MWh - $30/MWh). Figure 3-2c shows the potential profit and loss associated with the combined, or hedged, positions. At each spot market price, the hedged profit is the sum of profits from the physical and futures position. By hedging, the generator has locked in an electricity price of $18/MWh and a loss of $2/MWh. The same result occurs if the generator is required to physically deliver electricity at $18/MWh in six months time.

Figure 3-2 illustrates that hedging can guarantee *stable* income, but does not determine whether this income will be positive (a profit) or negative (a loss). In this example, the generator essentially locked in a price of $18/MWh and a loss of $2/MWh, because its production costs were $20/MWh. If the futures price were $22/MWh, the generator could have locked in a higher price and guaranteed itself a profit.

The risks associated with hedging are that the futures price would not converge with the spot price on the delivery date, that the monthly futures market would not match the daily spot market (i.e., the generator would be hedging daily price risk using a monthly instrument), and that the generator would miscalculate and have less (or more) electricity than initially anticipated. These risks are explored in greater detail in Section 3.6.

Figure 3-2a. Generator's Physical Position

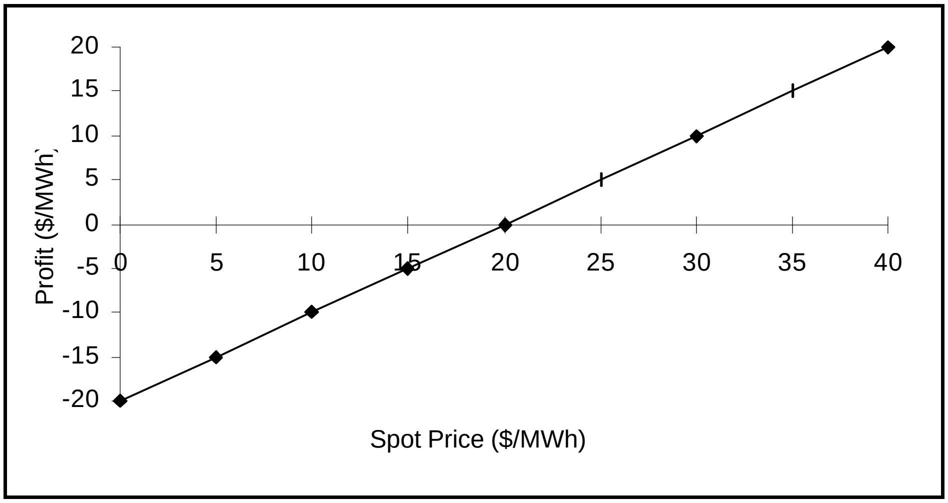


Figure 3-2b. Generator's Financial Position

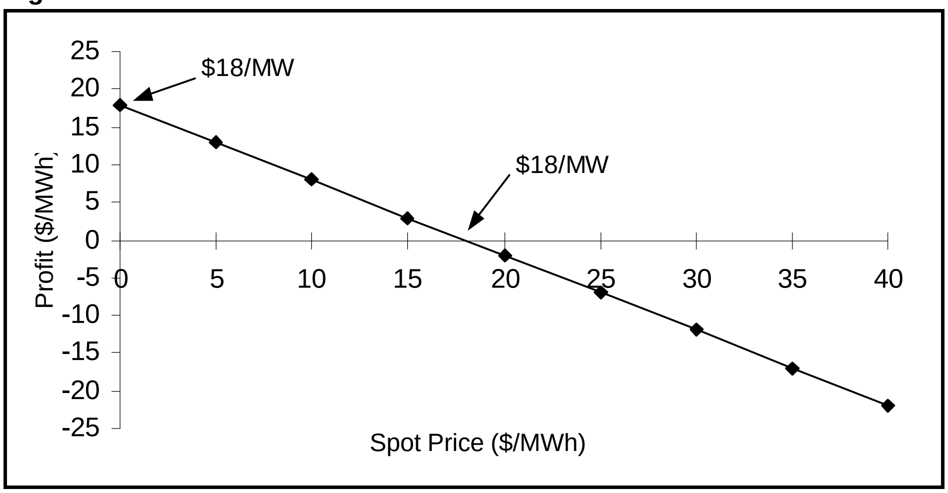
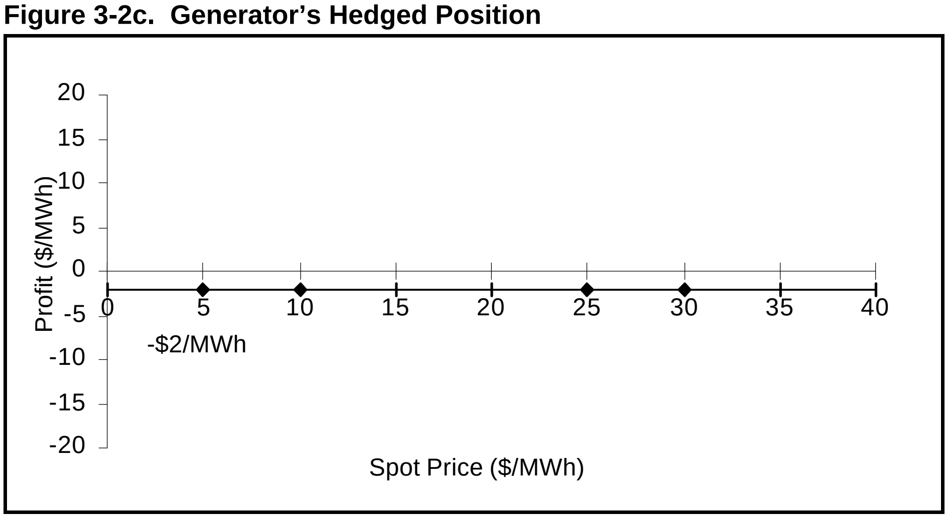


Figure 3-2c. Generator's Hedged Position

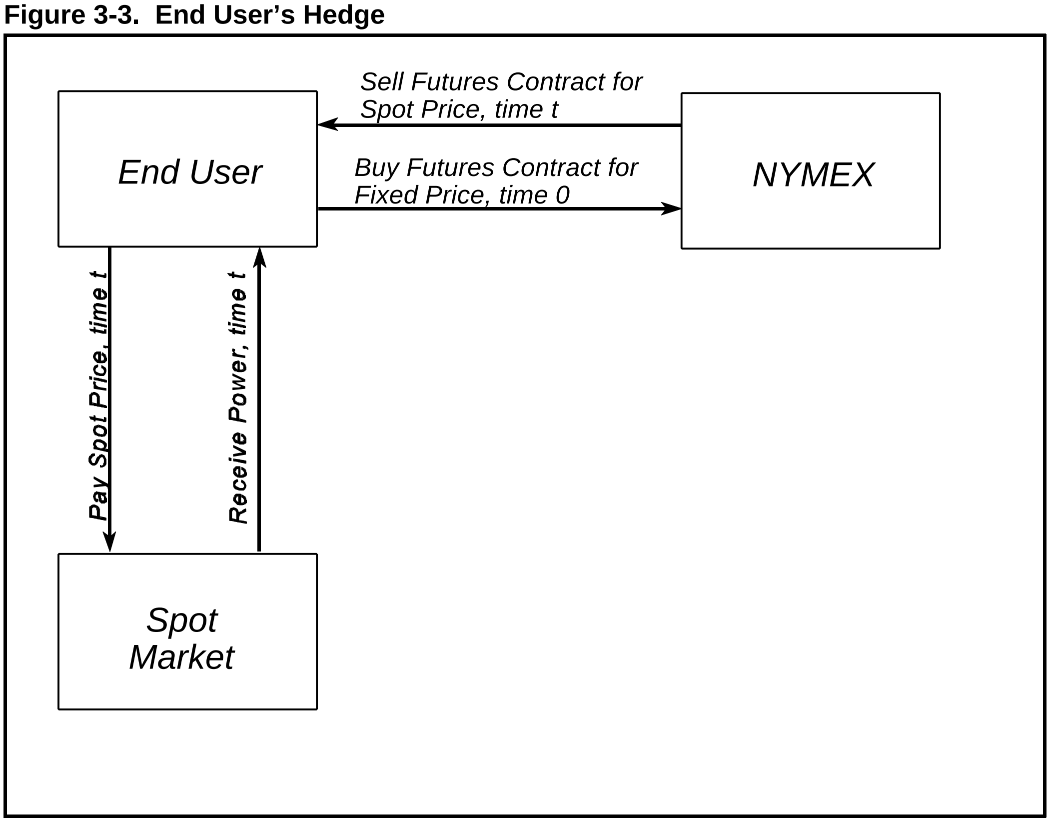


End Users Buy Futures Contracts

In this example, assume that an end user (e.g., a large industrial customer) anticipates needing electricity in six months and intends to buy it in the spot market at that time. The current spot price is $20/MWh and the futures price for delivery in six months is $18/MWh. In this instance, the end user is short electricity and will pay more for electricity if the spot price rises and pay less if the spot price decreases.

To mitigate this price risk, the end user could buy futures contracts for $18/MWh to lock in its electricity price. In six months, the end user would then buy electricity for the spot price and sell futures contracts to close out its financial position (see Figure 3-3). Again, we assume that the futures price converges with the spot price as the delivery date approaches and equals the spot price when the position is closed. In this case, the end user would be perfectly hedged. If the spot price rises to $30 MWh, the end user would pay $30/MWh for its electricity, would receive $30/MWh to close its futures position, and would pay $18/MWh for its original futures position. By contrast, if the price fell to $10/MWh, the end user would pay $10/MWh for its electricity, would receive $10/MWh to close out its futures positions, and would pay $18/MWh for its original futures position. In both instances, the end user ultimately pays $18/MWh for electricity and is unaffected by price changes.

Figure 3-3. End User's Hedge



In Figure 3-4, payoff diagrams illustrate the potential outcomes of the end user's hedged position if the spot price in six months falls to zero or increases to $40/MWh. In this example, we assume that the end user has fixed output prices and can pass on only $20/MWh to its customers. If the spot price converges with the futures price, the end user will be perfectly hedged and unaffected by price changes because the gains (losses) in the physical market are exactly offset by the losses (gains) in the financial market. In particular, if the end user locks in a price of $18/MWh and is able to pass on electricity prices of $20/MWh, it stands to make a profit of $2/MWh. The risks associated with hedging for the end user are similar to those faced by the generator and are explored further in Section 3.6.

Figure 3-4a. End User's Physical Position

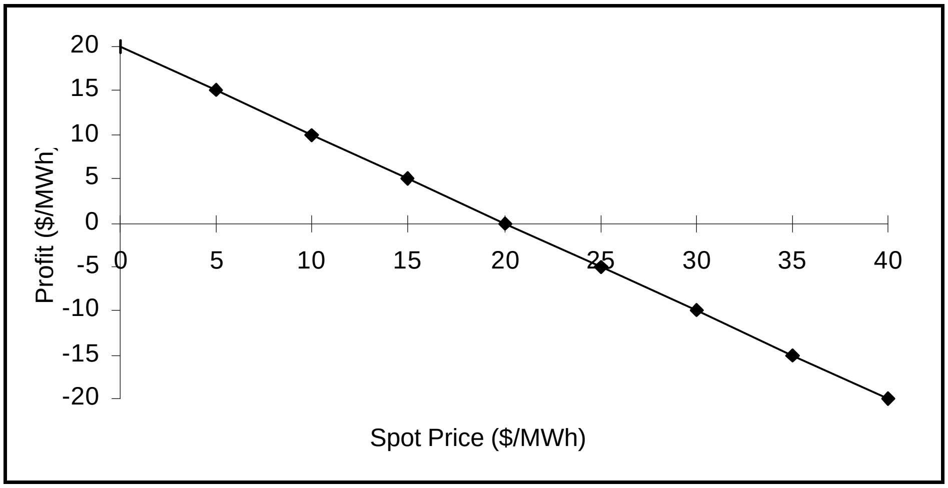


Figure 3-4b. End User's Futures Position

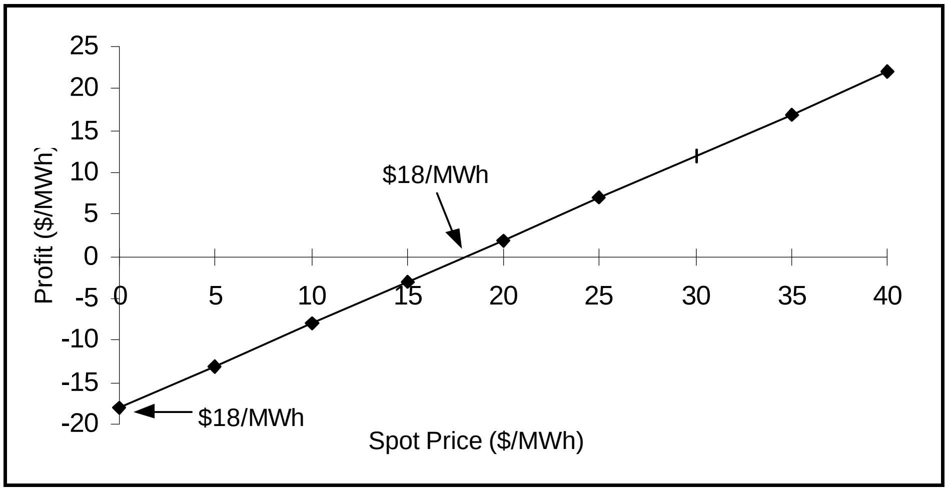
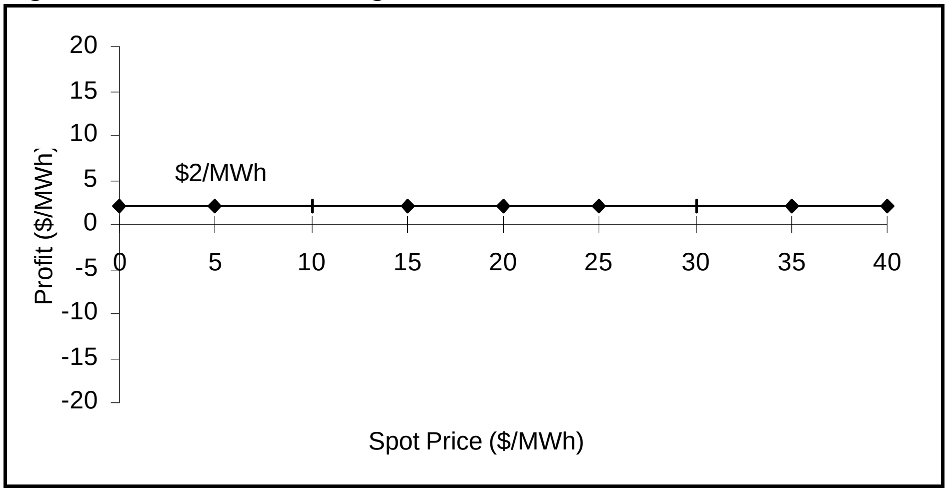


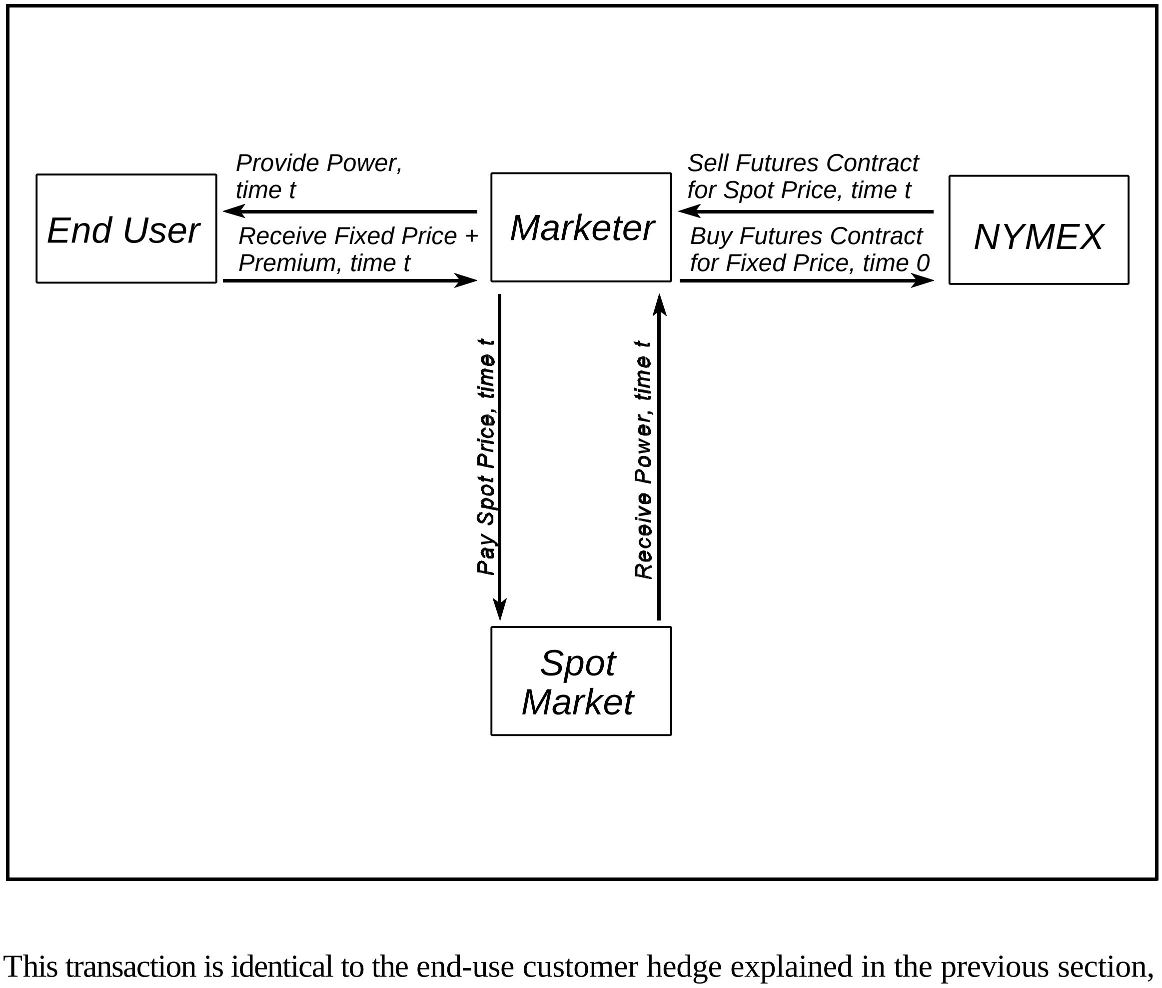
Figure 3-4c. End User's Hedged Position



Marketers Buy and Sell Futures Contracts

Marketers are likely to both buy and sell electricity and electricity futures. Assume that a marketer has guaranteed customers that it will deliver electricity in six months. In this instance, the marketer could buy futures contracts for $18/MWh and sell the end-use customers electricity at a small mark-up, say $18.10/MWh (see Figure 3-5). If the spot price rises to $30/MWh in six months, the marketer would buy electricity in the spot market for $30/MWh and deliver it to the customers for $18.10 (for a loss of $11.90 on the physical transaction). At the same time, the marketer would close out its futures position by selling futures contracts for $30/MWh (for a gain of $12/MWh over the original purchase price of $18/MWh). This transaction guarantees the end user fixed price power at $18.10/MWh and, if the spot price converges with the futures price, guarantees the marketer a profit of $0.10/MWh.

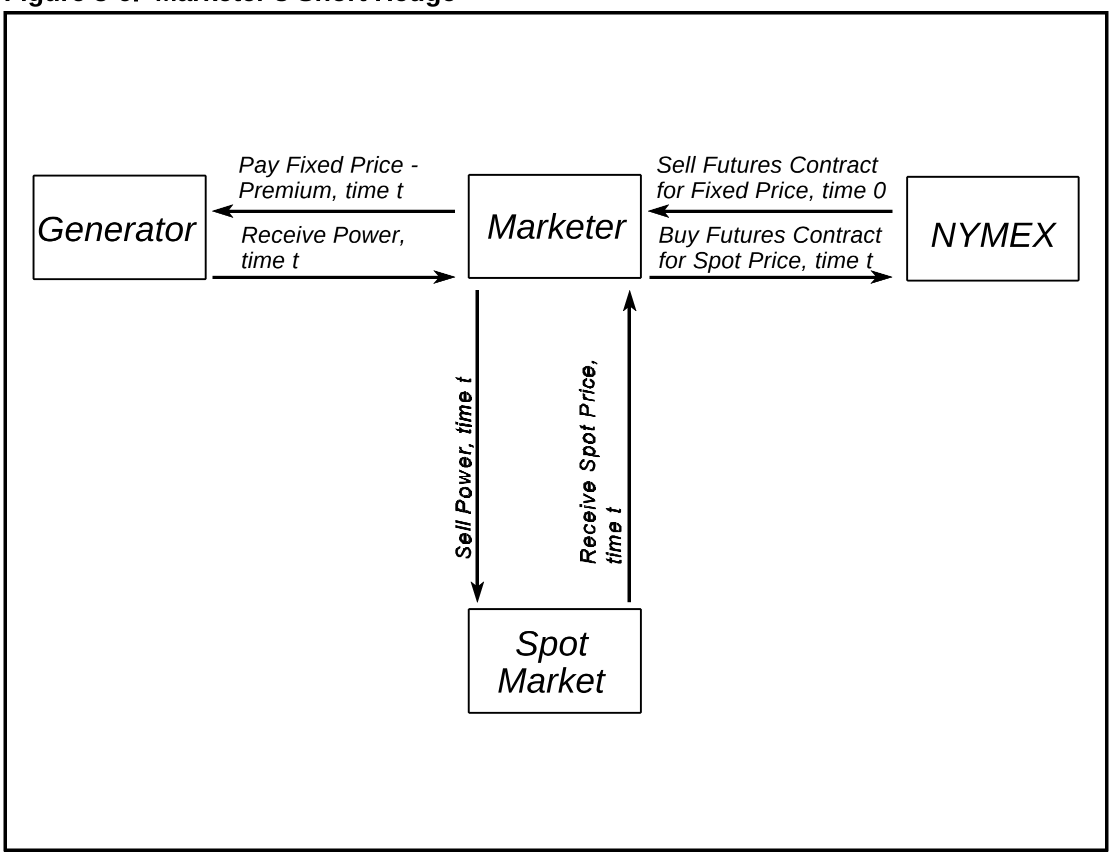
Figure 3-5. Marketer's Long Hedge



This transaction is identical to the end-use customer hedge explained in the previous section, with the exception of the fee collected by the marketer. End-use customers might prefer this arrangement because they may not understand financial instruments and/or might want to avoid the risk that the future price does not fully converge with the spot price on the date of execution.

Marketers buy as well as sell electricity. Assume that a marketer agrees to buy electricity from a generator at a fixed price in six months. The marketer could agree to buy electricity for $17.90/MWh and sell electricity futures for delivery in six months for $18, thus locking in the fixed price and a profit (see Figure 3-6). In six months, if the spot price has increased to $30/MWh, the marketer would pay the generator $17.90/MWh for the power, sell the power on the spot market for $30/MWh, making $12.10/MWh on the physical transaction. At the same time, the marketer would close out its futures position by buying futures contracts for $30/MWh, thus losing $12/MWh on its financial position. The combined physical and financial positions leave the marketer with a profit of $0.10/MWh.

Figure 3-6. Marketer's Short Hedge



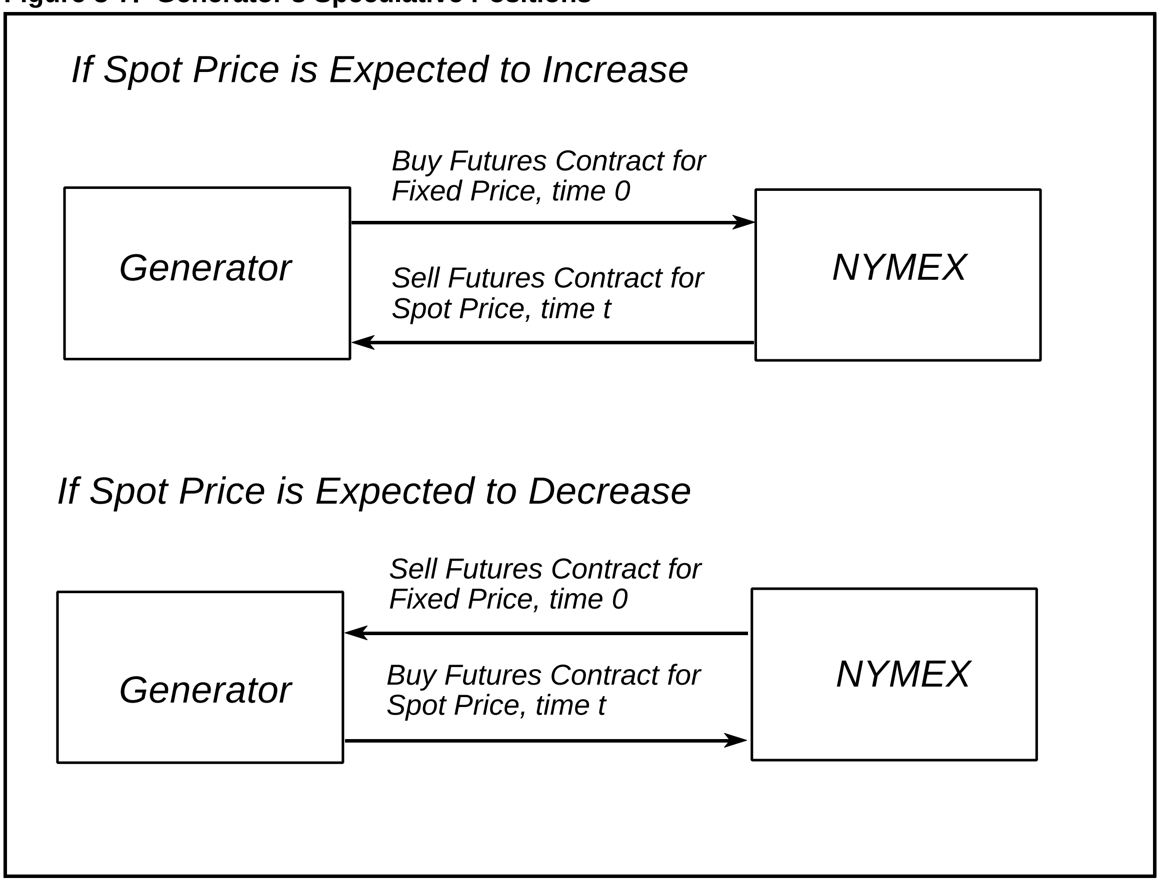
This transaction is identical to the generator's hedge shown above, except that the marketer takes a profit. Like the end user, a generator might be interested in selling electricity through a marketer to receive a fixed price and to avoid the real or perceived uncertainties associated with hedging using futures. We discuss the potential risks of these transactions in Section 3.6.

3.5 Speculating Using Futures Contracts

Before discussing the risks associated with hedging, we should note that generators, end users, and marketers could also speculate using futures contracts. These market participants could intentionally speculate in the market in an effort to make a profit. They could also unintentionally speculate if, for example, they bought futures contracts to hedge their purchase of electricity in six months, but found that they did not need the electricity at that time. Speculation simply requires that the generator not have a position in the underlying commodity market. We present a simple example involving a generator.

Assume that a generator sought to speculate using electricity futures contracts. If the generator thought that the spot price of electricity would increase, he would buy electricity futures (see Figure 3-7). If the electricity price increased, the generator would receive this higher amount when he sold a futures contract to close out his position and would pay the lower price for the futures contract that he originally bought. By contrast, if the generator expected prices to fall, he would sell futures contracts. We discuss speculation in more detail in Section 5.5.

Figure 3-7. Generator's Speculative Positions



3.6 Risks Associated with Hedging Using Futures Contracts

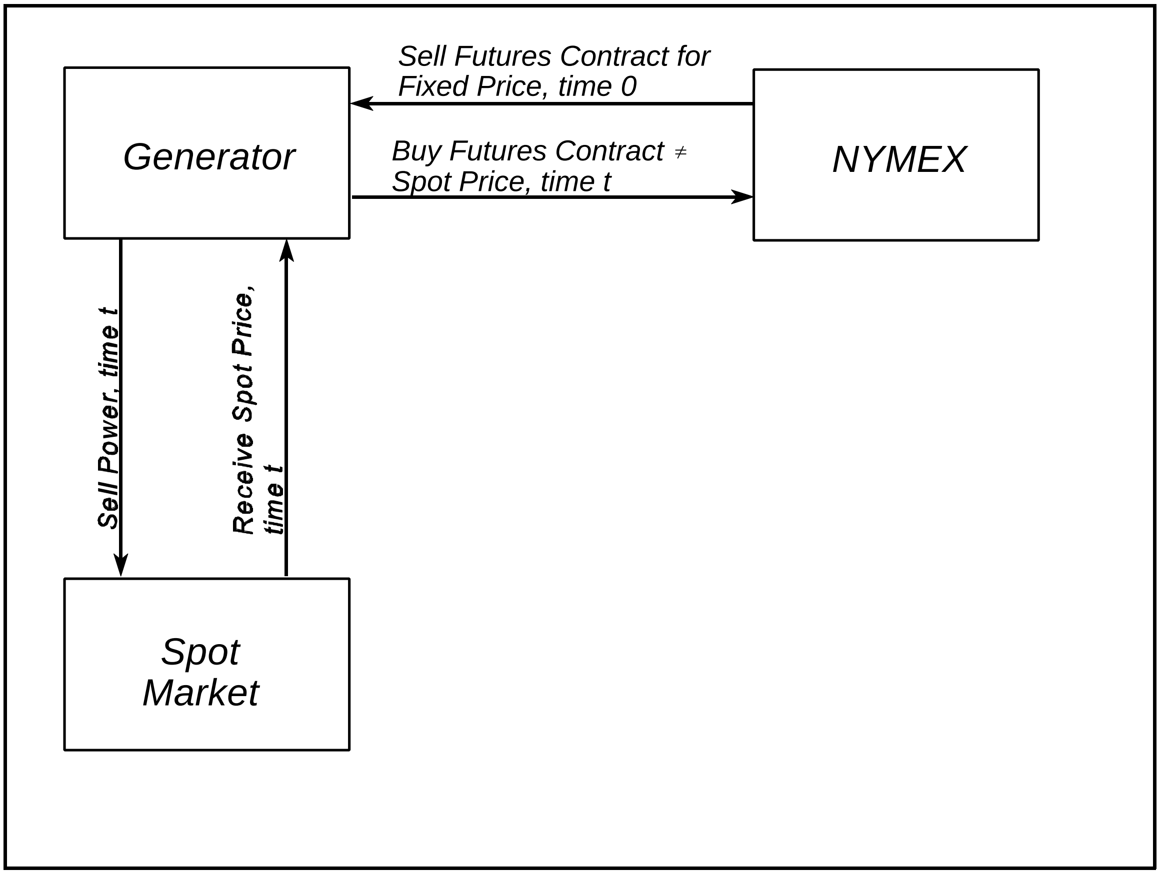
The primary risk associated with futures contracts is that the futures price and the cash price will not converge on the delivery date. The difference between the price of the futures contract and the price of the cash commodity being hedged is known as "basis." The chance that these will not converge is known as "basis risk." Basis risk can occur because of differences in time, location, or quality.

As discussed in Section 3.3, the futures price and the spot price should converge near or on the delivery date. This should occur because, if the two prices are different, arbitrage would be expected to occur. For example, if the futures price was $22/MWh, but the spot price was $20 near the delivery date, then an arbitrager should be able to buy electricity in the spot market for $20/MWh, sell a futures contract for $22/MWh, and secure a $2/MWh profit. In theory, increased demand in the spot market should drive up the spot price and an increased supply of individuals willing to sell futures contracts should drive the price of the futures contract down until the spot and futures prices are equal. In practice, the two prices may not converge if, for example, delivery is difficult and prevents arbitragers from taking advantage of the price differences. Nonetheless, generators, end users, and marketers can mitigate this risk by providing or taking physical delivery.

Another type of basis risk occurs because of location-specific factors (e.g., pipeline constraints, differences in transportation or transmission costs). The price of electricity in Denver is not likely to be the same as the price at the California-Oregon Border (COB), in which case using a futures contract for the COB would not perfectly hedge price risk in Denver. An example is illustrative. Assume that a generator expects to sell electricity into the spot market in Denver in six months and sells a futures contract for COB delivery for $18/MWh. On the delivery date, the spot price in Denver is $25/MWh, but the spot price (and the futures price) at the COB is $28. If the generator were able to deliver electricity to COB, he would do so and collect $18/MWh. If the generator were not able to deliver electricity, he would sell into the Denver spot market at $25/MWh and close his position financially by buying a futures contract for $28/MWh (see Figure 3-8). As a result of this transaction, the generator receives $25/MWh for his electricity in the spot market, but loses $10/MWh on his financial position and ultimately receives only $15/MWh, not $18/MWh for his electricity as initially planned. If the electricity price in Denver were perfectly correlated with the price at COB, the generator would be perfectly hedged and could expect, for example, that he could lock in the price at COB less $3/MWh. But if the prices in the two markets are not well correlated this will undermine the generators hedge. One way to deal with this risk is to use a basis swap to hedge this basis risk (see Chapter 4).

An advanced topic in hedging theory is the determination of the proper hedge size when there is basis risk. As mentioned previously, if there is no basis risk, then the spot prices in Denver and the COB will be perfectly correlated and the optimal hedge size is the same as

Figure 3-8. Spot Price Does Not Equal Futures Contract Price



the size of the contract being hedged. In contrast, if the correlation between the COB and Denver spot prices is zero, the optimal hedge size is also zero. For correlations between zero and one, the optimal hedge size takes on intermediate values. The procedures for determining the optimal hedge size are specific and well defined, but the correlation needed for this computation is always uncertain to some extent.

A final reason that the spot and futures prices might not converge is that the futures contract commodity might be different from the spot price commodity (i.e., product quality or definition). This could be a problem if the spot market sells electricity on a daily rather than a monthly basis because futures contracts call for delivery over an entire month. Thus, if a generator sells a futures contract for six months, the generator then buys back the futures contract at the end of the month prior to delivery, but then must sell in the spot market during the following month. There is no guarantee that the futures contract price on May 28 for June delivery will be the same as the spot price received for electricity on a daily basis throughout the month of June.

Another risk associated with using futures contracts is that the generator, end user, or marketer could miscalculate the amount of energy that he or she will generate or need. For example, a utility generator might anticipate having a surplus of electricity in six months and therefore sells a futures contract, but then needs that surplus to serve its existing customers because of an increase in demand or due to plant outages. If this occurs, the utility would be speculating in the futures market. The utility generator would have closed its position financially, but would not have an offsetting physical transaction. If the utility sold a futures contract for $18/MWh, the utility will lose money if the price of electricity increases and will make money if the price of electricity decreases. The utility could either make or lose money on this speculative transaction.

3.7 Long-Term Hedging via "Stack and Roll"

So far, we have assumed that the duration of the hedge is equal to or less than the duration of available futures contracts. Given this assumption, the firm knows the outcome of its hedge at the time it is initiated. For example, the "combined" or "hedged" positions depicted in Figures 3-2 and 3-4 show fixed profits, regardless of spot price levels in the futures. If the firm does not like this outcome, then it can choose not to hedge. However, the assumption that the duration of the hedge is equal to or less than the duration of available futures contracts is not realistic. Futures contracts are only available with delivery dates of up to 18 months in the future.[9] Generators have assets that last 20 or more years, and marketers could have fixed-price contracts that extend for several years. It is still possible to hedge these risks using futures contracts, but the outcome of the hedge, and therefore the risk, is much more uncertain.

A method of hedging known as the "stack and roll" is used to hedge a long term physical position with short term futures contracts (Edwards and Canter 1995). To hedge a ten-year position with a one-year futures contract, the hedger would buy a quantity of one-year futures contracts equal to the sum of all ten years worth of physical transactions.[10] For example, suppose a marketer has agreed to deliver 736 MWh of electricity for a fixed price in each of the next ten years. In year one, the marketer buys ten electricity futures contracts, each of which requires the delivery of 736 MWh in 12 months time. At the end of the first year, the marketer closes the futures position and opens a new one to hedge its remaining physical exposure, which requires buying nine contracts. Each year, the marketer has 736 MWh less to hedge, so it buys one less futures contract than the previous year.

While this strategy can reduce price volatility for the hedger, it also creates a new risk. In the early years of the hedge, the futures position vastly exceeds the year's physical transactions. Therefore, *cash* gains and losses in the futures and physical positions will not offset each

[9] In fact, futures contracts are most liquid for delivery dates of 12 months or less.

[10] This assumes a 1:1 hedge ratio to simplify the discussion. In reality, the size of the hedge would probably be smaller than the size of the physical position.

other. For example, if a marketer has hedged its obligation to provide fixed-price electricity, the value of its physical position increases and the value of its futures position decreases when spot prices decrease. In the first year, if prices decline by a dollar, the profit on its physical position increases by $736 ($1/MWh × 736 MWh delivered), while the loss on its futures position totals $7,360 ($1/MWh × 736 MWh/year × 10 years). Of course, the value of its undelivered physical position (the 736 MWh/year for the next nine years) has also increased in value, but this increase is on paper, not in cash.

The "stack and roll" method poses serious cash flow risks. A firm must have sufficient capital to ensure that it can pay for potentially large derivative losses in the early years, that will be offset by gains in the physical position in future years. This problem is particularly striking since futures-spot price relationships that are beneficial for generators are detrimental to marketers. If both generators and marketers are employing the "stack and roll" method at the same time, one of them will experience gains while the other will experience losses in the early years of the hedge. It was exactly this cash flow problem associated with the "stack and roll" that caused Metallgesellschaft to lose $1.3 billion trying to hedge its oil marketing activities. It is this risk that electricity regulators must be aware of when designing policies to control the use of electric rate derivatives.

The "stack and roll" method poses serious cash flow risks.

CHAPTER 4

How to Hedge Using Other Types of Derivatives

In considering whether or not to develop policies on the use of derivatives, regulators must understand electric rate derivatives other than futures contracts and how they can be used to mitigate risk or to speculate on price changes. In this chapter, we describe other types of derivatives that are commonly used in energy markets. After laying the foundation for how these derivative markets operate, we present tangible examples of how derivatives can be used to reduce the risk of competitive electricity markets.

4.1 Price Swaps

A price swap is a negotiated agreement between two parties to exchange or "swap" specific price risk exposures over a predetermined period of time. Swaps are widely used in natural gas and oil markets and were introduced in electricity markets in 1995. Price swaps, which are traded in the "over-the-counter" (OTC) markets rather than on an exchange, serve the same economic function as futures contracts.[11] One party agrees to pay a fixed payment stream, while the other agrees to pay a variable payment stream. The buyer of the swap makes the fixed payment while the seller of the swap makes the variable payment. When the swap transaction is initiated, the two parties must agree on the following: the fixed price, the determinant of the variable price, the time period covered by the swap, and the notional size of the swap.

A price swap is a negotiated agreement between two parties to exchange or "swap" specific price risk exposures over a predetermined period of time.

An example of a price swap clarifies how they work. In the electricity market, price swaps initially settled against the Dow Jones index of electricity prices at the COB. The buyer of the swap agrees to pay a fixed price, which is negotiated at the time of the transaction, and receive a price equal to the simple average of a given month's nonfirm, on-peak, COB index price published in the *Wall Street Journal*. Although swaps can trade in any size, they are typically traded in increments of 25 MW on-peak. Since peak hours in the western United States include sixteen hours per day (6 AM to 10 PM), six days a week (Monday through Saturday), the total notional volume equals the number of MWs multiplied by the number of days in the month (excluding Sundays and holidays)

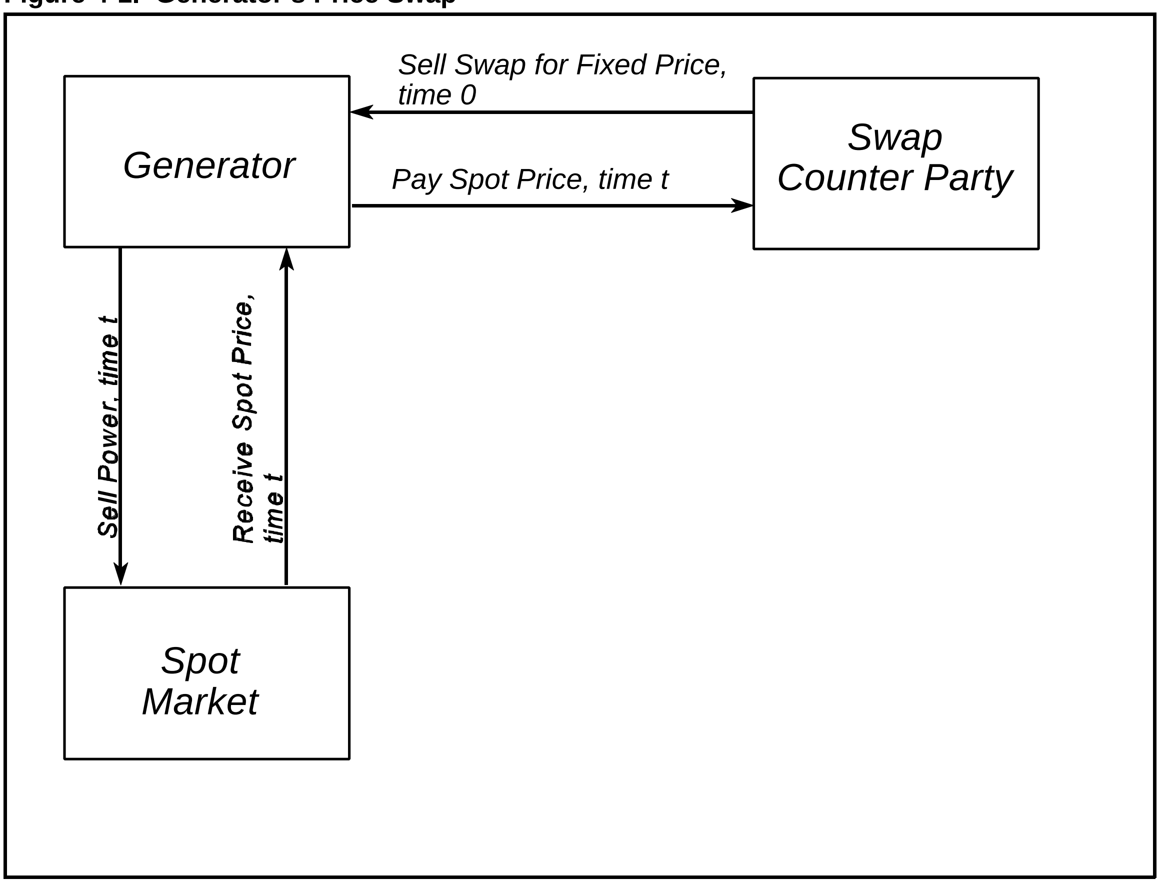
11 Although no official data is available on the volume of swap transactions, it is believed that the swap market at least equals and is probably several times larger than the futures market.

multiplied by 16. Just like the buyer of a future, the buyer of a swap profits when prices increase and loses when prices decrease relative to the fixed payment level. When the average of the on-peak Dow Jones COB prices exceeds the fixed price, the buyer of the swap (the fixed price payor) receives a positive cash flow from the transaction. When the average of the on-peak Dow Jones COB prices is below the fixed price, the seller of the swap receives a positive cash flow from the transaction. Swaps can be used to hedge or to speculate.

Generator

Swaps allow a generator to lock in a specific price for their commodity. To lock in an electricity price for July 1998, a generator would *sell* a price swap (see Figure 4-1). Assume the generator and the price swap counterparty agree on a fixed price of $25/MWh for 25 MW on-peak in July 1998, and a variable price equal to the average on-peak price in July 1998 at Dow Jones COB. If the average spot price at COB for July 1998 was $20/MWh, the generator would sell power into the spot market and receive the spot price of $20/MWh, would receive $25/MWh from the swap counter party, and would pay $20/MWh to the swap counterparty. The $20/MWh that the generator pays the swap counterparty cancels out the $20/MWh that the generator receives for electricity in the spot market. As a result, the price

Figure 4-1. Generator's Price Swap



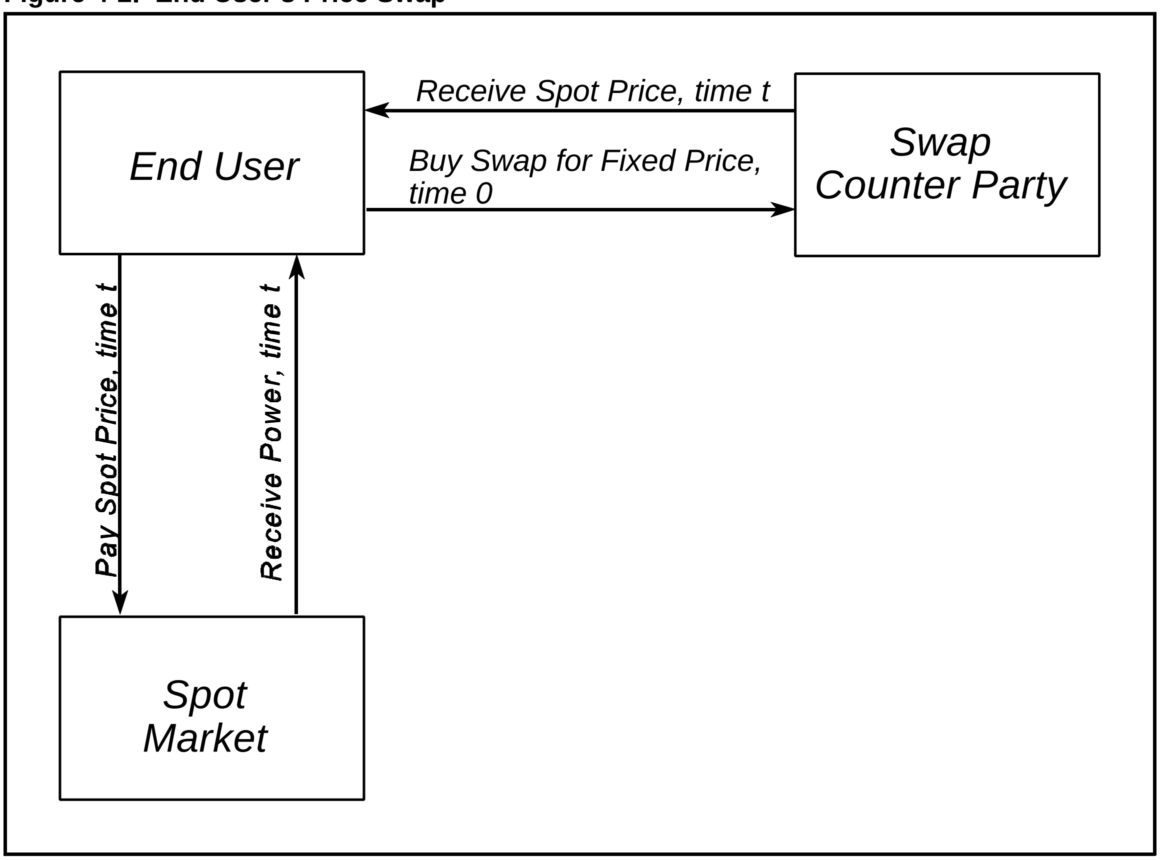
swap would lock in the fixed price of $25/MWh and protect the generator from the downside risk of a price decrease. If the spot price in July 1998 were to rise above $25/MWh, the generator would still receive $25/MWh, but would be unable to take advantage of price increases.

End User

Conversely, a swap allows an end user to lock in a specific price for the electricity that they purchase. For example, to lock in an electricity price for July 1998, an end user would *buy* a price swap (see Figure 4-2). Assume that the end user agrees to pay $25/MWh and to receive the average Dow Jones COB price. If the spot price at COB in July 1998 averaged $20/MWh, the end user would buy electricity in the spot market for $20/MWh, would receive $20/MWh from the swap counterparty, and would pay the swap counterparty $25/MWh. Using the price swap, the end user has a guaranteed electricity price of $25/MWh, but would be unable to take advantage of the lower-priced electricity if the price were to fall below $25/MWh.

Marketer

Figure 4-2. End User's Price Swap



A marketer could execute these price swaps with counterparties on behalf of generators and end users (see Figures 4-3 and 4-4). In these instances, the marketer guarantees the generators and end users fixed price contracts and executes the price hedges to lock in a profit on the deal. Marketers can also serve as counterparties negotiating between generators and end users.

Figure 4-3. Marketer's Price Swap for a Generator

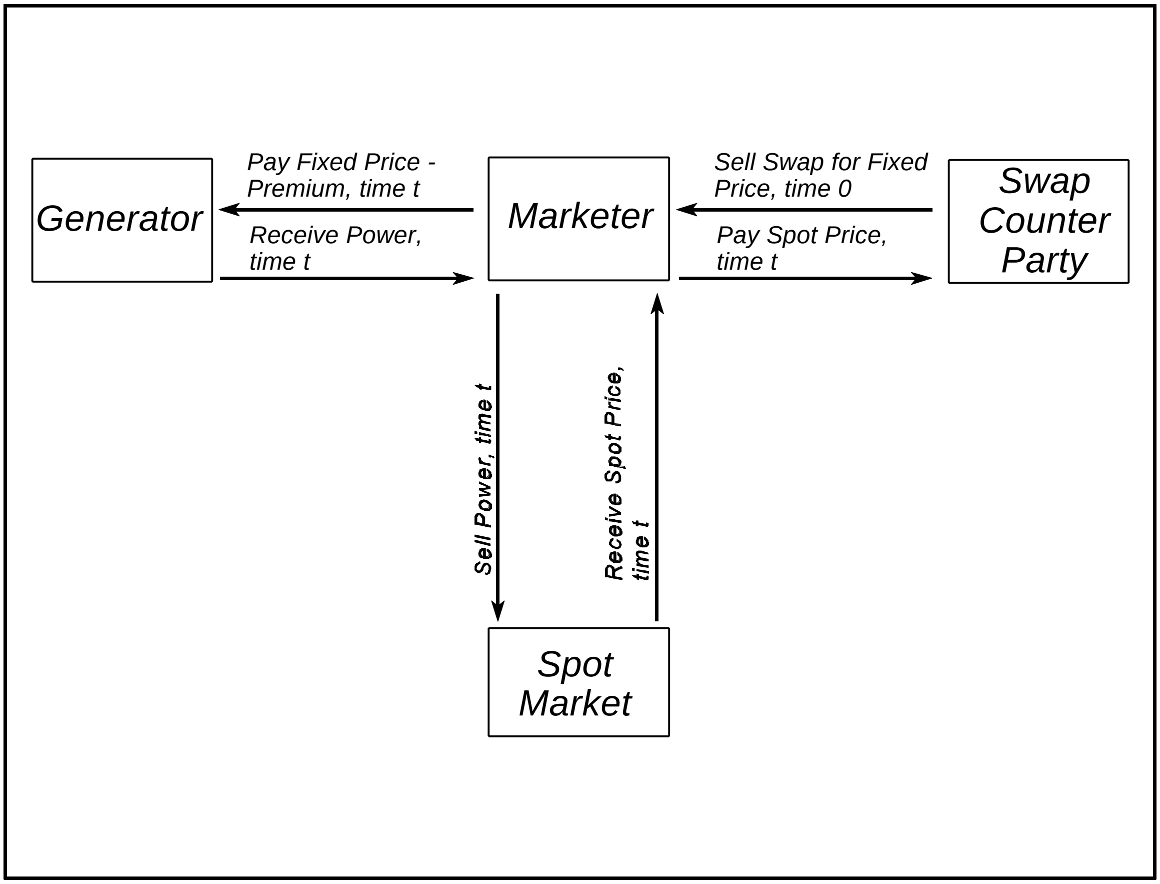
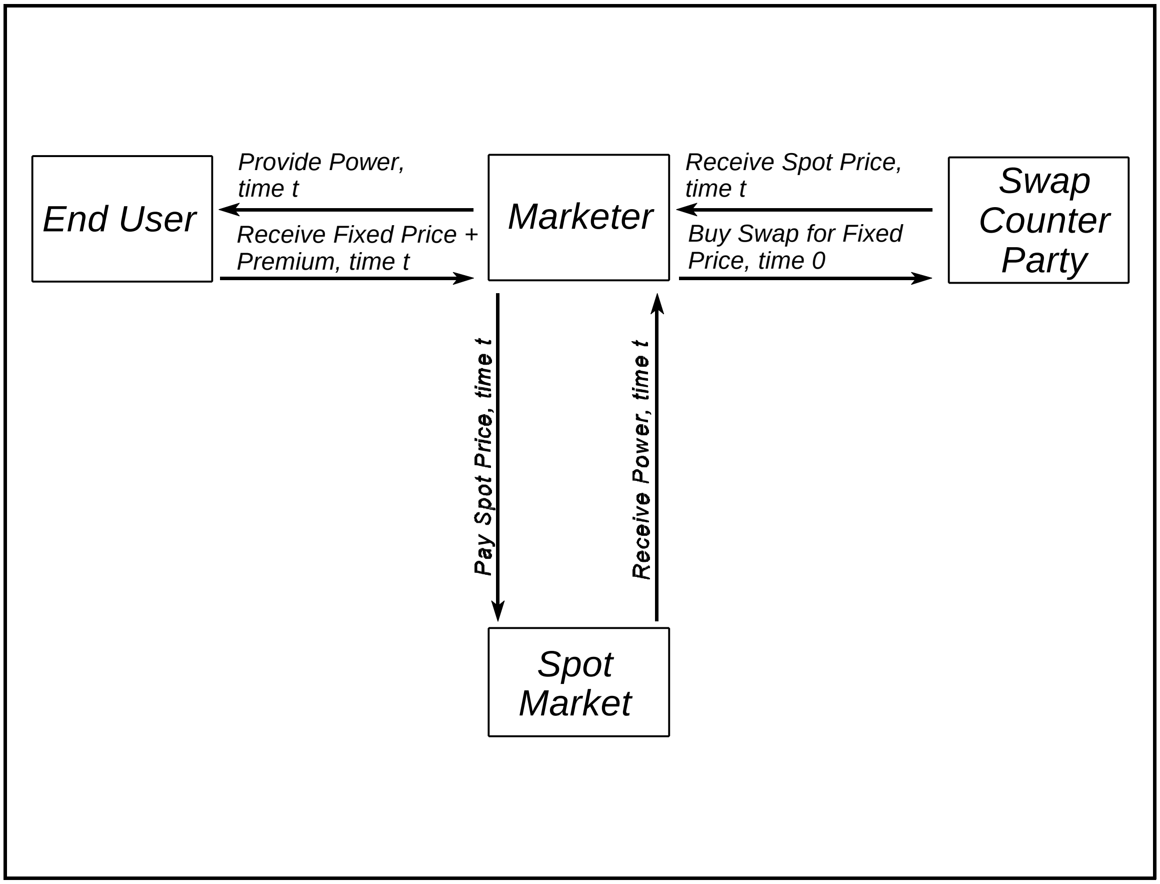


Figure 4-4. Marketer's Price Swap for an End User



Swaps vs. Futures

If swaps and futures serve the same economic function, why would market participants use one rather than the other? There are a number of reasons to use swaps. Since the terms are negotiable, swaps can be tailored to meet the needs of the buyer and seller. For example, given their delivery point specifications, NYMEX electricity futures contracts are not an effective hedge for risk exposure in the southeastern United States. A more effective hedge would be a price swap settling against a reliable price index such as Power Markets Week or Bloomberg. It is also possible to enter into a swap transaction that has a longer term than existing futures contracts. The futures markets only go out 18 months, while a swap transaction can be structured with any term. Someone might also find a swap attractive because it allows them to hedge a large exposure in one transaction at a known price. Hedging a large exposure using futures is likely to cause the futures price to change. This occurs as "locals" and other market participants realize that someone is trying to purchase a large number of futures. Responding to this demand, these traders will increase their offer prices, making it more expensive to purchase futures. Finally, if distribution utilities are required to buy on the spot market, as they are initially in California, they may be restricted from participating in the futures market given their inability to take delivery on the underlying commodity if required. Distribution utilities will still have incentives to hedge their price risks, however, and may utilize price swaps or other derivatives not dependent on an underlying commodity.[12]

In other circumstances, futures are a more effective hedging instrument. Entities trying to hedge short-term risks may find the anonymity and the liquidity of a futures contract desirable. In addition, futures transactions pose less credit risk. That is, there is less risk that the price swap counterparties will fail to follow through on the transaction.

4.2 Basis Swaps

The electricity futures market currently calls for delivery at either COB or Palo Verde, though new contracts will allow for delivery at the PJM Interconnection, and at the Cinergy and Entergy transmission systems. Most firms have price exposure at other locations. Thus, someone who uses the NYMEX futures contract to manage price risk at other locations is exposed to basis risk—price differences at different locations. Basis swaps, which are common in the natural gas markets, are used to manage this risk. The most widely used natural gas futures market calls for delivery at the Henry Hub in Louisiana. During the last five years, basis markets have evolved allowing firms to hedge risks at most major trading points in the United States and Canada. These basis markets are quite liquid, with narrow bid offer spreads (typically less than $0.02, but can be wider during volatile periods) and the ability to trade substantial volumes. Basis markets have also begun to develop in the electricity markets in the Western U.S. (e.g., COB, Palo Verde, and Mid-Columbia). Basis markets need not be physically connected by transmission wire or pipeline. For example, there is a Sumas natural gas basis market even though it would be extremely hard to move gas from this point to the Henry Hub.

A basis swap allows an individual to lock in a fixed price at a location other than the delivery point of the futures contract.

A basis swap allows an individual to lock in a fixed price at a location other than the delivery point of the futures contract. This can be done either as a physical or a financial deal. We illustrate financial transactions below.

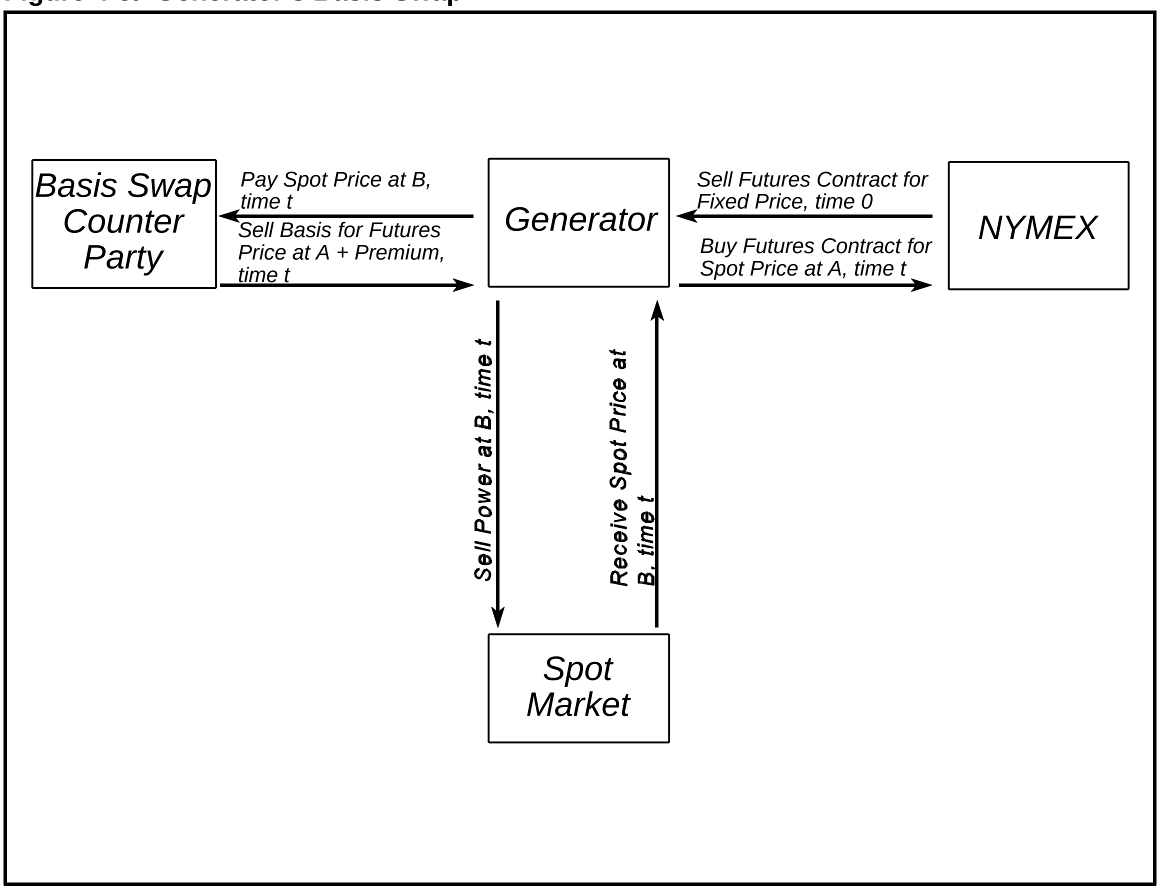
12 Where stranded cost recovery is assured and pegged to fluctuating spot prices, however, distribution utilities will have a stable source of income guaranteed and may have less incentive to hedge.

Generator

To lock in an electricity price in Denver, a generator would sell a futures contract (or a price swap) and a basis swap (see Figure 4-5). Assume that the generator sells a futures contract for $18/MWh for delivery in six months and sells a basis swap agreeing to pay the Denver spot price in exchange for the COB price plus a premium. In six months, the generator sells electricity in Denver and receives the Denver spot price (B), pays the Denver spot price (B) to the basis counterparty, receives the COB spot price (A) plus a fixed premium from the counterparty, and buys a futures contract for the COB spot price (A). All of these transactions cancel out, and the generator should expect to receive the fixed price for the original futures contract, $18/MWh, in addition to the premium received from the basis counterparty.

The above example represents a financial transaction. Physical transactions are also possible, where the generator provides power to the basis swap counterparty in return for the COB spot price plus a premium.

Figure 4-5. Generator's Basis Swap

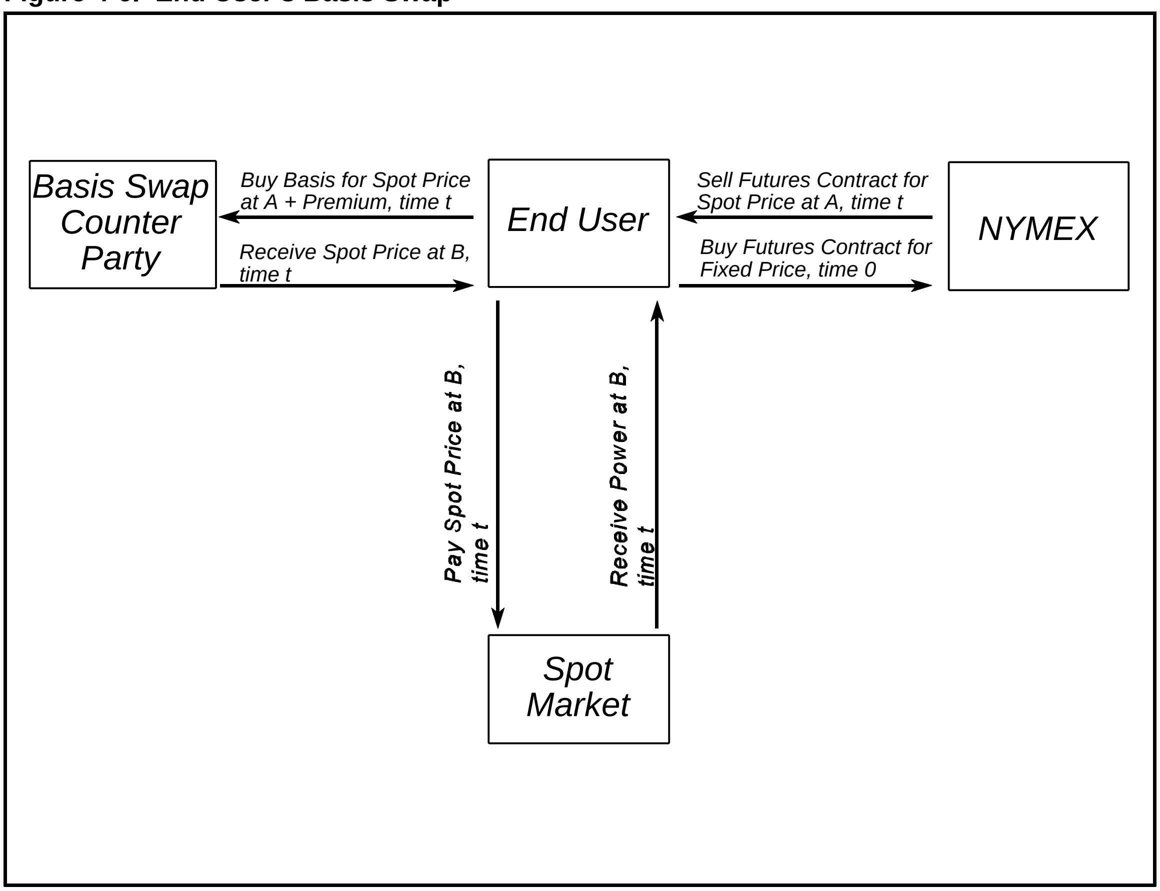


One risk associated with these transactions is that the generator may be unable to buy a futures contract at COB for the futures price used in the basis swap transaction. One way to avoid this risk is to use price swaps rather than futures contracts. The generator then pays the price swap counterparty the average of the Dow Jones COB Index, which would cancel out the average of the Dow Jones COB Index from the basis counterparty.

End User

To lock in a fixed price for electricity in Denver, an end user would buy a futures contract (or price swap) and a basis swap (see Figure 4-6). Assume that the end user buys a futures contract for $18/MWh and agrees to pay the COB spot price plus a premium in return for the variable spot market price in Denver. The end user can execute this agreement physically or financially. In either case, the end user locks in an electricity price of $18/MWh plus the premium. The end user can also buy a price swap, rather than a futures contract, to lock in the price in Denver or other locations.

Figure 4-6. End User's Basis Swap



Marketer

Marketers can execute these transactions on behalf of generators and end users in order to guarantee them a fixed price at a location other than the COB or Palo Verde. Marketers can also act as basis counterparties for generators and end users in these types of transactions. Generators and end users might work through marketers if they are uncomfortable using the financial tools associated with executing these transactions properly.

4.3 Options

Generators and end users can use combinations of calls and puts to ensure a particular price range.

In 1996, NYMEX also introduced options for electricity.[13] There are two types of options: a put option and a call option.[14] The buyer of an electricity put option (also called "floors") pays a premium for the right, but not the obligation, to sell electricity at a specified price, the strike or exercise price, at a specified point in time. End users use call options (also called "caps") to place a maximum ceiling price (relative to an indexed price) that they will pay for the commodity at a specified point in time. Generators and end users can use combinations of calls and puts to ensure a particular price range.

Generator

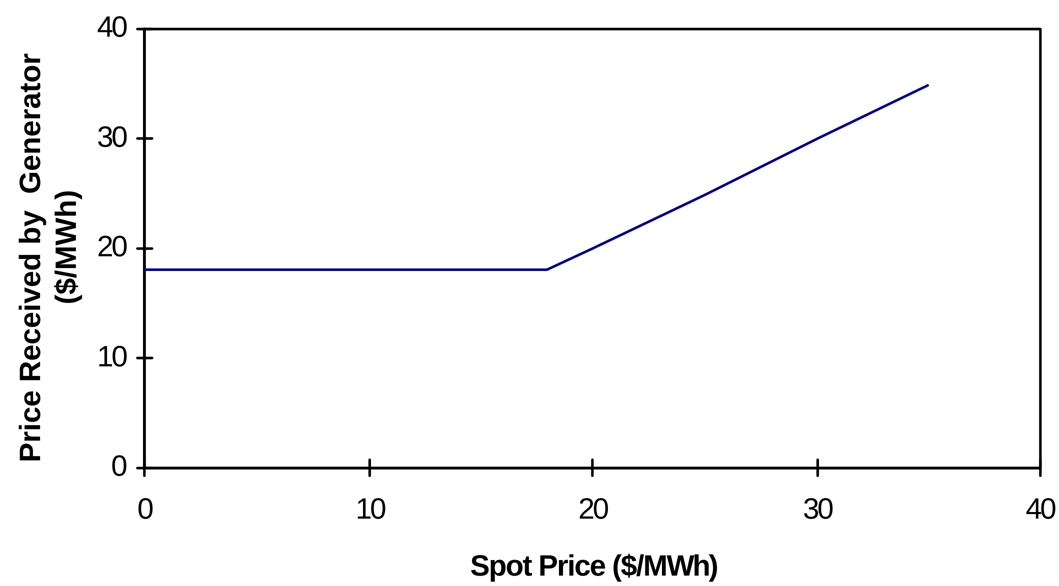
Generators use put options (also called "floors") to guarantee a minimum price for their electricity (relative to an indexed price) in conjunction with the physical sale of their commodity. A generator would still benefit from increases in commodity prices but would avoid the risk of lower prices. Assume that the futures contract price is $18/MWh and the generator would like to receive at least that amount. To do this, the generator would purchase a put option, say for $0.50/MWh, which the generator would pay for up front. If the price of electricity goes up, the generator would sell electricity into the spot market and receive the higher spot price (see Figure 4-7). If the price goes down, the generator would either sell electricity to the option holder for $18/MWh or sell his option at its exercise value, $18/MWh, on or before its expiration date.[15]

13 See Appendix A for NYMEX option contract terms.

14 Options are traded in both exchange and over-the-counter markets. The risk associated with OTC transactions is that the counterparty would fail to complete the transaction.

15 Generators can also sell put options either on an exchange or over the counter.

Figure 4-7. Put Option



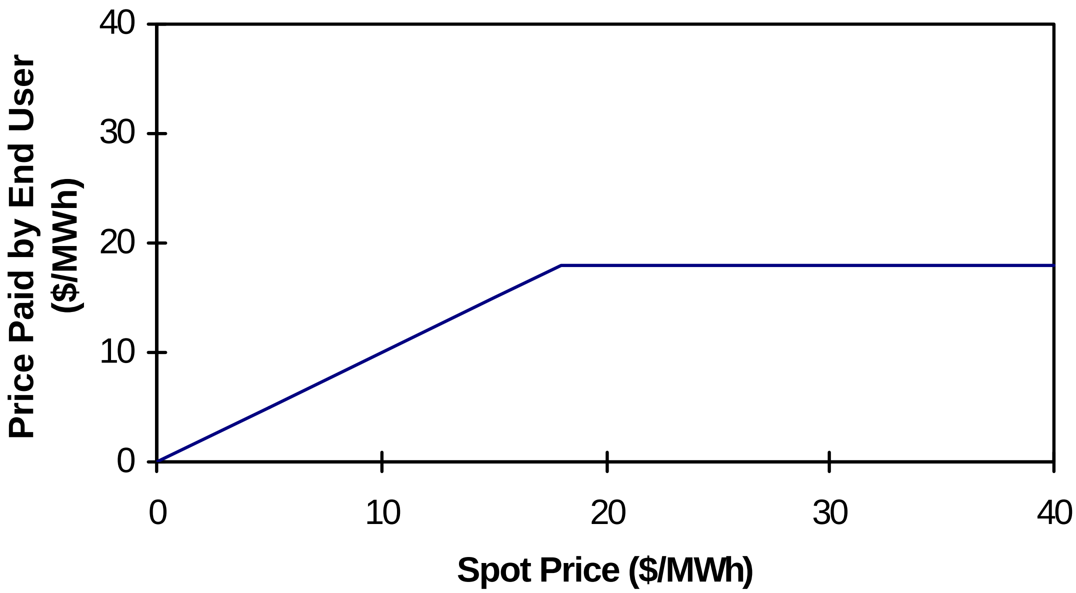
End User

An end user would utilize a call option (ceiling) to avoid the risk of higher prices, while ensuring his access to potentially lower prices. Assume that the futures contract price is \$18/MWh and the end user would like to pay no more than this amount. In this case, the end user would buy a call option, say for \$0.60/MWh, which the end user pays up front. If the price of electricity goes down, the end user would buy in the spot market (see Figure 4-8). If the price goes up, the end user would buy electricity from the option holder for \$18/MWh or sell his call option for its exercise value, \$18/MWh, on or before its expiration date.

Marketer

Marketers can either exercise put and call options on exchange or with another party on behalf of generators and end users and they can offer puts and calls to generators and end users.

Figure 4-8. Call Option



4.4 Forward Contracts

Electric power has long been purchased and sold under forward contracts. Under a forward contract, one party is obligated to buy and the other to sell, a specified quantity of a specified commodity at a fixed price on a given date in the future. At the maturity of a forward contract, the seller will deliver the commodity and the buyer will pay the purchase price. If, at that time, the market price of the commodity is higher than the price specified in the contract, then the buyer will make a profit. Conversely, if the market price is lower than the contract price, then the buyer will suffer a loss. The difference between a forward and a futures contract is that the terms and conditions of forward contracts are not standardized. Rather, they are negotiated to meet the particular business, financial or risk management needs of the parties to the contract.

4.5 Summary

In this chapter we have discussed a variety of derivatives other than futures. With the exception of options, which can be exchange traded, all of the derivatives described are fairly straightforward OTC instruments. These types of instruments work well because they can be tailored to the unique circumstances of generators, end users, and marketers. The primary risk associated with these OTC instruments is counterparty risk, which is the risk that the counterparty to the price swap or basis swap will not follow through with his or her end of the arrangement. If this occurs, what began as a safe hedge could turn into risky and potentially costly speculation.

CHAPTER 5

Regulating the Use of Futures and Other Derivative Instruments

This chapter discusses regulatory issues associated with the emergence and expansion of the electricity futures market. Protecting the interests of electricity consumers has been the responsibility of state regulators for more than 60 years, and, to the extent that regulated distribution utilities enter derivatives markets, state regulators will want to ensure that these transactions are in the best interest of retail customers. In addition, under retail competition, state regulators will also have an interest in ensuring that market transactions are conducted in a free and fair manner and that consumers and others are not subject to potentially anti-competitive behavior. Where the use of derivatives by large and potentially dominant utilities creates incentives to game spot market prices for electricity, regulators will have reason to be especially concerned.

Where regulated distribution utilities enter derivatives markets, regulators will want to ensure these transactions are in the best interest of retail customers.

At the same time, however, regulators must be aware of the risks faced by distribution utilities, marketers and others, and allow them to take steps to manage these risks responsibly. Futures and derivatives should not be regulated simply because they can produce losses. After all, not using futures in volatile commodity markets can also produce losses.

In Section 5.1, we touch on state PUCs' authority to regulate transactions in electricity futures and other derivatives before moving on to discuss regulatory concerns and the ways in which PUCs may might take action under varying circumstances. In Sections 5.2 - 5.4, we focus on how the use of derivatives will affect consumers and retail prices, and specifically address the regulator's role in ensuring consumer protection and fair competition.

5.1 Regulatory Authority

Policies affecting the use of derivatives are being developed by electricity and financial regulators, and by agencies at both the state and federal levels.

In the financial markets, trading in electricity futures and other derivatives is regulated by the Commodity Futures Trading Commission (CFTC). Yet while utility regulators scrutinize the activities of firms to ensure that they are acting in the consumers' interest, the CFTC is really only concerned with the smooth functioning of the futures market and with the elimination of deceptive practices. Because the CFTC does not focus on protecting consumers and the integrity of the electricity system, it will be up to electricity regulators to do so.

At the federal level, the Federal Energy Regulatory Commission (FERC) has taken the position that it has jurisdiction over any transaction which involves a transfer of legal title to power at the wholesale level.[16] However, as competition and the use of electric rate derivatives evolves, it is unclear what this standard will actually mean. Not all electric rate derivatives result in the "transfer of legal title to power." The FERC has expressed concern over the use of derivatives by marketers and brokers in the wholesale market.[17]

States' authority stems from their oversight of retail markets.

At the state level, Public Utility Commissions' authority to regulate aspects of derivative transactions stems from the PUCs' oversight of retail markets. Even though utilities may use derivatives to hedge wholesale market transactions, an activity that falls under the purview of the FERC, these transactions ultimately affect the price paid by consumers, giving state PUCs authority to act.[18] As retail markets are opened to competition, state PUCs will be in a position to regulate the use of derivatives by distribution utilities and may be able to regulate the use of derivatives by generators and marketers as well. Some PUCs have already established program limitations and other protective measures for hedging instruments used by utilities and telecommunications companies to manage interest and exchange rate fluctuations (CPUC 1995, 1997a, 1997b). These measures have included:

1) Requirements that utilities only enter into hedging agreements with entities that have a credit rating equal to or better than the utility itself;

2) Limitations on the amounts that can be hedged;

3) Reporting requirements, including both income affects and expenses, and the filing of agreement terms and contracts.

16 From Rae (1995) p. 18; citing Citizens Energy Corporation, 35 FERC ¶ 61, 198 (1986).

17 "FERC to Review Rules Relating to Derivatives." *Wall Street Journal*, January 17, 1995, page A8.

18 State PUCs regulate intrastate and the FERC regulates interstate sales of electricity. As regulators well know, however, because power shipped between two points within one state can affect power flows in other states, it is difficult to distinguish intrastate from interstate transactions. The result is a division of authority between the FERC and state PUCs. The FERC regulates wholesale transactions while state PUCs regulate retail transactions.

5.2 Regulatory Structure and Regulatory Concerns

Regulatory Structure and Utilities' Incentives to Hedge

With or without retail competition, utilities may use electricity futures to hedge both sales and purchases in the wholesale market. Yet whether or not utilities ultimately engage in futures transactions will depend in part on how they are regulated. Under rate-of-return (ROR) regulation and with fuel (and/or purchased power) adjustment clauses (FACs/PPACs), regulated utilities would have few incentives to hedge. In the absence of FACs and/or with performance-based ratemaking, incentives to hedge would be stronger.

In its simplest form, ROR regulation allows utilities to recoup their costs and provides an opportunity to earn a fair rate of return on capital (Comnes, Stoft, Greene, and Hill 1995). Many utilities also have FACs, which allow them to recoup fuel expenses and, frequently, purchased power costs. Typically, FACs allow automatic adjustments in rates subject to after-the-fact reasonableness reviews. This system ensures that the utilities will recover all of the fuel and purchased power costs regardless of intra-rate-case fluctuations. Because of this guarantee, regulated utilities have little incentive to hedge given that they are ensured cost recovery and bear no risk if their purchased power or fuel costs fluctuate. As we discuss in section 5.3, utilities and ratepayers in this situation may in fact face problems related to inadequately hedged risk. Nonetheless, utilities with FACs could still be motivated to hedge simply to reduce rate variability for their customers. In the absence of FACs, utilities would have incentives to hedge because they would be at risk between rate cases if their fuel or purchase power costs fluctuate.

In contrast, performance-based rate-making (PBR) sets a target price (price cap) for power purchases, and then allows utilities flexibility in achieving the target. If the utility's power purchases cost less than the target price, the savings accrue to shareholders. If the utility's power purchases cost more than the target price, shareholders suffer. Shareholders and ratepayers could also share profits and losses. This type of regulation encourages utilities to minimize costs and to engage in hedging activities to reduce profit variability due to cost fluctuations.

Table 5-1 summarizes utility incentives to hedge under different regulatory structures and notes some of the important regulatory concerns linked with each regulatory type. We discuss these and other important regulatory concerns below and in subsequent sections.

Table 5-1. Utility Incentives to Hedge

Utility Structure	Type of Regulation	Incentive to Hedge	Related Regulatory Concerns
Vertically Integrated	ROR with FAC	Minimal; all reasonable costs recoverable	Possibility of unhedged risk
	ROR without FAC	Yes; for fuel and power	Financial risk to ratepayers
	PBR	Yes; for fuel, power, and shareholder return	Financial risk to ratepayers
Distribution Utility (Purchasing from PX)	ROR with PPAC	Minimal; all reasonable costs recovered	Possibility of unhedged risk
	ROR without PPAC	Yes; for power	Financial risk to ratepayers and market power
	PBR	Yes; for purchased power and shareholder return	Financial risk to ratepayers and market power

Regulatory Concerns

The use of futures and other derivatives by regulated utilities raises at least three key regulatory concerns: system reliability, financial risk to ratepayers, and market power. We address each of these issues below.

System Reliability

The reliability of the U.S. electricity system is attributable to policies and practices developed by utilities, regional reliability councils, state PUCs, and the FERC. These policies have focused on the physical operation and integrity of the generation, transmission, and distribution infrastructure.

Restructuring and the introduction of competition is likely to increase financial risk for generators and distribution companies. The introduction of electric rate derivatives can both magnify and mitigate these financial risks. Yet, while it is possible that financial losses associated with futures or other derivatives contracts could produce losses catastrophic enough to result in the bankruptcy of a generator or distribution company, it is unlikely that physical reliability of the grid would be threatened even in such an extreme case.

Financial Risk to Ratepayers

The financial risks resulting from the use of derivatives are illustrated by the number of companies that have suffered significant losses in derivative markets (see Table 2-3). Large losses can be the result of well-intentioned hedging activities or wanton speculation. In either case, regulators must be concerned with the impact such losses could have on ratepayers who, absent protections, might be placed at financial risk for large losses.

In the context of futures, financial risk comes from three sources: speculation, margin calls, and unhedged price risk. Because futures are highly leveraged investments, speculation can lead to almost unlimited financial risk. A future purchased with an outlay of $2,000 can easily produce a loss of $5,000 if the price decreases, and if sold short can in theory produce an unlimited loss if the price increases. Unlike speculation, a properly executed hedge can only reduce risk. But the term "properly executed" includes the requirement that hedgers be able to meet all margin calls between the date of purchase and the settlement date. If hedgers have insufficient funds at their disposal, unexpected price movements can result in failure to post margin and the hedger will be "sold out." If this happens, the hedging strategy is broken and the intended hedge becomes defacto speculation. In these circumstances, substantial losses are quite likely to result. This is essentially what ended Metallgesellschaft's venture into the U.S. oil market (Culp and Miller 1995). Finally, unhedged price risk is not the result of hedging but results if the hedge is inadequate. The hedge can be inadequate for three reasons: (1) a utility has imprudently made inadequate use of futures, (2) a utility has prudently restricted its hedging because of cash flow or other considerations, or (3) because no fully adequate future is available.

In the context of futures, financial risk comes from three sources: speculation, margin calls, and unhedged price risk.

Market Power

Where restructuring involves the establishment of a power exchange (PX), distribution utilities may have an additional incentive to hedge if they have sufficient market power to influence PX prices and, in so doing, can earn returns on positions taken in the futures or other derivatives markets. Concern over this issue was raised in recent California PUC decisions, and was a key reason Pacific Gas and Electric (PG&E) was denied permission to deal in electricity derivatives contracts (CPUC 1997a, 1997b). In contrast, Southern California Edison (SCE) was granted permission to deal in derivatives but only in contracts for natural gas to be used in electricity production. In only seeking to deal in natural gas contracts, SCE argued that it would have no incentive to use its market power to affect PX rates, given that a shift in PX prices would be unlikely to impact the value of financial instruments for gas. The exact terms under which SCE's application was approved are noteworthy, as they highlight some of the tools PUCs can use to monitor the use of derivatives. These tools include reporting requirements, limits on recoverable costs, and absolute program limits designed to mitigate both ratepayer risk and market power concerns. In SCE's case, the CPUC utilized variants of each of these tools. The CPUC's terms for SCE are detailed in the text box below.[19]

CPUC's Terms for SCE's Use of Hedging Instruments

Reporting Requirements:

- SCE shall send a copy of each hedging instrument entered into under this program to the Energy Division within 10 days of executing the contract.
- SCE shall file a confidential monthly report with the CPUC Energy Division indicating its monthly maximum end-of-day hedging position, including but not limited to gross receivable (in-the-money) and gross payable (out-of-the-money), and at-the-money volumes on open financial positions, showing both contract volume (MMBTU) and market value ($M). To qualify for netting, instruments must meet three requirements: 1) the financial product must match, 2) the location must match, and 3) time must match (the product must be bought and sold within the same month). Additionally, the average maturity would be presented as the end of day average maturity for both receivables and payables.

Cost Recovery Restrictions:

- Recovery is limited to out of pocket costs, such as brokerage fees that do not include losses from changes in market prices; out-of-pocket costs shall be recorded in a memorandum account.
- SCE shall not be compensated for any increases in its costs of capital that result from the use of these hedging activities.

Ratepayer Risk & Market Power Mitigation Measures:

- SCE's program is limited to use of the gas instruments [for gas-fired power plants];
- SCE's use of gas hedging instruments is limited to hedging energy costs that are subject to gas price fluctuations. CPUC states, "Our understanding is that such energy is approximately 40-60% of SCE's energy needs over time and will not exceed $150 million."
- SCE shall not enter into any contracts for differences with its customers, generation facilities, or affiliates.

— CPUC Resolution E-3506, November 5, 1997.

19 SCE was also aided by language inserted in AB 1890, the California statewide electricity restructuring bill, that explicitly granted SCE the right to use risk management tools, including physical contracts, to manage natural gas price risk (AB 1890, 1996).

Because risks and the meaning of speculation vary over the term of hedging commitments, we look next at incentives to hedge and regulatory options in short and long-term hedging contexts.

5.3 Short-Term Hedging

How to Define?

It is difficult to define precisely the boundary between short-term hedging and long-term hedging. One operational definition would be to define short-term hedging in terms of the most distant maturity month (see Section 3.1.1). Currently 18 consecutive months of electricity futures contracts and 12 consecutive months for options contracts are listed, but often the listed months increase as a futures market matures. Basing regulation on such a simple but arbitrary definition would have no particular merit. As discussed in Section 3.7, it is quite possible to hedge 24 months in the future by rolling over one 12 month futures contract into another 12 month futures contract. A utility might handle such a hedge quite easily if it were for a small position, and a regulator might view it as an acceptable short-term hedge. On the other hand, hedging a very large position for only 18 months into the future with a stack-and-roll hedge might be deemed too risky for some utilities, and the regulator may wish to restrict this type of activity.

What Are the Risks?

The primary risks associated with short-term hedging are cash flow problems stemming from margin calls and unhedged price risk. As discussed in Section 5.2, if hedgers have insufficient funds to make margin calls, unexpected price movements can result in failure to post margin and, as a result, an intended hedging transaction becomes defacto speculation. Unhedged price risk results from inadequate hedging.

Should PUCs Regulate?

For short-term hedging, cash flow problems due to margin calls probably present little risk, but as the utility hedges further into the future, the risks increase because the cumulative obligations that are being hedged increase and because price fluctuations are likely to be greater. We discuss the risks associated with margin calls and long-term hedging in the following section. At this point, we simply note that other partially regulated industries (e.g., banking and insurance) use capital requirements and position limits to ensure that companies have sufficient capital to meet margin calls and absorb potential losses.[20]

In our view, inadequate hedging is of potentially greater concern than ensuring sufficient cash flow to meet margin calls. Where rate-of-return regulation and fuel-adjustment clauses remain, utilities will tend to hedge too little instead of too much. Historically, fuel costs and purchased power costs have been passed on to consumers through FACs. To protect customers, regulators conduct reasonableness reviews of purchased fuel and power expenditures on a periodic basis to ensure that they are prudent. As discussed earlier, firms under this type of regulatory regime have little incentive to hedge sufficiently because failing to do so should not result in any loss to its stockholders, although it may expose its customers to undue price risk. On the other hand, if a hedge exposes the utility to cash-flow risk, and it is unable to meet a margin call, it may be found to have been imprudent. This finding will be reinforced by the observation that if the utility had not hedged, its customers would have received energy at the unexpectedly low spot price.

Other partially regulated industries (e.g., banking and insurance) use capital requirements and position limits to ensure that companies have sufficient capital to meet margin calls and absorb potential losses.

What is the best regulatory scheme to encourage utilities to pursue a purchased power strategy that includes the use of electricity futures and is in the best interest of retail customers? One option, consistent with ROR regulation, is to modify the existing system of FACs coupled with reasonableness review. Currently, the level of scrutiny exercised in reasonableness reviews is relatively low. Utilities, with the consent of regulators, could more actively manage their purchased power portfolios, using electricity futures to manage risk. Regulators could review the utility's performance periodically (e.g., quarterly or semi-annually) to determine whether its actions were, indeed, in the best interest of retail customers.

A second alternative, and one that is consistent with the trend towards performance-based regulation, is to modify or eliminate the purchased-power adjustment clause (PPAC). Eliminating this adjustment essentially leaves the utility with a price cap on purchased power costs. Some PPACs require that rate-payers and shareholders share in any gains or losses from deviations in costs from an established target level. This is essentially a partial elimination of the PPAC. Either a partial or full elimination of the PPAC would induce the utility to hedge its cost risks, and thus partially insulate both ratepayers and shareholders from

20 PUCs have used similar mechanisms to place limits on utilities' derivative activities to manage interest rate and currency risks.

the effects of fluctuations in the spot price of purchased power.

It is useful to compare these policy options using two criteria. The first is which policy is likely to encourage hedging activities that are in the best interest of customers. Under the reasonableness review approach, the goal of utilities will be to undertake those hedging activities that they think will be approved by regulators. Utilities may be reluctant to undertake many hedging opportunities because what appears to be a good hedge today may not look as good when regulators review it later. From a utility's perspective, regulatory review may be a no-win proposition. If the utility effectively hedges, benefits will accrue to ratepayers. If a hedge is deemed imprudent, the costs will be borne by shareholders. Under the PBR approach, customers are held harmless to gains and losses in derivative transactions. Prices charged to customers are determined by the performance target established by regulators, and thus, are independent of the outcome of derivative transactions. Hedging and speculation will be undertaken based on the risk preferences of shareholders. One would expect a utility to perform better under such a system because it mimics the incentives of an unregulated market.

It is doubtful that state PUCs will have the time and expertise to reconstruct and dissect hedging decisions. As such, a performance target approach appears to be a much better policy than reasonableness review.

A second criteria is the ability of regulators to implement the policy. At the heart of this question is whether regulators will have the necessary information and technical expertise to determine whether hedging activities have been prudent or imprudent. The information requirements of the reasonableness review approach are quite large. Hedgers must make decisions quickly, employing the best information available at the time. The reasonableness approach will require regulators to have the analytic expertise necessary to judge the prudence of a particular hedging strategy. Hedging decisions are also often made using sophisticated, proprietary computer models, and new hedging strategies and instruments are developed frequently. It is doubtful that state PUCs will have the time and expertise to reconstruct and dissect hedging decisions made by distribution utilities and others. As a consequence, the regulator may well be tempted to base prudence judgements on hindsight, shifting risk unfairly to the utility and discouraging efficient hedging.

Since the PBR approach simply makes the utility responsible for the consequence of its hedging activities, it leaves to the shareholders the task of determining prudence. This makes the implementation requirements simpler. Once the method for calculating the target price is established, regulators simply allow the utility to recover the target costs from customers. There is no need to gather extensive market data or to understand sophisticated hedging models. Using these criteria, the performance target approach appears to be a much better policy than the reasonableness review approach.

Who Should Bear Profits and Losses?

Regulators and consumers may believe that utilities (or other market participants) are obtaining windfall profits whenever the price of energy rises unexpectedly and imprudent losses whenever the price of energy falls unexpectedly. If this perception is widespread, the utility may conclude that it is either at risk of having its gains from futures trading taken back, or being forced to absorb losses.

Gains and losses that accrue in the futures market when a hedge is undertaken must be viewed as part of the stable electricity price that the regulated utility provides to its customers. Sometimes the utility wins in the futures market and loses in the spot market, sometimes the reverse occurs. If this perspective is adopted, the treatment of hedging profits and losses becomes clear: they must be treated simply as part of the cost of purchasing energy. When viewed this way, profits in the futures market will always be seen to be canceled by losses in the spot market, so there will be no temptation to declare them a windfall and recoup them for ratepayers.

In the case of an imperfect hedge, the problem is slightly more complex. If the hedge involves some basis risk (i.e., if the underlying commodity of the future is not exactly the same—locationally—as the commodity being hedged), then the hedge itself will produce real profits and losses. With an imperfect hedge, the utility could earn more on its futures position than it loses between its fixed price contract and the spot market, or it could earn less. In this situation, the regulator has a choice. It can either allow the utility to pass through these real profits and losses, or not. Allowing a pass though will shift risk from the utility to the customer. Since one would expect the customers to bear this risk more cheaply (because it is such a small fraction of their portfolio) than the utility, there is a strong argument for the pass through. On the other hand, allowing the utility to bear this risk should encourage it to engage in optimal hedging in order to minimize it. Ultimately, regulators will have to examine the size of this risk and reach an appropriate compromise.

5.4 Long-Term Hedging

How to Define?

Like short-term hedging, long-term hedging, too, is difficult to define precisely. There is no bright line to distinguish these two types of activities. Rather, they represent a continuum, with the cash flow risks increasing due to margin calls as the duration of the long-term hedge increases. Generally the increase in risk is faster than linear because risk increases with the length of the hedge for two reasons. First, the amount being hedged is generally proportional to the length of the hedge because the utility will be hedging an essentially constant flow over this length of time. Second, the expected maximum price fluctuation increases approximately in proportion to the square root of the length of the hedge.[21]

What Are the Risks?

The primary risk associated with long-term hedging has to do with *cash flow risks* associated with margin calls. This point can be illustrated by comparing forward and futures contracts. A key difference between forward and futures contracts is that the buyer or seller of a futures contract will suffer short term losses (or realize short-term gains) as the futures price changes. With a forward contract, profit and loss is realized only at maturity or when the position is reversed, but with a futures contract, profit and loss is settled daily. This difference can be crucial, as is demonstrated by the following example (see Table 5-2).

Table 5-2. Forwards Can Generate Large Short-Term Losses

A 700-MW, Hedged Transaction		Future	Forward	
Time	**Action**	**Gain or Loss**		**Futures Price**
Start	Purchase future/forward	−$2000	$0	$30/MWh
	Sell power contract: $31/MW	$0	$0	
1 Month	Pay variation margin	−$7000	$0	$20/MWh
	Position reversed	$2000	−$7000	$20/MWh
2 Months	Spot purchase	−$14000	−$14000	
	Contract payment	+$21700	+$21700	
2 Months	Profit	$700	$700	

Notice that the only difference between using the forward and the futures contract is that there is a cash flow problem due to the payment of variation margin. This arises because of the rule that futures are settled daily and because of the decline in futures price. Of course the money lost on the future (and eventually on the forward) is entirely regained from the added profit on the fixed price contract that was sold at the start of this example. Notice from this example that the necessary cash flow is 10 times greater than the eventual profit from the sale of power. (Also notice that even if the spot price had returned to $30/MWh after two months, the futures contract still would have required a $2,000 initial margin, and a $7,000 variation margin.)

21 This is exactly true for a random walk, and is a very good approximation for most price sequences.

The magnitude of the temporary loss is crucial. If the loss is small, it can be easily and inexpensively covered by the hedgers. If the loss is large, it may be impossible for the hedgers to raise the funds necessary to meet the variation margin requirement. In this case, the clearing house will liquidate the hedgers' futures position. One question is why, since the hedgers have locked in a profit at maturity, they could not obtain a loan to cover their margin needs. As long as their contracts are viewed as rock solid, this should be possible. Unfortunately, with long term contracts this is not the case. The uncertainty associated with long-term commitments interacts with the fact that hedging over longer periods puts traders at risk for extremely large margin calls. The consequence is that long-term hedging requires extremely deep financial pockets. Without significant financial resources, hedgers may well find themselves unable to meet variation margin requirements and consequently find themselves with a hedge that has been broken. When this happens, traders will not only have sustained tremendous losses on the hedge, they will also be faced with the possibility that prices will return to their original values and they will not recoup these losses even when (and if) the contract they were hedging pays off.

Should PUCs Regulate?

The problem described in the previous section is essentially the problem that broke Metallgesellschaft's (MG's) American operations.[22] Because there are large risks associated with very long term hedges, and because, thanks to examples such as MG these risks are becoming very well known, we think that it is unlikely that utilities will be tempted to engage in very long-term hedging. However, because there are significant risks associated with long-term hedging, regulators might want to take a particularly cautious approach and ensure that utilities have sufficient funds to maintain their hedge over the long term.

5.5 Speculation

How to Define?

Typically, speculation involves selling or purchasing futures contracts with no position in the underlying commodity. In the electricity industry, a clear case of speculation would involve a utility purchasing agricultural futures. But a utility would also be speculating if it purchased electricity futures in amounts greater than its underlying obligation (e.g., if it purchased futures contracts for 200 MWh in 6 months, but was obligated to provide only 100 MWh at

[22] The only difference is that it is possible MG actually could have met the variation margin requirements had they had the resolve to do so. However after sustaining tremendous short-term losses in an attempt to hedge 10-year contracts, and not knowing how long and to what extent this would continue, MG eventually lost their nerve. (This glosses over internal politics, but is essentially correct.)

that time).[23] Speculation could also occur if the price of electricity futures and the electricity spot price were not perfectly correlated. This merits some explanation.

In our initial examples in Chapter 3, the futures contract and the hedged item were perfectly correlated and the losses (gains) from the futures contract offset the gains (losses) from the spot market. But if the price of the futures contract and the spot price are not perfectly correlated, the optimal size and the effectiveness of the hedge decrease.

Figure 5-1. Speculation vs. Hedging

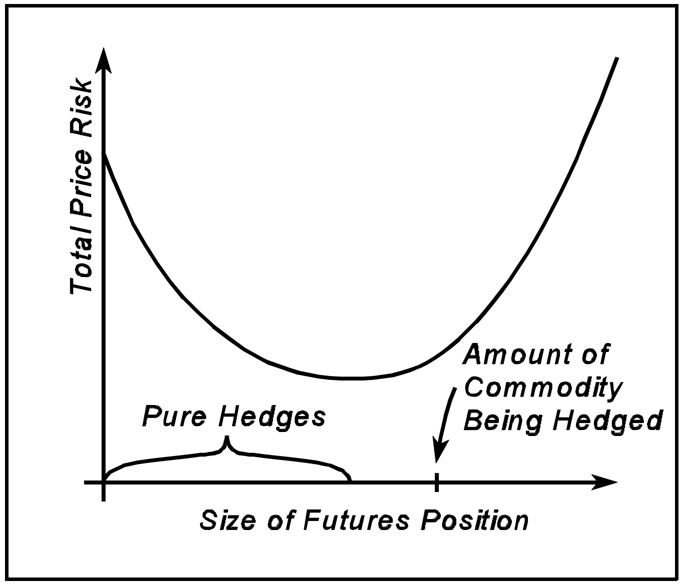


Figure 5-1 shows a typical hedging situation. Notice that as the size of the futures position increases, price risk first decreases and then increases. In the region where price risk is decreasing, the futures position is serving solely as a hedge. However, once the minimum price-risk is reached, any additional futures contracts will take on a speculative character. Notice also that the minimum price risk is reached before the size of the futures position reaches the amount of the commodity being hedged in this case, and that at this point price risk has not been reduced to zero. These effects are both the result of the futures not perfectly matching the commodity that is being hedged. In general, both the size and effectiveness of the optimal hedge declines as the correlation declines between the price of the commodity that underlies the future and the price of the commodity being hedged.[24]

23 This is true unless the hedging commodity is less variable than the hedged commodity.

24 See Stoll and Whaley (1993), Chapter 4, for an explanation of how the amount of the optimal hedge is calculated.

What Are the Risks?

Speculation is the opposite of hedging; it increases risk but holds out the possibility of gains from earning a risk premium. As we have discussed, speculation can result in extremely large financial losses and gains.

Should PUCs Regulate?

If the losses associated with speculation were borne solely by shareholders, speculatory risk would not necessarily be a regulatory concern. But large losses on the part of distribution utilities would likely be borne, at least in part, by ratepayers, especially in the case of bankruptcy. For this reason, we argue that regulators should prevent speculation. To do this, regulators will need to make clear legal distinctions between hedging and speculation and must provide the necessary oversight and penalties for violating this rule.

The regulator would have to know something about the relevant price correlation and volatilities in order to distinguish speculation from hedging. In practice it is difficult to measure the correlation between the underlying commodity and the hedged commodity because this correlation will change over time and because measurement during any finite time period is subject to statistical measurement error. Consequently, it will be difficult to determine if a strategy intended to maximally hedge a position has gone too far. Nonetheless, we believe that PUCs must guard against speculation by utilities, even though it may be difficult to establish simple rules that can prevent speculative transactions. One possibility, however, might be for regulators to require utilities to identify the obligations being hedged and report both the correlation between the obligation and the future contract, and the size of the hedge as a percentage of the purchased commodity being hedged.

We believe that PUCs must guard against speculation by utilities, even though it may be difficult to establish simple rules that can prevent speculative transactions.

5.6 Treatment of Unregulated Retail Energy Suppliers

Based on experience with the natural gas futures market, we expect that power marketers and other energy service providers (ESP) will be the predominant users of electricity futures, at least in the near term. Power marketers operate primarily in the wholesale market at present; however, with restructuring, they will increasingly focus on retail markets as well. FERC has indicated some concerns whether its reporting requirements for power marketers are appropriate and what, if any, jurisdiction it has over marketers' derivative transactions.[25] Regulatory approaches taken in the natural gas industry provide useful insights regarding the predilections of state regulators. For the most part, marketers in the natural gas industry have targeted large industrial customers and state PUCs have found little reason to intervene. However, as ESPs begin to target smaller commercial and residential customers, who are presumed to be less sophisticated, state PUCs are much more likely to consider consumer protection guidelines and a more explicit consumer protection role for themselves. One way to at least keep tabs on ESP derivatives activities is via statewide service provider registration requirements. As a condition of registration, PUCs could, for example, mandate some sort some basic reporting requirement under the rubric of consumer protection.

[25] "FERC to Review Rules Relating to Derivatives." Wall Street Journal, January 17, 1995, page A8.

CHAPTER 6

Conclusion

We expect continued, dramatic increases in the use of electric rate derivatives, and believe that regulators should formulate policies designed to deal with some of the issues derivatives engender. Regulators may be tempted to take the easy way out on this complex issue. This might be done by banning the use of derivatives by regulated utilities because they are not well understood and are perceived as too risky. In our view, such a policy would prevent a great deal of socially beneficial hedging. Alternatively, regulators could ignore derivatives until they become a more serious concern. This second path could lead to a situation where regulators are surprised by an Orange County-type financial disaster that significantly impacts ratepayers.

Conceptually, we have argued that speculation is simply not a proper function for a regulated entity and that state PUCs should discourage speculation by utilities. The danger of being "sold out" because of an inability to meet margin calls must also be protected against either by limiting the use of futures for long-term hedging or by securing a sufficient line of credit in advance. PUCs may wish to consider program limitations and other protective measures including:

1) Requirements that utilities only enter into hedging agreements with entities that have a credit rating equal to or better than the utility itself;

2) Limitations on the amounts that can be hedged;

3) Reporting requirements, including both income affects and expenses, and the filing of agreement terms and contracts.

We have also suggested that regulators should encourage utilities to hedge up to the point where the cash flow risks negate the risk-reducing properties of the hedge. Unfortunately, it will not be easy to demarcate clearly the point where increased hedging begins to increase rather than reduce risk. Finally, while encouraging prudent hedging, regulators should not expect that these strategies will eliminate all price risk. When unexpected negative outcomes occur it must not be assumed, without investigation, that the losses were the result of improper hedging. Competitive markets produce risks, not all of which can be fully hedged.

References

Black, D. 1986. "Success and Failure of Futures Contracts: Theory and Empirical Evidence." Salomon Brothers Center for the Study of Financial Institutions.

Brealey, R. and S. Myers 1996. *Principles of Corporate Finance, 5th Ed.* McGraw-Hill: New York, NY.

Brinkman, E. and R. Rabinovitch 1995. "Regional Limitations on the Effectiveness of Natural Gas Futures," *The Energy Journal.* Vol. 16, No. 3.

Brown, S. and S. Errera 1987. *Trading Energy Futures*. Quorum Books: New York, NY.

Bonbright, J.C 1961. *Principles of Public Utility Rates*. Columbia University Press: New York, NY.

California Office of Ratepayer Advocates (ORA) 1997. Regulatory filings. June 26.

California Public Utilities Commission (CPUC) 1997a. Decision 97-08-058. August.

California Public Utilities Commission (CPUC) 1997b. Resolution E-3506. November.

California Public Utilities Commission (CPUC) 1995. Decision 95-09-023. September.

Comnes, G.A., S. Stoft, N. Greene, and L.J. Hill 1995. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues.* Volume 1. LBL-37577. Berkeley, CA: Lawrence Berkeley National Laboratory.

Culp, C. and M. Miller 1995. "Metallgesellschaft and the Economics of Synthetic Storage." *Journal of Applied Corporate Finance*. Vol. 7, No. 4.

Deaves, R. and I. Krinsky 1992. "Risk Premiums and Efficiency in the Market for Crude Oil Futures," *The Energy Journal.* Vol. 13, No. 2.

Dow Jones Newswires 1997. "NYMEX Seeks Approval for Cheaper Permits in Electricity Contracts," *The Wall Street Journal.* April 4, p.A4.

Edwards, Franklin R. And Michael S. Canter 1995. "The Collapse of Metallgesellschaft: Unhedgeable Risks, Poor Hedging Strategy or Just Bad Luck?" *Journal of Futures Markets.* Vol. 15, No. 3.

Enron Capital and Trade Resources 1996. "Understanding Risk Management Products for the Energy Industry," Houston, TX.

Gedra, T. and P. Varaiya 1993. "Markets and Pricing for Interruptible Electric Power," *IEEE Transactions on Power Systems,* Vol. 8, No. 1 pp.122-128.

Goldman, Sachs & Co./J. Aron & Co. 1995. "Energy Risk Management in the Electric Power Industry: Emergency of Commodity Merchant Markets." Conference on Electric Rate Derivatives, Scottsdale, AZ, March 16-17.

Herbert J.H. 1993. "The relation of Monthly Spot to Futures Prices for Natural Gas," *Energy.* Vol. 18, No. 11.

REFERENCES

Hirschfeld, D. 1983. “A Fundamental Overview of the Energy Futures Market,” *Journal of Futures Markets*. Vol. 3, No. 1.

Hope, E., L. Rud and B. Singh 1993. "Markets for Electricity: Economic Reform of the Norwegian Electricity Industry," SNF Working Paper No. 12/1993, Bergen, Norway.

Hull, J. 1993. *Options, Futures, and Other Derivative Securities*. Prentice Hall, Englewood Cliffs, NJ.

Klitzman, K. and B. Leach 1993. "Futures Market Concepts," New York Mercantile Exchange mimeo, October 26.

Lee, P. 1995. “A question of collateral,” *Euromoney*. November.

Moen, J. 1994. Norwegian Department of Energy and Water, personal communication, May.

McGraw Hill 1997. Power Markets Week. December 8.

New York Mercantile Exchange (NYMEX) 1992. Natural Gas Futures Contract, Commerce Clearing House Rules 220.01-220.21.

New York Mercantile Exchange (NYMEX) 1993. Minutes of the Electricity Subcommittee. December 13.

New York Mercantile Exchange (NYMEX) 1996. “Electricity Futures and Options.” New York.

New York Mercantile Exchange (NYMEX) 1997. *Energy in the News* New York, Summer/Fall.
.
O’Driscoll, M. 1996. “Derivatives To Play Key Role In Competitive Utility Industry,” *The Energy Daily*. June 13, p. 3.

Outhred, H. 1993. "Principles of a Market-Based Electricity Industry and Possible Steps Toward Implementation in Australia," IEE 2nd International Conference on Advances in Power System Control, Operation and Management, Hong Kong.

Schnitzer, M. 1995. “Peak-Load Pricing,” Draft presentation to the Harvard Electricity Policy Group, September 27.

Stein, J. *The Economics of Futures Markets*. Oxford, Basil Blackwell Ltd, 1986.

Stoll, H.R. and R.E. Whaley 1993. *Futures and Options: Theory and Applications.* Southwestern Publishing Company: Cincinnati, Ohio.

Sukaly, B. 1995. “Natural Gas Derivatives: Current Applications and Potential for the Power Market,” Conference on Electric Rate Derivatives, Scottsdale, AZ, March 16-17.

United States General Accounting Office (GAO) 1994. *Financial Derivatives: Actions Needed to Protect the Financial System.* GAO/GGD-94-133 Washington, D.C.

Walls, W.D. 1995. “An Econometric Analysis of the Market for Natural Gas Futures,” *The Energy Journal*. Vol. 16, No. 1.

Williams, J. 1986. *The Economic Function of Futures Markets.* Cambridge University Press, Cambridge, U.K.

Wilson, M., M. Huffman, A. Beitel 1996. PG&E Application No. 96-11-037. San Francisco, November 25.

Working, H. 1949. "The Theory of Price of Storage," *American Economic Review*, Vol. 39 pp.1254-1262.

NYMEX Electricity Futures & Options Contract Specifications[26]

Trading Unit
Futures: 736 MWh delivered over a monthly period
Options: One NYMEX Division electricity futures contract.

Trading Hours
Futures and Options: 10:30 A.M. - 3:30 P.M. New York time for the open outcry session. After hours trading is conducted via the NYMEX ACCESS electronic trading system Monday - Thursday, 4:15 P.M. - 7:15 P.M. EST.

Trading Months
Futures: 18 consecutive months
Options: 12 consecutive months

Price Quotation
Futures and Options: in dollars and cents per MWh

Minimum Price Fluctuations
Futures and Options: $0.01 per MWh ($7.36 per contract)

Maximum Daily Price Fluctuation
Futures: $3.00 per MWh above or below the preceding day's settlement price. Expanded limits will apply when the contract settles at the maximum limit.
Options: no price limits

Last Trading Day
Futures: Trading will cease on the fourth business day prior to the first day of each month.
Options: Expiration will occur on the day preceding the expiration of the underlying futures contract.

Exercise of Options
By a clearing member to he Exchange clearinghouse no later than 5:30 P.M., or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including the day o the option's expiration.

26 Source: NYMEX 1996. "Electricity Futures and Options." New York.

Options Strike Prices
Increments of $1.00 per MWh with five below and five above at-the-money strike price.

Delivery Rate
Two MW throughout every hour of the delivery period (can be amended upon mutual agreement by the buyer and seller).

Delivery Period
16 On-peak hours: hour ending 0700 prevailing time to hour ending 2200 prevailing time (can be amended upon mutual agreement by the buyer and seller).

Scheduling
Buyer and seller must follow WSCC or other applicable scheduling practices.