Summary

Introduction

Derivatives are financial instruments (contracts) that do not represent ownership rights in any asset but, rather, derive their value from the value of some other underlying commodity or other asset. When used prudently, derivatives are efficient and effective tools for isolating financial risk and "hedging" to reduce exposure to risk.

Although derivatives have been used in American agriculture since the mid-1800s and are a mainstay of international currency and interest rate markets, their use in domestic energy industries has come about only in the past 20 years with energy price deregulation. Under regulation, domestic petroleum, natural gas, and electricity prices were set by regulators and infrequently changed. Unfortunately, stable prices were paid for with shortages in some areas and surpluses elsewhere, and by complex cross-subsidies from areas where prices would have been lower to areas where prices would have been higher, with accompanying efficiency costs. Free markets revealed that energy prices are among the most volatile of all commodities. Widely varying prices encouraged consumers to find ways to protect their budgets; producers looked for ways to stabilize cash flow.

Derivative contracts transfer risk, especially price risk, to those who are able and willing to bear it. How they transfer risk is complicated and frequently misinterpreted. Derivatives have also been associated with some spectacular financial failures and with dubious financial reporting.

The Energy Information Administration prepared this report at the direction of the Secretary of Energy to provide energy policymakers with information for their assessment of the state of markets for energy derivatives. It also indicates how policy decisions that affect the underlying energy markets, in particular natural gas and electricity transmission and spot markets, limit or enhance the usefulness of derivatives as tools for risk management.

Energy Derivatives and Risk Management

This report examines the role of derivatives in managing some of the risks in the production and consumption of petroleum, natural gas, and electricity. Price risk management is relatively new to these industries because for much of their history they have been regulated. Electricity has not been a thoroughly competitive industry since the early 1900s. Natural gas and oil pipelines and residential natural gas prices are still regulated. Operating under government protection, these industries had little need for risk management before the wave of deregulation that began in the 1980s—about the same time that modern risk management tools came into use.

There are five general types of risk that are faced by all businesses: *market risk* (unexpected changes in interest rates, exchange rates, stock prices, or commodity prices), *credit/default risk; operational risk* (equipment failure, fraud); *liquidity risk* (inability to buy or sell commodities at quoted prices); and *political risk* (new regulations, expropriation). Businesses operating in the petroleum, natural gas, and electricity industries are particularly susceptible to market risk—or more specifically, *price risk*—as a consequence of the extreme volatility of energy commodity prices. Electricity prices, in particular, are substantially more volatile than other commodity prices (Table S1).

Price volatility is caused by shifts in the supply and demand for a commodity. Natural gas and wholesale electricity prices are particularly volatile, for several reasons. Demand shifts quickly in response to weather conditions, and "surge production" is limited and expensive. In addition, electricity and natural gas often cannot be moved to areas where there are unexpected increases in demand, and cheap local storage is limited, especially for electricity. Public policy efforts to reduce price volatility have focused on increasing both reserve production capacity and transmission and transportation capability. There has also been recent emphasis on making real-time prices more visible to users so that they will reduce their usage when supplies are tight and costs are high, limiting the size and duration of price spikes.

To the extent that prices vary because of rapid changes in supply and demand, often associated with severe weather or international political events, energy price volatility is evidence that markets are working to allocate scarce supplies to their highest value uses; however, rapidly changing prices threaten household budgets and financial plans. In addition, price variation makes investments in energy conservation and production risky. Investors, whether individuals considering fuel-efficient hybrid cars or corporations assessing new energy production opportunities, have difficulty judging whether current prices indicate long-term values or transient events. Bad timing can spell ruin, and even good investments can generate large temporary cash losses that must be funded.

To a large extent, energy company managers and investors can make accurate estimates of the likely success of exploration ventures, the likelihood of refinery failures, or the performance of electricity generators. Diversification, long-term contracts, inventory maintenance, and insurance are effective tools for managing those risks. Such traditional approaches do not work well, however, for managing price risk.

When energy prices fall, so do the equity values of producing companies, ready cash becomes scarce, and it is more likely that contract obligations for energy sales or purchases may not be honored. When prices soar, governments tend to step in to protect consumers. Thus, commodity price risk plays a dominant role in the energy industries, and the use of derivatives has become a common means of helping energy firms, investors, and customers manage the risks that arise from the high volatility of energy prices.

Derivatives allow investors to transfer risk to others who could profit from taking the risk. The person transferring risk achieves price certainty but loses the opportunity for making additional profits when prices move opposite his fears. Likewise, the person taking on the risk will lose if the counterparty's fears are realized. Except for transactions costs, the winner's gains are equal to the loser's losses. Like insurance, derivatives protect against some adverse events. The cost of the insurance is either forgone profit or cash loses. Because of their flexibility in dealing with price risk, derivatives have become an increasingly popular way to isolate cash earnings from price fluctuations.

The most commonly used derivative contracts are forward contracts, futures contracts, options, and swaps. A forward contract is an agreement between two parties to buy (sell) a specified quality and quantity of a good at an agreed date in the future at a fixed price or at a price determined by formula at the time of delivery to the location specified in the contract. For example, a natural gas producer may agree to deliver a billion cubic feet of gas to a petrochemical plant at Henry Hub, Louisiana, during the first week of July 2005 at a price of $3.20 per thousand cubic feet. Forward contracts between independent generators and large industrial customers are used extensively in the electricity industry.

Table S1. Spot Market Price Volatility for Selected Commodities

Commodity	Average Annual Volatility (Percent)	Market	Period
Electricity			
California-Oregon Border	309.9	Spot-Peak	1996-2001
Cinergy	435.7	Spot-Peak	1996-2001
Palo Verde	304.5	Spot-Peak	1996-2001
PJM	389.1	Spot-Peak	1996-2001
Natural Gas and Petroleum			
Light Sweet Crude Oil, LLS	38.3	Spot	1989-2001
Motor Gasoline, NYH	39.1	Spot	1989-2001
Heating Oil, NYH	38.5	Spot	1989-2001
Natural Gas	78.0	Spot	1992-2001
Financial			
Federal Funds Rate	85.7	Spot	1989-2001
Stock Index, S&P 500	15.1	Spot	1989-2001
Treasury Bonds, 30 Year	12.6	Spot	1989-2001
Metals			
Copper, LME Grade A	32.3	Spot	January 1989-August 2001
Gold Bar, Handy & Harman, NY	12.0	Spot	1989-2001
Silver Bar, Handy & Harman, NY	20.2	Spot	January 1989-August 2001
Platinum, Producers	22.6	Spot	January 1989-August 2001
Agriculture			
Coffee, BH OM Arabic	37.3	Spot	January 1989-August 2001
Sugar, World Spot	99.0	Spot	January 1989-August 2001
Corn, N. Illinois River	37.7	Spot	1994-2001
Soybeans, N. Illinois River	23.8	Spot	1994-2001
Cotton, East TX & OK	76.2	Spot	January 1989-August 2001
FCOJ, Florida Citrus Mutual	20.3	Spot	September 1998-December 2001
Meat			
Cattle, Amarillo	13.3	Spot	January 1989-August 2001
Pork Bellies	71.8	Spot	January 1989-August 1999

Sources: Data from Commodity Futures Trading Commission. Calculations by Energy Information Administration staff.

Forward contracts have problems that can be serious at times. First, buyers and sellers (counterparties) have to find each other and settle on a price. Finding suitable counterparties can be difficult. Discovering the market price for a delivery at a specific place far into the future is also daunting. For example, after the collapse of the California power market in the summer of 2000, the California Independent System Operator (ISO) had to discover the price for electricity delivered in the future through lengthy, expensive negotiation, because there was no market price for future electricity deliveries. Second, when the agreed-upon price is far different from the market price, one of the parties may default ("non-perform"). As companies that signed contracts with California for future deliveries of electricity at more than $100 a megawatt found when current prices dropped into the range of $20 to $40 a megawatt, enforcing a "too favorable" contract is expensive and often futile. Third, one or the other party's circumstances might change. The only way for a party to back out of a forward contract is to renegotiate it and face penalties.

Futures contracts solve these problems but introduce some of their own. Like a forward contract, a futures contract obligates each party to buy or sell a specific amount of a commodity at a specified price. Unlike a forward contract, buyers and sellers of futures contracts deal with an exchange, not with each other. For example, a producer wanting to sell crude oil in December 2002 can sell a futures contract for 1,000 barrels of West Texas Intermediate (WTI) to the New York Mercantile Exchange (NYMEX), and a refinery can buy a December 2002 oil future from the exchange. The December futures price is the one that causes offers to sell to equal bids to buy—i.e., the demand for futures equals the supply. The December futures price is public, as is the volume of trade. If the buyer of a December futures finds later that he does not need the oil, he can get out of the contract by selling a December oil future at the prevailing price. Since he has both bought and sold a December oil future, he has met his obligations to the exchange by netting them out.

Table S2 illustrates how futures contracts can be used both to fix a price in advance and to guarantee performance. Suppose in January a refiner can make a sure profit by acquiring 10,000 barrels of WTI crude oil in December at the current December futures price of $28 per barrel. One way he could guarantee the December price would be to "buy" 10 WTI December contracts. The refiner pays nothing for the futures contracts but has to make a good-faith deposit ("initial margin") with his broker. NYMEX currently requires an initial margin of $2,200 per contract. During the year the December futures price will change in response to new information about the demand and supply of crude oil.

In the example, the December price remains constant until May, when it falls to $26 per barrel. At that point the exchange pays those who sold December futures contracts and collects from those who bought them. The money comes from the margin accounts of the refiner and other buyers. The broker then issues a "margin call," requiring the refiner to restore his margin account by adding $20,000 to it.

This "marking to market" is done every day and may be done several times during a single day. Brokers close out parties unable to pay (make their margin calls) by selling their clients' futures contracts. Usually, the initial margin is enough to cover a defaulting party's losses. If not, the broker covers the loss. If the broker cannot, the exchange does. Following settlement after the first change in the December futures price, the process is started anew, but with the current price of the December future used as the basis for calculating gains and losses.

In September, the December futures price increases to $29 per barrel, the refiner's contract is marked to market, and he receives $30,000 from the exchange. In October, the price increases again to $35 per barrel, and the refiner receives an additional $60,000. By the end of November, the WTI spot price and the December futures price are necessarily the same, for the reasons given below. The refiner can either demand delivery and buy the oil at the spot price or "sell" his contract. In either event his initial

Table S2. Example of an Oil Futures Contract

Date	Prices per Barrel: WTI Spot	Prices per Barrel: December Future	Contract Activity	Cash In (Out)
January	$26	$28	Refiner "buys" 10 contracts for 1,000 barrels each and pays the initial margin.	($22,000)
May	$20	$26	Mark to market: (26 - 28) x 10,000	($20,000)
September	$20	$29	Mark to market: (29 - 26) x 10,000	$30,000
October	$27	$35	Mark to market: (35 - 29) x 10,000	$60,000
November (end)	$35	$35	Refiner either: (a) buys oil, or	($350,000)
			(b) "sells" the contracts.	
			Initial margin is refunded.	$22,000

Source: Energy Information Administration.

margin is refunded, sometimes with interest. If he buys oil he pays $35 per barrel or $350,000, but his trading profit is $70,000 ($30,000 + $60,000 - $20,000. Effectively, he ends up paying $28 per barrel [($350,000 - $70,000) / 10,000], which is precisely the January price for December futures. If he "sells" his contract he keeps the trading profit of $70,000.

Several features of futures are worth emphasizing. First, a party who elects to hold the contract until maturity is guaranteed the price he paid when he initially bought the contract. The buyer of the futures contract can always demand delivery; the seller can always insist on delivering. As a result, at maturity the December futures price for WTI and the spot market price will be the same. If the WTI price were lower, people would sell futures contracts and deliver oil for a guaranteed profit. If the WTI price were higher, people would buy futures and demand delivery, again for a guaranteed profit. Only when the December futures price and the December spot price are the same is the opportunity for a sure profit eliminated.

Second, a party can sell oil futures even though he has no access to oil. Likewise a party can buy oil even though he has no use for it. Speculators routinely buy and sell futures contracts in anticipation of price changes. Instead of delivering or accepting oil, they close out their positions before the contracts mature. Speculators perform the useful function of taking on the price risk that producers and refiners do not wish to bear.

Third, futures allow a party to make a commitment to buy or sell large amounts of oil (or other commodities) for a very small initial commitment, the initial margin. An investment of $22,000 is enough to commit a party to buy (sell) $280,000 of oil when the futures price is $28 per barrel. Consequently, traders can make large profits or suffer huge losses from small changes in the futures price. This *leverage* has been the source of spectacular failures in the past.

Futures contracts are not by themselves useful for all those who want to manage price risk. Futures contracts are available for only a few commodities and a few delivery locations. Nor are they available for deliveries a decade or more into the future. There is a robust business conducted outside exchanges, in the over-the-counter (OTC) market, in selling contracts to supplement futures contracts and better meet the needs of individual companies.

An option is a contract that gives the buyer of the contract the right to buy (a call option) or sell (a put option) at a specified price (the "strike price") over a specified period of time. American options allow the buyer to exercise his right either to buy or sell at any time until the option expires. European options can be exercised only at maturity. Whether the option is sold on an exchange or on the OTC market, the buyer pays for it up front. For example, the option to buy a thousand cubic feet of natural gas at a price of $3.60 in December 2002 may cost $0.73. If the price in December exceeds $3.60, the buyer can exercise his option and buy the gas for $3.60. More commonly, the option writer pays the buyer the difference between the market price and the strike price. If the natural gas price is less than $3.60, the buyer lets the option expire and loses $0.73. Options are used successfully to put floors and ceilings on prices; however, they tend to be expensive.

Swaps (also called contracts for differences) are the most recent innovation in finance. Swaps were created in part to give price certainty at a cost that is lower than the cost of options. A swap contract is an agreement between two parties to exchange a series of cash flows generated by underlying assets. No physical commodity is actually transferred between the buyer and seller. The contracts are entered into between the two counterparties, or principals, outside any centralized trading facility or exchange and are therefore characterized as OTC derivatives.

Because swaps do not involve the actual transfer of any assets or principal amounts, a base must be established in order to determine the amounts that will periodically be swapped. This principal base is known as the "notional amount" of the contract. For example, one person might want to "swap" the variable earnings on a million dollar stock portfolio for the fixed interest earned on a treasury bond of the same market value. The notional amount of this swap is $1 million. Swapping avoids the expense of selling the portfolio and buying the bond. It also permits the investor to retain any capital gains that his portfolio might realize.

Figure S1 illustrates an example of a standard crude oil swap. In the example, a refiner and an oil producer agree to enter into a 10-year crude oil swap with a monthly exchange of payments. The refiner (Party A) agrees to pay the producer (Party B) a fixed price of $25 per barrel, and the producer agrees to pay the refiner the settlement price of a futures contract for NYMEX light, sweet crude oil on the final day of trading for the contract. The notional amount of the contract is 10,000 barrels. Under this contract the payments are netted, so that the party owing the larger payment for the month makes a net payment to the party owing the lesser amount. If the NYMEX settlement price on the final day of trading is $23 per barrel, Party A will make a payment of $2 per barrel times 10,000, or $20,000, to Party B. If the NYMEX price is $28 per barrel, Party B will make a payment of $30,000 to Party A. The 10-year swap effectively creates a package of 120 cash-settled forward contracts, one maturing each month for 10 years.

So long as both parties in the example are able to buy and sell crude oil at the variable NYMEX settlement price, the swap guarantees a fixed price of $25 per barrel, because the producer and the refiner can combine their financial swap with physical sales and purchases in the spot market in quantities that match the nominal contract size. All that remains after the purchases and sales shown in the inner loop cancel each other out are the fixed payment of money to the producer and the refiner's purchase of crude oil. The producer never actually delivers crude oil to the refiner, nor does the refiner directly buy crude oil from the producer. All their physical purchases and sales are in the spot market, at the NYMEX price. Figure S2 shows the acquisition costs with and without a swap contract.

Many of the benefits associated with swap contracts are similar to those associated with futures or options contracts.[1] That is, they allow users to manage price exposure risk without having to take possession of the commodity. They differ from exchange-traded futures and options in that, because they are individually negotiated instruments, users can customize them to suit their risk management activities to a greater degree than is easily accomplished with more standardized futures contracts or exchange-traded options.[2] So, for instance, in the example above the floating price reference for crude oil might be switched from the NYMEX contract, which calls for delivery at Cushing, Oklahoma, to an Alaskan North Slope oil price for delivery at Long Beach, California. Such a swap contract might be more useful for a refiner located in the Los Angeles area.

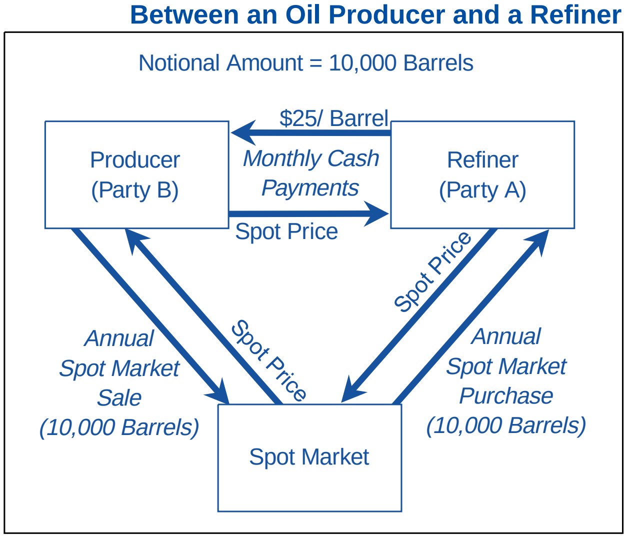
Although swaps can be highly customized, the counterparties are exposed to higher credit risk because the contracts generally are not guaranteed by a clearinghouse as are exchange-traded derivatives. In addition, customized swaps generally are less liquid instruments, usually requiring parties to renegotiate terms before prematurely terminating or offsetting a contract.

Oil and Natural Gas Markets: A Growing Role for Derivatives

Diversification and insurance are the major tools for managing exploration risk and protecting firms from property loss and liability. Firms manage volume risk—not having adequate supplies—by maintaining inventories or acquiring productive assets. Derivatives are particularly appropriate for managing the price risk that arises as a result of highly volatile prices in the petroleum and natural gas industries. The typical price risks faced by market participants and the standard derivative contracts used to manage those risks are shown in Table S3.

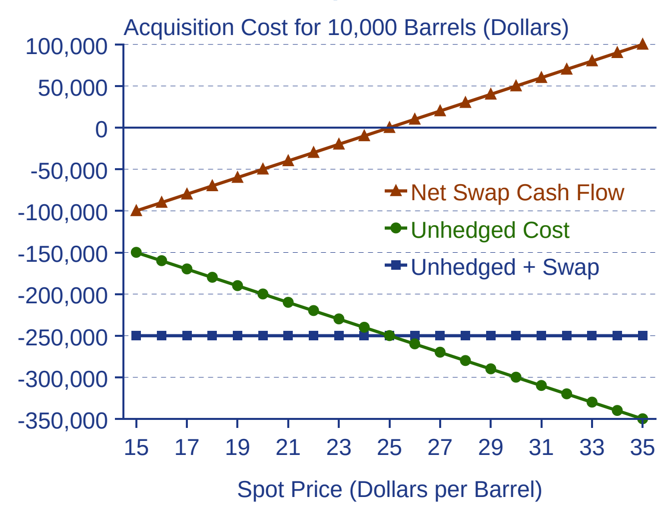
The growth in trading of petroleum and natural gas contracts has been tremendous. For example, the monthly volume of energy-related futures contracts on the NYMEX has grown from approximately 170,000 contracts per month in January 1982 to 7 million contracts per month in January 2000. Today, energy products are the second most heavily traded category of futures contracts on organized exchanges, after financial products. In addition to exchange-traded contracts, many energy companies enter into OTC forward contracts or swaps to manage price risk.

Figure S1. Illustration of Crude Oil Swap Contract Between an Oil Producer and a Refiner



Source: Energy Information Administration.

Figure S2. Crude Oil Acquisition Cost With and Without a Swap Contract



Source: Energy Information Administration

[1]A portfolio of a put and a call option can replicate a forward or a swap. See M. Hampton, "Energy Options," in *Managing Energy Price Risk*, 2nd Edition (London, UK: Risk Books, 1999), p. 39.

[2]Swaps and other OTC derivatives differ from futures in another functional respect that is related in part to their lack of standardization. Because their pricing terms are not widely disseminated, swaps and most other OTC derivatives generally do not serve a price discovery function. To the extent, however, that swap market participants tend to settle on standardized contract terms and that prices for transactions on those swaps are reported, it is potentially the case that particular swaps could serve this function. An important example is the inter-bank market in foreign currencies, from which quotes on certain forward rates are readily accessible from sizable commercial banks.

The Internet is responsible for the latest innovation in energy trading. In November 1999, EnronOnline was launched to facilitate physical and financial trading. EnronOnline was a principal-based exchange in which all trades were done with Enron as the counterparty. As a consequence, Enron's perceived creditworthiness was crucial to its ability to operate EnronOnline.

After the launch of EnronOnline, several other online exchanges quickly followed, including Intercontinental-Exchange (ICE), which was backed by major producers and financial services companies, and TradeSpark, which was backed by major electric utilities, traders, and gas pipeline companies. Both ICE and TradeSpark provide electronic trading platforms offering registered users anonymity for posting prices and executing trades. Unlike EnronOnline, they do not take trading positions. ICE offers swaps on crude oils other than Brent and West Texas Intermediate and on refined products in numerous locations, to complement the futures contracts trading of NYMEX and the International Petroleum Exchange (IPE). The bulletin boards also are doing a brisk business in physical trades, despite the fact that several have ceased operations in recent months.

Because natural gas pipelines (and electric power lines) have essentially no competitors, frustrated customers cannot buy supplies "off system." In addition, it is difficult to achieve competitive transmission pricing in networks. Changes in transmission charges (measured as the difference in prices between locations), therefore, do not necessarily reflect changes in marginal cost, nor do they reliably induce investment in congestion-relieving capacity. Over a given year, the variation in transmission charges to locations physically connected to Henry Hub can vary between one-half and twice the average charge itself. To the extent that the variation in transmission charges is solely the result of recurrent bottlenecks, new capacity could make transmission charges more predictable by relieving congestion. Until that happens, the uncertainty about transmission charges will make large trades hard to execute and limit the usefulness of derivatives for local markets.

All available evidence indicates that the oil industry has successfully used derivatives to manage risk. Natural gas derivatives based on the Henry Hub price are well established. For local gas markets where there is a predictable difference between the local price and the Henry Hub price, customers can use Henry Hub contracts with premiums or discounts to manage local price risk. Unfortunately, price differences are not predictable for many local gas markets, because natural gas (and electricity) markets are not integrated to the same extent as petroleum markets.

Derivative traders are competing vigorously for business, evidence that risk is being transferred to those who profit from bearing it at competitive rates. However, continuing problems with the reporting of natural gas price data and with pipeline transmission costs may be denying the benefits of derivatives to many potential users.

Table S3. Petroleum and Natural Gas Price Risks and Risk Management Strategies

Participants	Price Risks	Risk Management Strategies and Derivative Instruments Employed
Oil Producers	Low crude oil price	Sell crude oil future, buy put option
Petroleum Refiners	High crude oil price	Buy crude oil future or call option
	Low product price	Sell product future or swap contract, buy put option
	Thin profit margin	Buy crack spread[a]
Storage Operators	High purchase price or low sale price	Buy or sell futures
Large Consumers		
Local Distribution Companies (Natural Gas)	Unstable prices, wholesale prices higher than retail	Buy future or call option, buy basis contract[b]
Power Plants (Natural Gas)	Thin profit margin	Buy spark spread[c]
Airlines and Shippers	High fuel price	Buy swap contract

[a]Essentially, buy crude oil future and simultaneously sell product future.
[b]A basis contract fixes the transportation cost between Henry Hub and a local market.
[c]Buy natural gas future and sell electricity future.
Source: Energy Information Administration.

Electricity Markets: Limited Success for Derivatives So Far

The electricity generation industry is the latest to be deregulated, and participants have discovered that they are subject to wholesale price swings even greater than in the oil and gas markets. Before deregulation, electric utilities were guaranteed the ability to recover reasonable costs incurred in providing service to their customers. As a result, they had no need to hedge against unforeseen price risks. Consumers paid for stable prices in the form of higher average prices due to excess capacity, inappropriate technology, and inefficient operations.

As in the petroleum and natural gas industries, the opening of electricity generation markets to competition has exposed firms to greater price uncertainty, and market participants have tried to turn to derivative contracts to deal with the price risk. Unlike the oil and gas markets, derivatives in electricity markets have not met with a great deal of success. NYMEX began offering electricity derivatives in March 1996, and the Chicago Board of Trade and the Minneapolis Grain Exchange have also offered electricity derivatives. NYMEX had the most success, at one point listing six different futures contracts. Trading in electricity futures and options contracts peaked in the fall of 1998; however, by the fall of 2000 most activity had ceased. Today no electricity contracts are listed on the regulated exchanges.

Although futures and exchange-listed options failed in electricity markets, the trading of other derivative contracts continues. Commonly used electricity derivatives traded in OTC markets include forward contracts, swaps, and options. Aggregate data on the overall size of the OTC market in electricity-related derivatives do not exist; however, anecdotal evidence from the trade press and market participants indicates significant interest in their use and trading. Other, tangential derivatives for managing risk are being used in the industry, including emissions trading, weather derivatives, and outage derivatives.

Many of the current problems with electricity derivatives result from problems in the underlying physical market for electricity. Until the market for the underlying commodity is working well, it is difficult for a robust derivatives market to develop. Competitive electricity markets require competitive, robust transmission markets. A physical grid that has sufficient capacity to move large amounts of cheap power to force down prices in areas where they are high fosters competition; however, creating competitive transmission markets has proven particularly difficult. Competitive transmission charges are the marginal cost of moving power. Except in a few locations, transmission charges are currently set arbitrarily with no regard to the system's marginal cost. Many States actively discourage transmission of their cheap power to higher cost areas in neighboring States. Similarly, high-cost suppliers have not been anxious for lower cost supplies to be imported into "their" territory. The result is a balkanized marketplace, where trade does not discipline electricity prices.

In addition to structural obstacles and regulatory uncertainties, deregulation of electricity generation and the development of truly competitive spot markets are hindered by the nature of electricity as a commodity, the extreme volatility of wholesale prices, the balkanization of the existing spot markets, and a lack of price transparency.

Unlike many commodities, electricity is expensive to store. As a result, it is consumed the instant it is produced, and any excess is dissipated. Standard risk management textbooks provide numerous formulas for valuation of derivative contracts on storable assets, but none that apply to non-storable commodities. As a consequence, risk managers have difficultly valuing the risk associated with electricity derivatives.

The extreme volatility of wholesale electricity prices is due to the rapid increase in marginal generation cost for near capacity operations, combined with the lack of customer demand response to wholesale price changes. With very few exceptions, the retail price customers see does not vary with the wholesale price (marginal cost) of electricity. When demand and marginal generation costs are high, retail prices do not increase. Likewise, when demand and generation costs are low, retail prices do not decrease. Consequently, customers consume too much when supplies are stressed and too little when supplies are ample. Compared to a competitive market, electricity wholesale prices increase too much in periods of tight supplies and fall too much in surplus. Moreover, because retail price increases do not limit demand, regulated suppliers have to maintain expensive excess capacity to meet infrequent demand peaks.

The complexity of electricity markets and their limited price transparency have created an environment that allows market participants to guess the behavior of others and "game the system." The task of valuing (pricing) derivatives is further complicated to the extent that gaming affects prices. The California ISO rules explicitly prohibit such behavior.

Whether gaming in the California market reflected efforts to make money within the rules or efforts to affect prices outside the rules is currently an open question.[3] Analysts also continue to debate whether gaming affected California electricity prices.[4] Markets for derivatives would be adversely affected only if the market and futures prices of electricity changed unexpectedly because of gaming.

The Federal Energy Regulatory Commission (FERC) has taken two recent steps to encourage competitive wholesale electricity markets. On January 6, 2000, FERC published Order 2000 requiring ". . . all transmission owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate regional transmission institutions [RTOs] in a timely manner."[5] The purpose of this order was to encourage trade and competition by ensuring open, equal access to transmission within large areas. On July 31, 2002, FERC issued a notice of Proposed Rulemaking (NOPR) to establish a Standard Market Design that would apply to "all public utilities that own, control or operate transmission facilities . . . ."[6] This

[3]Federal Energy Regulatory Commission, letter to Sam Behrends, IV, Esq. (May 6, 2002), concerning "Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, FERC Docket No. PA02-2-000."

[4]Although most commentators accept that gaming increased prices in California, some analysts argue that the effects, if any, were small. See J. Taylor and P. VanDoren, *Did Enron Pillage California?*, Briefing Paper No. 72 (Washington, DC: The Cato Institute, August 22, 2002).

[5]Federal Energy Regulatory Commission, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000).

[6]Federal Energy Regulatory Commission, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 18 CFR Part 35, Docket No. RM01-212-000 (Washington, DC, July 31, 2002), p. 9.

NOPR would ensure that all areas have similar market rules, particularly in regard to spot electricity markets and transmission pricing.

If these initiatives are successful, they will go a long way toward making wholesale electricity markets more competitive. However, neither the Order nor the NOPR requires that retail customers be exposed to changing wholesale prices. Until then, either wholesale electricity prices will remain volatile or the industry will have to maintain significant excess capacity.

Accounting for Derivatives

There are a number of accounting issues related to derivatives that have existed and been debated for some time:

- How should a derivative be accounted for when its value at inception may be very small or zero but may vary greatly over a potentially long lifetime?
- If the derivative is being used to hedge a physical asset or commitment to buy or sell a physical asset, how should such hedged positions be accounted for?
- Once an accounting method has been agreed to, what is the appropriate methodology to use in valuing the derivative, particularly when long maturities are involved?

After 6 years of deliberation, the Financial Accounting Standards Board (FASB) issued Statement 133, *Accounting for Derivative Instruments and Hedging Activities*, in June 1998. Statement 133 was subsequently amended by Statement 137 in June 1999 and Statement 138 in June 2000. In developing these statements, the FASB identified four problem areas under previous accounting conventions:

- The effects of derivatives were not transparent in basic financial statements.
- Accounting guidance for derivative instruments and hedging activities was incomplete.
- Accounting guidance for derivative instruments and hedging activities was inconsistent.
- Accounting guidance for derivatives and hedging was difficult to apply.

The statement issued by FASB addresses each of these shortcomings. First, the visibility, comparability, and understandability of the risks associated with derivatives are increased by the requirement that all derivatives be reported as assets or liabilities and measured at fair value. Second, inconsistency, incompleteness, and the difficulty of applying previous accounting guidance and practice were reduced by the provision of guidance for all derivatives and hedging activities. Third, the statement accommodates a range of hedge accounting practices by permitting hedge accounting for most derivative instruments, including cash flow hedges of expected transactions. Further, the statement eliminates the requirement that an entity demonstrate risk reduction on an entity-wide basis to qualify for hedge accounting. These changes have the effect of reducing uncertainty about accounting requirements and may therefore encourage wider use of derivatives to manage risk.

Although Statement 133 is comprehensive and rigorous, it is also new. Its limits undoubtedly will be tested as publicly traded companies reporting to their shareholders gain familiarity with its complexity. At least one aspect of accounting practice—estimation of the fair value of derivatives—could prove problematical. Statement 133 holds that market prices should be used to measure fair value (mark-to-market valuation); however, when there are no market values for either the derivative or the underlying commodity (such as electricity that is to be supplied 5 years in the future), the guidance from the statement is more general than concrete. Market values are to be estimated, usually by means of models. Hence, the term “mark-to-model” is often used to describe these valuations.

Because Statement 133 does not restrain the firm’s choice of assumptions and models for making estimates of market values, different companies could report a wide range of values for the same derivative. The variance surrounding such estimates could be so large as to seriously impair their credibility. Indeed, “mark-to-model” has taken on a pejorative connotation. Valuation techniques might well be the subject of future opinions and standards issued by the accounting authorities.

Economic Impacts

There are a number of questions about the actual economic impacts of derivatives: Do they make the underlying energy commodity markets more volatile? Do they lower the cost of capital or encourage investment? Do they simply transfer private risk to the public?

The effects of derivatives on the volatility of underlying commodity prices have been one of the most intensively studied subjects in finance. One recent study reviewed more than 150 published analyses on the subject.[7] With a very few exceptions, the available research suggests that the use of derivatives has either reduced or had no effect on price volatility.

Derivatives are often used to hedge (insure) against adverse or ruinous financial outcomes. Firms incur costs when they are in financial duress or bankruptcy. To the extent that companies avoid such costs by hedging, the use of derivatives could increase the profitability of a

[7] S. Mayhew, “The Impact of Derivatives on Cash Markets: What Have We Learned?” Working paper, Department of Banking and Finance, Terry College of Business, University of Georgia (Athens, GA, February 2000).

given investment and make it more attractive. Consistent with that interpretation, several recent studies have found that firms more likely to face financial duress are also more likely to use derivatives to hedge. Smaller and medium-sized firms in the oil and gas industry that cannot limit price risk by integrating their operations and diversifying are particularly likely to benefit from the use of derivatives.

A 2001 study by Allayannis and Weston found that hedging activity increases the value of the firm. Specifically, they used a sample of firms that faced currency risk directly because of foreign sales or indirectly because of import competition. They found that firms with sales in foreign countries that hedged with currency derivatives had a 4.87-percent higher firm value (hedging premium) than similar firms that did not use derivatives.[8] Firms that did not have foreign sales but faced currency risk indirectly had a smaller, but statistically insignificant, hedging premium. The study also found evidence that after firms began hedging, their market value increased, and that after firms quit hedging, their value fell. Thus, there is evidence that hedging increases the value of the firm and, by implication, increases investment.

Although derivatives meet legitimate needs, they have also been implicated in tremendous losses. For example, Orange County, California, lost $1.7 billion in 1993; Metallgesellschaft lost about $1.3 billion in 1993 in energy trading; and in 1998 the Federal Reserve Bank of New York organized a rescue of Long Term Capital Management in order to avoid disrupting international capital markets. And in 2001 Enron became at that time the largest bankruptcy in American history. Enron was a large user and promoter of derivative contracts. Although Enron's failure was not caused by derivatives, its demise raised significant concerns about counterparty (credit) risk and financial reporting in many energy companies.

A reasonable question, then, is whether the benefits conferred by derivatives are sufficient to compensate for their occasional, but probably inevitable, misuse. Derivatives, properly used, are generally found to be beneficial. They can allow a firm to invest in worthwhile projects that it otherwise would forgo. In addition, they rarely if ever increase volatility in spot markets. Nor have they been shown historically in oil markets to be a major tool for market manipulation. As recent history makes clear, however, derivatives have been associated with spectacular financial failures and, possibly, fraud.

Prospects for Energy Derivatives

Derivatives have proven to be useful in the petroleum and natural gas industries, and they still are being used in the electricity industry despite the setbacks discussed above. They probably would be used more extensively if financial and market data were more transparent. Managers may limit derivative use because their presence in company accounts is troubling to some classes of investors. In addition, the lack of timely, reliable spot price and quantity data in most markets makes it difficult and expensive for traders to provide derivatives to manage local risks.

More fundamentally, the effectiveness of derivatives is dependent upon the nature of the underlying commodity market. Commodity markets with large numbers of informed buyers and sellers, each with multiple means of moving the commodity to where it is needed, support derivative markets. Derivatives for managing local price risks can then be based on the overall market price with relatively small, predictable adjustments for moving the commodity to local users. Federal energy policy has a significant impact on competitors' access to transportation (transmission), on the volatility of transmission charges, and therefore on derivative markets.

Price risk managers in natural gas markets have to contend with frequent, unexpected, and large changes in the difference between prices in physically connected markets. The effect of highly variable price spreads—the transmission charge—between areas is to subdivide the national market into multiple small pricing hubs. New pipeline construction and capacity additions should eventually promote more competition in the markets they serve by relieving the congestion that may account for some of the variation in price spreads. Until then, market fragmentation will make it hard and relatively expensive to protect against local price variation.

The prospects for the growth of an active electricity derivatives market are tied to the course of industry restructuring. Until the electricity spot markets work well, the prospects for electricity derivatives are limited.

[8]About 36 percent of the firms in this sample that had foreign sales did not hedge. Note that this study did not address the issue of why they failed to hedge if doing so would increase firm value. See G. Allayannis and J. Weston, "The Use of Foreign Currency Derivatives and Firm Market Value," *Review of Financial Studies*, Vol. 14 (2001), pp. 243-276.