Impact of Changing Fuel and Power Market Structures on Price Behavior

EPRI 1001197
GTI GRI-01/0163

Final Report, August 2001

Cosponsor
Gas Technology Institute
1700 S. Mount Prospect Road
Des Plaines, Illinois 60018

EPRI Project Manager
J. Platt

GTI Project Managers
J. Fay
R. Rinholm

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

The Brattle Group

Energy Ventures Analysis, Inc.

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CITATIONS

This report was prepared by

The Brattle Group
44 Brattle Street
Cambridge, MA 02138-3276

Principal Investigator
L. Borucki
R. Broehm

Energy Ventures Analysis, Inc.
1901 N. Moore Street, Suite 1200
Arlington, VA 22209-1706

Principal Investigator
A.M. Schaal
S. Thumb

This report describes research sponsored by EPRI and GTI.

The report is a corporate document that should be cited in the literature in the following manner:

Impact of Changing Fuel and Power Market Structures on Price Behavior, EPRI, Palo Alto, CA and GTI, Des Plaines, IL: 2001. EPRI 1001197 / GTI GRI-01/0163.

REPORT SUMMARY

Managing electricity and fuel price risks is a daily task in today's competitive markets. It is tempting to try to extract insights from past price behavior. This report analyzes short term price relationships for electricity and natural gas (e.g., price volatilities and correlations) but goes farther, examining overarching price regimes that provide the context for observed prices and required risk management. Spanning electricity, natural gas, oil, coal and emission allowances markets, the interpretation addresses market structures, regulatory factors, and supply-demand conditions.

Background

In response to growing industry interest in energy price behavior and implications for managing price risks, this project examines how changes in market structures have impacted price behavior within fuel and power markets. The report is part of a coordinated research effort between EPRI and GTI (formerly GRI) assessing restructuring and market impacts since 1996. A critical focus is on pricing regimes in restructured markets, especially electricity and natural gas, where heightened volatility is direct consequence of structural change. Leading up to this study are reports on restructuring *(EPRI TR-107614 and GRI 97/0109; EPRI TR-107900 and GRI 97/0108; EPRI TR-108999 and GRI 97/10289; and EPRI TR-111506 and GRI 98/0298),* natural gas price behavior *(EPRI TR-109001 and GRI 97/0290),* and an initial body of information on fuel and power price volatilities and convergence *(EPRI TR-111564).* With respect to forecasting, a report describes the practical use of structural modeling to simulate electricity and ancillary services prices and volatilities *(EPRI-LCG 1000571).*

Objectives

To examine changing energy price regimes, regional price behavior, and the interpretation and use of this information in fuel and electricity price risk management.

Approach

The research team proceeded along three fronts: (1) identifying major drivers defining pricing regimes in the fossil fuels and power over the past 20 years, (2) conducting a systematic analysis of regional price distributions, volatilities and correlations for electricity, natural gas and electricity-natural gas spark spreads, and (3) assessing implications of volatility for power plant operations and development. Key sources of data included *Power Markets Week* and *Natural Gas Week* for historical spot prices. Electricity prices referred to regional daily on-peak prices for a 16-hour block transaction. New York Mercantile Exchange futures prices were obtained from Bridge/CRB. The principal factors defining price regimes were supply-demand fundamentals and market structure-regulatory conditions. The principal time frame for detailed statistical analysis is 1995-1999, predating the price excursions of 2000 and 2001. Historical

volatility measures and approaches to electric-electric, gas-gas, and electric-gas correlations are delineated in the appendix.

Results

The report provides a comprehensive view of prices and price volatility of electricity and fuels from a statistical and historical precedent, and provides implications for power plant owners and fuel and energy managers. Among the results:

- Electricity is the last energy commodity to enter a transition to competitive markets from circumstances characterized by controlled or regulated prices or long term contracts. Regulatory and regional market structures greatly affect volatility and, for electricity as for the fuels, price risk management in non-regulated markets leads to taking shorter positions.
- Wholesale gas-electric price convergence is non-existent. Most regional gas markets have become integrated, with orderly regional basis differentials. The same is not at all true for power, where supply curves and other factors produce unstable and volatile spark spreads. Not surprisingly, tools for hedging gas price risk are more advanced than for electric. An example of locking in a spark spread is contrasted with the effects of trading on a forward month or trading daily.
- Analysis of price histories provides only a partial and largely unreliable profile of what the future holds. While underscoring the need to manage price risk, the analysis confirms that it is not possible to hedge all physical and financial risk. A wealth of contributing data include: weekly on-peak price distributions by season and region, monthly and seasonal regional power price volatilities based on daily data, effects of price levels, year by year regional correlations of weekly prices, electric and natural gas regional basis differentials, and numerous additional correlations tracked by year or by month.

Perspective

Going beyond the largely descriptive material developed to date, this study integrates all the key concepts of volatility into a single report and draws implications for risk management and fuel procurement. The report is an accessible treatment of information that typically resides in trading floors of national scope.

Keywords

Electricity, natural gas, coal, oil, and emission allowance markets
Regulation and competition
Energy prices
Price volatility
Price correlation
Risk management

ABSTRACT

Managing electricity and fuel price risks is a daily task in today's competitive markets. Increasing price volatility is characteristic of the progression of energy markets from regulated and controlled prices to non-regulated, competitive structures. Responding to growing industry interest in energy price behavior and implications for managing price risks, this report provides a comprehensive view of prices and price volatility of electricity and fuels from a statistical and historical precedent, and provides implications for power plant owners and fuel and energy managers. It first identifies the major drivers defining pricing regimes in the electricity, natural gas, oil, coal and emission allowance markets, focusing on events over the past 20 years as well as on regional differences. Next it provides detailed price analyses focusing on electricity and natural gas, developing weekly on-peak price distributions by season and region, monthly and seasonal regional power price volatilities based on daily data, effects of price levels, year by year regional correlations of weekly prices, electric and natural gas regional basis differentials, and numerous additional correlations tracked by year or by month. It concludes with a discussion of the implications of volatility for risk management and fuel procurement, using futures and forwards to lock in spark spreads and other techniques. As a general message, the results caution against extracting insights about future price profiles from past price behavior. Price information from the mid-1990s, methodological details on volatility and correlation measurement and on valuing opportunities from participating in multiple markets, and calculated price correlations are summarized succinctly in a set of appendices.

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1 EXECUTIVE SUMMARY

Overview

The ongoing deregulation of the electric industry since FERC's Order 888 has resulted in the development of price information that provides insight into the underlying structure and the behavior of market participants. However, deregulation has also brought unprecedented levels of price risk and has thereby created a strong need for market participants to gauge and account for energy market uncertainty in business planning decisions. This report reviews how recent past, and likely future, price volatility in fuel and power markets are interrelated and reflective of market structures. It also provides insight into how this price uncertainty has changed (or should change!) business practices, particularly for fuel managers and powerplant owners.

Foundational to the analysis and insights presented is previous work by the authors, sponsored jointly by EPRI and GRI, describing the changing structure of the industry since deregulation began. Those studies have also considered how other industries, notably natural gas, grappled with and responded to deregulation. The progression of these and several additional interrelated studies is shown in Figure 1-1.

Report Organization. Our report is organized under four broad, but related, topics.

- First we review the regulatory and market histories of other energy markets. This reveals distinct eras of pricing for fuels or electricity, with each pricing era being driven by a different set of fundamentals.
- Second, we dissect the US electric industry regionally to see whether any of its market areas reflect some of the features of past pricing regimes. This analysis provides a 'snapshot' of preconditions for potential price behavior in the electric markets, and as compared to the fuel markets.
- Third, we report on a very comprehensive statistical analysis of patterns (if any) to be found in regional volatility and correlation statistics on power and fuels.
- Finally, we provide some examples and suggestions for how to incorporate information on volatility into fuel and power plant management decisions.

Figure 1-1
Progression of EPRI-GRI/GTI and Related Studies

Fuel and Electricity Price Regimes

While there are numerous interesting and informative aspects concerning the historical pricing regimes for electricity and the fossil fuels used by that industry, the dominant conclusion from surveying past restructurings is that effective fuel management techniques are significantly different in a regulated market than in a competitive free market. Figure 1-2 provides a broadscale timeline for the transition between these two types of markets. When the structure of a market is determined by regulatory requirements, both fuel price and price risk, among other things, are largely controlled—at least in the short run. In this environment, reliability of supply often becomes the dominant concern, and as a consequence the long-term contract becomes the primary tool for managing fuel supplies and prices. In addition, in this type of environment there is often a focus on average cost-based pricing mechanisms, which itself discourages attention to and/or masks short-run perturbations in the markets. Planning tools and decision processes honed in this environment are unlikely to be suitable to a more dynamic restructured environment.

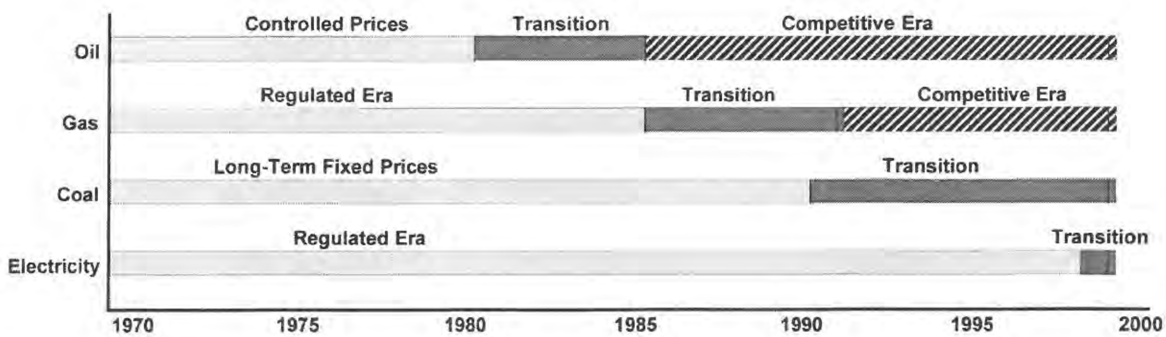


Figure 1-2
Timeline of Energy Price Regimes

On the other hand, in a free market structure prices are determined by changes in supply and demand. This is particularly important when either short-term supply or demand can fluctuate as it exposes the inherent volatility of prices and tends to make the management of price risk the dominant consideration of the fuel manager. The tools for managing price risk, particularly short-term price risk, are very different from the long-term contract used in a regulated market structure.

The access to cheap storage, or the lack of it, can significantly dampen or exacerbate the price volatility of the fuel. For the fuels reviewed in this report, market storage characteristics range from essentially no storage for electricity to very plentiful and cheap storage for coal, with both oil and natural gas having more expensive storage, though substantial capabilities to store. Electricity is technically storable, but not economically in bulk, i.e. at quantities equal to a significant percentage of total market supply. Storage became increasingly critical in natural gas as that market was unbundled and deregulated, and storage is handled through routine inventory policies for coal and oil. Storage will likely become more important eventually (over shorter time frames) in the electric industry, especially once the volatile wholesale prices become visible to retail customers.

In reaching these conclusions, the report reviews key factors affecting the price regimes of natural gas, coal, oil, electricity, and emission allowances (Section 2) and further evaluates the current regional attributes of these markets (Section 3). The most critical elements comprising a "price regime" are supply-demand fundamentals, i.e., the cyclic condition of generally "ample" of generally "tight" supplies, and the market structure reflected in the regulatory environment, which to date has moved more or less unidirectionally from regulated toward free-market conditions. Other factors affecting market structure include technology (such as the advances and implications of gas-fired combined cycle units), industry consolidations, and institutional factors. A sketch of the interplay of some of these factors is outlined in Figure 1-3, yet seldom are these determinants the same for each fuel at any given point in time. The report does not specify causative linkages, e.g., that tight supplies foster regulation and, with cyclic progression, eventual ample supplies foster opening of markets to enhance customer benefits. Instead the focus is on providing a cross-cutting view of pricing dynamics over the past 20 years and a systematic analysis of price behavior under increasingly competitive conditions in the late 1990s.

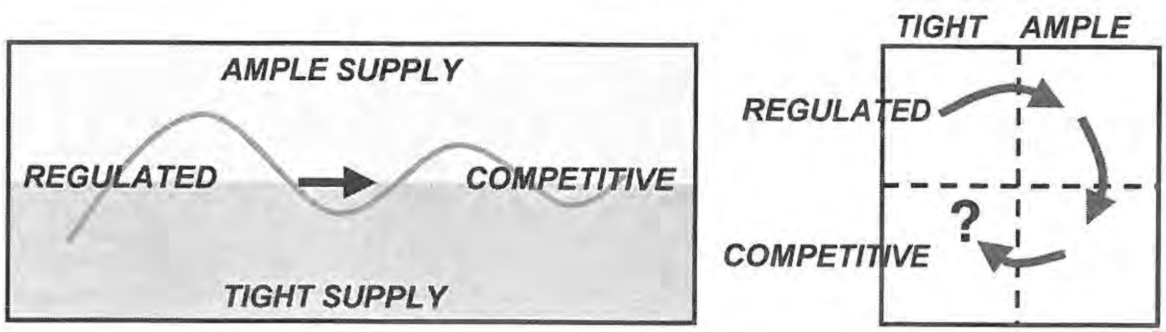


Figure 1-3
Interplay of Factors Affecting Market Structure and Price Regimes

Changing Electric Industry Price Regime

The historical powerplant financial model, as illustrated in Figure 1-4, emphasized reliability. As a result, price volatility was dampened. The changing powerplant financial model, as illustrated by Figure 1-5, reflects the changes brought about by industry restructuring as well as a maturation in the fuel supply and power delivery network infrastructure.

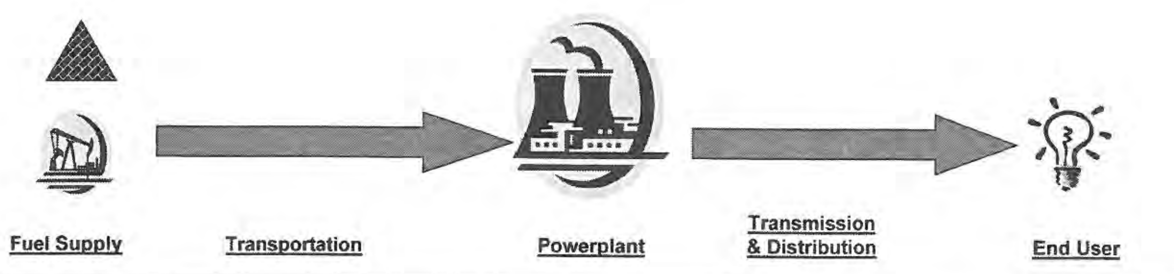


Figure 1-4
Historical Powerplant Financial Model

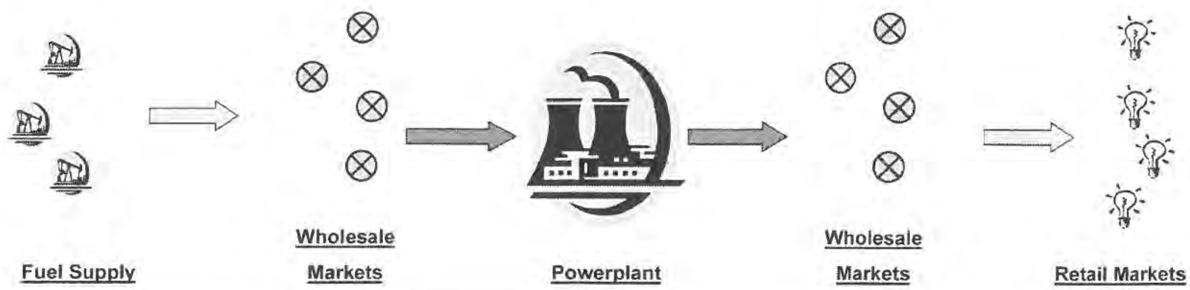


Figure 1-5
Post PURPA/888 Powerplant Financial Model

By virtue of industry unbundling, a great deal of coordination must be achieved in order to capture value. A non-inclusive list of interdependent decisions to consider includes:

- Where and how much fuel to purchase from one or more locations
- What routes to use to deliver fuels to plants
- When to operate (scheduling)
- Where to locate new assets
- Where to sell power, how to contract for any necessary electric transmission rights
- How to allocate capacity and energy to different electric product markets
- How far in advance to sell power and under what terms
- How far in advance to buy fuel
- How to adjust positions and commitments in light of changed circumstances

Electricity and Gas Price Volatility

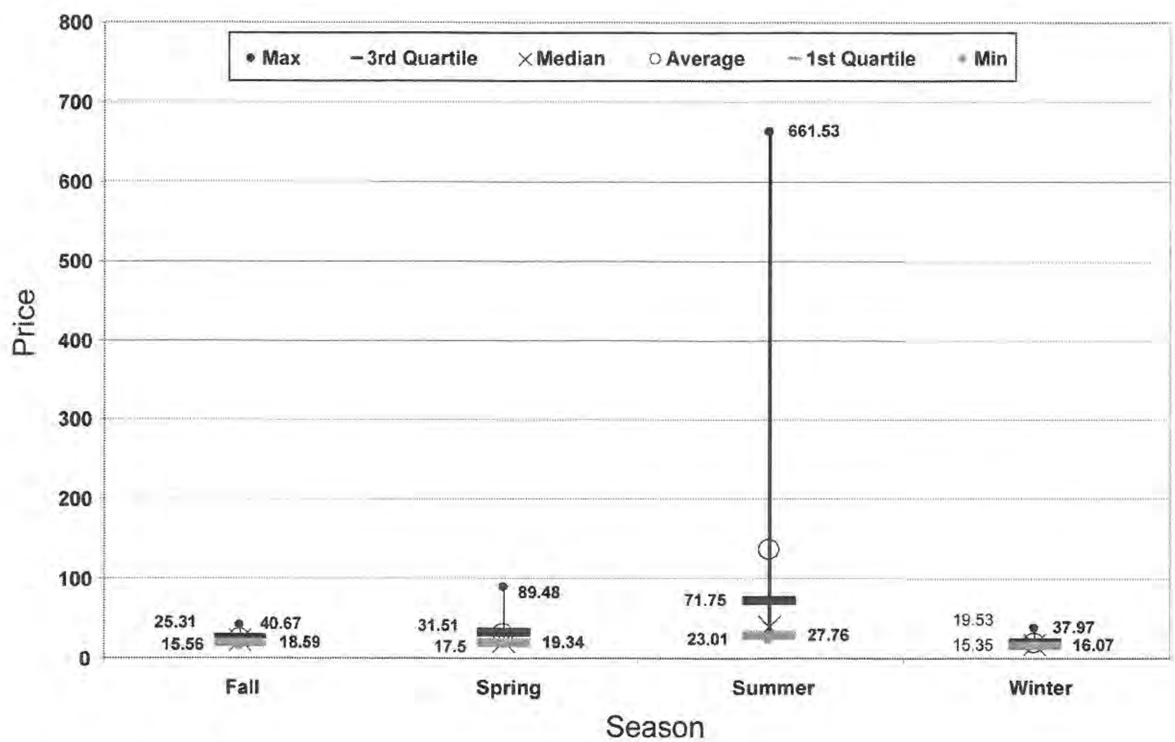
Volatility of electric prices is now a widely accepted fact of life, even acknowledged in newspaper articles as higher than any other industry or commodity. What is less well known is that there is considerable structure to this volatility, albeit a structure that is evolving rapidly with the rules and participation levels in the industry. Electric volatility cannot be characterized by any simple or single metric, as it varies significantly by season, locale, horizon, time of day, and the like—sometimes predictably, sometimes not. As important as understanding the volatility of electricity is, that awareness by itself is not enough because it is often the relationship of electricity to fuels or transmission that really matters.

Two products, electricity and gas, were reviewed in depth for their seasonal and annual volatilities, regional correlations and basis differentials. In addition, characteristics of the spark spread between electricity and gas were also reviewed in detail. The emphasis on gas reflects the fact that of the various fuels, gas markets are the most active and the most influential on electricity.

Electric-on-Electric

Figure 1-6 provides an example of the distribution of weekly prices for electricity by season in the Cinergy market region for 1998. This figure illustrates several characteristics common to regional electricity prices, including:

- Prices are generally not normally distributed. Instead, they are heavily skewed to the right during the summer.
- Price levels and volatility vary by time, season and duration—but not by any simple rule. For example, in Cinergy the 1997 fall volatility was greater than spring; yet in 1998 that relationship had switched. As a rule, volatility is higher when average prices are high.
- Regionally, prices tend to follow the same fairly contemporaneous price patterns as those of neighboring regions. That is, they are well correlated, suggesting either that adjacent regions face similar weather, and/or that trading between regions is fairly brisk.
- In the West, the strength of the correlations among market regions is high with only brief episodes of low correlations. This tends to drive the basis differentials to low levels that are roughly equivalent to the cost of transmission.
- In the East the strength of the correlations is less. More telling of the heterogeneity of eastern markets are the large basis differentials that can exist for prolonged periods of time during the summer for neighboring regions. This may be due to transmission constraints that make trading difficult.

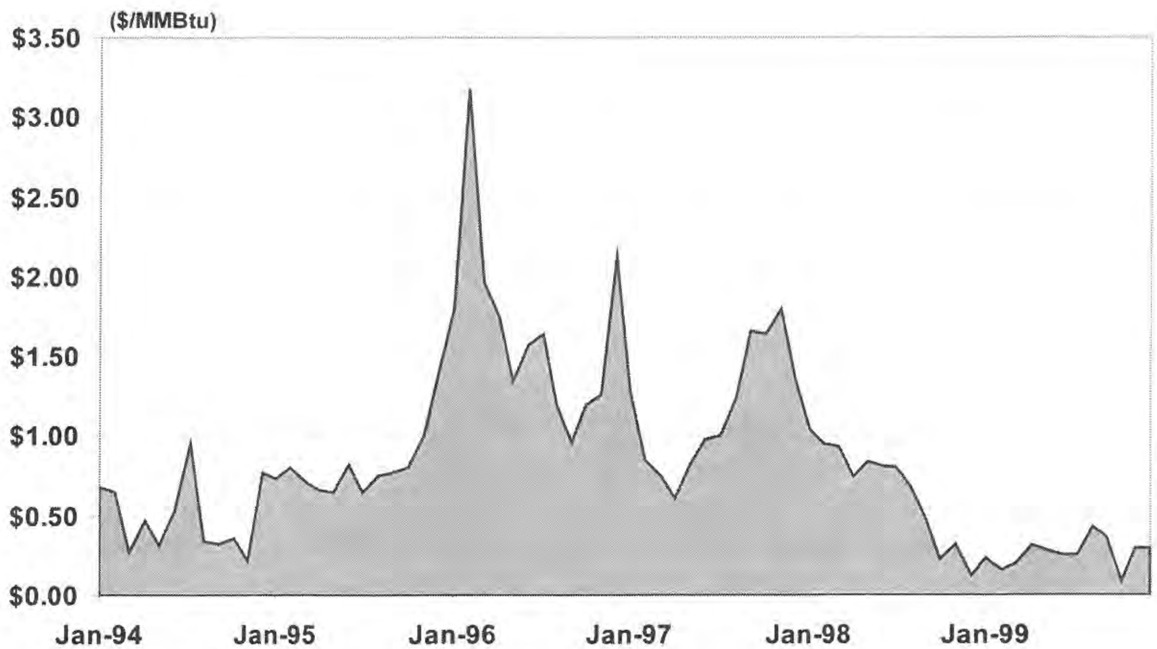


Source: *Power Markets Week*

Figure 1-6
1998 Weekly Peak Cinergy Prices Across Seasons

Gas-on-Gas

For natural gas, the North American market is better integrated than any time in the past. The effects of recently added pipeline capacity have significantly reduced the basis differentials between Henry Hub and western Canada (Alberta) gas prices, as shown in Figure 1-7. Prior to 1999 the Henry Hub/Alberta basis differential was highly volatile. Since that time this key indicator of an East/West split in the North American basis differentials has exhibited much less volatility. In the current era for natural gas, it is expected that regional gas price anomalies will occur during periods of stress, but that these anomalies will not persist for extended periods of time.



Note: Alberta price is the AECO-C Hub
Source: NGW and EVA

Figure 1-7
Henry Hub/Alberta Basis Differential

Gas-on-Electric Spark Spreads

The analysis showed that gas-electric wholesale price convergence is relatively weak to non-existent. There are several possible explanations. For one, gas is not yet the marginal fuel the majority of the time in most regions. Even where it is often on the margin, there are many gas units involved that span a broad range of efficiencies. More importantly, peak electric prices seem to reflect on implicit capacity scarcity value that has to do with reserve margins (or LOLP), not fuel type. Whatever the reasons, the instability of spark spreads is striking, as is their relatively low average value, except for a very efficient gas unit.

Implications for the Firm and the Fuel Planner

This new regime of increasing exposure to price volatility and market risk calls for an executive-level commitment to internally consistent return targets and risk for the individual firm. Even with the most sophisticated and expensive state-of-the-art risk analysis and planning tools, it is not possible to eliminate all risk for several reasons. First, despite the breadth of trading activity, most energy commodity markets are fairly illiquid, especially many months or years ahead. Thus, there may be no counter-party available to "buy" the risk. Second, the rules of the market have not been finalized. As they change, the value of positions will shift in uncompensated ways. Third, there is a lot of subjective judgment in using risk assessment parameters because they cannot be explained fully in terms of predictable, structural aspects of the industry, or in terms of extrapolation of past patterns. Accordingly, any single expectation of future value is likely to be wrong. This means that firms that participate in the electric markets must make judgments about their willingness to take the risk of losses in the pursuit of profits. Fuel planners must play a role in the analyses used to measure the risk, as well as in the design and pricing of services for generators that involve bearing some of the market risk.

Planning Horizons in the "New Age"

In this new age, planning and operational decisions can only capture value if they map into the kind of information and opportunities available over different time horizons.

Figure 1-8 traces the types of decisions that are made for the production of power at any one point in time back through its antecedents. This is represented by the electron (e^-) on the right side of the figure. As decisions involving the production of that electron are traced further back in time, those decisions necessarily involve larger and larger quantities of production at a future time (represented by the widening triangle). The planning horizon can be broken down into three different eras:

- Short-Term (6 months to hourly or less).
- Mid-Term (6 months to 2 years)
- Long-Term (+2 years)

Summary

The results presented here provide a comprehensive view of prices and price volatility of electricity and fuels from a statistical and historical precedent, and provide implications for powerplant owners and fuel managers. In a general sense, the results showed:

- ***Regulatory and Regional Market Structure Greatly Affect Volatility***: Key determinants are tightness of supply, grid congestion policies, spot and forward market price transparency, and entry.
- ***Not every Arbitrage Opportunity can be Realized***: Price departures that are very attractive on paper will often arise, but may not be actionable. Often transmission is constrained or electric markets are not liquid at the same points as gas. To close these gaps would require strategically placed entry by transmission or generation. Risk analysis can help shape such an entry strategy, but some risk must be taken by the firm willing to pursue the arbitrage opportunity.

- ***Wholesale Gas-Electric Price Convergence Is Non-Existent*:** While gas markets are integrated, the complexity of supply curves and price function in the electric markets results in unstable and volatile spark spreads.
- ***Profitable Participation Requires Understanding Risks and Alternative Statistics all along the Fuel-Electric or Electric-Electric Chain:*** There exist a number of strategies and tools yet it is unlikely that all physical and financial risk can be hedged. In particular, if one holds very long-lived "long" positions (like generators) or "short" positions (like discos), it will be almost impossible to find counter-parties to take the other side.
- ***Methods Exist to Quantitatively Evaluate Price Risks for Various Strategies, but There Is No Per Se Right Amount of Risk Exposure to Cover Versus Leave Open:*** Again, it is not possible to eliminate all price risk, and the risk of hindsight regret may block out all participation. Yet, the firm must choose where to hedge potential losses and gains in light of the fact that price histories can only provide a partial profile of what the future holds.
- ***Tools for Hedging Gas Price Risk Are More Advanced than Electric:*** For gas, the combination of storage and a somewhat standard set of Over-The-Counter (OTC) financial products provides for hedging mechanisms for individual needs. For electric, the OTC products are much less developed with issues of counter-party risk, extreme parameter instability (regarding the variables that describe the expected market conditions), force majeure, and lack of storage, providing less assurance that a particular hedging strategy will work as planned.

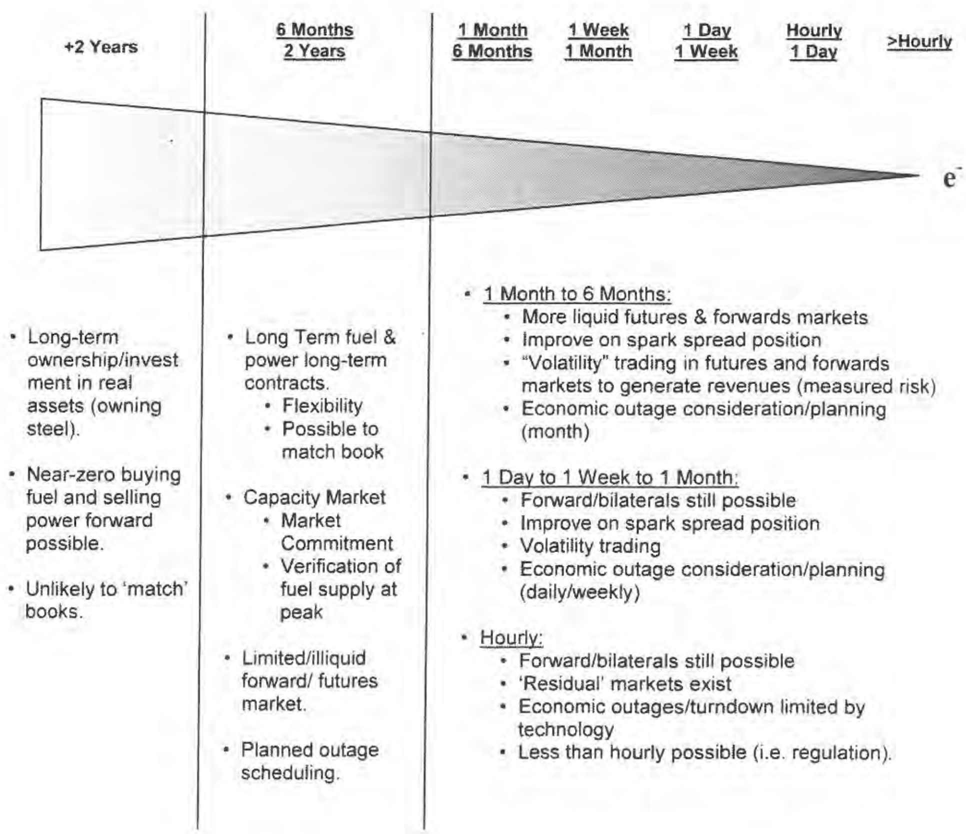


Figure 1-8
Planning Horizons in the Post PURPA/888 World

2
PRICING REGIMES

Overview

Fuel management practices tend to vary with changes in the pricing regime for a specific fuel. This section examines the historical pricing regimes for natural gas, coal, oil, electricity, and to a limited degree, the evolving market for emission allowances. This examination focuses on the principal determinants of these pricing regimes and the fuel management tools commonly used by the industry driving each regime. The conclusions to this section seek to find commonalities across the pricing regimes for these fuels and extrapolate what likely will be the best fuel management tools in the future.

In order to avoid a voluminous analysis of historical pricing regimes, this chapter primarily focuses on pricing regimes at the national level over approximately the last 20 to 30 years. Chapter 3 takes this analysis a step further by examining differences among the various regional markets. However, this regional analysis is primarily limited to a current assessment of regional characteristics and their differences.

Background

A pricing regime refers to a distinct era of pricing for a fuel, with each era being driven by a different set of fundamentals or a different market structure. In most instances, the tools used to optimize the profits and manage the risk associated with fuel prices vary between pricing regimes. As a result, it is useful to examine historical pricing regimes in order to gain some insight into the appropriate fuel management tools in future pricing regimes.

In general, there are two principal determinants of a pricing regime and hence, significant changes in these determinants can cause a shift from one pricing regime to another pricing regime. These broad categories of principal determinants apply to each of the fuel groups, although seldom are these determinants the same for each fuel at a given point in time. These two principal determinants are:

- **Supply and Demand Fundamentals:** Probably the most obvious determinant of a pricing regime is the underlying supply and demand fundamentals of the fuel. In a competitive market, price cycles (i.e., the shift from one pricing regime to another) are usually caused by changes in the supply and demand fundamentals. Furthermore, the appropriate tools for managing price risk and optimizing profits associated with price will vary as these fundamentals change, for example from excess supply to limited supply.

- **Market Structure/Regulatory:** The second major determinant of a pricing regime is the structure of the market for a particular fuel. While there are a number of factors that can affect the structure of a market, probably the most significant is regulation. The market structures for natural gas and electricity, in particular, have been heavily influenced by regulatory controls. In addition, the tools for managing price risk and optimizing profits associated with fuel prices vary significantly between a heavily regulated market and a free-market (i.e., non-regulated market). In general, the former tends to focus on taking a long position and the latter takes a short position. There are other factors that can affect market structure, and these would include technology (e.g., the gas-fired combined cycle unit), industry consolidations and institutional factors.

Among the fuel markets being examined by this report, there is considerable variation as to how and when these two principal determinants impact each fuel. Moreover, the pricing regimes haven't occurred simultaneously. As a result, it is beneficial to examine the historical pricing regimes for each fuel independently and then assess commonalties between these various fuel pricing regimes. While the time frame of this historical examination varies by fuel, the primary focus is on events over the last 20 years. The overall timeframe does not extend earlier than the 1930's.

Natural Gas

In its simplest terms, the history of natural gas pricing has been a long transition from heavily regulated market gas supplies with related services bundled into a single product for the end user, to a free-market commodity (i.e., minimal regulations) where gas supply and related services are unbundled. During the regulated era, because of the defined market structure, the optimum price management tool was a long-term contract (i.e., a long position). Subsequently, during the more recent free-market era, a variety of price management tools have evolved to deal with price volatility, and in general, market participants have focused on a short position. Further insights into each of pricing regimes for natural gas over the last several decades and the price management tools used in each regime are presented below.[1]

Market Structure Defined by Regulation

The early pricing regimes for natural gas were heavily impacted by regulation. A secondary factor affecting the price was the existence of excess natural gas supplies. Prior to the early 1970's as a result of the Natural Gas Act of 1938 (NGA) and the 1954 *Phillips* decision by the Supreme Court, nearly every aspect of interstate natural gas, including price, was controlled by federal regulation. During this pricing regime the entire structure of the interstate natural gas market was determined by federal regulation. The net result was that natural gas was sold to end users as a bundled product (i.e., supply, transportation and services were contracted for as a single unit). Consequently, the only parties that could contract for wellhead supplies of natural gas that would be used for interstate commerce were the interstate pipelines. The dominant

[1] For further discussion on the history of natural gas, consult GRI/EPRI, *Natural Gas Market Regionalization and Implications*, (GRI-97/0290 or EPRI TR-109001), March 1998, Section 2.

contracting practices of the interstate pipelines were to contract for gas supplies for the life of the field. Figure 2-1 provides an overview of natural gas prices since the enactment of NGA.

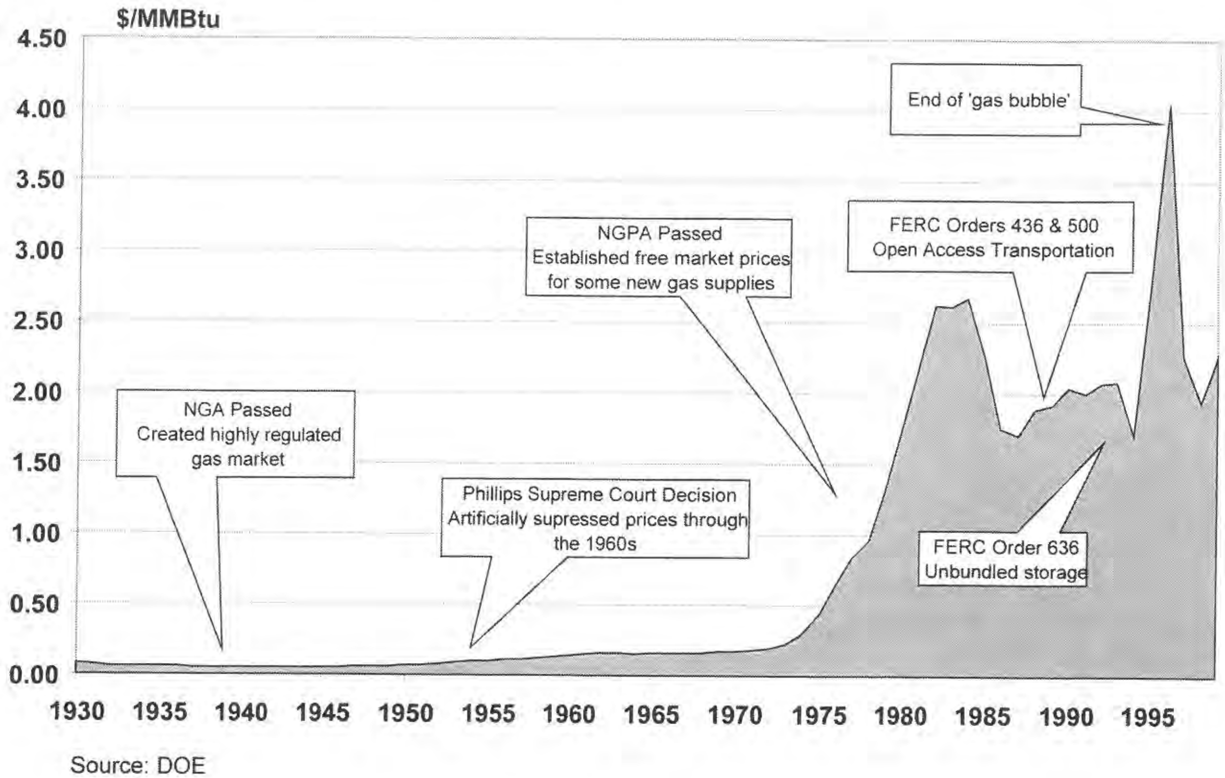


Figure 2-1
Henry Hub Natural Gas Prices, 1930-1999

This placed the pipelines in a long position for natural gas supplies, which was their primary objective at the time. With demand growth at five to seven percent per year, the price of natural gas set by federal regulation and the ability to pass through cost to one's customers, contracting practices focused on the long-term reliability of supply. In essence, the market structure was so fixed by federal regulation that reliability of supply was the only issue left to manage.

On the other hand, natural gas suppliers accepted this practice because there were excess natural gas supplies, which were a by-product of drilling for oil at that time. Since federal regulation controlled entry into the interstate pipeline segment of the industry, there was little competition among pipelines for supplies. Suppliers entered into long-term contracts in order to get their gas fields connected to a pipeline.

During this era, the standard practice was to engage in life-of-the-field contracts with gas prices defined by federal regulation. Furthermore, despite very large contracts specifying various items in great detail, contract negotiations focused primarily on the take-or-pay clause. Typically, pipelines agreed to take a minimum of 70 percent of available gas supplies. This practice created a very useful mechanism for managing the seasonal nature of natural gas demand (i.e., a 30 percent supply above the minimum requirement was available on call).

At the end user level, local distribution companies (LDC's) entered into long-term contracts with pipelines (e.g., 20 years) for a bundled product consisting of supplies, transportation and services (e.g., storage). In this market, which was structured by federal regulation, LDC's were also able to pass through costs to their customers. LDC's were primarily concerned with showing adequacy of supply in a growing market.

The long-term contract (i.e., 20 years to the life-to-the-field) was the primary tool used by most parties for managing supplies, price and risk. The regulated structure of the market eliminated almost every other factor as a consideration. Initially suppliers accepted this practice because of the lack of alternatives (i.e., competition) and the existence of excess supplies. However, this rigid market structure of the market eliminated any incentive to further increase supplies, which was the primary factor in the development of subsequent pricing regimes for natural gas.

Intrastate Markets—Post 1970

Federal regulations only applied to interstate commerce—natural gas sold within a state was excluded. The key intrastate markets for natural gas were Texas, Louisiana and Oklahoma, which together represented about 70 percent of U.S. production and accounted for about 30 percent of U.S. consumption prior to 1970. Distinctions between interstate and intrastate gas were very specific and precluded any commingling of supplies earmarked for one or the other market.

Initially, contracting practices in these key intrastate markets paralleled the practices of their interstate counterparts, primarily because there were excess gas supplies (i.e., no reason to pay a higher price or offer other terms than those set by federal regulations). However, with the lack of incentive to drill for gas, the underlying fundamentals of natural gas shifted from excess supplies to limited supplies and a new pricing regime was created in the intrastate market at the beginning of the 1970's.[2]

While intrastate markets continued to offer long-term contracts, now the annual price of gas supplies was negotiable. Because the interstate price of gas was fixed by federal regulation, this enabled intrastate markets to capture incremental gas supplies in a growing market. By 1975 intrastate gas prices were more than double those of the interstate market (e.g., $0.44 per MCF versus $1.10 per MCF, or $0.016 per cubic meter versus $0.041 per cubic meter).

While there were significant differences in the regulatory environment for the two markets, both primarily relied on the long-term contract with annual prices for managing gas supplies, albeit with differences in terms and conditions within each market. This commonality of contracting practices at this time was the result of both markets being focused upon reliability of supplies, which in turn was due to the underlying fundamentals of the gas market (i.e., limited supplies in a growing market). Furthermore, in both markets, contracting options for suppliers were limited to the pipelines—either interstate or intrastate.

[2] At the beginning of the 1970's U.S. gas demand was growing at about four to five percent per year, while proven reserves were declining at about three percent per year.

Significant to the pricing regime within the intrastate market was that it afforded the first price discovery within the gas industry, even though pricing was limited to the producing areas of three key states, was on an annual basis only and was of very limited transparency.

Market Structure under Revised Regulations (NGPA)

The limitation of new supplies in the interstate market eventually led to the natural gas shortages in the winter of 1975/1976. The U.S. response to this shortage was to revise natural gas regulations with the implementation of the Natural Gas Policy Act of 1978 (NGPA). While the NGPA dealt with the supply side of the equation, the Powerplant and Industrial Fuel Use Act (FUA)[3] was implemented at the same time to deal with the demand side of the equation by precluding electric utilities, but not non-utility generators, from using gas in new facilities for power generation. The FUA was amended in 1987 to allow electric utilities to use gas in new power generation facilities, thus leveling the playing field. These revised regulations preserved the regulated bundled structure of the interstate gas industry, and provided free-market prices for certain categories of new gas supplies.

These revised regulations leveled the playing field between interstate and intrastate pipelines competing for new supplies. The specifics of the NGPA pricing requirements were quite complex, establishing 17 price categories for natural gas, which were technically referred to as vintages. At the extreme, prices for these categories ranged from $0.20 to over $6.00 per MCF (i.e., $0.007 to over $0.224 per cubic meter), and even up to $10.0 per MCF (i.e., $0.373 per cubic meter) for the unregulated deep gas category (i.e., Section 107). A two tier pricing market consisting of new gas and old gas (from existing supplies) quickly developed within the interstate market. Interstate pipelines blended the costs of their low-cost existing gas supplies with the much higher-cost new contracts for gas. This provided their customers with a weighted average cost of gas (WACOG), which simplified a very complex pricing system for the consumer.

During this pricing regime, the primary tool for managing natural gas supplies remained the long-term contract. This was due, in part, to the continuation of the bundled structure in the industry caused by regulation, and the continued focus on reliability of supplies because of limited gas supplies (i.e., at least in the near term). Importantly, during this pricing regime meaningful price discovery for natural gas began to evolve throughout the nation, although it was limited to an annual price and was not very transparent.

By 1983 the competitive bidding for new supplies under the perception of limited gas supplies caused the price of new gas supplies to increase so much that demand began to decline (i.e., eventually demand declined 20 percent). By itself this resulted in a new price regime for gas because of the change in the fundamentals of supply and demand, however at about the same time the regulatory structure of the industry also changed.

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[3] The NGPA and FUA were two of the five components of the National Energy Act of 1978. The other components were the Energy Tax Act, the Public Utility Regulatory Policies Act and the Energy Conservation Act.

Spot Market for Gas: Excess Supply

In 1984 the Federal Energy Regulatory Commission (FERC) took the initial step to unbundle the natural gas industry when it issued Order 380. This initial order, which eliminated gas costs from the pipeline minimum bill, in essence enabled customers (i.e., LDC's) to break prior commitments with pipelines and shop for the least expensive gas supplies. This represented a significant change in the structure of the industry and quickly affected contracting practices throughout the industry. It required several court cases and a series of other FERC orders[4] over a period of several years to fully unbundle the industry, so that gas supplies would be sold to the final consumer independently from transportation and other gas services, such as storage.

This restructuring of the gas industry significantly changed the approach of contracting for natural gas supplies and caused the industry participants to directly manage for the first time price risk, in addition to gas quantities, transportation and other gas services. In addition, this restructuring also impacted the fundamentals of gas supply. While the industry already had excess supplies because of declining demand, the FERC orders resulted in a significant volume of 'released gas' appearing on the market. This 'released gas' was an artifact of the regulated era for gas when take-or-pay contracts, in essence, withheld approximately 30 percent of supplies from the day-to-day market. Contract negotiations between suppliers and pipelines resulted in the release of these excess supplies, as a revenue mechanism for suppliers and to minimize potential liabilities for pipelines. This was the first step in pipelines completely unbundling gas supplies from transportation. This 'released gas,' in combination with the excess supply due to declining demand, was the genesis of the 'gas bubble,' or excess deliverability, that lasted for approximately 10 years.

For industry participants managing the transition from the prior pricing regime to a new pricing regime based upon unbundling, the industry was a challenge to say the least. Disputes over gas contracts developed in one pricing regime but still in effect in another price regime, primarily between producer and pipeline, led to court cases involving in some instances huge settlements. It also resulted in some companies having to declare bankruptcy (e.g., Columbia Gas), as their strategies for managing this transition were not as successful as those of other entities.

This restructuring of the industry resulted in the birth of the spot market for natural gas[5] and significant revisions in gas contracting practices. For example, contract terms initially declined from long-term to annual and then to seasonal and/or monthly and eventually to daily purchases of gas supplies. In addition, a new set of tools evolved to manage gas prices and gas price volatility.[6] Probably the most important of these was the creation of the NYMEX futures market

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[4] These FERC orders include Order 436 (1985), which was eventually perfected as Order 500 (1987), and Order 636 (1992). During the same time frame NGPA prices were decontrolled in a series of steps (i.e., January 1985, July 1987, July 1989 and January 1993). The decontrolling of NGPA prices was somewhat academic as the prevailing market prices were below regulatory ceilings.

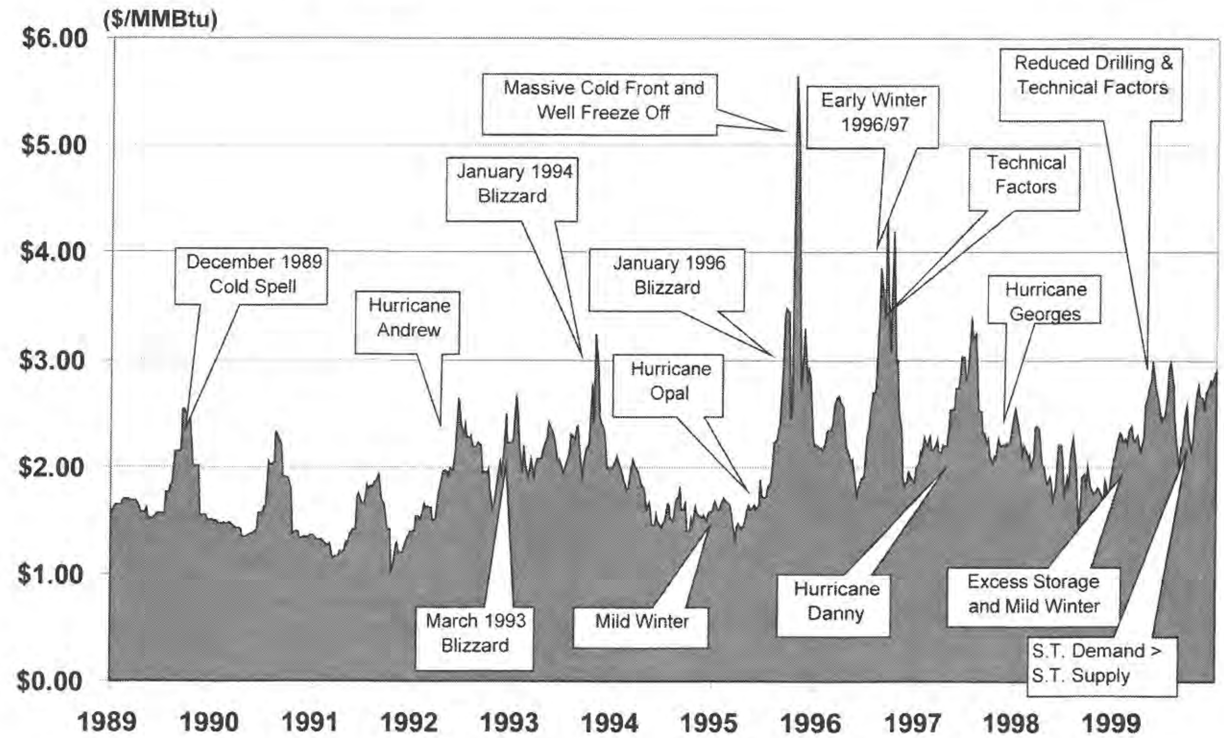
[5] See GRI/EPRI, *Natural Gas Market Regionalization and Implications*, (GRI-97/0290) or EPRI TR-109001, March 1998 for a more complete discussion on the evolution of the spot market for natural gas.

[6] The tools and their usefulness are discussed in depth in Section 4.

(1992). Also, this restructuring resulted in the evolution of a series of well-tracked, liquid, market hubs, which quickly revised the valuation process for near-term transportation services within the industry.

The other attribute of this pricing regime was significant excess gas supply (i.e., the "gas bubble"). During the initial stages of this transition to a competitive, non-regulated,[7] spot market for gas, excess supply resulted in a downward movement in gas prices and suppressed the inherent volatility in the price of this commodity.

Subsequently, the volatility and hence the price risk associated with gas began to materialize, particularly when unusual weather events occurred (see Figure 2-2). This volatility reached a peak during 1996 and 1997 as a result of a tightening of the overall supply and demand balance, and the unusual weather during the winters for these two years. The industry's ability to manage price risk during such periods steadily progressed during the first decade of the evolution of the competitive spot market for natural gas.



Source: NGW

Figure 2-2
Henry Hub Natural Gas Price Weekly Data

Another attribute of the change that the industry was going through at this time, albeit a secondary effect, was change in technology. The change in technology accelerated the industry's

[7] The transportation section is still under FERC regulation, although a secondary market for transportation does exist.

ability to make the transition from one price regime to another, and included the acceleration of demand increases because of the adoption of the highly efficient gas-fired combined cycle unit, and the capability of the industry to offer a wider variety of gas related services due to changes in storage technology (e.g., salt dome storage in the market area and the horizontal well Salternatives storage facilities). The rapid adoption of combined cycle technology, while influencing the gas industry, is considered part of the restructuring of the power industry and the regulatory changes that occurred within that sector.

During this pricing regime, industry participants (i.e., buyers) have, for the most part, adopted a short-term position on natural gas supplies, in order to better manage price risk. This is in sharp contrast to the reliance on long-term contracts during the regulatory driven price regimes for gas.

Spot Market with Limited Supply: An Untested Combination

The spot market for natural gas, which is still a relatively young industry, in a very broad sense has gone through three phases:

- **1984-1994:** Excess deliverability (i.e., the Gas Bubble), which occurred primarily because of a transition from a regulated to a deregulated industry. There was considerable downward pressure on gas prices during this phase.
- **1995-1999:** Gas supply and demand remained in balance. Most of the volatility in gas prices during this phase was attributable to weather events.
- **2000-?:** It appears that short-term increases in gas supply will not be able to keep pace with short-term increases in gas demand. During this phase, there will be significant upward pressure on gas prices.

This latter phase has only just begun, and there is considerable industry debate over how long it will last because of a number of imponderables, such as whether winter demand will be high or low. Some industry observers see this phase lasting three to five years before short-term supply and demand are back in balance. At present, the only empirical evidence of how the industry will adapt to this most recent phase in the spot market for gas has been to increase prices substantially with prospects for even higher prices.

While some argue that these higher prices will stimulate increases in supplies, if in fact the supply and demand balance does become tight for an extended period, greater focus on reliability of supplies could renew interest in longer term contracts for gas supplies. If this occurs, it will likely represent only one part of a gas portfolio, which balances both price risk and reliability of supply concerns. However, the industry likely will not return, without massive re-regulation, to its prior nearly 100 percent dependence on long-term contracts.

Coal

Coal has several distinguishing characteristics, including the fact that this fuel lacks homogeneity. Indeed, there are immense varieties of coal with boilers designed to only burn certain types of coal. This specific characteristic of coal, more than any other feature of this fuel, sets it apart from the other fuels analyzed in this report. Historically, this characteristic of coal has influenced coal buyers to enter into long-term contracts for coal supplies that meet very specific requirements. Thus, throughout much of the history of coal, the fuel buyer has taken a long position with respect to fuel supply. As a result, the major objectives of these fuel buyers were to find: (a) supplies that could meet the required specifications and (b) parties that were qualified to enter into long-term contracts (i.e., financial strength).

Within this broad framework for coal there have been several pricing regimes, each with their own characteristics. As was the case for the other fuels discussed in this report, both regulation and supply and demand fundamentals were the major determinants of these coal-pricing regimes.

Pre-Late 1970's: Supply Limitations and Financial Requirements

Prior to 1960, the reduction of residential coal use for heating led to a decline in U.S. coal consumption. A sharp increase in electrification and new coal-fired power plants within the electric utility industry spurred two to three percent per year demand growth between 1960 and the late 1970's. At the same time, new mining regulations, primarily concerned with safety, lowered productivity in the mining industry, which reduced supply. As a result, this was an era of growing demand and limited supplies, although it was relatively easy to open a new mine, particularly if one had a long-term supply contract.

The focus on long-term contracts during this era by both buyers (in order to ensure adequate supply of a particular type of coal) and sellers (beneficial for opening new mines), was encouraged, if not mandated, by the financial community. Among the firms building new coal-fired powerplants were municipalities and regional financial authorities (RFA's) which did not have the financial wherewithal of the larger investor owned utilities. In order for these and similar entities in the power industry to gain financing for large powerplant projects, financial institutions required long-term supply contracts to assure reliability of supply and supposedly minimize price risk.

While the terms and conditions[8] of these long-term contracts were later found not to be flexible enough to meet changing market conditions (leading to years of litigation in the 1980's), during this pricing regime, the long-term contract was the primary tool used to manage coal supplies and prices. A contributing factor was the view of many industry participants at that time that coal prices would increase faster than inflation. As a result, many contracts excluded price reopener provisions in order to lock in the price of coal, albeit in hindsight this was a relatively high price.

Powder River Basin

A result of the development of railroad transportation to the region, the development of the Powder River Basin coal supply in the early 1970's marked a tuning point in the dynamics of coal supply in the U.S. It took almost 20 years before this remarkably endowed region (thick, shallow, low-sulfur coal beds) would impact significantly the supply and demand fundamentals of the industry. Initially the relatively high rail rates from this supply area (i.e., up to 80 percent of the delivered price of this coal) limited the market for Powder River Basin coal. However, in 1984 competition between the railroads developed when the UP/CNW entered the basin. Over time this competition led to declines in rail rates and expansion of the market that could be served by Powder River Basin coal. The passage of the Clean Air Act Amendments in 1990

[8] This is particularly true of the 'cost plus' contracts that were signed during this era.

accelerated the rate of this expansion because of the lower sulfur content of Powder River Basin coal.[9]

Since the development of this supply source occurred over a significant period of time, it is difficult to establish a specific pricing regime directly linked to this event. Instead, it is interlinked with other events that shaped coal-pricing regimes. However, its impact has been significant in changing the structure of the coal market, which is the reason for its separate identification, and it has demonstrably affected the competition of coal generation and power prices in much of the U.S. With the penetration of the Powder River Basin coals, the industry has been able to develop a large volume of fairly homogeneous coal. This factor has enabled the industry to consider alternative contracting practices (e.g., shorter-term contracts) as more routine, rather than as a niche opportunity or on a supplemental basis. Furthermore, because of both the large volumes and homogeneous nature of Powder River Basin coals, the industry focus shifted more heavily to the pricing of the fuel rather than the unique specifications of the coal.

Mid-1980's: PURPA Units

During the mid-1980's there was a shift in the supply and demand fundamentals in the industry, creating an era of excess supply. This shift lessened industry dependence on long-term contracts, however, a regulatory event also occurred that pushed a segment of the coal industry to rely almost exclusively on the long-term contract to manage coal supplies and prices. This event was the Public Utility Regulatory Policies Act of 1978 (PURPA). Coal-fired powerplants that were built under the PURPA guidelines (i.e., approximately 10,000 MW)[10] were generally required to obtain long-term supply contracts by financial institutions. These units were developed by independent power producers, most of whom had limited financial wherewithal. As a result, the financial institutions pushed these firms to obtain long-term contracts for supply. This situation was very similar to that which occurred in the prior decade for municipalities and RFA's, and represented a continuation of the long-term contract as the primary tool to manage coal supplies and prices, at least within a submarket of the coal industry.

Mid-1980's: Changing Fundamentals and Contract Renegotiations

Since the early 1980's excess supply has dominated the fundamentals for the coal industry. The two key factors behind this shift to excess supply were: (1) significant improvements in productivity within the industry due to improvements in mining technology, economics of scale associated with larger equipment and a host of changes in labor practices, and (2) excess capacity at newer mines. In many cases, the latter occurred as a result of producers being able to generate more from the mine than called for under the original long-term contract(s) for which the mine was developed when it was opened in the prior time period. In an effort to optimize profits, producers attempted to sell this production in the evolving shorter-term market for coal. This

[9] The expansion opportunities of Powder River Basin coal are presented in EPRI, *Impact of Powder River Basin Coal on Powder and Fuel Markets* (TR-10900), July 1998.

[10] Edison Electric Institute, *Non-Utility Sources of Energy*, 1998. The key period of contracting for coal supplies by these units was between approximately 1982 and 1988.

event is similar to the 'released gas' phenomenon that was a critical component in the initial establishment of the spot market for natural gas.

The second, and potentially more far reaching, development during the 1980's was the utility-led re-negotiation of higher priced long-term contracts once it became apparent that the market price of coal was below the levels specified in long-term contracts. Key factors that contributed to this downward pressure on coal prices included improvements in coal mining productivity, new mining technology (e.g., longwall and surface) and mining industry consolidations. While the electric utility industry had taken a long position for fuel supply in the 1970's, in hindsight this proved to be an inadequate mechanism for managing price risk. Although new tools likely will evolve to aid in managing price risk in the future, the utility industry relied on contact re-negotiations, some of which were very contentious, as a means to correct the initial inadequate handling of the price risk for this fuel.

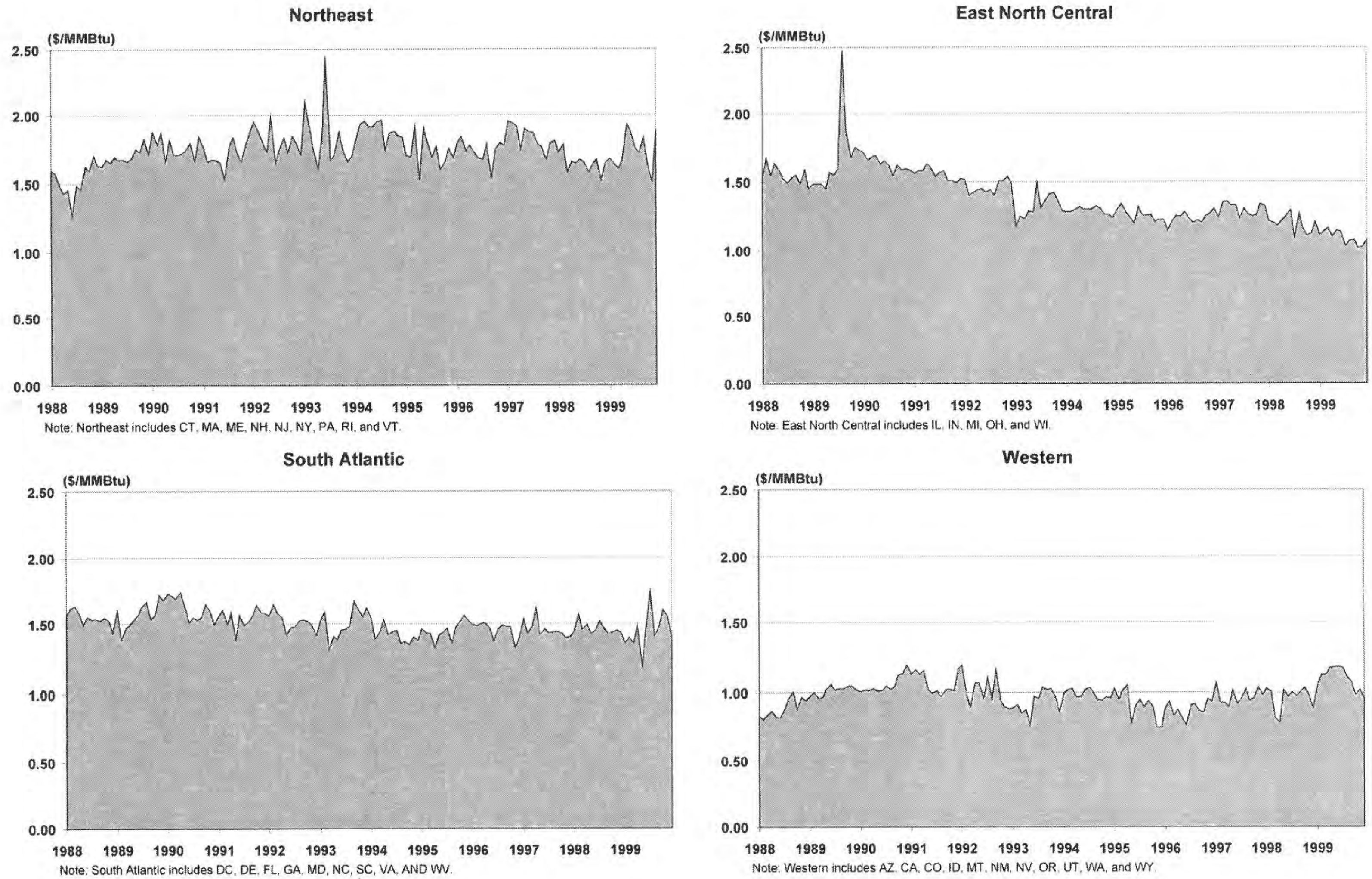
Current Market

The combination of the development of excess supply and the sharp reduction in the development of new powerplants, in order to curb demand growth, resulted in the industry adopting shorter-term contracting practices (e.g., three years). In addition, some participants who consume some of the more uniform coals (e.g., Powder River Basin and Central Appalachian coals) have been able to take advantage of the excess supply situation to purchase supplemental amounts of coal, even on a monthly basis. This has enabled these participants to widen their contracting practices for managing coal supplies and prices, such that they now have a portfolio of contracts with a variety of time horizons.

This evolution to a shorter term set of contracting practices, which significantly alters price and risk management practices, is a significant step for the industry. However, a true spot market for coal has not yet developed. Similarly, a forward market for coal has only just been established (launched by NYMEX and based upon Huntington, WV deliveries, in July 2001, postdating the data compiled for this report). Nevertheless, the volatility of cash coal prices has increased in recent times due to the increased focus on shorter term contracting practices, as illustrated in Figure 2-3, which illustrates spot delivered coal prices for several regions, prior to the 2000/01 price run-ups.[11] The two spikes in the regional coal prices presented in Figure 2-3 (i.e., August 1989 for the East North Central and June 1993 for the Northeast) represent data anomalies rather true price volatility. In both instances, a single reported price greatly skewed the average price for that month.

While this pricing regime has primarily reflected shifting supply and demand fundamentals, regulatory changes also have had a significant influence. The reduction in the growth rate of coal demand is largely the result of a series of environmental regulations to reduce power plant emissions.

[11] A further discussion of the limited volatility in coal prices is contained in EPRI, *Fuel and Power Price Volatilities and Convergence* (TR-111564), May 1999.



(1)Delivered Prices
Source: FERC 423 Data

Figure 2-3
Regional Coal Spot Prices (Delivered), S02<1.2 lb/mmBtu (<0.7% S)

Oil

Oil is the largest cash commodity in the world and is traded on an international basis. This latter characteristic makes it truly unique among the fuels reviewed in this report. U.S. regulations, while having some impact on petroleum products (e.g., gasoline), currently have little or no impact on crude oil.

While there is a long and rich history on the pricing regimes for crude oil, much of it is primarily of academic interest and is only briefly addressed in this report. Figure 2-4 provides an annotated assessment of oil prices over the last thirty years.

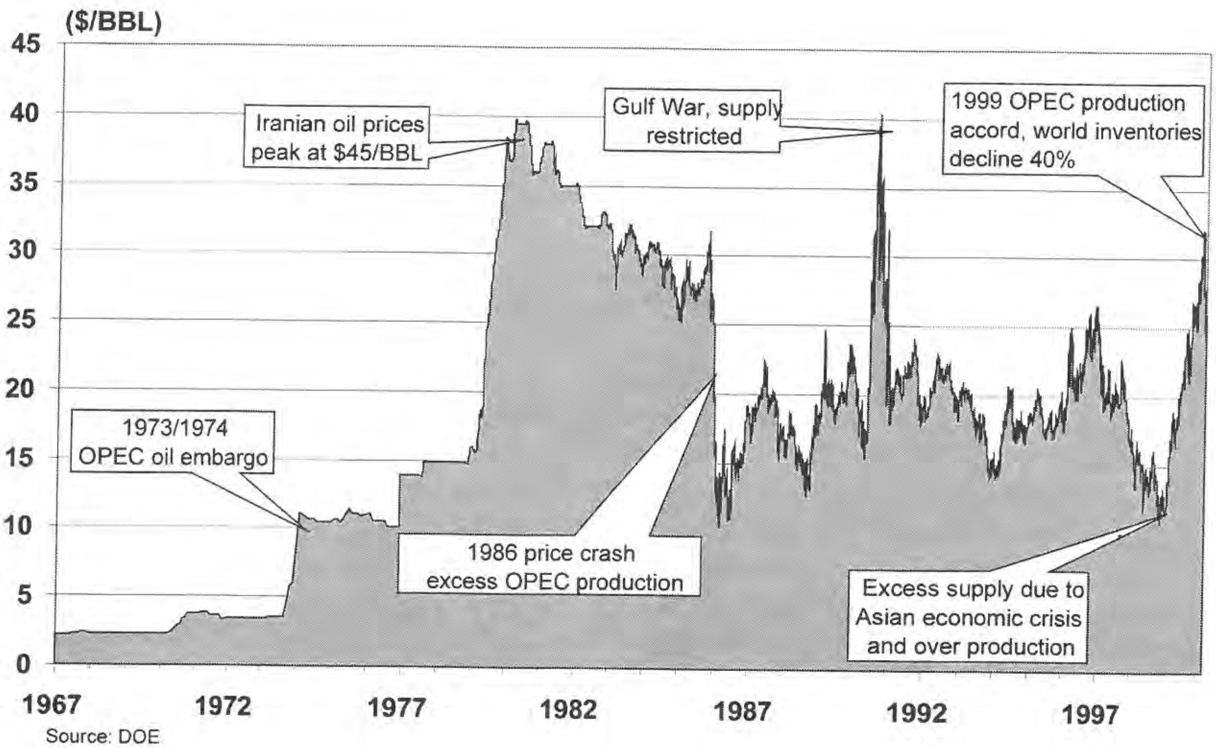


Figure 2-4
West Texas Intermediate Crude Oil Prices, 1967-1999

Historical Perspective

Historically, the oil industry had been noted for a series of boom/bust cycles as first one, and then another, new discovery resulted in significant excess supplies. This caused considerable fluctuations in the price of crude oil. Post World War II, the first significant effort to stabilize (i.e., control) crude oil prices was by the Texas Railroad Commission (TRC). At that time, the U.S. was the largest producer of crude oil in the world and had substantial excess capacity. The TRC regulated the volumes each producer could generate in the state with the greatest production within the U.S. This system was effective until about 1970 when spare capacity in the

U.S. disappeared and the U.S. began to rely on oil imports. There were other regulatory phenomena along the way that influenced the overall structure of the market—for example import quotas, which lasted from the 1950's to 1973.

The next major effort to control oil prices occurred in the international arena with the birth of OPEC (1973). This effort resulted in substantial increases in the price of crude oil, as world supply and demand fundamentals had shifted to a relatively tight supply and demand balance, particularly when a small amount of world oil production was curtailed. The two most noticeable events during the early years of OPEC were the first Oil Embargo (1973-1974) and the Iranian Revolution (1978-1979). Typical contracts at the time were for a term of three years at official prices.

Subsequently, in response to high prices, demand declined and supply from Non-OPEC sources increased. This resulted in spot supplies for crude oil, and prices for these spot supplies quickly dipped below official OPEC prices. By the mid-1980's, as much as 65 percent of all crude oil transactions were on a spot basis.[12] One of the responses to this phenomenon was Saudi Arabia's attempt to establish netback pricing (i.e., the price of crude oil being determined by the value of refined petroleum products) in 1985 and 1986. Finally, as a result of too much excess supply, prices briefly declined to under $10 per barrel in 1986 after reaching a peak price of $45 per barrel in 1980.[13] Since then, OPEC has made repeated efforts to regulate both production and price. Some of the more recent events are discussed below.

The combination of the enormous volume of crude oil markets, the rapid evolution of a spot market, and significant volatility in prices resulted in a NYMEX forward contract for U.S. home heating oil (i.e., No. 2 oil) first in 1978. This was followed by the establishment of contracts for crude oil (WTI) in 1983, unleaded gasoline in 1984, and propane in 1987. Elsewhere in the world, forward contracts for other actively traded crude oils were established—for example North Sea Brent in 1989. Not all efforts to establish forward market for crude oils and petroleum products have been successful, primarily due to limited price volatility and limited trading volumes. The failure of the forward market for residual fuel oil within the U.S., which was originally established in the late 1980s, is one example.

With the establishment of both active cash spot markets and forward markets for both crude oil and petroleum products, the oil industry quickly began using a host of tools to manage oil prices and price risk. This has been the case for approximately the last 15 years, as the industry now relies on shorter-term contracts for supplies and uses a variety of tools to manage price. Prior to the industry developing the institutions to fully utilize both spot and forward market pricing, the oil and oil-consuming industries were almost universally dependent on the preparation of long-term forecasts of oil prices as a barometer for future industry prices. This common business

[12] F.R. Edwards and C.W. Ma, <u>Future & Options</u>, McGraw-Hill, 1992.

[13] The pivotal event that caused the final sharp drop in oil prices was Saudi Arabia's return to its historical production levels in early 1986. Previously, Saudi Arabia had been pushed into the role of the world's swing supplier as other OPEC countries exceed their quotas. This situation became untendable to Saudi Arabia when in July 1985 its production declined to 2.2MMBD from a prior peak of slightly over 11MMBD.

practice heavily influenced many long-term contracts for oil, as well as the development of alternatives to oil and some major pieces of energy legislation (i.e., specifically the National Energy Act of 1979). In hindsight, particularly near the end of the era of controlled prices, these forecasts proved to be significantly in error. The same was true for the gas industry. Subsequently, even though it took several years, the industry became less reliant on the long-term forecast and began to integrate price information from forward markets, if not to rely on them exclusively. With respect to the business processes that guide an industry, this transition represented a watershed event for forecasting practices.

Recent Oil Pricing Regimes

Over at least the last ten years, the market structure for oil has been a worldwide market with few regulatory influences. While OPEC continues to attempt to control production and price of this highly fungible fuel, supply and demand fundamentals probably have been the dominant influence since about 1986. As a result, oil-pricing regimes are, for the most part, driven by changes in world oil supply and demand fundamentals. An examination of the oil price regimes over the last dozen years provides some useful insights, as noted below:

- **Excess Supply:** Three times during this period (i.e., 1986, 1989, and 1994) excess supply has emerged. However, in each instance it took only a relatively short period for demand growth, which has been robust for the oil industry, to catch up and pull supply and demand back in balance. As a result, the associated decline in oil prices stemming from these excess supply episodes has been for only a few months (i.e., in 1986 prices rebounded within ten months, in 1988 within four months, and in 1994 within six months).
- **Supply Limitations:** As a result of the 1990 Gulf War, oil supplies were curtailed. Prices rose sharply but the price increase lasted for only six months.
- **Excess Supply and Declining Demand:** Unique to the 1998 decline in crude oil prices was the combination of the occurrence of excess supplies as a result of the Asian financial crisis (i.e., OPEC increased its production quotas in its battle for market share, Non-OPEC brought online new supplies, and Iraq reemerged as an oil exporter) and a sharp reduction in the growth rate of demand. These combined effects on the supply and demand fundamentals of crude oil resulted in an extended period of price decline (i.e., approximately 16 months). This event was also a major factor in OPEC, and in particular Saudi Arabia, revising its strategy of maintaining market share.
- **Controlled Supply:** The current pricing regime for oil is one where OPEC has been successful in controlling incremental supplies for the world and adopted a new mechanism[14] for controlling increases in OPEC supplies. It is envisioned that this new mechanism will enable OPEC to control oil prices within a relatively high price band for recent times (i.e., $24 to $30 per barrel WTI). OPEC success in even initiating this new pricing regime is due to the resolve of five OPEC members with excess capacity to limit supplies, as well as the fact that it currently faces no significant competition from Non-OPEC in capturing

[14] The new mechanism for controlling prices involves monitoring prices based upon a 20-day rolling average and then adjusting production levels by 0.5 MMBD increments via telephone directions from a designated coordinator.

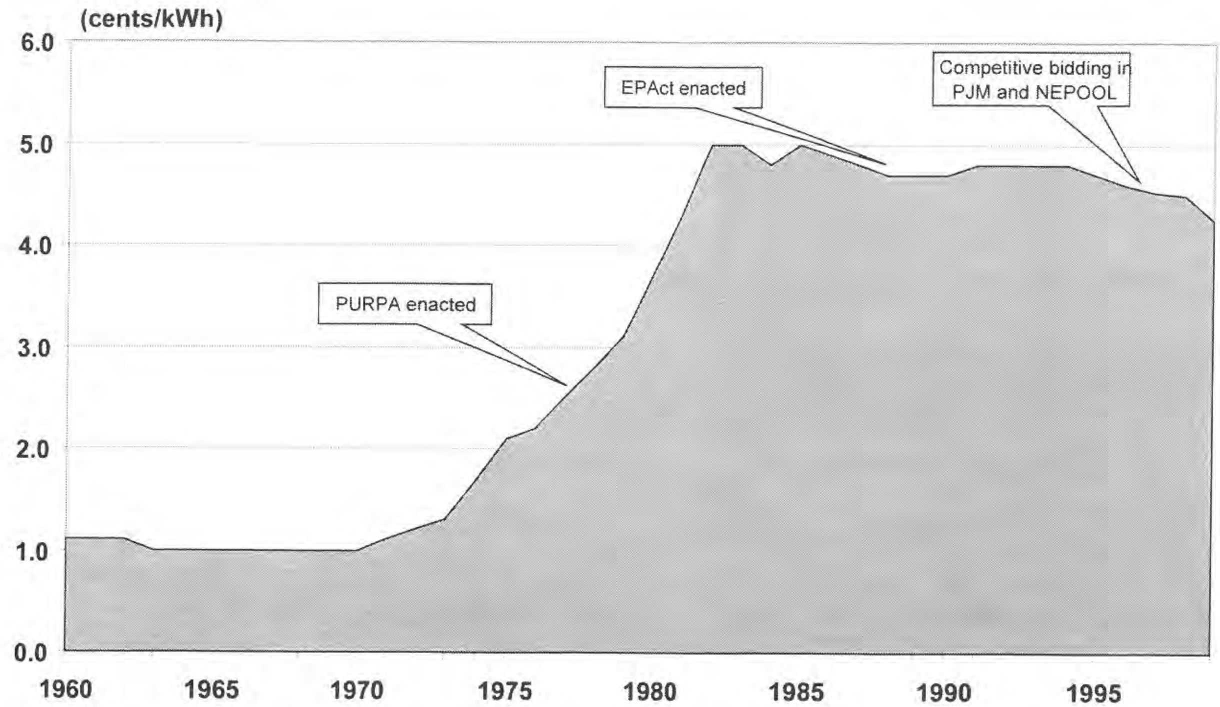
incremental demand. Both of these factors evolved from the prior pricing regime when prices declined to $10 per barrel. With respect to Non-OPEC, the impact on profits and cash flow by exploration and production companies was so severe that worldwide drilling declined approximately 50 percent and has recovered only modestly for oil directed drilling, as firms have retreated to drilling only in areas that will be profitable in a low price regime. Similarly, OPEC's new found resolve evolved from the same set of events, as the $10 per barrel prices nearly resulted in civil unrest in several OPEC countries. While time will tell the duration of this current regime, it potentially represents a significant turning point for the oil industry based upon significant structural damages in industry.

The implications for the future are that the shift in oil fundamentals caused by a single factor appear to impact prices for only a relatively short period of time. However, when both supply and demand shift to alter the balance in fundamentals the period for which prices are affected is much more extended

Electricity

Throughout most of its history, the structure of the U.S. electricity market has been dictated by federal regulations. Only recently has a competitive free market for electricity emerged, and it currently exists in only a few regions of the country. For example, competitive bidding in the wholesale market for electricity in PJM started on April 1, 1999 and in NEPOOL on May 1, 1999, while competitive bidding within NYPOOL is not scheduled to start until January 1, 2000, pending the completion of the required systems. The only other regional market at this stage is California, dating from April 1998. The long-term trend in electricity prices is presented in Figure 2-5.[15]

[15] Since there is no widely accepted index of long-term prices for electricity for the entire U.S., the average retail price for the industrial sector is presented as a surrogate. It may be the best representation of the long-term price trends for the country.



Note: Delivered industrial electricity prices are used to approximate wholesale prices.
Source: EIA

Figure 2-5
Industrial Electricity Prices, 1960-1999

Regulated Market Structure

Historically, the market structure for electricity was determined by federal regulations dating back to the Federal Power Act and the Public Utilities Holding Company Act (1935). The federal regulations, which for the most part were endorsed at the state level, controlled competition by eliminating market entry, and through state jurisdiction over rates, controlled prices and price risk. For most companies, the chief price risk was one of recovery of costs, which were examined on a retroactive basis as part of relativity complex regulatory process.

Under this historical structure electric pricing was determined by a cost-based system, where the average of the lowest variable cost forms of generation at any instance determined the price of electricity. The price of electricity was levelized even though demand varied by year, season, hour, and second. This variation in electricity demand is more critical than the demand variation for the other fuels reviewed in this report, in that there is no storage for electricity.

Another attribute of this market structure is that the dominant share of electricity was produced and sold on a regional basis. This attribute is primarily an artifact of the transmission system, which evolved over many decades, and with a few exceptions, was designed to promote reliability rather than economic transfer. The result is that the wholesale price of electricity has varied at the regional level because the costs to produce electricity vary by region (e.g., different transportation costs to deliver fuels and different fuel portfolios).

Even though this regulated bundled market structure that was fragmented into regional submarkets has come under considerable scrutiny in recent times, this structure did result in several decades of real price decline for the wholesale price[16] of electricity, with two exceptions. The two exceptions were (1) the oil price shock of the late 1970's, and (2) the sharp rise in the utility asset base during the nuclear cost overrun era of the early 1980's.

Throughout this era the dominant tool used by electric utilities for fuel procurement was the long-term contract.

PURPA Era

The passage of the Public Utilities Regulatory Policies Act (1978) (PURPA) made one significant change to the historical market structure for electricity. Under the PURPA requirements entry (new capacity) was no longer completely controlled, as one of its aims was to promote an independent power industry. Non-utility generators (NUGs) could build new capacity within certain guidelines independent of the capacity plans of the host utility. While it took several court cases and time before this change took effect within the industry, it did represent a key step towards an unbundled, competitive, free market structure for wholesale electricity. Despite its significance, its impact was largely confined to a few key regions (e.g., California, Texas and New York). While PURPA revised the competition within the industry for new capacity, overall the price structure of the industry remained basically the same. Among the reasons was that new plants were initially granted relatively high rates under long-term contracts. These rates were initially deemed lower than utility 'avoided costs' for adding new capacity themselves. However, these rates were soon overtaken by advances in technology and by a shift toward over-supply conditions that drove prices below the long-term contract levels. As in the case of coal supply contracts, these over-priced contracts entered a prolonged period of re-negotiation during the mid-to-late 1990's.

A critical aspect of this era was the accelerated introduction of new technology into an industry that traditionally incorporated changes in technology relatively slowly. The key change was the introduction and rapid progressive improvements of the gas turbine, which was borrowed from the aircraft industry. These units, as either turbines or as combined cycle units, were much more efficient than existing competing power generation technology, and were smaller and less costly –eventually accounting for about half of all the capacity added by non-utility generators. The non-utility generators were the first to adopt this gas-fired combined cycle technology, primarily because the Fuel Use Act restricted gas capacity additions by electric utilities to only peaking units. With even further improvement, technical and financial benefits of gas technology led it to eventually dominate all segments of the industry.[17]

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[16] Wholesale and retail prices of electricity do not necessarily have the same attributes, as the retail price of electricity is heavily impacted by taxes, which vary by region.

[17] See EPRI, *A Thousand Pieces-How Non-Utility Fossil Fuel Generation Adds Up* (TR-102944), November 1993 for a further discussion on non-utility generators and their use of the newer gas-fired technology.

Competitive Era

The transition from a regulated to deregulated market for electricity likely will take longer than the similar transition for natural gas because of the need to revise both federal and state regulations, rather than just the former. As a result, the present electricity market is in the midst of a transition with a number of regional variations. This limits the empirical data from which conclusions about the change in market structure for electricity can be derived. Nonetheless, significant insights can be established.

The initial step in deregulating the electricity industry on a national level occurred in 1992 with the enactment of the Energy Policy Act (EPAct), which among other things eliminated significant barriers for independent power producers (IPPs) in building non-rate-based powerplants, and also gave FERC the authority to provide nondiscriminatory access to transmission. It took FERC several years to complete its notice of public inquiry, but the agency finally issued FERC Orders 888 and 889 in 1996, which provided for open access to transmission of electricity at the wholesale level and functional separation between generation and transmission. The intent of these orders was to create a level playing field between the larger more established electric utilities and smaller independent power producers. Critical to this level playing field was access to information concerning the availability of transmission, which was covered under the requirements of the Open Access Same-Time Information System (OASIS) requirements of the FERC orders.

The FERC continued to advance deregulation by issuing Order 2000 in 1999. Order 2000 represents the next step in promoting wholesale competition after Order 888 through the use of various mechanisms to encourage all transmission owners to join regional transmission organizations (RTOs). Among the weak points in Order 888 that have surfaced since its implementation are that not all transmission owners are subject to FERC jurisdiction (i.e., Federal and municipal power utilities), and that experience has shown that efficient and reliable operation of the bulk power system is best achieved through large regional systems.[18] In the absence of legislation, the FERCs issuance of Order 2000 provides more in the way of guidance in how FERC can, or is willing to, facilitate a collaborative voluntary process on a regional basis involving all stakeholders. By using this approach, FERC will attempt to cajole "stakeholders" not currently under its jurisdiction to enter into contracts that would effectively bind them into participating in the RTO.

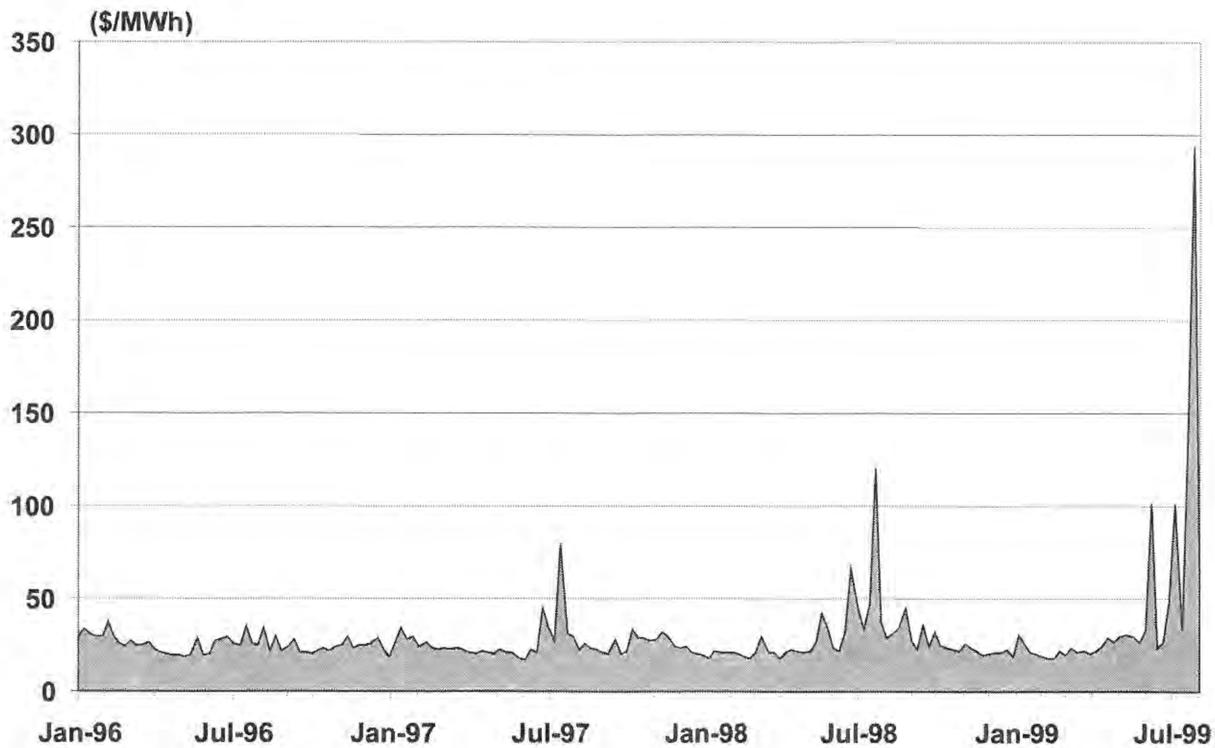
It remains unclear at the time of this writing whether Order 2000 will achieve its aim of building large regional transmission organizations, or even whether these RTOs will be able to perform to expectations in facilitating a robust and reliable power market. The comments of FERC Chairman James Hoecker capture this sentiment when he said, "In five years, we will understand

[18] A discussion of these issues can be found in Chapter 3 of *Energy Market Impacts of Electric Industry Restructuring: Understanding Wholesale Power Transmission and Trading*, EPRI TR-10899, GRI-97/0289, March 1998.

Order 2000 not as the end of bulk power restructuring, or perhaps not even the beginning of the end, *but at least as the end of the beginning* [italics added]." [19]

In addition to these federal initiatives, several state efforts have occurred which further support the unbundling of the electricity market. Some of these efforts have occurred in parallel with the FERC efforts and some have occurred subsequently. While to date there is no national legislation on the subject other than EPAct, at present there are 18 states that have enacted legislation to restructure the electricity industry within their jurisdictions and others will follow suit. Even for the states that enacted legislation it will be some time before full deregulation is implemented, as there are a number of issues that require resolution before the industry can be fully deregulated (e.g., stranded costs and the establishment of regional ISO's).

At present only a few regions have made the transition to a deregulated industry in which wholesale electricity prices are determined by market forces and even in these regions the markets are still in their infancy. Nevertheless, these regions have made significant progress in establishing a liquid market for electricity and price transparency. Figure 2-6 highlights the volatility of wholesale electricity prices for a specific region in this new era for the industry.



Source: *Power Markets Week*

Figure 2-6
Weekly On-Peak Power Prices in PJM

[19] *Foster Electric Report*, p.2, December 29, 1999.

Currently, a forward market for electricity has been established for nine regions. Five of these forward markets are listed on the NYMEX with the first one being established in March 1996 and the last in March 1999. As might be anticipated trading volumes for these various forward markets have been slow to develop. Despite the infancy of this restructured wholesale market for electricity, there is now clear indications of the price volatility of electricity and the need to shift to the use of a wide range of different tools to manage the inherent price risk. The historical approach of using long-term contracts for fuel and selling electricity on a transfer price basis within an integrated firm likely will no longer be adequate to manage electricity prices in the future. Simply put, fuel is a commodity whose prices are set by market forces, and electricity prices are moving in the same direction—a notable exception being regulated price reductions to recover stranded costs. Importantly, both fuel and power prices are uncertain. These conclusions reached in early 2000 are only reinforced by the linked natural gas and California power price surges of 2000/01.

Emission Allowances

At present there is over-the-counter trading in emission allowances for both sulfur dioxide (SO_2) and nitrogen oxide (NO_x). However, both markets are in their infancy, particularly the NO_x market, which started May 1, 1999. In addition, while both markets are the product of the Clean Air Act Amendments of 1990 (CAAA), there are significant differences in the underlying structures of the two markets.

SO_2 Emission Allowances

The acid rain requirements of Title IV of CAAA are the genesis of the current SO_2 emission allowance market, and while regulations dominate in the structure of this market, supply and demand fundamentals have also had an impact.

While the EPA had hoped initially to stimulate trading in SO_2 emission allowances by holding annual auctions[20] for SO_2 credits, it took approximately five years to develop significant trading volumes (i.e., from 1992 to 1997).[21]

There were a number of reasons for the initial slow beginning of this market and these include among others:

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[20] As a matter of background the EPA withheld a small amount (i.e., approximately three percent) of the allowable SO_2 emissions within the U.S. to auction on an annual basis. SO_2 credits were divided into two categories: (a) spot basis for use starting in 1995 (i.e., Phase I was from 1995 through 1999) and (b) long-term for use in Phase II (i.e., 2000 and thereafter).

[21] Volumes that were traded at "no cost", such as a result of ownership transfer, are excluded from this discussion for obvious reasons.

- the uncertainty over regulatory treatment at the state level;
- a relatively small market for Phase I (i.e., only 12 to 19 percent of the possible coal and oil-fired units in the U.S. were affected in Phase I), which curbed demand;
- the relative ease to comply with Phase I requirements, largely because of fuel switching among coal types, which increased supply and curbed demand; and
- the ability to bank SO_2 credits for future use (i.e., storage), which enabled supply to be diverted to another time period.

During the initial years for this market it was very much a buyers market with few participants in the market, and a few large trades accounting for most of the activity. As a result, prices continually declined and were a factor of 10 below EPA's initial anticipation. By the beginning of 1998 over-the-counter volumes in the market increased to several million tons and the market began to shift to a sellers market with some increases in prices. One of the driving forces was that with the restructuring of the electricity market most electricity trades involving coal-fired power included associated SO_2 emission allowances. In addition, with the year 2000 quickly approaching more market participants began to focus on their SO_2 emission allowance needs for Phase II, which began in 2000 and incorporated all 2,200 coal and oil-fired plants. In late 1999, there was a significant shift in the market for SO_2 allowances, as speculation concerning certain regulatory factors overshadowed the fundamentals for the market. In late 1999, the Department of Justice (DOJ) sued several electric utilities over the definition of modifications to coal-fired facilities. If the DOJ prevails, almost any modifications that result in additional capacity at a coal-fired facility would force the facility to comply with new source performance standards (i.e., install scrubbers). The installation of scrubbers at facilities that might be affected by the DOJ definitions would create significant downward pressure on SO_2 allowance prices, in that they would increase the supply and decrease the demand for SO_2 allowances. The uncertainty over whether the DOJ will prevail has forced a major segment of the current market, namely speculators, to withdraw from the market, which has significantly reduced the number of participants that would purchase SO_2 credits.

Once the DOJ issue is resolved, the forecast is that the SO_2 emission allowance market will become a more actively traded market, albeit still over-the-counter, with much better price discovery. In the near to intermediate term the large existing bank of SO_2 credits will be a significant factor in reducing the volatility of prices (i.e., see Figure 2-7 for the history of SO_2 allowance prices; by June 2001 prices had once again reached the \$200/ton mark). Only once the DOJ litigation is concluded it is likely that the market will be driven more by supply and demand fundamentals than regulatory forces; thus the market outlook remains highly uncertain. Further electric restructuring eventually should eliminate the uncertainty associated with state PUC guidelines and the EPA auction slowly will become a non-event as industry trading volumes increase.

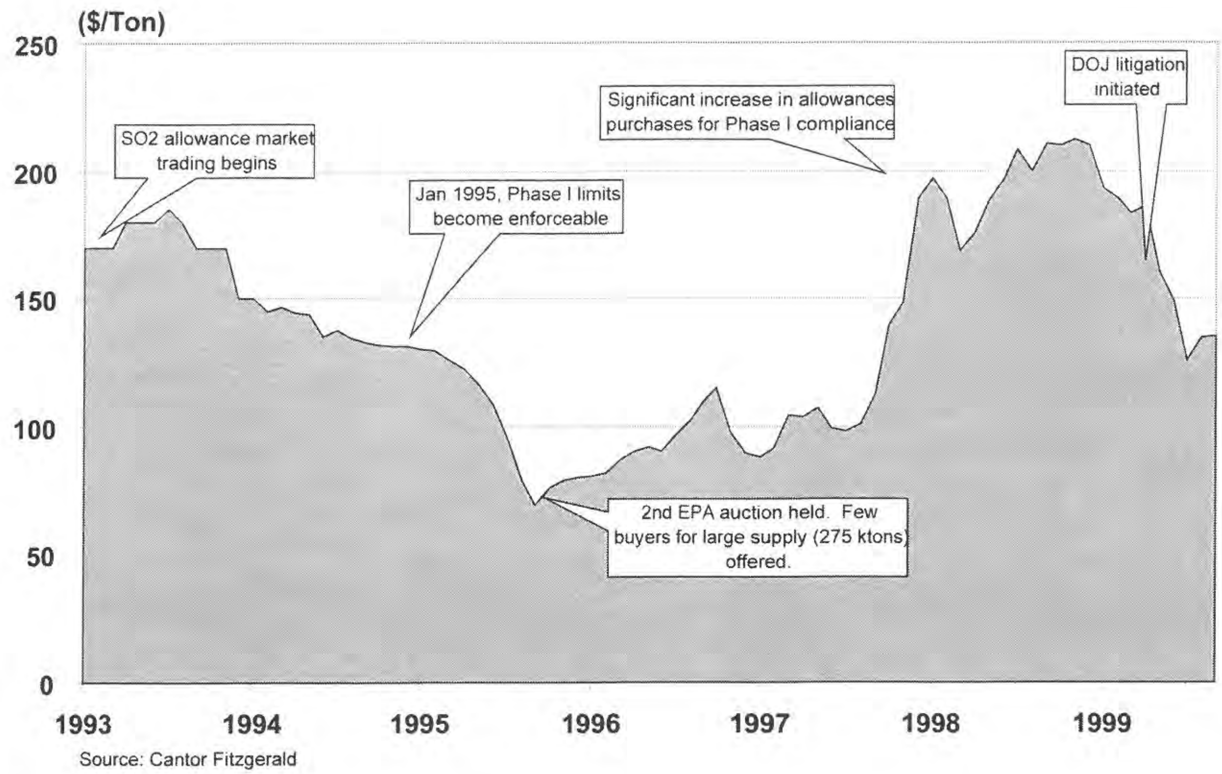

Figure 2-7
SO_2 Emission Allowance Market Value, 1993-2000

NO_x Emission Allowances

The NOx emission allowance requirements are also a product of the CAAA, however in this case Title I requirements concerning ground level ozone apply. As a result, there are a number of significant differences in the structure of this market from the market for SO_2 emission allowances. Specifically, the current NO_x market has the following attributes:

- **Smaller Market:** The NO_x guidelines at present only apply to the 12 northeastern states[22] and that condition likely will exist until 2003, at which time most of the states on the eastern side of the Mississippi will be subject to NO_x guidelines.[23]
- **Seasonal Timeframe:** NO_x requirements only apply to the summer ozone season (i.e., May through September), while SO_2 requirements apply for the entire year.

[22] As of March 1999 eight states (CT, DE, MA, NJ, NH, NY, PA and RI) were eligible to participate in the NOx trading program. ME and VT had adopted a command and control approach rather than participate in a trading program, while MD requirements were suspended until 2000 due to litigation and northern VA is attempting to withdraw.

[23] The states impacted by NOx guidelines in 2003 include AL, CT, DE, IL, IN, KY, MD, MA, MI, NJ, NY, NC, OH, PA, RI, SC, TN, VA and WV with the states of GA and MO still in limbo.

- **No Banking:**[24] NO_x allowance credits can't be banked. As a result any excess allowances must be sold in the current period.
- **Tougher Compliance Standards:** Relative to the Phase I SO_2 compliance requirements the NO_x compliance requirements are much more difficult to meet. This has created a framework in which there likely will be shortages, unless historical operating conditions change (e.g., plants either shut down or reduce capacity factors).
- **Shorter Implementation Time:** While several years were available to prepare for SO_2 trading, the time to prepare for NO_x trading was only a matter of months.

This difference in the dynamics and structure likely will lead to significantly different price characteristics for the two emission allowances and precludes drawing meaningful analogies between the two markets. Specifically, NO_x prices likely will be much more volatile and are likely at times to be high enough to affect economic dispatch in the Northeast. SO_2 prices on the other hand should be less volatile (e.g., banking and a larger geographic market) and have a smaller impact on the price of electricity (e.g., ease of compliance). Both likely will remain over-the-counter markets and subject to uncertainty over further environmental regulations.

Conclusions

While there are numerous interesting and informative aspects concerning the historical pricing regimes for electricity and the fossil fuels used for power generation, the dominant conclusion is that effective fuel management techniques are significantly different in a regulated market than in a competitive free market. Specially, in a competitive unbundled market, there is a need to stay *short* in order to manage price risk; whereas in a regulated market, participants tend to go *long* in order to ensure reliability of supply, because the associated price risk has been mitigated, if not eliminated.

Figure 2-8 provides an approximate timeline for the transitions between these two types of markets, while Table 2-1 identifies key events for each fuel that have affected this transition.[25] When the structure of a market is determined by regulatory requirements, both fuel price and price risk may be controlled or greatly mitigated. At least historically, reliability of supply became a dominant concern and as a consequence the long-term contract became the primary tool for managing fuel supplies and prices. Along with long-term contracting comes a focus on cost-based pricing mechanisms. While often of secondary importance, supply and demand balance, or imbalance, conditions make a difference in a regulated setting.

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[24] Technically in certain circumstances up to 10 percent of NOx credits can be banked without penalties.

[25] The reader may also want to consult EPRI, *Fuel Management for Competitive Power Generation - A Guide to Managing Change* (TR-1078901), April 1997, Section 9 for another portrayal of industry milestones.

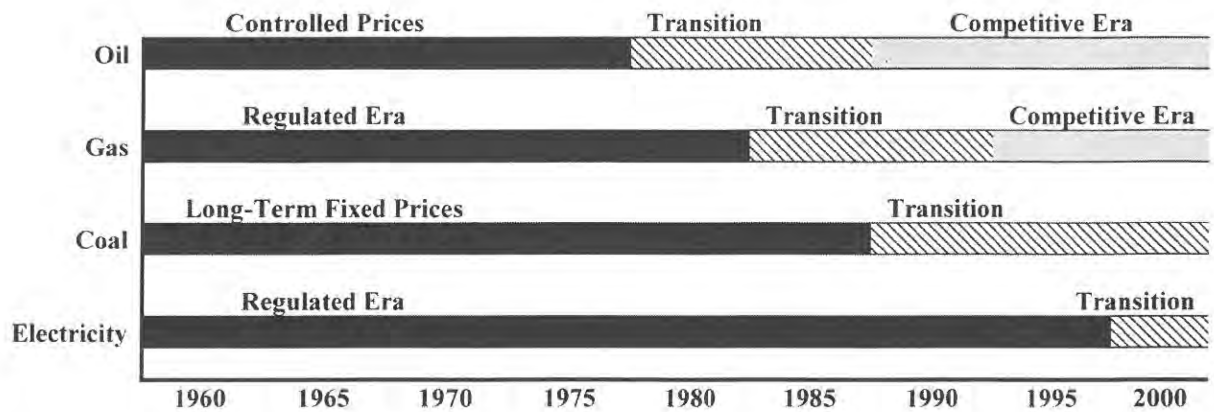


Figure 2-8
Broadscale Timeline for Energy Price Regimes

Table 2-1
Key Events for each Fuel

I. NATURAL GAS	
1938	NGA
1954	Phillips Supreme Court decision
Winter of 1975/76	Failure to deliver gas in interstate market
1978	NGPA and Fuel Use Act
1984	FERC Order 380 (Minimum Bill)
1985	FERC Order 436 (Open Access Transportation)
1987	FERC Order 500 (Open Access Transportation)
1992	FERC Order 636 (Unbundled Storage)
1992	NYMEX Futures for Henry Hub
1996	NYMEX Futures for Waha
1996	NYMEX Futures for Alberta
2000/01	Price runup, record drilling response.
II. COAL	
1960-late 1970's	Demand growth and financial institutions required Munis & RFAs obtain long-term contract.
Early 1970's	Powder River Basin opened.
1978	PURPA (Long-Term Contracts Required by Financial Institutions).
Early 1980's	UP/CNW increased railroad competition in Powder River Basin.
Mid 1980's	Over-supply and contract re-negotiations.
1990	CAAA
2000/01	Tight supplies and multi-region price runup

Table 2-1
Key Events For Each Fuel (Continued)

III. OIL	
Pre-1960's	Boom/Bust cycles
1960-1970	TRC controls world production balance and consequently price.
1970	U.S. spare production capacity dominated.
1973	OPEC
1973/74	First Oil Embargo
1978/79	Iranian production oil prices peak at $45/BBl.
Mid-1980's	Spot market for oil dominates; spot prices below official prices.
1986	Excess supply period
1989	Excess supply period
1994	Excess supply period
1990	Gulf War supply restricted
1998/99	Excess supply and demand decline due to Asian Economic Crisis (July 1997).
1978	NYMEX for No. 2 Oil
1983	NYMEX for WTI.
1984	NYMEX for Gasoline
1987	NYMEX for Propane
1989	NYMEX for Brent
IV. ELECTRICITY	
1935	Federal Power Act and PUCHA
1978	PURPA
1990	EPAct
1996	FERC Orders 888/889
1996	NYMEX for COB & Palo-Verde
1998	NYMEX for Cinergy, Entergy
1998	CBT for TVA & ComEd
1998	Competitive bidding California
1999	Competitive bidding PJM (4/1/99) and NEPOOL (5/1/99)
1999	NYMEX for PJM
2000/01	Competitive bidding NYPOOL; California crisis; slowdown in pace of restructuring.
V. EMISSION ALLOWANCES	
1990	CAAA
1992	Start EPA SO_2 auctions.
1995	Phase I for SO_2 Title I of CAAA
1999	Start NOx trading (5/11/99) Title IV of CAAA.
1999	DOJ actions over modifications and New Source Review.
2000	Phase II for SO_2

In contrast, prices in a free market structure are determined much more immediately by changes in supply and demand. This is particularly important when fluctuations in either short-term supply or demand translate directly into price volatility, which makes the management of price risk the dominant consideration of the fuel manager. Furthermore, the tools for managing price risk, particularly short-term price risk, are very different from the long-term contract used in a regulated market structure.

In addition, in a free market the access to cheap storage, or the lack of it, can significantly dampen or exacerbate the price volatility of the fuel. For the fuels reviewed in this report, market storage characteristics range from virtually no storage for electricity (the exception being pump storage), to very plentiful and cheap storage for coal, with both oil and natural gas characterized by having more expensive storage.

Looking to the future, it appears that all of the fuels reviewed in this report will have market structures determined by competitive free-market forces rather than by regulation. This has and will continue to expose the inherent price volatility of all these fuels. The chief exception to this trend, based on conditions and experience up through mid-2000, is expected to be coal, largely because of its access to cheap storage, its relatively flat supply curve and the lack of fungibility among coal types. In addition, it is not clear that a viable forward market will be developed for coal, which is another characteristic that sets it apart from the other fuels. Interestingly, the historical characteristic of coal that it is subject to very limited short-term fluctuations in demand, because it is a baseload fuel, may be altered in some areas in the future, at least seasonally, because of the environmental costs associated with this fuel. This likely will increase the price risk of the fuel, but only marginally. With 20:20 hindsight, all the regional coal markets have experienced a prolonged tightening of their supply-demand balance beginning in late 2000 and staggered into early 2001. Analysts and market participants are still digesting the significance of these events for volatility and risk management.

With respect to electricity and natural gas historic short-term changes in demand are expected to continue to drive the price volatility of these fuels. A similar condition exists for oil, however short to intermediate-term supply fluctuations remain an added factor. Following the discussion in Chapter 3 concerning regional variations in current markets, Chapter 4 of this report reviews the tools that have evolved in the industry to manage fuel price risk.

3

REGIONAL CHARACTERICTICS AND ATTRIBUTES

Overview

The prior section provided an overview of pricing regimes for the fossil fuels and electricity and of the major determinants of the various pricing regimes. This section expands this assessment by reviewing the unique aspects of regional markets within the U.S. Unlike the national assessment, this examination of regional markets is confined to the current structure of these markets and does not review historical changes. A key focus is on regional electricity markets, as the regional characteristics of the fossil fuel market for the most part has been adequately covered in prior EPRI/GRI publications, which are referenced.

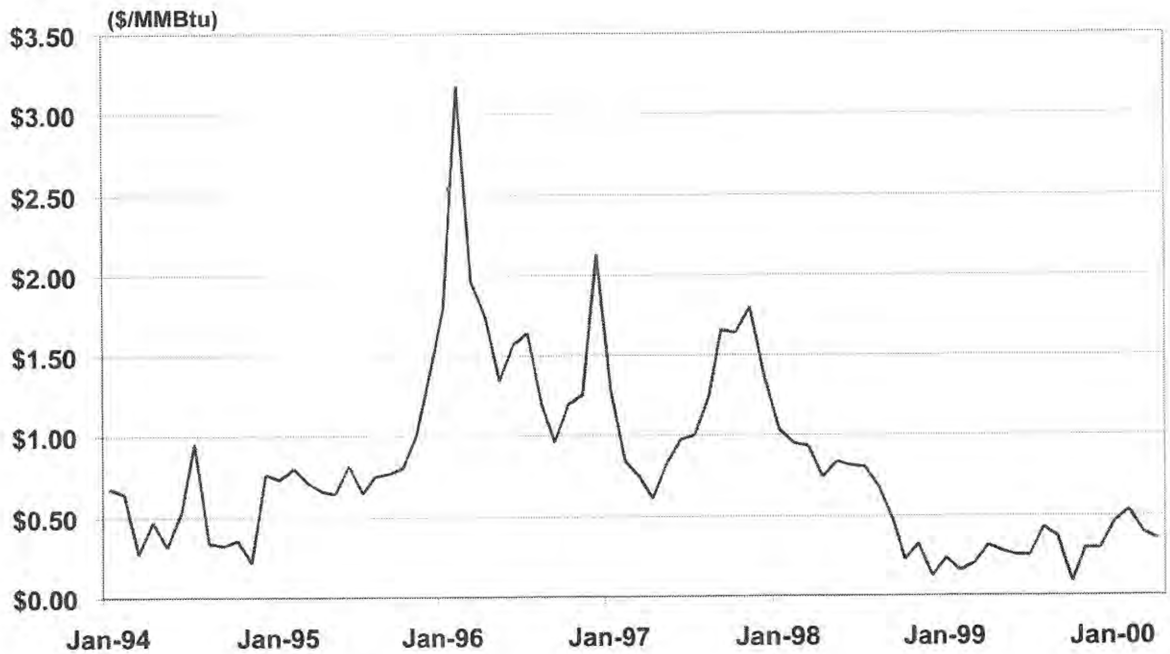
The differences in the regional electricity markets are quite dramatic, as electricity is probably the least integrated of all the energies being examined in this report. The sole exception is the evolving market for NOx emission allowances. The differences in the regional electricity markets have led to different approaches and different timetables for the restructuring the power industry in each region. Furthermore, there are significant differences in the liquidity and volatility of regional electricity prices, which can impact purchasing strategies for electricity, as well as fuels.

Natural Gas: A Recently Integrated Market

A relatively recent joint GRI/EPRI report[26] provides an assessment of the regional characteristics of the natural gas market and examines key structural issues within the industry. Since the time this report was published, there has been a substantial expansion of Canadian pipeline capacity for export gas to the U.S. (i.e., 1.1 BCFD) and more will occur over the next two years (i.e., approximately 1.8 BCFD). These expansions have already eliminated some of the bottlenecks between key North American supply points and major market centers. As a result of these major infrastructure developments, the historic split between eastern and western gas markets has for all practical purposes been eliminated. The North American gas market on a broad scale at present is better integrated than any time in the past. While there always will be regional nuisances as a result of extreme weather conditions, supply disruptions, and/or pipeline outages, these regional differences, and hence the volatility in regional basis differentials, should be less than at any point in the history of the gas industry. With even more expansions of Canadian pipeline capacity scheduled to occur over the next two years, this relatively new condition of a largely integrated North American gas market likely will persist in the future.

[26] GRI and EPRI, Natural Gas Market Regionalization and Implications (GRI-97/0290 or TR-109001), March 1998.

One of the quickest ways to appreciate the impact of this structural change in the North American gas industry, which was predicted in the referenced GRI/EPRI report, is to examine the Henry Hub/Alberta basis differential. As illustrated in Figure 3-1, prior to 1999 the basis differential between the Henry Hub, which is the key U.S. supply point, and Alberta, which is the key Canadian supply point, was extremely volatile, as these two markets were not linked very well. Since Canadian supply exceeds export pipeline capacity, the gas prices for these two supply points often moved in opposite directions. Furthermore, since the West was much more dependent on Canadian supply than the East, historically there had been a division between Eastern and Western gas markets.



Note: Alberta price is the AECO-C Hub.
Source: NGW and EVA

Figure 3-1
Henry Hub/Alberta Basis Differential

With the building of significant additional Canadian pipeline capacity, the Henry Hub and Alberta markets are much more closely linked. Secondarily, because of excess, rather than inadequate, Canadian pipeline capacity both the absolute value of the Henry Hub/Alberta basis differential and the associated volatility have declined significantly.

While there will be some regional gas price anomalies, primarily during periods of stress, in general the North American gas market on a broad scale is linked and the east/west split has been eliminated. The classic example of a potential anomaly is the limitation of pipeline capacity between Texas (i.e., Katy and Carthage Hubs) and the Henry Hub during periods of very high demand. This situation has the potential to cause a significant increase in the basis differentials between these key supply points—which has occurred in the past.[27] Similarly, for pipeline capacity into New York City (i.e., Transco Zone 6-NY) basis differentials can rise sharply during periods of stress.

Coal: Some Steps to Integration

Primarily because of the significant differences in the quality of the various coal reserves (i.e., lack of fungibility) there are significant differences between the regional markets for coal, particularly at the major supply points. Also, there are significant differences in the production costs between western and eastern coal, as well as limitations on transportation, which can be a huge factor in the delivered price of coal. There are several recent EPRI reports[28] that discuss these regional differences for coal markets and it is suggested that the reader consult them for an in-depth assessment of the regionality of coal markets.

For the purpose of this report it should be appreciated that coal types are usually not fungible and that most boilers have been designed for a specific coal type. As a result, coal substitution is limited. This limitation tends to balkanize the coal market and create regional markets that largely function independently of each other with respect to coal prices. Furthermore, largely because the storage of coal is inexpensive and demand is relatively predictable and flat, coal price volatility is limited. This lack of coal price volatility for all types of coals reduces the significance of separate regional markets for coal supplies; whereas, in the case of electricity, the existence of regional markets has proven to be very significant. At present Northern Appalachia, Central Appalachia, and Powder River Basin coals account for about 70 percent of national coal supply. The price differences between these coals is significant with Northern Appalachia coal ranging from $24.50 to $28.60 per ton prior to the 2000-2001 price run-ups, Central Appalachia coal from $22.70 to $28.65 per ton and Powder River Basin coal from $3.85 to $5.25 per ton.[29]

Looking to the future, structural changes in the industry could reduce, but not necessarily eliminate, the regional nature of the U.S. coal market. Key among these are emission allowance requirements, which at least for SO_2 will be on national basis in 2000. The existence of SO_2 emission allowances, in essence, provides a mechanism for arbitrating the price between various coal sulfur qualities. This is an important step in linking regional coal prices. Another important step is the increased penetration of Powder River Basin coal,[30] which increases the commonality of coal in the industry. Indeed, many firms have been successful in modifying their boilers, so

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[27] Ibid, pages 4-18 and 4-19.

[28] EPRI, *Fuel Industry Response to Power Industry Environmental Pressures (TR-111565)*, June 1999; EPRI, *Fuel and Power Price Volatilities and Convergence (TR-111564)*, May 1999; and EPRI, *Impact of Powder River Basin Coal on Power and Fuel Markets (TR-109000)*, July 1998.

[29] EPRI, *Fuel and Power Price Volatilities and Convergence (TR-111564)*, May 1999.

[30] See EPRI, *Impact of Powder River Basin Coal on Power and Fuel Markets (TR-109000)*, July 1998.

that they can burn more than one type of coal and in particular, Powder River Basin coal. This permits a limited degree of price arbitrage among coal types.[31]

Oil

With rare exception there are not regional differences in wholesale market for crude oil and petroleum products. For the most part oil is a worldwide market that is not impacted by regional aspects of the U.S. market. The exceptions to this observation occur primarily in the retail market, where inventory fluctuations can cause short-term regional price variations, and differences in state taxes yield differences in regional prices. Also, different regional petroleum product specifications will lead to differences in regional markets with the classic example being the more stringent specifications for gasoline within the California market. The other exception is for West Coast crude oil, which had historically been under-priced when compared to the national reference point, namely West Texas Intermediate (WTI). This situation existed because of the dedication of Alaskan crude oil to West Coast markets and the lack of a feasible means to move this crude to other markets. To a large extent this unique regional pricing phenomenon was eliminated when U.S. restrictions on exporting Alaskan crude oil were eliminated in 1996.

Emission Allowances

The market for emission allowances is still evolving. Nevertheless, during its initial stages (Phase I of the Clean Air Act Amendments), it has been primarily an eastern market phenomenon, as the initial impact of SO_2 and NOx emission limitations have been concentrated in the East. For example, most of the approximately 400 plants affected by the Phase I SO_2 requirements were located in the East and the initial NOx emission requirements for the summer ozone season only apply to 12 Northeastern states. Post-2000 the SO_2 emission limitations apply to all fossil fuel plants greater than 25 MW, causing the SO_2 markets to have a more national character. Similarly, the NOx emission requirements likely will be extended in about the 2003 timeframe to cover 21 eastern states. While NOx will be a broader market, it is still limited to the East.

Electric

Electricity markets are far more distinct regionally than any of the previously discussed commodities. The physical properties of the transmission grid are the most important reason for this regionalism, increasing the importance of cost and regulatory differences that might otherwise be smoothed away in a competitive market. The U.S. electric transmission grid is neither fully interconnected nor routinely slack across the entire continent; it is not a "copper sheet". (In fact, this is good, although concern about reliability is growing with the recent increase in power trading. If the grid were unlimited, it would have been grossly overbuilt and

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[31] Changes in buying practices could also drive coal pricing in unfamiliar directions. A new EPRI study is examining coal trading practices, standardized contracts, electric bidding and other developments, including efforts to introduce more market measures into coal transportation.

inefficient, since the savings from expanding a constrained interface are often smaller than the cost of, say, strategically siting new generations to relieve the constraint.[32]) Since it is not physically possible to trade power across all regions simultaneously, arbitrage cannot be used to keep all local markets in phase with each other. Moreover, when the grid does become constrained, regional prices can diverge much more significantly than other commodities do when they become transportation-limited. This divergence is extreme because electricity cannot be stored locally in large quantities, making it more difficult for regional markets to balance supply with demand. Lacking storage, sharp wholesale price spikes can and do occur in supply-limited areas that also lack an efficient means of enabling transactions to occur within the region among those needing the limited capacity that may be available on a daily or hourly basis.

These transmission limits tend to separate market regions with different cost structures and regulatory climates. The different cost structures exist since the predominant means of producing power tends to differ by region, based in large part on what fuels are locally available and what local environmental restrictions prevail. The Midwest tends to rely on coal-fired generation, while the southeast and California rely more on natural gas, the Northwest on hydro, and the mid-Atlantic and Northeast on a spectrum of fuels including oil. Such cost differences by themselves do not dictate that markets remain regionally distinct, but under the influence of the limited capacity of the grid, electric services tend to be priced based on these local costs of production, which vary considerably. Prices also vary across regions based on how much depth of generation supply exists locally. As mentioned above, when demand approaches available supply, prices rise to reflect willingness to pay, in addition to marginal fuel costs. Such scarcity premiums can be an order of magnitude or two larger than fuel costs, though they tend to be relatively short-lived (a few hours to a few days). Scarcity in one region will not necessarily induce it in neighboring regions; all it can induce is full loading of the interties. Thus regions may disconnect, even when trading actively.

Finally, regulatory policy differs by region, itself affecting what kinds of prices are observed. For example, generally inexpensive regions like the MAPP, SPP, and NWSCC are not feeling much political or customer pressure to rapidly restructure their state electricity regulation for retail access and generation deregulation. In contrast, expensive regions like California, New England, New York, and MAAC have already taken or completed major strides towards retail access and ISO or PX-based spot power trading. Such centralized exchanges tend to attract sophisticated traders who are interested in power dealing as well as in speculation and arbitrage-motivated trading. Such exchanges are favored by FERC for wholesale price deregulation as evidenced by ongoing RTO formation efforts. Most of the country is still obligated to offer power for sale at cost-based rates, except for areas that the FERC has deemed competitive (CA, PJM, NEPOOL), for Exempt Wholesale Generators (EWGs), and for select, FERC-approved producers operating a small amount of capacity, usually outside of their franchise service territory. In regions without a large centralized exchange market, hubs have still developed in various regions of the country where trading among power marketers, both affiliated and not affiliated with a native utility, occurs on a more ad hoc basis through the use of bilateral contracts.

[32] See EPRI, *Regional Impacts of Electric Utility Restructuring on Fuel Markets* (TR-107900), April 1997.

Large regional exchanges also tend to be managed under correspondingly large, unified transmission pricing procedures. For instance, PJM, NYPOOL, and NEPOOL all operate under spot based, nodal pricing for congestion plus postage stamp/license plate pricing for long term access via FTRs (Firm Transmission Rights). CAISO/WEPEX operate similarly, but under zone pricing for congestion. One can ship anywhere within these large market regions under a single tariff. In contrast, shipping within and across, say ECAR (which has not yet agreed on an ISO structure) involves pancaking of numerous postage stamp transmission rates. This creates an economic barrier to long distance trading, even among those subregions where little or no physical impediment may exist. Furthermore, the control areas and transcos in regions lacking large ISOs or RTOs may suffer from weak coordination of transmission line loading relief (TLR), procedures resulting in more disruptions to the regional grid than would otherwise be necessary. Such breakdowns disrupt the prevailing flows and trades, and they also discourage parties from entering long term contracts that would hedge some of the volatility of power markets, because they cannot be assured of firm available transmission.[33]

In general, there should be greater volatility and regional separation in electric prices wherever and whenever a few of the following conditions simultaneously occur:

- Local generation offers a steep short run marginal cost supply curve topped by old, inefficient units burning expensive fuels—e.g., in NEPOOL, FRCC, and SWSCC but not in ECAR, MAPP, NWSCC, or most of SERC.
- Tight supply reserves expose the region to scarcity premiums—as in ECAR, FRCC, MAIN, and SERC.
- Limited interties to adjacent region prevent aggressive imports—primarily affecting NEPOOL, PJM, NYPP, FRCC, ERCOT.
- Hoarding behavior by utilities of their own supplies during periods of system peak.

The first two of the above conditions will also tend to make spot electric prices disconnect from the underlying costs of fuel. That is, the spark spreads will be more unstable in regions that have mixed, steep supply curves (since the fuel type and heat rate of the plants on the margin will vary significantly by time of day or season) and/or tight reserves (since scarcity premiums bear no relation to fuel costs). This suggests that one of the few regions to expect reasonably steady spark spreads would be ERCOT, because it is heavily reliant on natural gas generation and not especially tight on reserves. NEPOOL may evolve to a condition of fairly steady spark spreads, if the announced dramatic expansions of pipelines and gas-fired generation both continue. California is a region to expect seasonal spark spread stability (relatively) in the seasons (mostly fall and winter) and years (dry ones) in which hydro-generation does not produce a large share of the marginal supply.

Hoarding behavior, the last condition listed above, goes directly to the psychology of the market participants. In this case, during times of system stress, utilities that both own generation and

[33] Many of these issues, their basis and implications, are further discussed in *Energy Impact of Electric Industry Restructuring: Understanding Wholesale Power Transmission and Trading* (EPRI TR–10899a/GRI-97/0289), March 1998.

serve load may, on a daily or hourly basis, have some spare capacity to sell into the market. However, the utility holding spare capacity in an otherwise tight market is likely to be extremely reluctant to part with <u>any</u> 'spare' capacity, even at high bid prices. There is a small probability that the utility may, at some point, actually need that capacity for its own use, and would not then be able to get that capacity back. As a result, those utilities needing the capacity can be left without adequate supplies despite offering high prices. This hoarding behavior explains how prices that are thousands of $/MWh in excess of cost can be observed in wholesale markets in regions that have, on paper, more supplies than actual load (i.e., in the end the lights stayed on). Chapter 4 reveals past instances of these price spikes and Chapter 5 provides a specific example drawn from the summer of 1999.

This discussion underscores how fuel and electric price volatility and the correlations between the two depend on many factors, which can change independently: a wet year, a hot summer, a major, protracted outage, entry or retirements, a large collection of speculative forwards that must be covered, etc. This means that no set of observed relationships between prices across regions or across commodities can be expected to prevail for very long. One must constantly reassess the state of the market, looking for clues about shifts in its structure, regulatory policies, participant sophistication and psychology, and so on to develop reliable planning tools for hedging transactions. It cannot be done perfectly, but it can be done usefully.

In Table 3-1 below, each of ten major regions is briefly described. Accompanying tables in Appendix A provide detailed side-by-side comparisons of the regions in terms of capacity adequacy, fuel mix and costs, price levels, and regulatory restructuring activity. The more significant changes that have taken place since these tables were compiled are the price volatilities and runups in California in 2000-2001, with rapid tightening of reserve margins in the WSCC South, and the accompanying decline in hydro generation in WSCC North.

Table 3-1
Regional Summary of U.S. Electric Markets

Region	Supply / Demand	Fuel	Prices	Regulatory
WSCC North	• Hydro & Coal dominant • Huge Reserve Margins (47%) • High Load Factor (78%) • 5% Capacity growth '94-'97	• Cheap, Cheap, Cheap • Good as burned heat rates • 37% AAGR in gas req's projected '97 to '02 = 552 MMcfd @ 100% lf	• Stable & low retail rates • relatively low wholesale prices • Low volatility, though 2x higher in '98 vs. '97	• 2 of 8 states restructured • Rest in consideration phase • No real NG restructuring, b/c gas is cheap
WSCC South	• Equal capacity shares by fuel • Reserves in 20% range • Lower load factor and reserve margin than north	• Gas & coal much more expensive than north • Gas units often older, steam units	• Retail rates much higher than north • Big decreases post-restructuring • No volatility change '97 to '98	• All states restructured è markets • CA ISO & PX, • Desert Star in 2002 • NG active in CA & NV • No NG activity in AZ
MAPP	• Smallest region (MW) • No growth, stable mix • Reserves margins to 14% in '02	• Gas requirements up 20% '94-'97 = 65 MMcfd @ 100% lf • Coal dominates gas • Coal dirt cheap even with average as burned heat rates • Gas at US average	• Cheapest rates for all classes • Much cheaper '97 vs. '94 (2nd biggest decrease) • Wholesale on cheaper side • High volatility, much higher in '98	• Nobody cares with cheap rates
SPP	• Gas & coal equally dominant • Some cap retires '94-'97 • Reserve margin growth '94-'97 ('97 = 20%)	• High coal and NG as burned heat rates • 2X energy from coal vs. NG	• Average retail rates • High '98 wholesale driven by top 5% • Volatile even w/o peaks	• Restructuring activity in half of states in region • Less action in NG
ERCOT	• Gas capacity dominant • Isolated transmission island • Shrinking reserves 17% ('97)	• Slightly more energy produced by coal • Gas slightly cheaper than rest of US • High coal and avg. gas as burned heat rates	• Avg. retail and wholesale rates	• Restructured electric market • ISO since '96, no PX • Considering NG
ECAR MAIN	• Coal very dominant • Some gas additions Low margins (15%)	• Increasing gas requirements • Coal use dominates NG • Coal prices on low side of avg. • Terrible gas as burned heat rates	• Above avg. retail rates with slight decreases '94-'97 • '98 extreme wholesaleσ driven by top 5% prices (spikes)	• 2 of 7 states restructured • Midwest ISO by 2000 • Some NG activity in 6 of 7

Table 3-1
Regional Summary of U.S. Electric Markets (Continued)

Region	Supply / Demand	Fuel	Prices	Regulatory
NPCC	• Equal capacity shares by fuel • Projected drop in reserve margins, but lots of planned capacity in next 5 years	• Expensive coal • Gas heat rate improvements (as burned) • Gas use up '94-'97	• Very high retail • Big C &I rate reductions post restructuring • Cheap & boring wholesale	• Hyperactive ė restructuring • 2 ISO's: NEPOOL, NYISO • Active NG in NY, MA • Inactive NG in CT, RI
MAAC VACAR	• Coal dominant, largest percentage of nuclear in US • Increasing coal capacity '94 to '97 • Low load factor (58%)	• Large projected NG use growth in future • Higher than average coal costs, but best coal as burned heat rates	• Average retail rates and wholesale prices	• Active ė restructuring in 5 of 8 • PJM ISO since '98 • Some NG activity in most states, one active program (VA)
TVA Southern	• Coal dominant, significant hydro • Low reserve margins (14%)	• Increasing gas requirements projected (38% for '97 to '02) • Gas clunkers in use, average coal units	• Low residential rates, average C & I rates • Higher wholesale in '98 vs. '97 even w/o price spikes • Volatile wholesale	• Nothing doing in electric • GA only active NG
FRCC	• Coal, Gas, & Oil equal shares • Low load factor 57% • Stable reserve margins	• Great Gas units in use • Gas more competitive with coal than in other regions	• Average retail rates • Wholesale price increases '97 To '98 • Volatile wholesale	• Investigation stage for electric • No action in NG
US	• Coal dominant across US • Stable mixes between '94-'97 • Reserve margins in teens and projected to decrease in future.	• Coal dominant but new gas plants have improved as burned efficiencies • '97 to '02 Projections for significant growth in gas req's (9% to 38% in 6 of 10 regions)	• Rate decreases in restructured areas • Higher prices in '98 than '97 • '98 more volatile than '97, even ignoring extreme peaks	• Most activity took place where rates were high. Had positive effect on rates.

4
VOLATILITY & CORRELATION ANALYSIS

Overview

Restructuring the electric industry has brought competition to the wholesale electric markets, resulting in market prices that are highly volatile and uncertain. While the industry has made progress in developing capabilities to forecast wholesale market prices of electricity, the published research on electric volatility and correlation is quite limited. There is limited understanding of behavior (such as seasonality or instability) over time or between regions and across fuels. In this chapter we undertake a comprehensive look at the behavior of wholesale market prices of electricity and fuels in seven regions across the U.S. over the past several years. Price distributions, volatility, cross-region price correlations and basis differentials are examined.

The observed behavior of wholesale electric prices is put into perspective by comparing it to the natural gas prices. The price regimes for natural gas and other fuels were looked at in Chapters 2 and 3 to set the stage for what one might expect from electricity. A key question examined in this chapter is whether electric prices are tending to follow the same evolution as natural gas as the market has matured to the point where there is largely one price in the U.S. and Canada. In particular, do electric prices show heterogeneity or are they becoming homogeneous—converging to the price of natural gas? To this end, similar statistics are calculated for natural gas as were calculated for electricity. Convergence is assessed by examining the correlation between electricity and natural gas spot prices, as well as by examining the stability and similarity of regional spark spreads.

The statistical evidence reveals that history tells us little about what to expect about long-term "equilibrium" power price volatility. Under a comprehensive look at volatility for many regions over several years, no strong or recurring patterns emerge. Volatility of spot power prices for peak hours vary from year to year, by season, and by region. Annualized peak power price volatility is an order of magnitude larger than natural gas volatility, 200% to 500% using weekly data (and higher for daily data!). Similar parameter magnitudes are implied by forward prices. Power prices are generally correlated for neighboring regions but not nationwide. However, when transmission constraints become binding, power prices for neighboring regions can be very uncorrelated. The extreme volatility of power prices and the unpredictability of that volatility should not be surprising. Electricity is not economically storable in large quantities for long periods. Thus, any sudden surges in demand (e.g., due to weather changes) can push power prices unexpectedly higher, as more expensive units farther up the dispatch curve are employed, or as capacity scarcity premiums begin to set price. The summer of 2000 is a prime example. In California, unexpectedly high temperatures and growth in the demand for energy resulted in scarce capacity that drove power prices off the charts. In contrast to previous summers, which had comparatively low volatility of 100% to 150%, the summer of 2000 volatility in California was on track to exceed 1000%. Changes in market rules implemented in August, specifically price caps, were expected to begin a new price regime, likely reducing volatility going forward. Unexpectedly, the pools in PJM and the Northeast enjoyed a marked and fortuitous contrast. As luck would have it, it was a very cool and wet summer, and the few hot days usually occurred on weekends. If those hot days had occurred a few days later, i.e., midweek, the Northeast could have experienced at least a few price spikes and more volatility.

While the introduction of real-time response capability from customers is likely to reduce the overall level of volatility in power markets, it is not likely to come down to the levels or predictability observed in the gas markets. Natural gas price volatility, while high compared to other commodities (on the order of 40% to 80%), is considerably lower than that for electricity prices. The behavior of natural gas volatility has been considerably predictable, consistently peaking in the winter around 150% to 200%. Forward price volatility (using prices for contracts approximately one month prior to delivery) is also a useful predictor of spot price volatility for natural gas. Natural gas price volatility is also comparable across most regions. Historically, Alberta tended to behave differently, but since completion of expansion to the TransCanada pipeline, it has adopted a pattern similar to other natural gas hubs. Prices for natural gas hubs nationwide have become reasonably correlated[34]. The price differentials are relatively stable supporting the claim that natural gas prices are nearly convergent with each other. In essence, the North American gas market is starting to act like a unified whole.

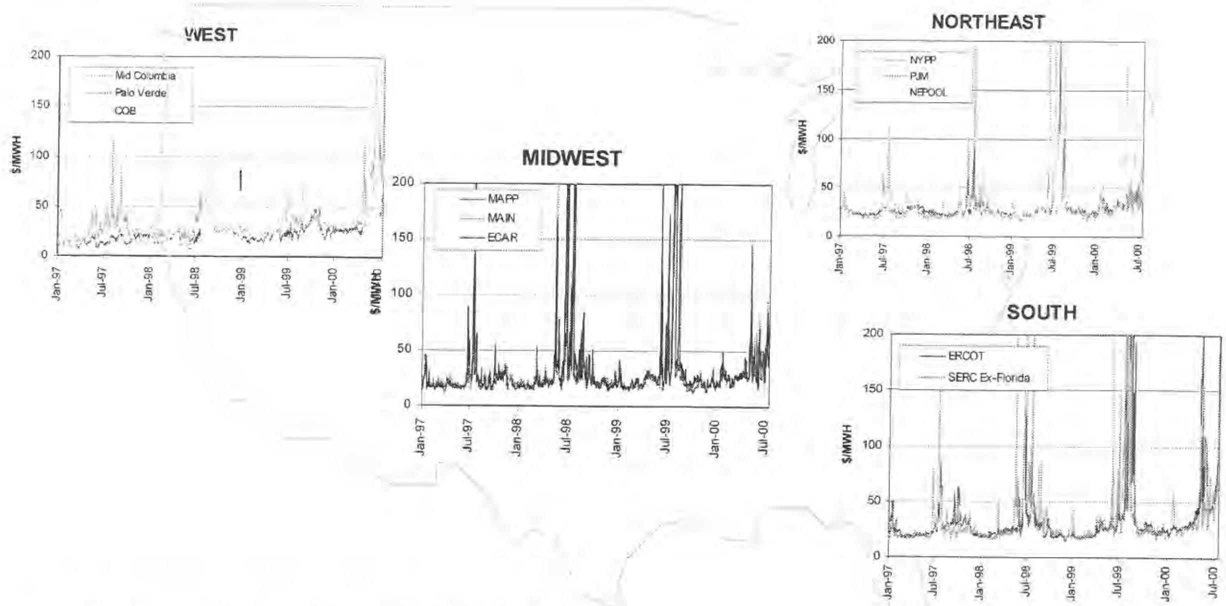
Our findings on wholesale electric prices, including observations of peak power price distributions, measures of volatility, electric on electric price correlation and basis differentials are presented first. Findings on the same statistics are then presented for wholesale natural gas prices. The chapter concludes with a discussion of cross-fuel price correlation and spark spread statistics.

Electricity Price Profiles

Well-publicized price spikes like those in ECAR in the summers of 1998 and 1999 and California in 2000 have highlighted the fact that wholesale peak power prices in the U.S. are extraordinarily volatile. Examination of (daily or weekly) peak power prices in U.S. markets from 1997 to 1999 as shown in Figure 4-1 provide specific confirmation of this volatility. Plots such as these may tempt analysts into making generalizations about the behavior/personality of electric price volatility over time and across regions. However, one need only look at the behavior of power prices in California for the last several years and compare it to the summer of 2000 to know that history does not necessarily repeat itself. The findings in this report in fact confirm that historical data is not a good indicator of future price behavior. This report highlights the danger in making such broad generalizations. Useful, qualitative predictions can be made, but these must be grounded in detailed understanding of regional structured

[34] The dramatic excursion of California prices during 2000/01 postdated the body of analysis in this report. By July 2001, these prices had returned much closer to historic norms.

(supply/demand/transmission) configurations and regulatory conditions, and even then the weather or bad grid performance can make forecasters look naïve.[35]



Source: *Power Markets Week* and Project Team

Figure 4-1
Peak Power Prices in U.S. Markets: 1997-1999

Electricity Price Distributions

The first step undertaken to examine the behavior of electric prices was to look at how regional weekly spot prices for peak hours were distributed for each season, fall, spring, summer, and winter, from 1996 to 1999 to the extent that data were available. Descriptive statistics, maximum, minimum, 1st quartile, 3rd quartile, mean and median of weekly wholesale peak spot power prices as reported by *Power Markets Week* were calculated for 13 market regions (Cinergy, COB, Entergy, ERCOT, Florida, MAIN, MAPP, NEPOOL, Palo Verde, PJM, SERC, SPP, and TVA) for each season[36] for each year from 1996 to 1999. These results are charted in the figures included in Appendix B and described below.

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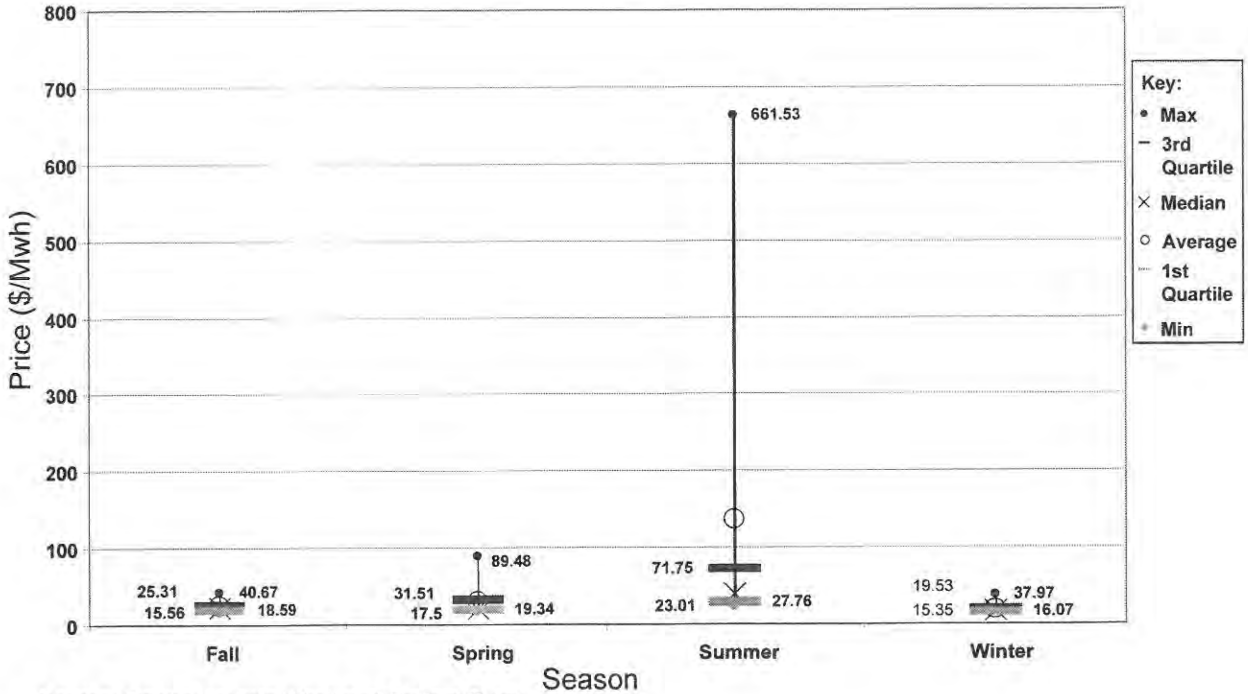
[35] Editor's note: A recent EPRI-LCG report provides examples of structural market modeling to develop quantitative estimates of electricity prices and their volatilties: *Analyzing Multiple-Product Power Markets – Simulation of Energy and Ancillary Services Prices and System Adequacy*, 1000571, 2000. An important caution in such simulations is to extend analysis beyond "most likely" assumptions to capture the range of uncertainty/volatility in prices, asset values, etc.

[36] For these plots, fall is defined as September 15 to December 14, winter as December 15 to March 14, spring as March 15 to June 14, and summer as June 15 to September 14.

Figure 4-1 presents the raw data (graphically), while Figure 4-2 is a representative example of one of these summary "box plots." It depicts the summary statistics for weekly (5x16) peak prices into Cinergy in 1998.



Source: *Power Markets Week* and Project Team

Figure 4-2
1998 Weekly Peak Cinergy Prices Across Seasons

Box plots, as the method of display in Figure 4-2 is called, are an extremely useful way of visualizing and comparing distributions of data. They are an example of what is called "non-parametric" statistics in that they do not rely upon mean-variance optimization of fits or comparison of summary statistics. In particular, they allow one to see at a glance:

- the presence or absence of symmetry in the data—present if median is approximately equal to mean, lower and upper quartile data points are equally spaced around the median;
- reliance of mean on extreme values—apparent if the first quartiles are symmetric but the overall range is not (hence, median is not equal to mean);
- potential transformations of data to make it more amenable to conventional (mean-variance) statistical analysis.

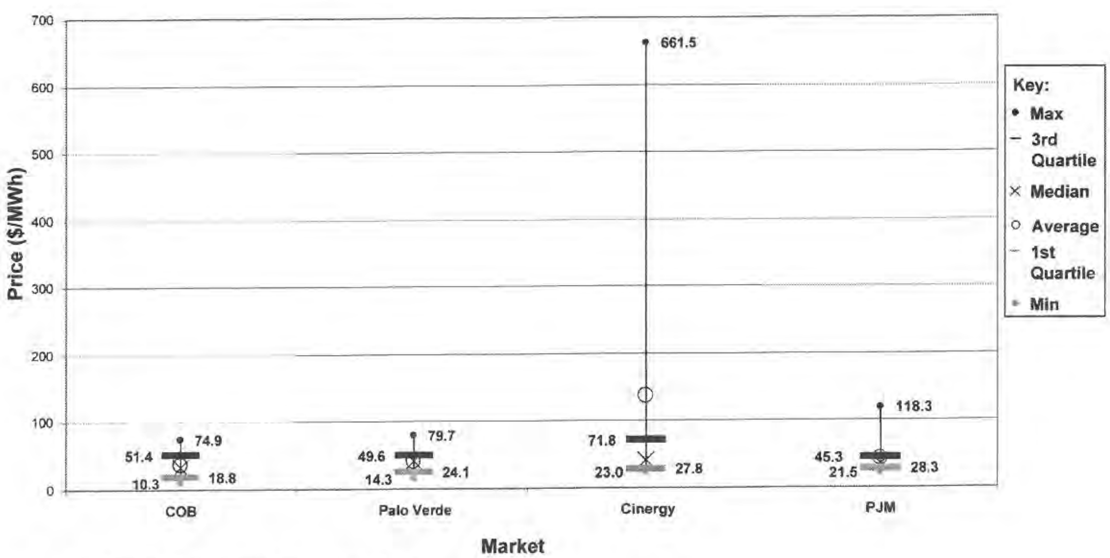
Such insights are more difficult using conventional statistical summaries. By highlighting the median, this approach provides a statistic that is not susceptible to upward bias from a few extreme points. For electricity, the median may be a better indicator of underlying supply operating costs than the mean.

The price profiles depicted in Figure 4-2 indicate that for Cinergy in 1998, prices were not at all distributed normally throughout the year. They were heavily skewed to the right, especially during the summer. Upon review of the other regions, similar though less extreme skewness is present. This has important implications for how volatility should be calculated for power prices.

Recall that volatility is a measure of the likely standard deviation of the observed value from the expected value; the deviation is symmetric about the mean. The less symmetric, or normal, a price distribution is, the more care must be taken to calculate and interpret variance statistics. It is for this reason that electric prices (market prices in general) are usually assumed to have a log normal distribution. Volatility is thus calculated for the change in the natural logarithm of prices and not the actual prices. This automatically injects skewness into the statistics, but may not be enough for valuing electric products, as discussed more in Chapter 5.

Aside from the general observation that prices are skewed and most heavily skewed in the summer, few other patterns emerge. Upon review of several such graphs, it is clear that the skewness of the summer prices has mostly increased steadily from 1997. Exceptions to that are for prices in COB, Palo Verde, and NEPOOL. The presence of a developed market for competitive power is not the explanatory factor here. One needs only look at the distributions for weekly peak prices in PJM West for a counter-example; PJM West is a well-organized market which has experienced growing summer spikes in 1998 and 1999.

Anyone reviewing the full set of graphs in Appendix B should come to the conclusion that electric power price distributions vary by time, and by season—but not by any simple rule. For example, weekly peak prices for Cinergy in spring 1999 are less widely distributed than in spring 1998. The reverse is true for summer. On the other hand, price distributions do tend to follow a similar pattern between neighboring regions. Figure 4-3 plots descriptive statistics for weekly summer peak price data for COB, Palo Verde, Cinergy and PJM. COB and Palo Verde appear similarly skewed, as do Cinergy and PJM. Later in this section a statistical measure of this correlation is presented supporting this observation.



Source: *Power Markets Week* and Project Team
Note: Summer defined as June 15 to September 14.

Figure 4-3
Electric Price Distributions Across Regions—Summer 1998 (Weekly Peak Prices)

While the price dispersion for these distributions appears non-predictable, the median of the distribution may be at least explainable, if not predictable. The median price does tend to follow the supply curve for the particular region precisely because it does not reflect scarcity premiums. Compare for example the median weekly peak prices for COB in 1998 to those for MAPP in 1998 as shown in Figures 4-4a and 4-4b respectively.

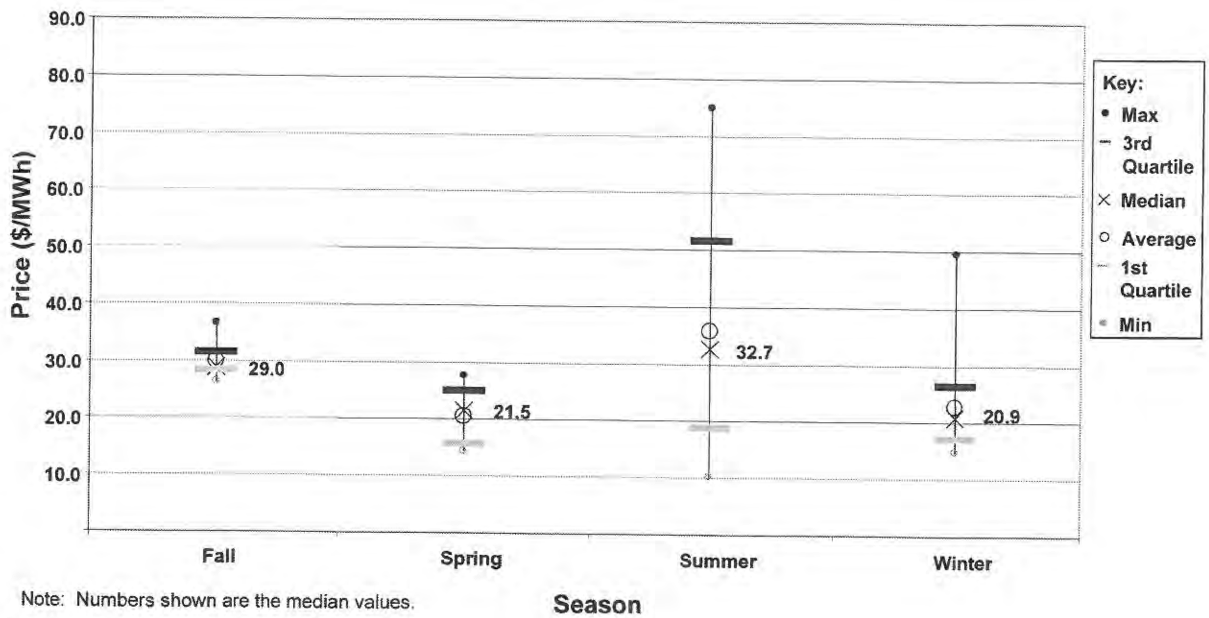


Figure 4-4a
1998 Weekly Peak Price Distribution—COB

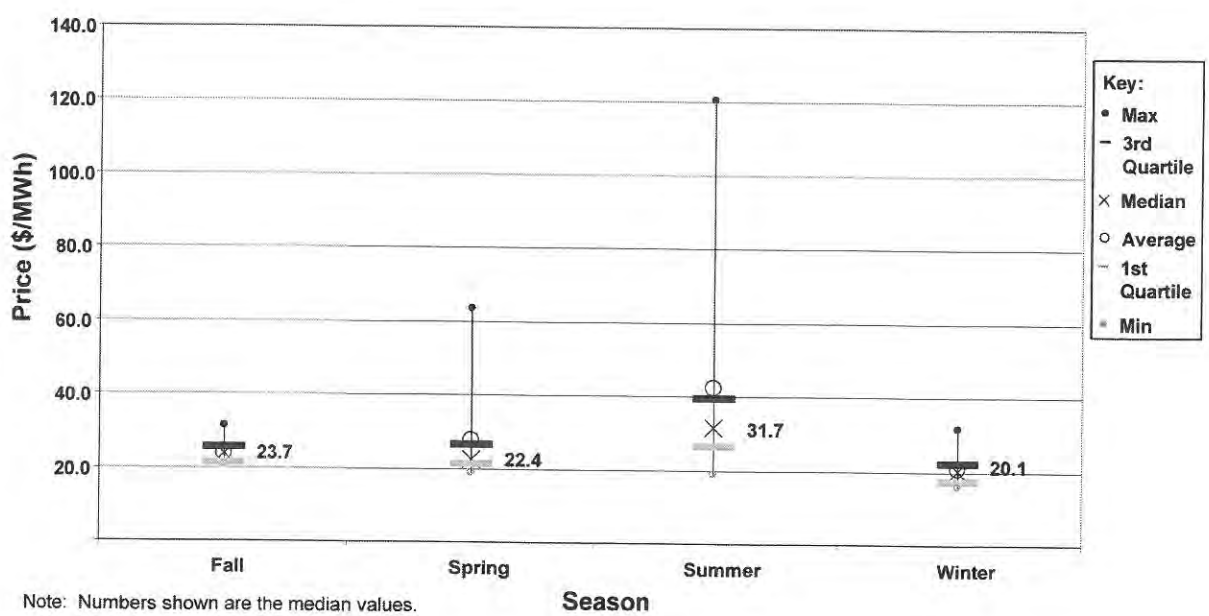


Figure 4-4b
1998 Weekly Peak Price Distribution—MAPP

In COB, the seasonal median jumps in accordance with the changes in the supply curve.[37] For MAPP, the seasonal values at the median are fairly tightly distributed. This is consistent with a relatively flat supply curve that is common to regions with a significant amount of coal generation. Given these data, it would be surprising if two parties negotiating contracts had essentially the same "most-likely" forecasts, but the safety net required for protection based on forecasts of volatility or price dispersion could be very different.

Electricity Price Volatility

Given the extreme complexity in average power prices, it is worthwhile to ask whether the statistics that capture this complexity regarding volatility might be "better behaved." If so, it would have important consequences for planning. The next best thing to having a good forecast is having confidence in the uncertainty in that forecast. Indeed, uncertainty (volatility) is a critical determinant of asset value in the electric industry, for at least two reasons. First, many buyers are interested in price insurance against extreme events. Once prices exceed some critical threshold, they want out, while below that they can tolerate the spot price variation. This means that options, complex contracts, or regulatory guarantees (such as rate freezes or fixed-price "standard offer source") are, at least in part, best understood as protection against volatility. Second, some generation assets, especially peaking units, are assets whose use and value depends more on the character of price spikes than on mean or median prices. They are essentially assets that benefit from volatility, and a proper assessment of their value must reflect this in a way that baseload assets do not require.

Accordingly, the dispersion observed in the price distribution charts discussed above is now presented and reviewed to determine if there are any discernable patterns in the behavior of the volatility of electric prices over time, across seasons, or across regions, as well as to get a sense of the magnitude of power price volatility. Volatility is measured by the annualized standard deviation of a time series of changes in the natural logarithm of power prices. (See Appendix B for additional details on the methodology of the volatility calculations, especially regarding annualizing the data.)

In essence, this is the standard deviation of percentage changes in prices, rather than the standard deviation of changes in prices themselves. The standard deviation of change in prices is more useful because most traded commodities and securities have a log (% change) price distribution that is more normally distributed than the prices themselves. (Two successive 10% increases in price result in a bigger price change than two successive 10% decreases.) Also, it is percent changes in asset values that determines returns, hence the parity of financial values between claims on different kinds of electricity positions, not the absolute value of returns.

[37] For a visual a description of the supply curves for these regions see Volume 2 of the EPRI/GRI report "Regional Impacts of Electric Utility Restructuring on Fuel Markets", EPRI TR-107900-V2. In summer, gas from relatively old, inefficient steam generators tends to be on the margin.

Annualized volatility of daily peak spot power prices as reported by *Power Markets Week* were calculated for each month in 1998 and 1999 for 11 regions. These data are summarized in Table 4-1. At first pass, it is clear that there is a lot of variation in the numbers, from a low of 44% (October 1998 in Palo Verde, and September 1998 in New England) to 3403% (July 1998 in Cinergy). In 1999, monthly volatility of power prices range from a low of 24% (March in ERCOT) to 4084% (July in TVA). The only obvious pattern that emerges from cursory review of these data is that volatility of power prices in the summer are multiples larger than for any other period of the year.

Plots of these volatility data drive home the seasonality, but are only slightly more illuminating. Figures 4-5a and 4-5b are plots of the monthly volatility for regions in the western-half and eastern-half of the U.S., respectively. It is clear from these figures that volatility is different from month to month and year to year even within the same region. A striking example of the lack of consistency is New England, plotted in Figure 4-5b. The volatility in 1998 was tightly distributed between 44% and 116% (finely dotted line) in 1998. However, June, July and August of 1999 were a striking contrast—peaking at 1153% in July. Moreover, while the summer can be 10 to 30 times more volatile than other times during the year, COB and Palo Verde summer 1998 and 1999 were only 1/5 to 1/3 times as volatile as other regions. Data from 2000 would show yet a new pattern.

These plots also confirm that neighboring regions generally behave similarly. That is, volatility, as well as price levels, seem to move up and down at the same time. However, the amount by which the value moves up and down varies. That is, the magnitude of shifts in volatility are not necessarily comparable between regions. See for example Palo Verde and COB in Figure 4-5a. Until August 1999, the volatility for these regions moves in sync, neither value consistently exceeding the other.

Table 4-1
Volatility of Daily On-Peak Power Prices by Month (Annualized)

	COB	Palo Verde	Entergy	ERCOT	Cinergy	PJM West	New England	MAPP	TVA	SERC	Florida/ Georgia
Jan-98	140%	104%	85%	48%	133%	127%	56%	127%	97%	113%	71%
Feb-98	119%	207%	55%	76%	82%	71%	63%	89%	91%	116%	124%
Mar-98	166%	132%	263%	110%	398%	214%	71%	266%	332%	379%	281%
Apr-98	95%	79%	149%	62%	292%	189%	54%	98%	227%	162%	107%
May-98	173%	226%	573%	115%	1003%	307%	81%	536%	774%	1198%	664%
Jun-98	388%	429%	1258%	564%	1204%	325%	116%	943%	1449%	900%	1547%
Jul-98	292%	342%	2724%	398%	3403%	914%	103%	929%	2949%	1968%	1549%
Aug-98	312%	341%	563%	132%	856%	582%	98%	349%	680%	615%	639%
Sep-98	169%	187%	385%	291%	539%	438%	44%	233%	476%	493%	359%
Oct-98	123%	44%	138%	71%	214%	129%	49%	107%	180%	180%	117%
Nov-98	117%	102%	93%	50%	167%	118%	78%	125%	142%	104%	87%
Dec-98	343%	204%	124%	127%	162%	123%	95%	176%	122%	102%	103%
Jan-99	150%	116%	275%	105%	334%	227%	68%	185%	338%	341%	298%
Feb-99	100%	79%	95%	37%	156%	140%	57%	94%	160%	140%	69%
Mar-99	154%	87%	111%	24%	165%	120%	46%	84%	141%	146%	135%
Apr-99	224%	165%	191%	123%	179%	132%	39%	160%	197%	216%	336%
May-99	133%	104%	121%	97%	177%	175%	103%	77%	163%	184%	218%
Jun-99	394%	343%	917%	149%	1389%	1078%	615%	515%	1186%	1201%	1058%
Jul-99	386%	374%	3385%	627%	3732%	1898%	1153%	2841%	4084%	3844%	3935%
Aug-99	275%	270%	1214%	867%	910%	980%	286%	428%	1070%	872%	883%
Sep-99	357%	186%	133%	211%	231%	210%	104%	91%	201%	167%	174%
Oct-99	194%	265%	150%	69%	183%	95%	62%	131%	200%	153%	118%
Nov-99	265%	220%	159%	85%	288%	222%	146%	182%	224%	224%	187%
Dec-99	172%	132%	177%	84%	213%	165%	71%	207%	230%	175%	222%
Max 1998	388%	429%	2724%	564%	3403%	914%	116%	943%	2949%	1968%	1549%
Min 1998	95%	44%	55%	48%	82%	71%	44%	89%	91%	102%	71%
Max 1999	394%	374%	3385%	867%	3732%	1898%	1153%	2841%	4084%	3844%	3935%
Min 1999	100%	79%	95%	24%	156%	95%	39%	77%	141%	140%	69%

Source: Data from *Power Markets Week*.

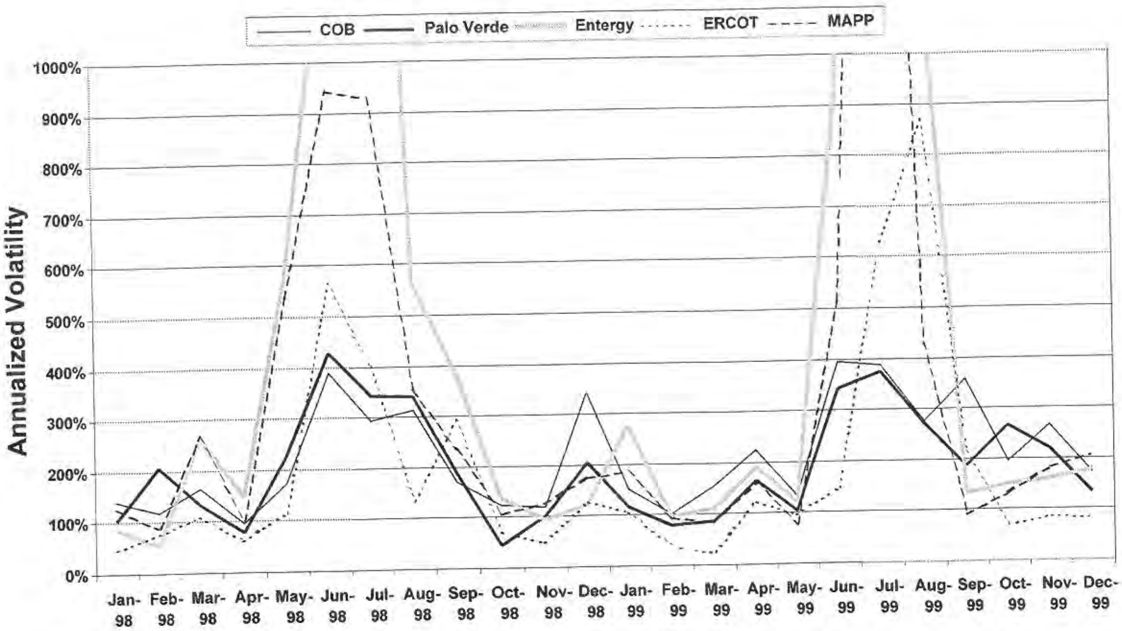


Figure 4-5a
Volatility of Daily On-Peak Power Prices by Month—Western-Half of U.S.

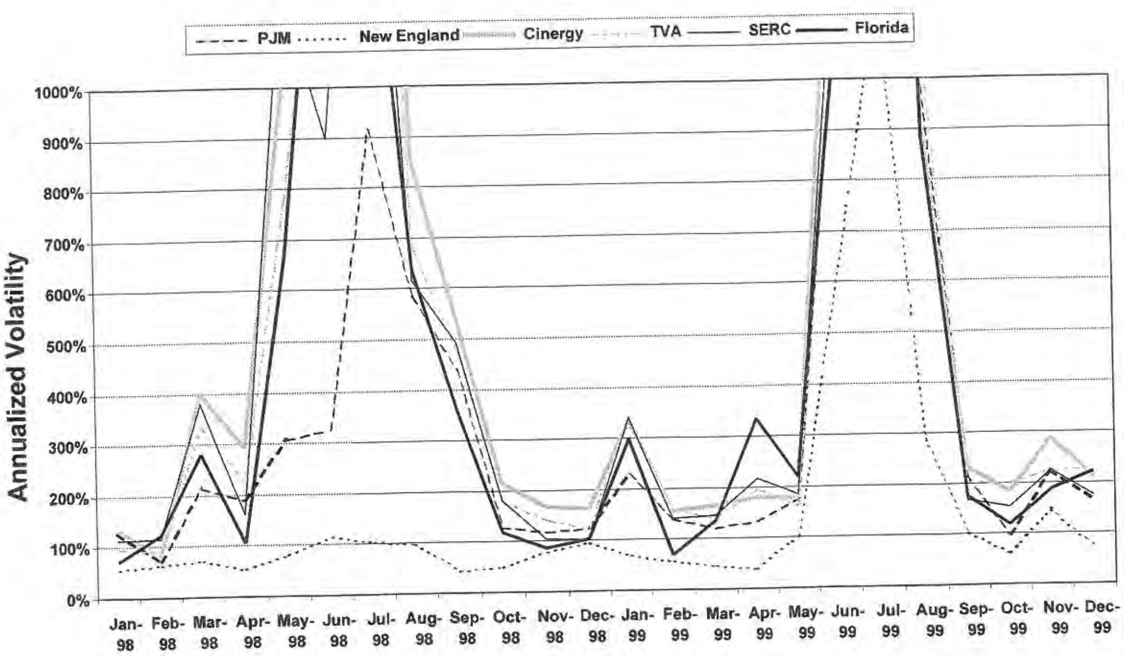


Figure 4-5b
Volatility of Daily On-Peak Power Prices by Month—Eastern-Half of U.S.

In an effort to see if there were any large-scale seasonal trends, averages were calculated for each season of each year, 1998 and 1999. These seasonal volatility averages are reported in Table 4-2 and plotted in Figure 4-6. This figure illustrates three points. First, for any given season, the magnitude of the volatility varies dramatically from region to region. The range of variability is significant. For example, even for winter, where power price volatility appears to be at its lowest, volatility can range from 60% to 217%, larger than essentially all other commodities. Summer volatility shows the most divergence, ranging from 106% (New England in 1998) to 2113% (TVA in 1999). Second, there is a lot of variation in the value of volatility from season to season. Winter appears to have the lowest volatility followed by fall, spring, then summer. However, since volatility changes from year to year, even this hierarchy is not likely to be stable, except on average over long periods. This leads to the final point, that is from year to year, seasonal volatility in the same region varies. This is most visible by looking at the results for spring. Volatility on average is higher for spring 1998 than for 1999, the reverse is true for winter. Moreover, this is true even in regions like ERCOT or PJM that are not sensitive to annual hydro variation that is often pronounced in Spring (like COB).

Table 4-2
Volatility of Daily On-Peak Power Prices by Month—Seasonal Averages

	COB	*Palo Verde*	*Entergy*	*ERCOT*	*Cinergy*	*PJM West*	*New England*	*MAPP*	*TVA*	*SERC*	*Florida/ Georgia*
1998 Entire Year	203%	200%	534%	170%	704%	295%	76%	332%	627%	528%	471%
1999 Entire Year	234%	195%	577%	207%	663%	454%	229%	416%	683%	639%	636%
1997-98 Winter	130%	156%	70%	62%	108%	99%	60%	108%	94%	115%	98%
1998-99 Winter	198%	133%	165%	90%	217%	163%	73%	152%	207%	194%	157%
1998 Spring	145%	146%	328%	96%	564%	237%	69%	300%	444%	580%	351%
1999 Spring	272%	224%	147%	122%	234%	176%	104%	135%	208%	181%	160%
1998 Summer	331%	371%	1515%	365%	1821%	607%	106%	740%	1693%	1161%	1245%
1999 Summer	352%	329%	1839%	548%	2010%	1319%	685%	1261%	2113%	1972%	1959%
1998 Fall	136%	111%	205%	137%	307%	228%	57%	155%	266%	259%	188%
1999 Fall	272%	224%	147%	122%	234%	176%	104%	135%	208%	181%	160%

Note: Winter average includes the months December, January, February.
Spring average includes the months March, April, and May.
Summer average includes the months June, July, and August.
Fall average includes the months September, October, and November.

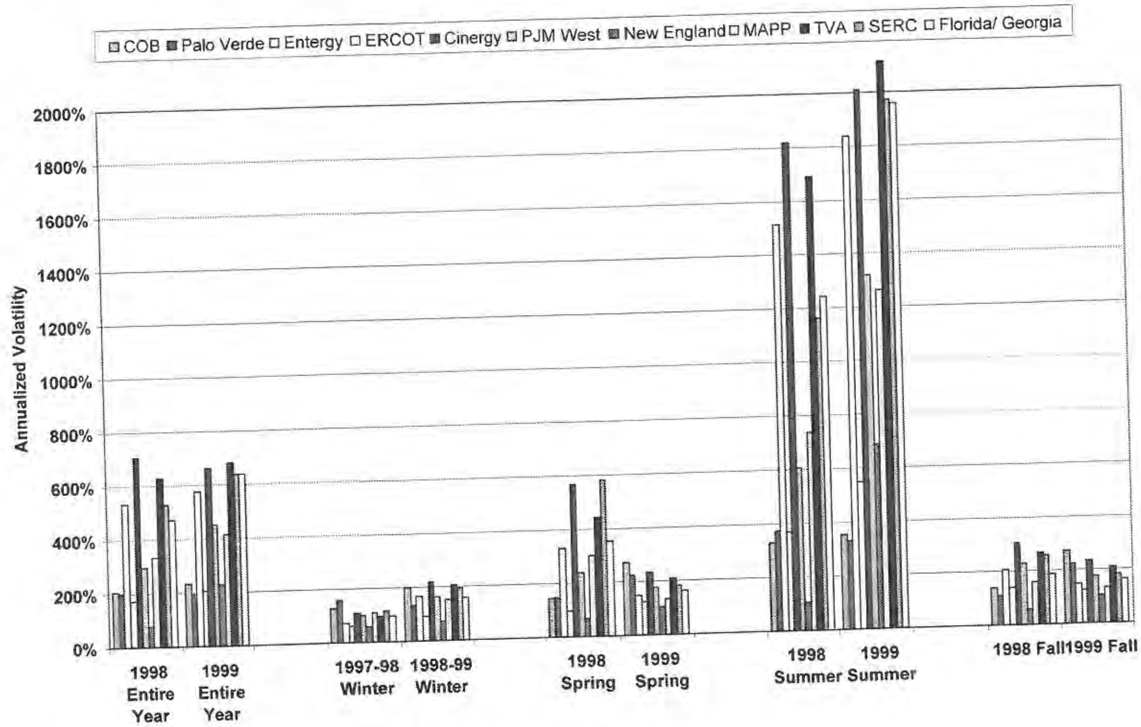


Figure 4-6
Volatility of Daily Spot Power Prices by Season

Volatility calculations were also made using weekly rather than daily peak power price data as reported by *Power Markets Week* for the same 11 regions for 1999. This analysis revealed two important findings that are useful to practitioners using these data. First, the volatility measures presented in Table 4-2 for daily spot data are higher than that measured from average weekly data. Table 4-3 compares the annual average volatility for each of the 11 regions in 1999. The first column summarizes the average volatility measured from daily data, the second column measures that from average weekly power price data. In all but two regions the volatility measured from daily data exceed that measured from average weekly data.

Further analysis of the weekly volatility results yields one fruitful pattern for understanding the behavior of power price volatility. That is, volatility is nicely linearly related to the average price level. Figure 4-7 plots the average weekly price for summer against the corresponding volatility for that region. A similar pattern holds for the annual average data as well. This has application in assessing future spot price volatility with forward prices, since the latter may well be directly observable, but the former is not.

Table 4-3
Comparison of 1999 Annualized Volatility: Daily vs. Weekly Data

Region	*1999 Average Annual Volatility Weekly Data*	*1999 Average Annual Volatility Daily Data*
COB	127%	234%
Palo Verde	120%	195%
Entergy	440%	577%
ERCOT	258%	207%
Cinergy	503%	663%
PJM West	356%	454%
New England	225%	229%
MAPP	451%	416%
TVA	482%	683%
SERC	450%	639%
Florida/Georgia	421%	639%

Source: *Power Markets Week* and Project Team.

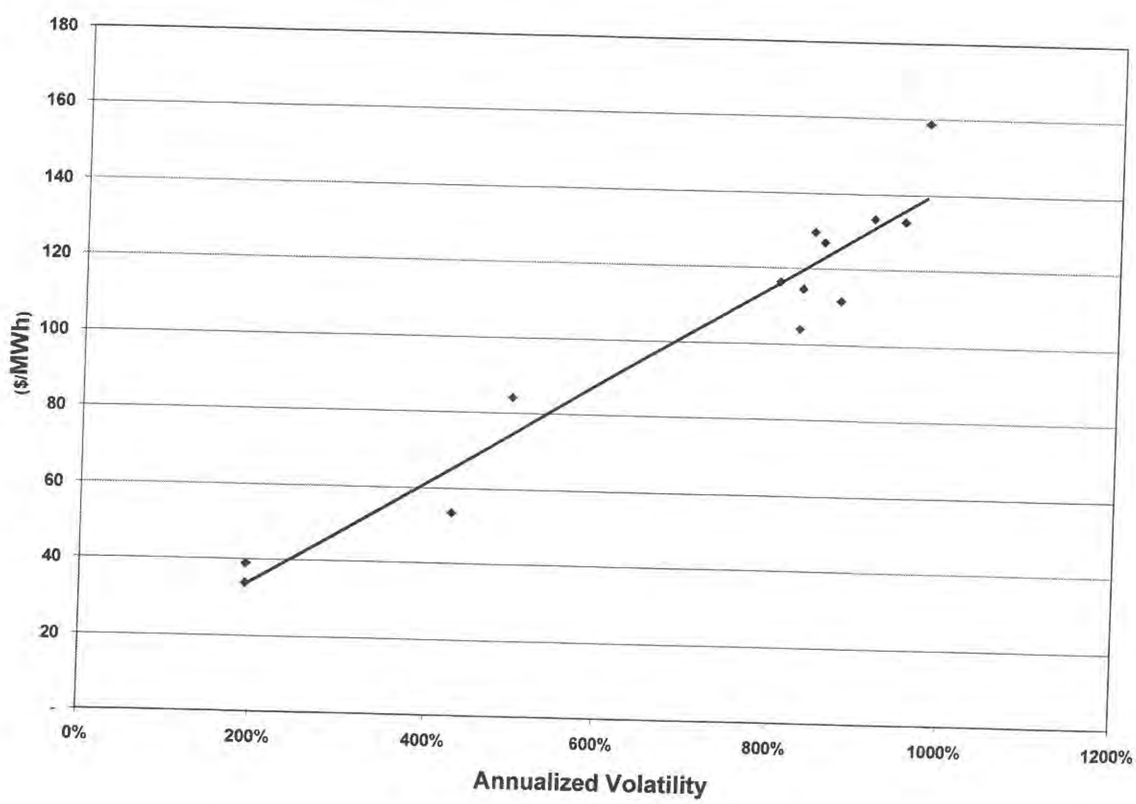


Figure 4-7
Volatility of Weekly Electric Prices by Region vs. Average Weekly Price—Summer 1999

The preceding results should highlight the difficulties in drawing conclusions about expected volatility from historical spot price data for a given region. Just as there is not one price of electricity, there is not one measure of the volatility of electric prices—even within a single region. While this may seem "obvious," the degree to which it is done is much greater than most people would expect. It also has important implications for explaining to senior management why a particular contract may be very difficult to value objectively!

The discussion so far has focused on the "personality" of daily and weekly peak spot power price volatility. Today, risk managers rely heavily on forward markets, the most public of which are the electricity futures. Futures price data allow a unique opportunity to track the volatility of the monthly price of a commodity as the date of delivery approaches. Table 4-4 shows the annualized volatility for the price of electricity to be delivered in August 1998 inferred in this fashion.[38] Specifically, 55% is the measure of the volatility of the price of the August Cinergy futures contract in February 1998 (6 months prior to delivery), while 33% is a measure of the volatility of the price of the August Cinergy futures contract in May (3 months prior to deliver). At the bottom of the table the volatility of the annual weekly spot price, the summer weekly spot price and daily summer spot price are reported. Several things are worth noting. The future price of the commodity is less volatile than the spot price—it is less susceptible to stochastic shocks. (Compare 55% to 957%, the volatility of the weekly summer spot price.) Second, the tendency for volatility to increase as the date of expiration approaches is to be expected. In essence, volatility increases as recent conditions begin to be more critical to expectations. Thus, Table 4-4 illustrates another dimension to volatility—term structure.

Table 4-4
Annualized Volatility: Cinergy 1997 and 1998

August Futures	**1997**	**1998**	**Data**
6 Month	N/A	55%	Daily August Futures
3 Month	N/A	33%	Daily August Futures
1 Month	N/A	97%	Daily August Futures
Spot			
Annual	303%	533%	Weekly Spot
Summer	506%	957%	Weekly Spot
Daily Summer	559%	1190%	Daily Spot

Source: Data from *Power Markets Week.* Calculations by Project Team.

Near-term volatility, i.e., volatility of daily prices for a power contract over the one month prior to expiration, was calculated for COB, Cinergy, and Palo Verde futures contracts expiring in each month January 1998 to July 1999 when data were available. These volatility results are reported in Table 4-5 with monthly volatility estimates using daily spot prices. It is clear that the volatility using futures data is more predictable, and comparatively, more tightly distributed. Of

[38] See Appendix B for a discussion of how volatility was calculated using futures data.

course it must be understood that this is the volatility of the forward price itself, not the prediction of future spot price volatility. The future average monthly spot price uncertainty is the compound uncertainty in the distant forward volatility. That is, expected prices do not become more certain the farther out we look. Rather, the susceptibility to change in expectations per period (day, month, etc.) goes down while the period of total uncertainty exposure (horizon until the futures contract matures) increases. Nevertheless, this does not happen to an equal degree for the July & September forwards, even when they are roughly comparably distant (hence the term structure). Once a contract is about one month out, it is a pretty good predictor of expected, but not realized, spot volatility.

Table 4-5
Futures vs. Daily Spot Power Price Volatility by Month

	Month-Ahead Futures Contract Volatility			Realized Daily Spot Volatility		
	Cinergy	*COB*	*Palo Verde*	*Cinergy*	*COB*	*Palo Verde*
Jan-98		54%	61%	133%	140%	104%
Feb-98		55%	57%	82%	119%	207%
Mar-98		46%	45%	398%	166%	132%
Apr-98		39%	29%	292%	95%	79%
May-98		62%	46%	1003%	173%	226%
Jun-98		105%	81%	1204%	388%	429%
Jul-98		89%	79%	3403%	292%	342%
Aug-98	105%	65%	67%	856%	312%	341%
Sep-98	65%	24%	32%	539%	169%	187%
Oct-98	44%	49%	42%	214%	123%	44%
Nov-98	91%	41%	38%	167%	117%	102%
Dec-98	50%	73%	53%	162%	343%	204%
Jan-99	45%	57%	39%	334%	150%	116%
Feb-99	25%	35%	30%	156%	100%	79%
Mar-99	77%	41%	28%	165%	154%	87%
Apr-99	76%	48%	35%	179%	224%	165%
May-99	113%	48%	50%	177%	133%	104%
Jun-99	103%	78%	137%	1389%	394%	343%
Jul-99	109%	47%	40%	3732%	386%	374%

Source: Data from *Power Markets Week*. Calculations by Project Team.

The volatility for power price futures contracts is found in Figure 4-8. Like the results derived from daily spot power price data, there appear to be no precise patterns aside from summer being more than twice as volatile as other months, ranging from around 40% in non-summer months to 80-100% in summer, and winter being a bit more volatile than spring and fall. This result is particularly notable from studying the results for the Palo Verde and COB futures contracts. Cinergy futures, still a relatively young market, are starting to display a similar pattern.

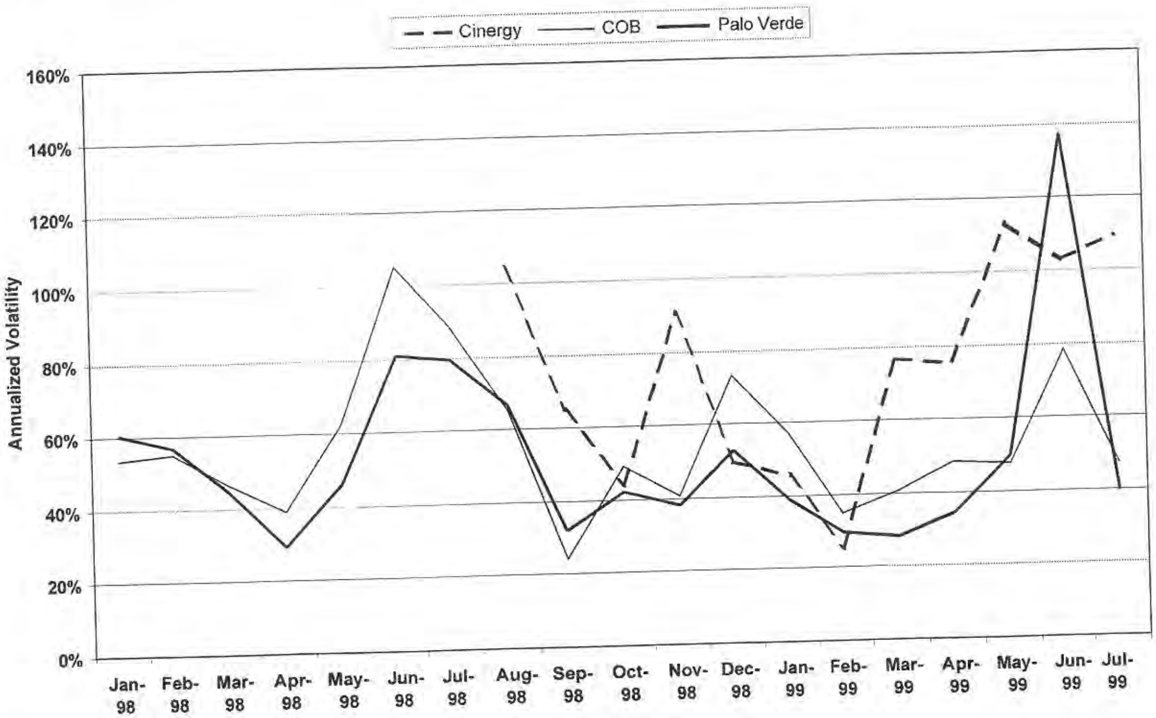


Figure 4-8
Volatility of Power Price Futures Contracts by Month

Electricity Price Correlation

One of the most striking findings from these statistics is how dramatically contemporaneous weekly spot prices vary by location. A comprehensive assessment of how spot power prices of electricity vary by region was undertaken by evaluating power price correlation. Correlation statistics provide a snapshot of how prices vary between regions. This statistic was calculated using both daily and weekly power price data as reported by *Power Markets Week*. Table 4-6 summarizes the correlation statistics by year for 1995 to 1999 and by season. For example, the fall correlation statistic incorporates fall electricity prices for all years where data are available. Correlation statistics between 0.8 and 1.0 are highlighted. Correlation statistics for 1998 and 1999 were also calculated by month using daily power price data. They are reported in Appendix B to this report along with a discussion of how this statistic was calculated.

Table 4-6
Correlations of Electricity to Electricity Prices: Weekly On-Peak Prices

Electricity Market		CIN	COB	ECAR	ENTERGY	ERCOT	Florida	MAIN	NEPOOL	Palo Verde	PJM	SERC	SPP	TVA
Cinergy	1995													
Cinergy	1996													
Cinergy	1997	**1.00**	-0.01	**1.00**	**0.98**	0.37	**0.91**	**0.99**	0.62	0.20	**0.97**	**0.99**		**1.00**
Cinergy	1998	**1.00**	-0.05	**1.00**	**0.97**	**0.87**		**0.89**	0.40	0.12	0.80	**0.97**	**0.97**	
Cinergy	1999*	**1.00**	0.15	**1.00**	**0.99**	0.52		**0.97**	**0.91**	0.31		**0.99**	**0.99**	
Cinergy	Fall	**1.00**	-0.16	**1.00**	**0.91**	0.28		**0.95**	0.14	-0.19	**0.97**	**0.92**	**0.95**	
Cinergy	Spring	**1.00**	0.02	**1.00**	**0.99**	0.42	**1.00**	**0.99**	0.78	0.05	**0.95**	**0.98**	**0.97**	0.34
Cinergy	Summer	**1.00**	-0.15	**1.00**	**0.97**	**0.84**		**0.89**	0.22	-0.20	0.73	**0.97**	**0.96**	**1.00**
Cinergy	Winter	**1.00**	0.31	**0.99**	**0.91**	0.52	**0.91**	**0.97**	0.07	0.27	0.71	**0.97**	**0.91**	
COB	1995		**1.00**	0.17					-0.28	0.79	0.15			
COB	1996		**1.00**	0.08		0.58	-0.25	0.26	0.61	**0.87**	-0.02	-0.09		
COB	1997	-0.01	**1.00**	0.00	0.03	0.31	**0.82**	0.01	0.04	0.68	-0.02	0.04		-0.29
COB	1998	-0.05	**1.00**	-0.05	-0.02	0.07		-0.05	-0.11	**0.92**	0.19	-0.06	-0.04	
COB	1999*	0.15	**1.00**	0.63	0.24	0.65		0.70	0.37	**0.94**		0.24	0.24	
COB	Fall	-0.16	**1.00**	0.23	-0.35	-0.31	0.43	0.06	0.16	0.66	0.38	0.07	-0.48	
COB	Spring	0.02	**1.00**	0.02	0.03	0.17	-0.28	0.06	0.19	**0.89**	-0.21	0.05	-0.20	0.05
COB	Summer	-0.15	**1.00**	0.03	-0.12	0.04	-0.25	-0.02	-0.10	**0.86**	0.11	-0.03	-0.51	-0.38
COB	Winter	0.31	**1.00**	0.22	0.32	0.32	0.75	0.35	-0.13	**0.95**	-0.19	0.34	0.51	
ECAR	1995		0.17	**1.00**					0.38	0.20	0.70			
ECAR	1996		0.08	**1.00**		0.49	0.76	**0.92**	0.19	0.17	0.68	**0.90**		
ECAR	1997	**1.00**	0.00	**1.00**	**0.98**	0.37	**0.92**	**0.99**	0.61	0.21	**0.97**	**0.99**		**1.00**
ECAR	1998	**1.00**	-0.05	**1.00**	**0.97**	**0.87**		**0.89**	0.40	0.12	0.80	**0.97**	**0.97**	
ECAR	1999*	**1.00**	0.63	**1.00**	**0.97**	0.77		**0.97**	0.58	0.66		**0.97**	**0.95**	
ECAR	Fall	**1.00**	0.23	**1.00**	**0.92**	0.40	**0.87**	**0.96**	0.24	0.27	**0.92**	**0.92**	**0.95**	
ECAR	Spring	**1.00**	0.02	**1.00**	**0.99**	0.32	**0.83**	**0.98**	0.25	0.08	**0.85**	**0.98**	**0.99**	0.40
ECAR	Summer	**1.00**	0.03	**1.00**	**0.97**	**0.84**	0.71	**0.89**	0.27	0.07	0.73	**0.97**	**0.96**	**1.00**
ECAR	Winter	**0.99**	0.22	**1.00**	**0.91**	0.55	**0.93**	**0.93**	0.19	0.18	0.65	**0.96**	**0.92**	
ENTERGY	1995													
ENTERGY	1996													
ENTERGY	1997	**0.98**	0.03	**0.98**	**1.00**	0.47	0.76	**0.98**	0.66	0.28	**0.95**	**0.99**		**0.99**
ENTERGY	1998	**0.97**	-0.02	**0.97**	**1.00**	**0.90**		**0.95**	0.42	0.15	**0.88**	**0.96**	**0.96**	
ENTERGY	1999*	**0.99**	0.24	**0.97**	**1.00**	0.61		**0.95**	**0.92**	0.39		**1.00**	**1.00**	
ENTERGY	Fall	**0.91**	-0.35	**0.92**	**1.00**	0.52		**0.92**	0.34	-0.06	**0.87**	**0.95**	**0.99**	
ENTERGY	Spring	**0.99**	0.03	**0.99**	**1.00**	0.51	**1.00**	**0.97**	0.71	0.06	**0.93**	**0.99**	**0.99**	-0.13
ENTERGY	Summer	**0.97**	-0.12	**0.97**	**1.00**	**0.88**		**0.94**	0.24	-0.16	**0.81**	**0.95**	**0.95**	**1.00**
ENTERGY	Winter	**0.91**	0.32	**0.91**	**1.00**	0.43	**0.80**	**0.92**	0.19	0.27	0.51	**0.95**	**0.90**	
ERCOT	1995													
ERCOT	1996		0.58	0.49		**1.00**	0.31	0.54	0.31	0.54	0.16	0.53		
ERCOT	1997	0.37	0.31	0.37	0.47	**1.00**	**0.82**	0.40	0.34	0.45	0.40	0.43		0.46
ERCOT	1998	**0.87**	0.07	**0.87**	**0.90**	**1.00**		**0.87**	0.43	0.25	0.79	**0.89**	**0.90**	
ERCOT	1999*	0.52	0.65	0.77	0.61	**1.00**		0.76	0.70	0.66		0.60	0.61	
ERCOT	Fall	0.28	-0.31	0.40	0.52	**1.00**	0.55	0.50	0.50	0.50	0.54	0.52	0.69	
ERCOT	Spring	0.42	0.17	0.32	0.51	**1.00**	0.62	0.25	0.39	0.14	0.24	0.47	0.41	-0.63
ERCOT	Summer	**0.84**	0.04	**0.84**	**0.88**	**1.00**	0.68	**0.87**	0.22	0.07	0.67	**0.87**	**0.91**	0.34
ERCOT	Winter	0.52	0.32	0.55	0.43	**1.00**	**0.85**	0.59	0.49	0.28	0.39	0.59	0.49	
Florida	1995													
Florida	1996		-0.25	0.76		0.31	**1.00**	0.61	-0.19	0.00	0.61	**0.89**		
Florida	1997	**0.91**	**0.82**	**0.92**	0.76	**0.82**	**1.00**	**0.93**	0.49	0.77	**0.86**	**0.96**		
Florida	1998													
Florida	1999*													
Florida	Fall		0.43	**0.87**		0.55	**1.00**	**0.82**	0.54	0.23	**0.86**	**0.86**		
Florida	Spring	**1.00**	-0.28	**0.83**	**1.00**	0.62	**1.00**	0.51	0.26	-0.28	0.27	**0.84**		
Florida	Summer		-0.25	0.71		0.68	**1.00**	0.62	0.22	-0.21	0.58	**0.92**		
Florida	Winter	**0.91**	0.75	**0.93**	**0.80**	**0.85**	**1.00**	**0.95**	0.49	0.78	**0.84**	**0.97**		

Table 4-6
Correlations of Electricity to Electricity Prices: Weekly On-Peak Prices (Continued)

Electricity Market		CIN	COB	ECAR	ENTERGY	ERCOT	Florida	MAIN	NEPOOL	Palo Verde	PJM	SERC	SPP	TVA
MAIN	1995	.	.	.	.	.	.	.	.	.	.	.	.	.
MAIN	1996	.	0.26	**0.92**	.	0.54	0.61	**1.00**	0.37	0.27	0.67	**0.82**	.	.
MAIN	1997	**0.99**	0.01	**0.99**	**0.98**	0.40	**0.93**	**1.00**	0.64	0.17	**0.97**	**0.98**	.	**1.00**
MAIN	1998	**0.89**	-0.05	**0.89**	**0.95**	**0.87**	.	**1.00**	0.35	0.08	0.75	**0.96**	**0.96**	.
MAIN	1999*	**0.97**	0.70	**0.97**	**0.95**	0.76	.	**1.00**	0.72	0.76	.	**0.95**	**0.96**	.
MAIN	Fall	**0.95**	0.06	**0.96**	**0.92**	0.50	**0.82**	**1.00**	0.17	0.17	**0.96**	**0.90**	**0.96**	.
MAIN	Spring	**0.99**	0.06	**0.98**	**0.97**	0.25	0.51	**1.00**	0.28	0.11	**0.84**	**0.95**	**0.98**	0.61
MAIN	Summer	**0.89**	-0.02	**0.89**	**0.94**	**0.87**	0.62	**1.00**	0.24	-0.03	0.71	**0.96**	**0.96**	**1.00**
MAIN	Winter	**0.97**	0.35	**0.93**	**0.92**	0.59	**0.95**	**1.00**	0.23	0.33	0.49	**0.96**	**0.87**	.
NEPOOL	1995	.	-0.28	0.38	.	.	.	.	**1.00**	-0.14	0.70	.	.	.
NEPOOL	1996	.	0.61	0.19	.	0.31	-0.19	0.37	**1.00**	0.39	0.49	0.08	.	.
NEPOOL	1997	0.62	0.04	0.61	0.66	0.34	0.49	0.64	**1.00**	-0.04	0.73	0.63	.	**0.82**
NEPOOL	1998	0.40	-0.11	0.40	0.42	0.43	.	0.35	**1.00**	0.12	0.52	0.37	0.43	.
NEPOOL	1999*	**0.91**	0.37	0.58	**0.92**	0.70	.	0.72	**1.00**	0.50	.	**0.92**	**0.91**	.
NEPOOL	Fall	0.14	0.16	0.24	0.34	0.50	0.54	0.17	**1.00**	0.35	0.53	-0.02	0.25	.
NEPOOL	Spring	0.78	0.19	0.25	0.71	0.39	0.26	0.28	**1.00**	0.20	0.48	0.69	0.68	-0.03
NEPOOL	Summer	0.22	-0.10	0.27	0.24	0.22	0.22	0.24	**1.00**	0.10	0.58	0.24	0.49	**0.83**
NEPOOL	Winter	0.07	-0.13	0.19	0.19	0.49	0.49	0.23	**1.00**	-0.18	0.32	0.28	0.13	.
Palo Verde	1995	.	0.79	0.20	.	.	.	.	-0.14	**1.00**	0.13	.	.	.
Palo Verde	1996	.	**0.87**	0.17	.	0.54	0.00	0.27	0.39	**1.00**	0.04	0.07	.	.
Palo Verde	1997	0.20	0.68	0.21	0.28	0.45	0.77	0.17	-0.04	**1.00**	0.14	0.29	.	0.19
Palo Verde	1998	0.12	**0.92**	0.12	0.15	0.25	.	0.08	0.12	**1.00**	0.35	0.09	0.11	.
Palo Verde	1999*	0.31	**0.94**	0.66	0.39	0.66	.	0.76	0.50	**1.00**	.	0.40	0.39	.
Palo Verde	Fall	-0.19	0.66	0.27	-0.06	0.50	0.23	0.17	0.35	**1.00**	0.33	0.34	-0.08	.
Palo Verde	Spring	0.05	**0.89**	0.08	0.06	0.14	-0.28	0.11	0.20	**1.00**	-0.15	0.09	0.01	-0.15
Palo Verde	Summer	-0.20	**0.86**	0.07	-0.16	0.07	-0.21	-0.03	0.10	**1.00**	0.14	-0.03	-0.43	0.08
Palo Verde	Winter	0.27	**0.95**	0.18	0.27	0.28	0.78	0.33	-0.18	**1.00**	-0.28	0.34	0.48	.
PJM	1995	.	0.15	0.70	.	.	.	.	0.70	0.13	**1.00**	.	.	.
PJM	1996	.	-0.02	0.68	.	0.16	0.61	0.67	0.49	0.04	**1.00**	0.80	.	.
PJM	1997	**0.97**	-0.02	**0.97**	**0.95**	0.40	**0.86**	**0.97**	0.73	0.14	**1.00**	**0.96**	.	**0.98**
PJM	1998	0.80	0.19	0.80	**0.88**	0.79	.	0.75	0.52	0.35	**1.00**	0.74	0.76	.
PJM	1999*	.	.	.	.	.	.	.	.	.	.	.	.	.
PJM	PJM	**0.97**	0.38	**0.92**	**0.87**	0.54	**0.86**	**0.96**	0.53	0.33	**1.00**	**0.87**	.	.
PJM	PJM	**0.95**	-0.21	**0.85**	**0.93**	0.24	0.27	**0.84**	0.48	-0.15	**1.00**	**0.89**	**0.97**	0.67
PJM	PJM	0.73	0.11	0.73	**0.81**	0.67	0.58	0.71	0.58	0.14	**1.00**	0.68	0.68	**0.98**
PJM	PJM	0.71	-0.19	0.65	0.51	0.39	**0.84**	0.49	0.32	-0.28	**1.00**	0.76	**0.95**	.
SERC	1995	.	.	.	.	.	.	.	.	.	.	.	.	.
SERC	1996	.	-0.09	**0.90**	.	0.53	**0.89**	**0.82**	0.08	0.07	0.80	**1.00**	.	.
SERC	1997	**0.99**	0.04	**0.99**	**0.99**	0.43	**0.96**	**0.98**	0.63	0.29	**0.96**	**1.00**	.	**0.99**
SERC	1998	**0.97**	-0.06	**0.97**	**0.96**	**0.89**	.	**0.96**	0.37	0.09	0.74	**1.00**	**1.00**	.
SERC	1999*	**0.99**	0.24	**0.97**	**1.00**	0.60	.	**0.95**	**0.92**	0.40	.	**1.00**	**0.99**	.
SERC	Fall	**0.92**	0.07	**0.92**	**0.95**	0.52	**0.86**	**0.90**	-0.02	0.34	**0.87**	**1.00**	**0.96**	.
SERC	Spring	**0.98**	0.05	**0.98**	**0.99**	0.47	**0.84**	**0.95**	0.69	0.09	**0.89**	**1.00**	**0.99**	0.64
SERC	Summer	**0.97**	-0.03	**0.97**	**0.95**	**0.87**	**0.92**	**0.96**	0.24	-0.03	0.68	**1.00**	**1.00**	**0.99**
SERC	Winter	**0.97**	0.34	**0.96**	**0.95**	0.59	**0.97**	**0.96**	0.28	0.34	0.76	**1.00**	**0.88**	.
SPP	1995	.	.	.	.	.	.	.	.	.	.	.	.	.
SPP	1996	.	.	.	.	.	.	.	.	.	.	.	.	.
SPP	1997	.	.	.	.	.	.	.	.	.	.	.	.	.
SPP	1998	**0.97**	-0.04	**0.97**	**0.96**	**0.90**	.	**0.96**	0.43	0.11	0.76	**1.00**	**1.00**	.
SPP	1999*	**0.99**	0.24	**0.95**	**1.00**	0.61	.	**0.96**	**0.91**	0.39	.	**0.99**	**1.00**	.
SPP	Fall	**0.95**	-0.48	**0.95**	**0.99**	0.69	.	**0.96**	0.25	-0.08	.	**0.96**	**1.00**	.
SPP	Spring	**0.97**	-0.20	**0.99**	**0.99**	0.41	.	**0.98**	0.68	0.01	**0.97**	**0.99**	**1.00**	.
SPP	Summer	**0.96**	-0.51	**0.96**	**0.95**	**0.91**	.	**0.96**	0.49	-0.43	0.68	**1.00**	**1.00**	.
SPP	Winter	**0.91**	0.51	**0.92**	**0.90**	0.49	.	**0.87**	0.13	0.48	**0.95**	**0.88**	**1.00**	.
TVA	1995	.	.	.	.	.	.	.	.	.	.	.	.	.
TVA	1996	.	.	.	.	.	.	.	.	.	.	.	.	.
TVA	1997	**1.00**	-0.29	**1.00**	**0.99**	0.46	.	**1.00**	**0.82**	0.19	**0.98**	**0.99**	.	**1.00**
TVA	1998	.	.	.	.	.	.	.	.	.	.	.	.	.
TVA	1999*	.	.	.	.	.	.	.	.	.	.	.	.	.
TVA	Fall	.	.	.	.	.	.	.	.	.	.	.	.	.
TVA	Spring	0.34	0.05	0.40	-0.13	-0.63	.	0.61	-0.03	-0.15	0.67	0.64	.	**1.00**
TVA	Summer	**1.00**	-0.38	**1.00**	**1.00**	0.34	.	**1.00**	**0.83**	0.08	**0.98**	**0.99**	.	**1.00**
TVA	Winter	.	.	.	.	.	.	.	.	.	.	.	.	.

Notes: January 1999 - June 1999.

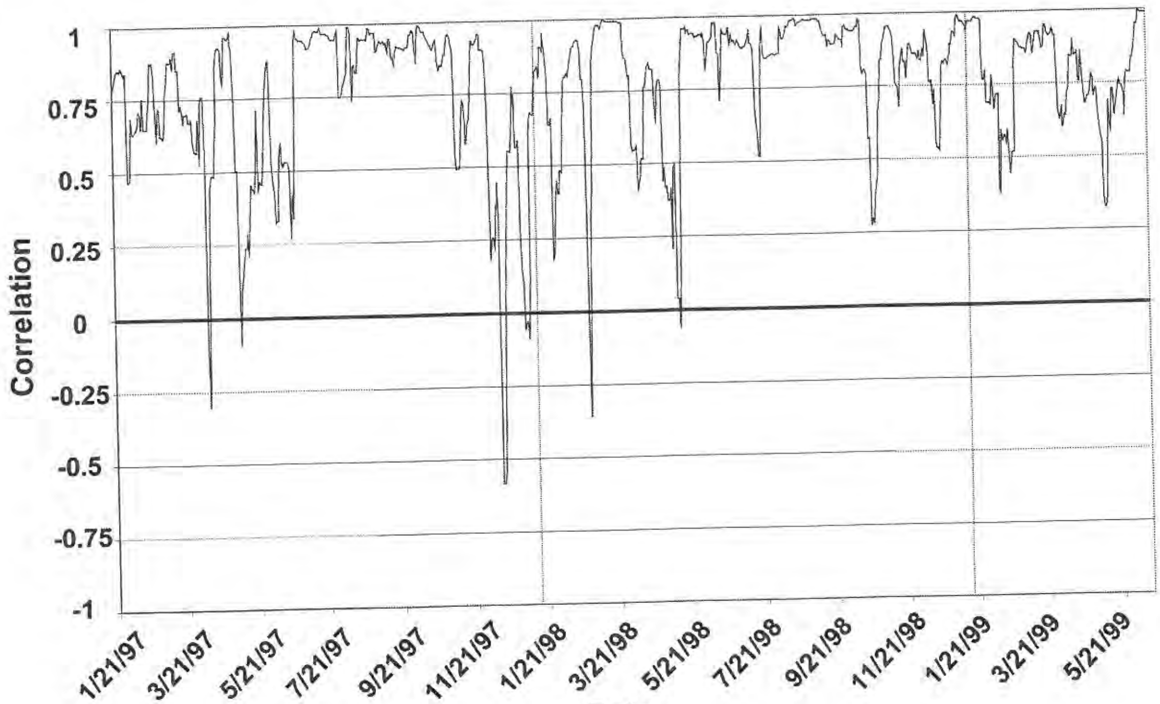
It is clear from these statistics that prices are indeed highly correlated for neighboring regions. What is striking, is the high correlation between many of the regions in the central U.S. Spot power prices in Cinergy, Entergy, MAIN, SERC, SPP and TVA are all highly correlated year round, with a correlation statistic of roughly 0.90 or greater. PJM is correlated with its neighbors on a seasonal basis, spring and fall, when transmission constraints are not so limiting. PJM is also highly correlated with many of these Midwest regions in 1997, likely the last year before markets generally started to tighten.

Areas that are isolated nearly year-round for transmission reasons are also evident from the correlation analysis results. Spot prices for COB and Palo Verde, with few exceptions, are highly correlated with each other, but not with power prices in other regions. Similarly, spot power prices in ERCOT are not correlated with any regions as a result of the lack of interconnections with any neighboring regions. Note that while visual inspection of the weekly data might suggest that in 1998 ERCOT spot prices were correlated with the neighboring regions in the Midwest, under formal testing of the monthly results for 1998, there does not appear to be any correlation, as is seen by the lack of shading in the ERCOT column. This should not be surprising in light of its asynchonicity. NEPOOL and New York are similarly isolated, though synchronized. The spot prices for these two regions are generally uncorrelated with any other regions.

Florida shows strong seasonal patterns, especially upon examining the monthly data in Appendix B. Florida/Georgia spot prices are highly correlated with Cinergy, ECAR, SERC and TVA in the summer. This is a result of the large amount of imports flowing to Florida in the summer needed to peak load. There also appears to be strong correlation, especially from the weekly data, that winters are similarly highly correlated.

Finally, it is worth noting that the level of correlation, when regions are correlated, has been relatively steady over time. Even the introduction of markets in some regions has not altered the old or introduced new patterns. This stable behavior contrasts to what is observed in the natural gas markets.

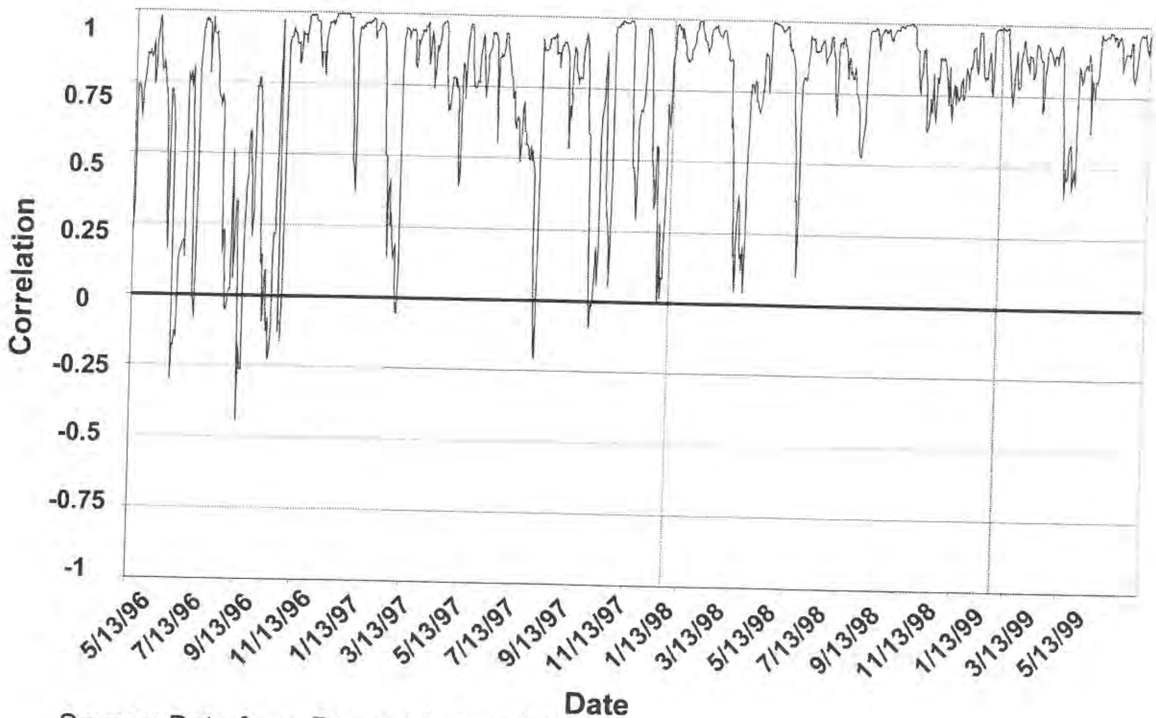
The correlation statistics in Table 4-6 can be used to provide a broad overview of how prices between neighboring regions vary on average. However, today, electricity price risk is often managed over shorter time intervals. The statistics discussed thus far may be calculated over too large a time interval to tell the complete story. To assess the volatility of electric spot price correlation, fifteen-day correlation statistics were calculated on a rolling basis for two pairs of neighboring regions, Cinergy vs. PJM, and COB vs. Palo Verde. Daily spot price data as reported by *Power Markets Week* were used. (See Appendix B for a detailed discussion of how these statistics were calculated.) Figure 4-9 is a plot of the fifteen-day correlation statistics for Cinergy vs. PJM. The correlation of daily spot power prices over 15-day intervals for these two neighboring regions are volatile. The correlation between the electric prices for Cinergy and PJM over the entire summer of 1998 is 0.67. The micro perspective shown in this figure reveals that these prices are highly correlated at many times during the year; and uncorrelated or even sharply negatively correlated at other times.



Source: Data from *Power Markets Week.*

Figure 4-9
Fifteen-Day Rolling Correlation of Electricity Spot Markets: Cinergy vs. PJM

One might ask whether the correlation of prices when calculated over a long time interval tells you anything about the behavior or volatility of correlation. It is not that surprising to see the volatility of correlation for Cinergy and PJM since the average seasonal correlation was relatively low at 0.67. However, this volatility even appears in regions that are highly correlated. Consider the graph of fifteen-day rolling correlations between COB and Palo Verde daily spot power prices in Figure 4-10. The correlation of these spot prices is volatile throughout the entire time period as well. For the summer of 1998 in aggregate, however, the correlation of electric spot prices for these regions is 0.92—suggesting prices that generally move together across California. Correlation is important to planning and valuations because it informs where to place power outputs. If MAIN and ECAR are highly correlated, it is less critical to find the right offtake market. Likewise, valuation of products that depend on volatility often also depend on correlation. If two products are correlated, the variance between them is low, conversely. Thus, the risk and value of regional swaps or "basis" contracts will depend on correlations.



Source: Data from *Power Markets Week.*

Figure 4-10
Fifteen-Day Rolling Correlation of Electricity Spot Markets: COB vs. Palo Verde

The key lesson to draw from these results is that the correlation of electric prices between neighboring regions has a complex, sometimes idiosyncratic "personality"—just like volatility. Electricity price correlations can vary by time, duration, year, and season and do not necessarily recapitulate themselves. The behavior of the correlation between electric prices for neighboring regions can be linked to the physical structure of the regions' electric infrastructure, namely transmission.

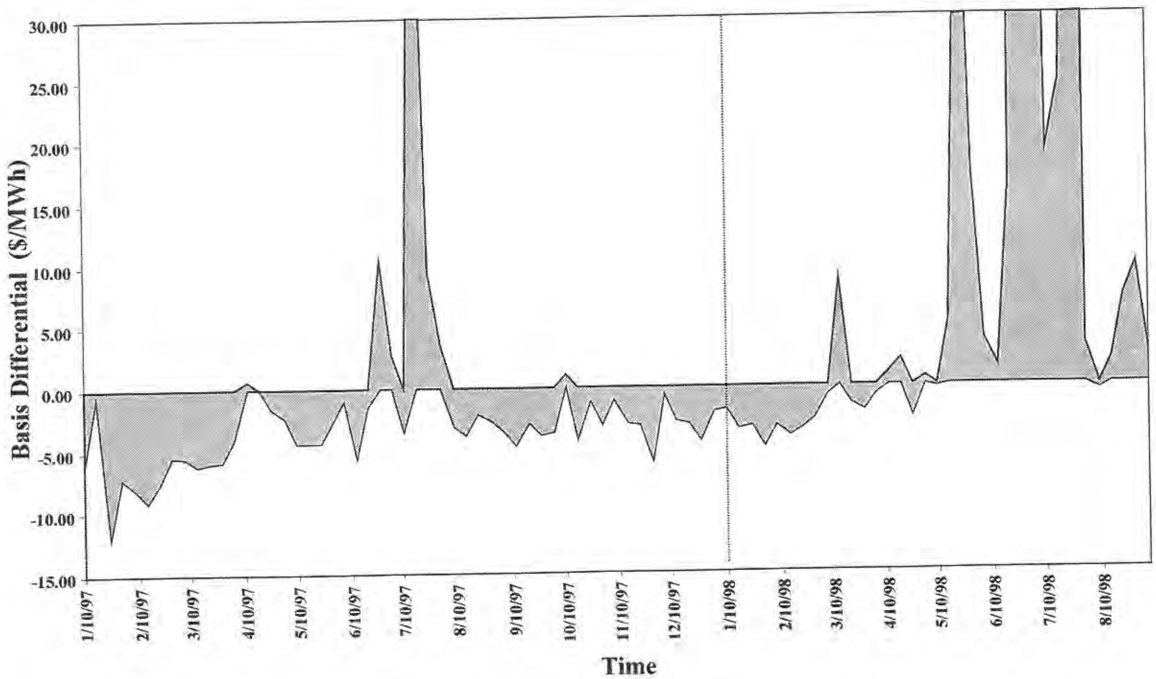
Electric Price Basis Differentials

Risk managers are not only concerned about the relative variation of prices between neighboring regions but also the absolute difference between the prices and how it varies over time. A marketer residing in Region A would prefer to buy from a generator in Region B whenever the market price in Region A exceeds the market price in Region B plus the price of transmission.

The term of art for cross-location contemporaneous price differences is *basis differentials.*[39] Basis differentials might be expected to be stable, perhaps seasonal, reflecting average transportation costs. However, when transmission is binding, basis differentials will deviate

[39] More generally, basis differentials refer to any inconsistency in value movement between products that act as imperfect surrogates or substitutes for one another.

substantially from this average transmission figure. Figure 4-11 shows the weekly westward basis differentials for Cinergy vs. PJM from January1997 to June 1999.

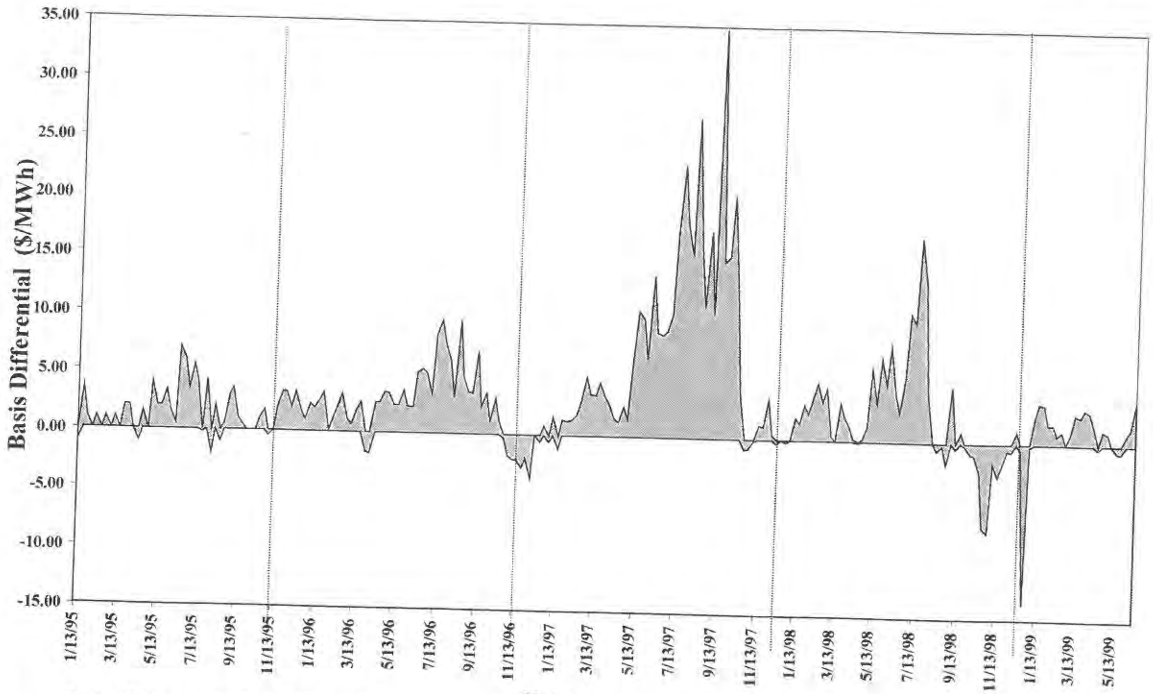


Note: Cinergy price - PJM price.
There are 5 values that fall outside the scale of this graph, ranging from 47.31 on 5/23/98 to 594.99 on 6/27/98.

Figure 4-11
Weekly Basis Differentials for Cinergy vs. PJM

During periods when prices are relatively stable, the basis differential tends to hover around minus $5/MWh, approximately the average cost of transmission charges. If one were to overlay the corresponding weekly correlation statistics for Cinergy vs. PJM power prices a similar pattern would appear. Correlation would be close to 1.0 in those months when the basis differerential is close to or less than $5/MWh. Obviously, it can occasionally be much larger. The median is minus $2/MWh, indicating that the PJM area is typically more valuable than Cinergy. The mean basis differential is about $11/MWh, reflecting a few substantial spikes in Cinergy. Correlation would drop accordingly, even going negative, as basis differentials increase.

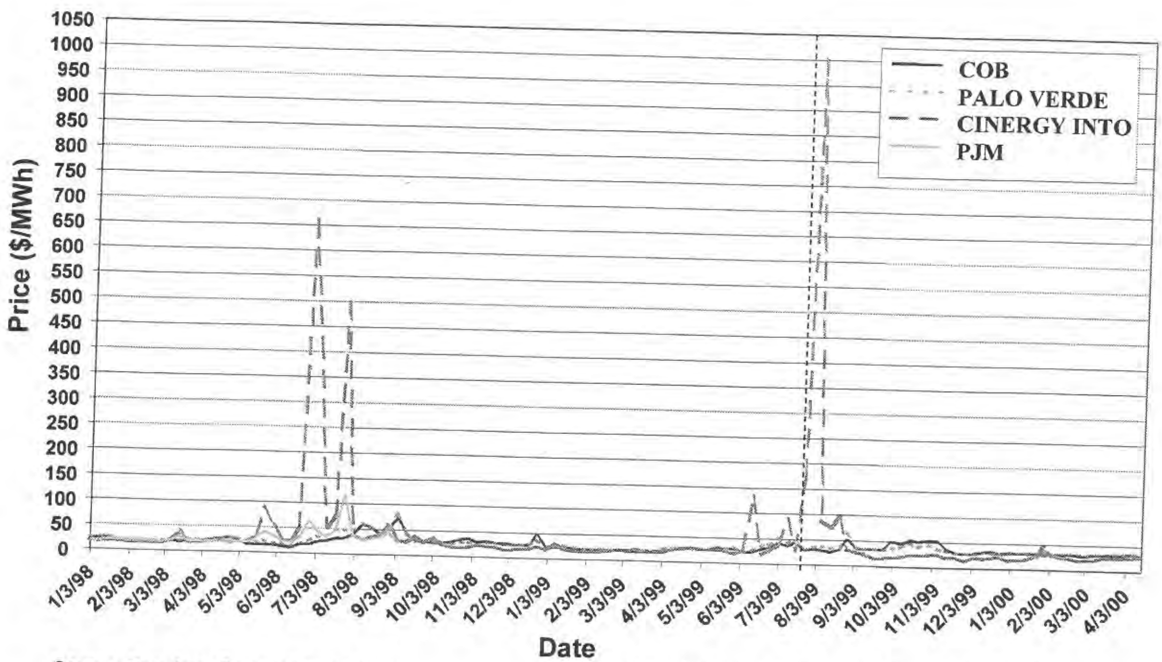
Figure 4-12 shows the weekly basis differentials for Palo Verde versus COB. The basis differential also varies considerably over time, but is much more unidirectional, with Palo Verde consistently higher. This is to be expected, in light of its warmer climate, lack of hydro, and California transmission constraints.



Note: Palo Verde price - COB price.

Figure 4-12
Weekly Basis Differentials for Palo Verde vs. COB

This result would not be as obvious if one were just to observe the relative COB and Palo Verde prices depicted in Figure 4-13.



Source: Data from *Power Markets Week*

Note: PJM data only to September 1998. Saturday date given.

Figure 4-13
Summer 1998 Weekly Spot Electric Prices: January 1, 1998 to April 15, 2000

Figure 4-13 suggests that prices move in tandem—indicative of a relatively stable basis differential. The basis differential can vary by time, in part, due to each region's generation mix and availability.

The results presented thus far strongly indicate that volatility and correlation of wholesale power prices (both spot and forward) have a complex, nearly unstable structure. They vary by time, duration, season and region. Thus, any analyst that assumes electric price volatility this period will be like the last could be making a fatal mistake. Electricity prices are on average highly correlated between neighboring regions. This correlation dissipates as the distance between neighboring regions, and transmission constraints increase. Note that this heterogeneity of prices differs from the increasing price homogeneity observed in the natural gas spot market. We next turn to how gas markets are related to electricity.

Natural Gas Prices

Previous chapters suggested that regional natural gas prices have become more integrated over time. The previous discussion in this chapter describing the behavior of spot and forward power prices clearly proves that electric prices are still heterogeneous. Different prices prevail in different regions. In this section the behavior of natural gas price distributions, volatility, correlation and price differentials are examined. The objective is to explore the comparability of gas and electric price behavior.

Natural Gas Price Distributions

Descriptive statistics, comparable to those calculated for electric prices, were calculated for average weekly spot prices of natural gas as reported by *Natural Gas Weekly*. The statistics were calculated for Alberta, Appalachia, Atlanta, Carthage, Henry Hub, Katy, New York, San Juan, Ventura, and Waha by season using data from April 1994 to June 1999. (Appendix B contains box plots by year for each of these natural gas hubs.)

These data on natural gas spot prices reveal that natural gas prices are distributed differently than electric spot prices. Winter prices tend to be peaky for natural gas; for electric, summer prices are peaky and tend to have a more skewed distribution. In general, natural gas prices are more normally distributed than are electric spot prices. (This is important because it makes them more amenable to simple option valuation models, rather than numerical models needed for normal distributions.) Moreover, for natural gas prices, winter prices are not as extreme as the summer is for electric prices. In fact, for some years, and some regions, the fall or even the spring price distributions, can on average have a mean price that exceeds the average winter price and be more skewed. The 1997 price distributions provide an excellent example of this phenomenon. With the exception of Alberta and Topock, the other hubs experienced prices that were distributed higher in fall than in any other season. The fact that Alberta and Topock did not behave the same is evidence that in 1997 natural gas prices were not yet homogeneous. However, prices for the San Juan hub did behave similar to the eastern hubs.

Since winter is the month when natural gas is at peak demand, and consequently, prices are expected to be most volatile, a more comprehensive examination of the behavior of weekly natural gas spot prices in winter was undertaken. Appendix B contains plots comparing the distribution of weekly spot natural gas prices in the winter for the years 1994 to 1999 for selected regions. Figure 4-14 is a representative plot of the descriptive statistics for winter.

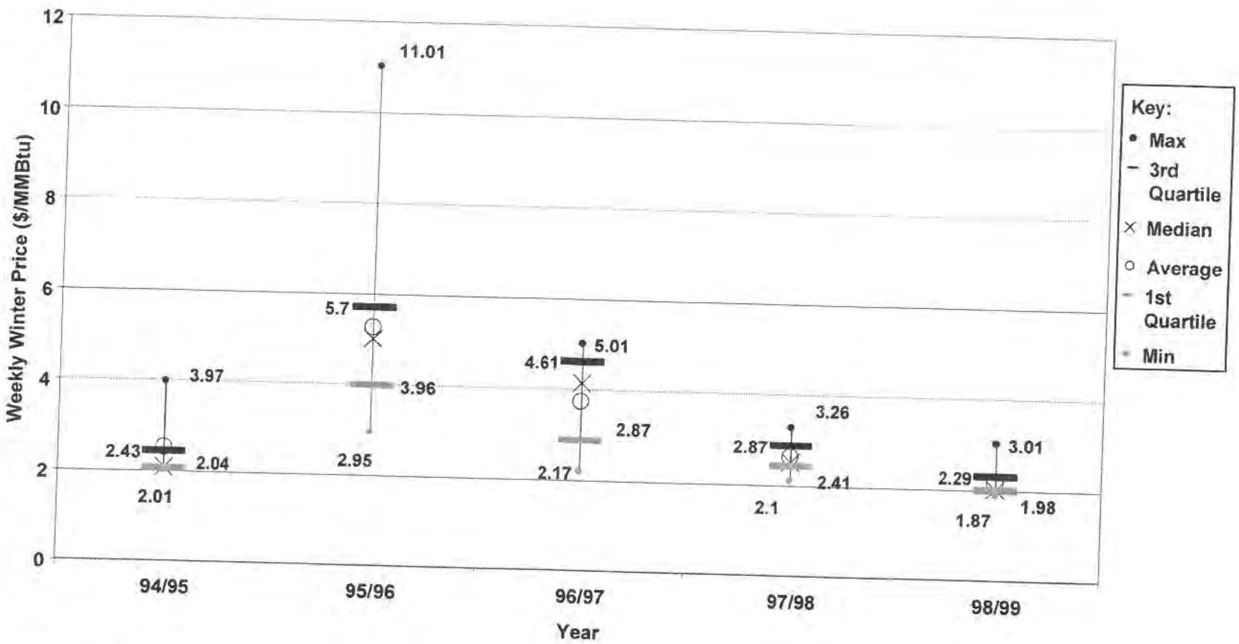


Figure 4-14
Natural Gas Price Distribution: New York Hub – Weekly Data for Winter Spot Prices

Overall, with the exception of San Juan, the prices for the winter of 1995 to 1996 are the most skewed and have the highest mean when compared to the price distributions for the other winters. This extreme was the result of a massive cold front and well freeze-offs. Data for 2000 may supercede these extremes. Post 1997 the distributions appear, on their face, more similar. This is indicative of the fact that regional gas prices were starting to become more homogeneous, at least in the U.S.

Natural Gas Price Volatility

Volatility of daily spot prices for natural gas by month for the years 1998 and 1999 are reported in Table 4-7 for hubs where data were available. These data are obtained from *Gas Daily*. The methodology is the same as that applied to the power price data. These data are plotted in Figure 4-15.

Table 4-7
Volatility of Daily Peak Natural Gas Prices by Month (Annualized)

	Henry	*Alberta*	*Carthage*	*Katy*	*Waha*	*Chicago*	*TETCO, M3*	*Transco, Z6 Ny*	*New England*
Jan-98	36%	54%	40%	37%	44%	36%	34%	39%	81%
Feb-98	32%	30%	42%	35%	47%	38%	24%	26%	29%
Mar-98	32%	31%	33%	32%	35%	34%	55%	65%	68%
Apr-98	49%	52%	53%	49%	46%	47%	42%	43%	43%
May-98	38%	184%	44%	41%	42%	44%	39%	39%	52%
Jun-98	41%	51%	43%	41%	53%	40%	44%	43%	50%
Jul-98	37%	55%	40%	41%	47%	30%	38%	40%	39%
Aug-98	41%	162%	49%	51%	53%	44%	40%	38%	46%
Sep-98	82%	122%	86%	85%	85%	69%	76%	70%	82%
Oct-98	85%	190%	92%	96%	101%	73%	80%	83%	103%
Nov-98	70%	182%	81%	79%	71%	85%	71%	59%	56%
Dec-98	229%	305%	230%	218%	280%	188%	182%	212%	239%
Jan-99	63%	63%	58%	54%	67%	78%	75%	202%	131%
Feb-99	25%	32%	26%	27%	34%	28%	58%	72%	111%
Mar-99	44%	33%	49%	54%	47%	41%	44%	43%	66%
Apr-99	30%	26%	42%	46%	44%	38%	38%	29%	26%
May-99	31%	33%	34%	32%	34%	30%	29%	30%	26%
Jun-99	26%	21%	34%	33%	38%	32%	37%	38%	35%
Jul-99	36%	21%	40%	35%	37%	42%	43%	55%	52%
Aug-99	32%	26%	34%	32%	35%	28%	31%	33%	31%
Sep-99	60%	53%	68%	68%	69%	52%	61%	61%	55%
Oct-99	54%	51%	63%	62%	65%	57%	67%	61%	73%
Nov-99	86%	65%	85%	71%	69%	58%	141%	193%	158%
Dec-99	44%	49%	54%	46%	47%	55%	73%	168%	94%
Max 1998	229%	305%	230%	218%	280%	188%	182%	212%	239%
Min 1998	32%	30%	33%	32%	35%	30%	24%	26%	29%
Max 1999	86%	65%	85%	71%	69%	78%	141%	202%	158%
Min 1999	25%	21%	26%	27%	34%	28%	29%	29%	26%

Source: Data from *Natural Gas Daily*.

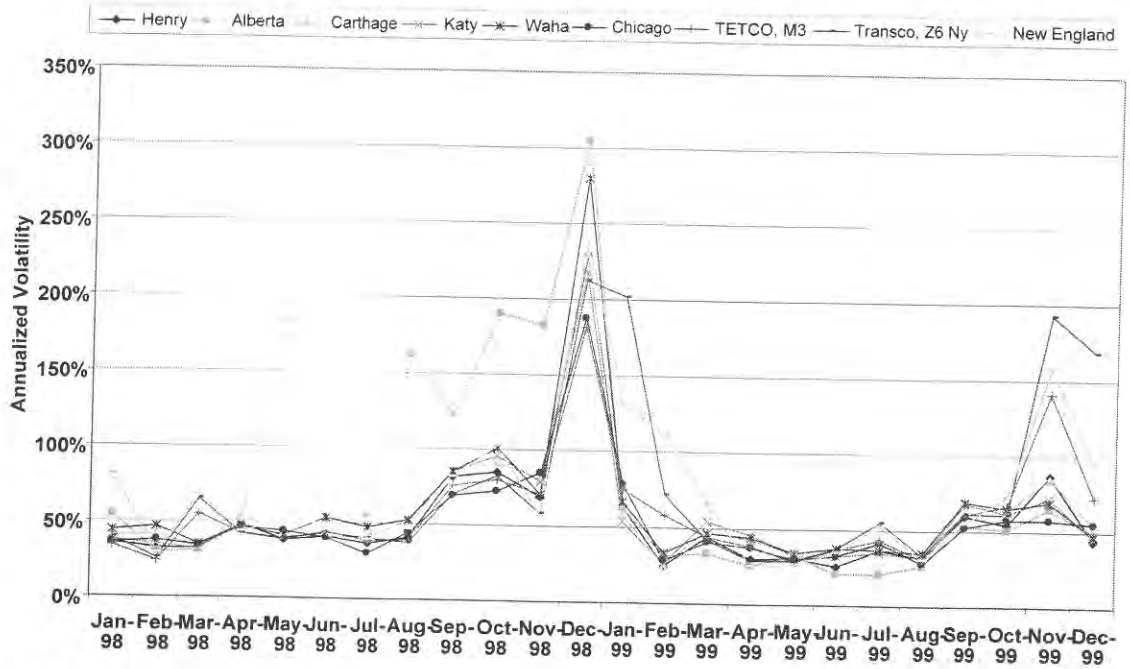


Figure 4-15
Volatility of Daily On-Peak Natural Gas Prices

The volatility of natural gas prices is an order of magnitude smaller than electric market's volatility. For daily electric spot prices, volatility estimates of 200% to 300% were not uncommon. Natural gas price volatility for non-winter months is roughly 30% to 60%. The volatility of natural gas is at its highest in the winter, as high as 200% to 300%, for the winter of 1998-1999, 150% to 200% for December 1999. Recall volatility estimates of 2000% to 3000% for daily spot power prices in the summer. Note also the considerable tightness of the data across regions, except for Alberta prior to 1999.

Figure 4-15, the plot of volatility of daily natural gas spot prices by month, is a stark contrast to Figures 4-5a and 4-5b, the plot of volatility of daily power spot prices by month. Natural gas price volatility is relatively well behaved; except for the winter, the volatility estimates are tightly distributed. Volatility of prices at the Alberta hub is more erratic and does not track the volatility of prices for the other regions until spring 1999. There also appears to be less seasonal and year to year variation for all hubs.

Figure 4-16 is a plot of the seasonal averages of the monthly volatility estimates using daily data. The supporting data are found in Table 4-8.

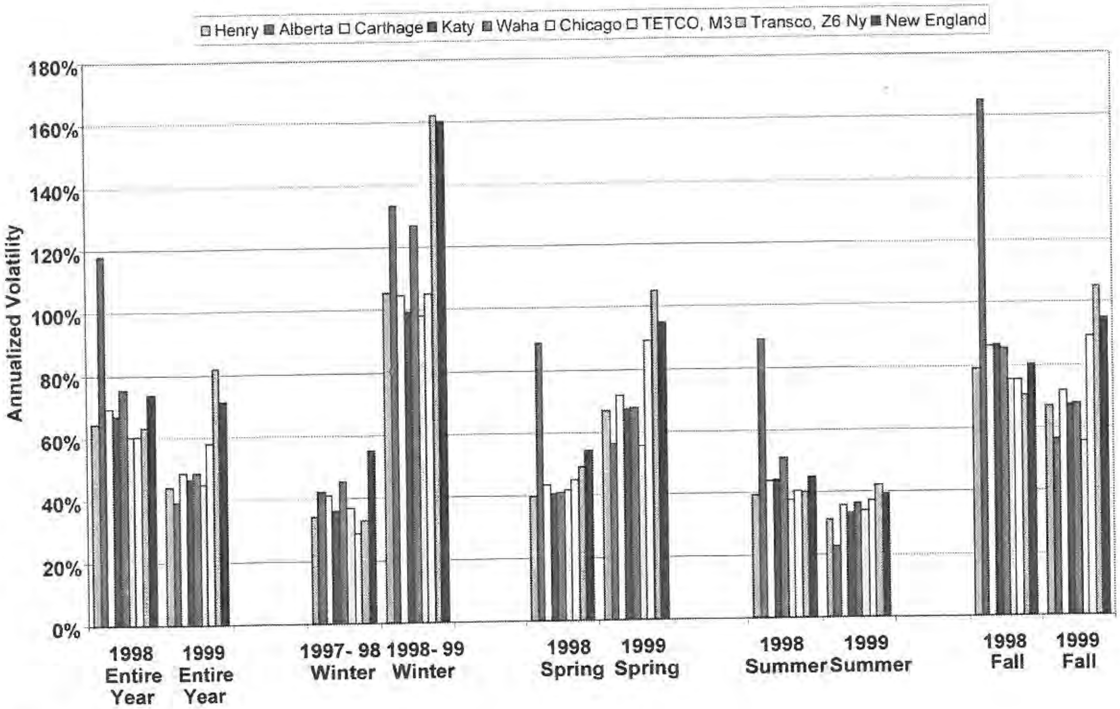


Figure 4-16
Volatility of Daily Peak Natural Gas Prices by Season

Table 4-8
Volatility of Daily On-Peak Natural Gas Prices by Month—Seasonal Averages

	Henry	*Alberta*	*Carthage*	*Katy*	*Waha*	*Chicago*	*TETCO, M3*	*Transco, Z6 Ny*	*New England*
1998 Entire Year	64%	118%	69%	67%	75%	61%	60%	63%	74%
1999 Entire Year	44%	39%	49%	47%	49%	45%	58%	82%	71%
1997-98 Winter	34%	42%	41%	36%	45%	37%	29%	33%	55%
1998-99 Winter	106%	133%	105%	99%	127%	98%	105%	162%	160%
1998 Spring	40%	89%	43%	40%	41%	42%	45%	49%	54%
1999 Spring	67%	56%	72%	67%	68%	56%	89%	105%	95%
1998 Summer	40%	89%	44%	44%	51%	38%	41%	40%	45%
1999 Summer	31%	23%	36%	33%	36%	34%	37%	42%	39%
1998 Fall	79%	165%	86%	87%	86%	75%	75%	71%	80%
1999 Fall	67%	56%	72%	67%	68%	56%	89%	105%	95%

Note: Winter average includes the months December, January, February.
Spring average includes the months March, April, and May.
Summer average includes the months June, July, and August.
Fall average includes the months September, October, and November.

It is evident from Figure 4-16 that the volatility of natural gas prices in the winter is not equal from year to year. The volatility of prices for the winter of 1998-1999 was considerably higher than the volatility of prices for the winter of 1997-1998. Similarly, the volatility of prices for spring 1999 exceeds that for spring 1998. However, the difference is not as great as that observed for electric prices. Summer and fall price volatility are roughly comparable from year to year, with fall price volatility consistently exceeding summer price volatility. Generally, fall and winter natural gas prices are 10% to 20% more volatile than spring and summer price volatility

Results from analyzing the volatility of Henry Hub futures contract prices also provides evidence that natural gas prices behave differently than electric prices. The volatility of Henry Hub futures exhibits similar term structure; that is, as the date of delivery approaches the contract price volatility increases. However, the volatility of the futures contract price one month prior to delivery is a remarkably good indicator of the spot price volatility—much more so than was observed for electricity. Table 4-9 compares daily spot and one-month nearby futures price volatility for Henry Hub natural gas. The two data series are similar.

Table 4-9
Futures vs. Spot Natural Gas Volatility by Month (Annualized)

	Futures Contract Volatility	*Daily Spot Volatility*
Jan-98	40%	36%
Feb-98	42%	32%
Mar-98	30%	32%
Apr-98	50%	49%
May-98	34%	38%
Jun-98	58%	41%
Jul-98	40%	37%
Aug-98	54%	41%
Sep-98	74%	82%
Oct-98	54%	85%
Nov-98	50%	70%
Dec-98	63%	229%
Jan-99	46%	63%
Feb-99	37%	25%
Mar-99	46%	44%
Apr-99	23%	30%
May-99	34%	31%
Jun-99	31%	26%
Jul-99	29%	36%

Source: Data from *Natural Gas Daily*. Calculations by Project Team.
Note: Futures Volatility is for one-month nearby delivery date.

Looking back at a 10-year history of the volatility of Henry Hub futures contract prices (one month to delivery) provides an interesting glimpse at how volatility may evolve over time in a competitive market. Figure 4-17 plots the nearby month futures contract price volatility by month from April 1990 through August 1999. While volatility appeared quite erratic in the first year of trading, volatility quickly settled into a range between 40% to 80%. The range of values has remained steady over time—not trending down over time as the market matures. And except for the winters of 1995-1996 and 1996-1997, the behavior of this price volatility has been remarkably steady.

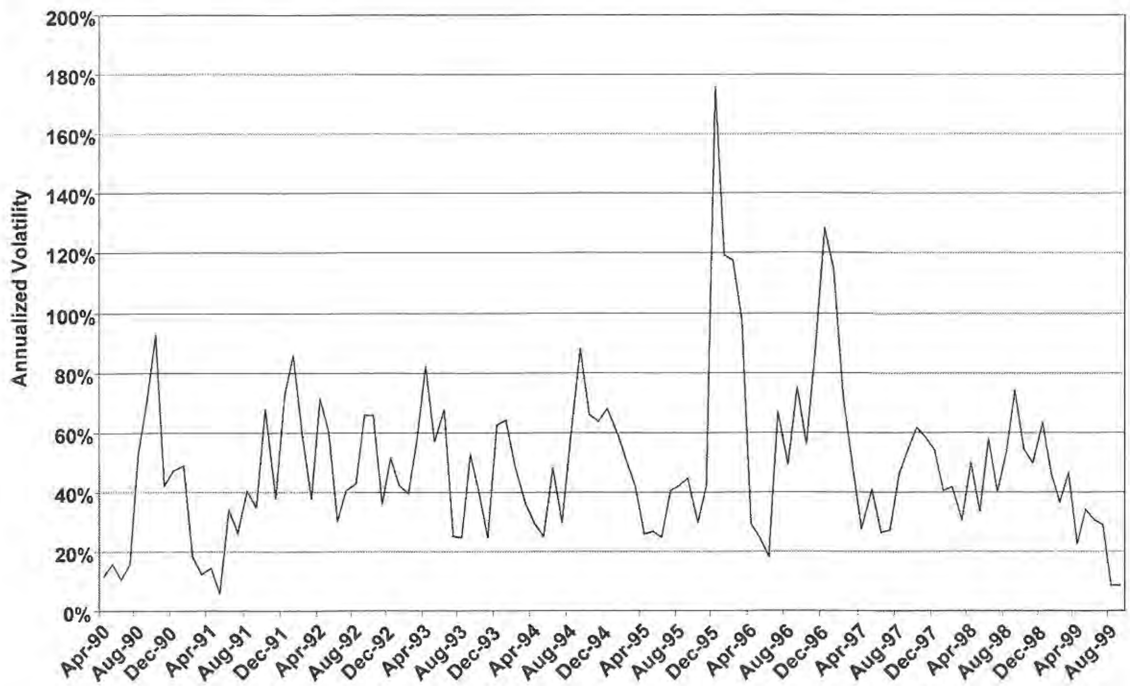


Figure 4-17
Nearby Month Henry Hub Futures Contract Volatility

Natural Gas Price Correlation

An analysis of the correlation between weekly spot prices for selected natural gas hubs generally supports the claim that the natural gas markets are becoming more homogeneous. For most hubs, prices have become more correlated since 1997. This conclusion can be drawn by examining the correlation statistics in Table 4-10. Table 4-10 summarizes the correlation by year for winter prices only. Correlation statistics are shaded gray if they exceed 0.8. Note the much greater extent of shading than in Figure 4-6 for electricity.

The correlation statistics for Alberta do not exceed 0.8, suggesting that natural gas prices at the Alberta hub are still not in sync with the rest of the market which generally moves with Henry Hub. It is expected that with more recent data Alberta correlation statistics will continue to increase. Topock is also an outlier. Topock price correlation has been relatively steady over time at 0.5 to 0.7, but to date these data do not show its price converging to the Henry Hub price. An examination of 2000/01 data would likely show continued isolation of this particular region, evidenced by the extreme winter price runups in California gas prices. However, like Alberta after additional pipe was added joining the west with the Midwest, increased price correlation is expected.

Table 4-10
Gas to Gas Price Correlation by Year (Winter only)

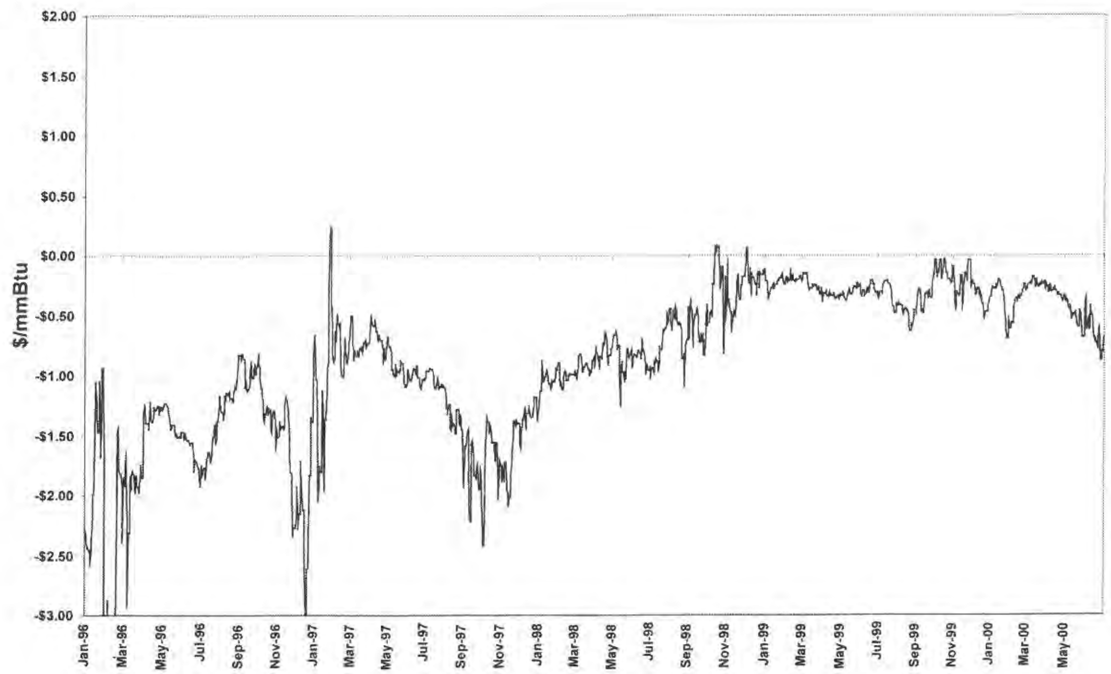
Gas Market		Henry Hub	Carthage	Katy	San Juan	Waha	Alberta	Appalachia	Topock	Ventura	Chicago	NY	Atlanta	Panhandle
Alberta	1994	0.51	0.50	0.67	0.85		1.00	-0.30	0.91	0.83				
Alberta	1995	0.90	0.95	0.94	0.55	0.94	1.00	0.87	0.57	0.96	0.86	0.69	0.49	0.95
Alberta	1996	0.26	0.70	0.73	0.81	0.77	1.00	-0.36	0.82	0.70	-0.02	-0.38	0.11	0.77
Alberta	1997	0.81	0.81	0.80	0.70	0.77	1.00	0.81	0.75	0.76	0.81	0.78	0.77	0.77
Alberta	1998	-0.30	-0.24	-0.25	0.05	-0.04	1.00	-0.41	0.54	-0.07	-0.34	-0.31	-0.23	-0.18
Alberta	1999	0.70	0.68	0.74	0.71	0.65	1.00	0.70	0.80	0.68	0.65	0.55	0.62	0.78
Appalachia	1994	-0.85	-0.75	-0.76	-0.66		-0.30	1.00	-0.63	-0.77				
Appalachia	1995	0.98	0.94	0.96	0.61	0.92	0.87	1.00	0.57	0.86	1.00	0.55	0.59	0.94
Appalachia	1996	0.49	-0.21	-0.16	-0.32	-0.28	-0.36	1.00	-0.33	-0.17	0.31	0.96	0.57	-0.25
Appalachia	1997	0.99	0.97	0.98	0.97	0.99	0.81	1.00	0.98	0.99	0.99	0.97	0.99	0.98
Appalachia	1998	0.99	0.98	0.98	0.79	0.91	-0.41	1.00	0.38	0.90	0.96	0.86	0.89	0.93
Appalachia	1999	0.96	0.97	0.99	0.88	0.96	0.70	1.00	0.53	0.89	0.89	0.74	0.97	0.96
Atlanta	1994													
Atlanta	1995	0.60	0.56	0.59	0.50	0.63	0.49	0.59	0.68	0.57	0.63	0.72	1.00	0.61
Atlanta	1996	0.82	0.29	0.24	0.15	0.23	0.11	0.57	0.15	0.14	0.33	0.64	1.00	0.41
Atlanta	1997	0.99	0.96	0.97	0.98	0.99	0.77	0.99	0.99	0.99	0.99	0.98	1.00	0.98
Atlanta	1998	0.87	0.86	0.85	0.74	0.82	-0.23	0.89	0.35	0.80	0.86	0.88	1.00	0.83
Atlanta	1999	0.97	0.97	0.97	0.85	0.99	0.62	0.97	0.49	0.91	0.91	0.79	1.00	0.94
Carthage	1994	0.97	1.00	0.96	0.86		0.50	-0.75	0.76	0.75				
Carthage	1995	0.93	1.00	0.99	0.66	0.96	0.95	0.94	0.69	0.96	0.93	0.56	0.56	0.99
Carthage	1996	0.57	1.00	0.94	0.71	0.96	0.70	-0.21	0.72	0.89	0.51	-0.16	0.29	0.92
Carthage	1997	0.99	1.00	1.00	0.91	0.97	0.81	0.97	0.94	0.97	0.98	0.91	0.96	0.99
Carthage	1998	1.00	1.00	1.00	0.85	0.97	-0.24	0.98	0.51	0.95	0.95	0.81	0.86	0.96
Carthage	1999	0.98	1.00	0.97	0.80	0.96	0.68	0.97	0.50	0.89	0.90	0.82	0.97	0.94
Chicago	1994													
Chicago	1995	0.99	0.93	0.95	0.81	0.93	0.86	1.00	0.74	0.84	1.00	0.58	0.63	0.94
Chicago	1996	0.64	0.51	0.52	-0.18	0.28	-0.02	0.31	-0.17	0.54	1.00	0.42	0.33	0.22
Chicago	1997	1.00	0.98	0.99	0.96	0.99	0.81	0.99	0.97	0.99	1.00	0.96	0.99	0.99
Chicago	1998	0.95	0.95	0.94	0.85	0.91	-0.34	0.96	0.46	0.93	1.00	0.86	0.86	0.98
Chicago	1999	0.93	0.90	0.90	0.87	0.96	0.65	0.89	0.57	0.99	1.00	0.94	0.91	0.95
Henry Hub	1994	1.00	0.97	0.98	0.88		0.51	-0.85	0.80	0.83				
Henry Hub	1995	1.00	0.93	0.95	0.61	0.94	0.90	0.98	0.54	0.87	0.99	0.67	0.60	0.94
Henry Hub	1996	1.00	0.57	0.64	0.14	0.42	0.26	0.49	0.15	0.60	0.64	0.55	0.82	0.50
Henry Hub	1997	1.00	0.99	0.99	0.95	0.99	0.81	0.99	0.97	0.99	1.00	0.96	0.99	0.99
Henry Hub	1998	1.00	1.00	0.99	0.82	0.95	-0.30	0.99	0.45	0.93	0.95	0.83	0.87	0.95
Henry Hub	1999	1.00	0.98	0.98	0.81	0.98	0.70	0.96	0.49	0.92	0.93	0.82	0.97	0.95

Table 4-10
Gas to Gas Price Correlation by Year (Winter only) (Continued)

Gas Market		Henry Hub	Carthage	Katy	San Juan	Waha	Alberta	Appalachia	Topock	Ventura	Chicago	NY	Atlanta	Panhandle
Katy	1994	0.98	0.96	1.00	0.96		0.67	-0.76	0.90	0.88				
Katy	1995	0.95	0.99	1.00	0.63	0.96	0.94	0.96	0.66	0.95	0.95	0.57	0.59	0.99
Katy	1996	0.64	0.94	1.00	0.59	0.87	0.73	-0.16	0.61	0.99	0.52	-0.14	0.24	0.81
Katy	1997	0.99	1.00	1.00	0.93	0.98	0.80	0.98	0.96	0.98	0.99	0.92	0.97	0.99
Katy	1998	0.99	1.00	1.00	0.85	0.97	-0.25	0.98	0.49	0.95	0.94	0.80	0.85	0.95
Katy	1999	0.98	0.97	1.00	0.87	0.97	0.74	0.99	0.55	0.91	0.90	0.77	0.97	0.96
NY	1994													
NY	1995	0.67	0.56	0.57	0.66	0.73	0.69	0.55	0.60	0.67	0.58	1.00	0.72	0.64
NY	1996	0.55	-0.16	-0.14	-0.36	-0.25	-0.38	0.96	-0.37	-0.15	0.42	1.00	0.64	-0.21
NY	1997	0.96	0.91	0.92	0.96	0.96	0.78	0.97	0.96	0.96	0.96	1.00	0.98	0.94
NY	1998	0.83	0.81	0.80	0.78	0.79	-0.31	0.86	0.41	0.82	0.86	1.00	0.88	0.82
NY	1999	0.82	0.82	0.77	0.77	0.85	0.55	0.74	0.60	0.93	0.94	1.00	0.79	0.86
San Juan	1994	0.88	0.86	0.96	1.00		0.85	-0.66	0.98	0.94				
San Juan	1995	0.61	0.66	0.63	1.00	0.72	0.55	0.61	0.89	0.62	0.81	0.66	0.50	0.86
San Juan	1996	0.14	0.71	0.59	1.00	0.87	0.81	-0.32	1.00	0.52	-0.18	-0.36	0.15	0.88
San Juan	1997	0.95	0.91	0.93	1.00	0.98	0.70	0.97	0.99	0.98	0.96	0.96	0.98	0.96
San Juan	1998	0.82	0.85	0.85	1.00	0.93	0.05	0.79	0.77	0.96	0.85	0.78	0.74	0.92
San Juan	1999	0.81	0.80	0.87	1.00	0.87	0.71	0.88	0.78	0.92	0.87	0.77	0.85	0.94
Topock	1994	0.80	0.76	0.90	0.98		0.91	-0.63	1.00	0.97				
Topock	1995	0.54	0.69	0.66	0.89	0.71	0.57	0.57	1.00	0.70	0.74	0.60	0.68	0.87
Topock	1996	0.15	0.72	0.61	1.00	0.87	0.82	-0.33	1.00	0.53	-0.17	-0.37	0.15	0.88
Topock	1997	0.97	0.94	0.96	0.99	0.98	0.75	0.98	1.00	0.98	0.97	0.96	0.99	0.97
Topock	1998	0.45	0.51	0.49	0.77	0.68	0.54	0.38	1.00	0.71	0.46	0.41	0.35	0.61
Topock	1999	0.49	0.50	0.55	0.78	0.52	0.80	0.53	1.00	0.65	0.57	0.60	0.49	0.71
Ventura	1994	0.83	0.75	0.88	0.94		0.83	-0.77	0.97	1.00				
Ventura	1995	0.87	0.96	0.95	0.62	0.97	0.96	0.86	0.70	1.00	0.84	0.67	0.57	0.95
Ventura	1996	0.60	0.89	0.99	0.52	0.81	0.70	-0.17	0.53	1.00	0.54	-0.15	0.14	0.73
Ventura	1997	0.99	0.97	0.98	0.98	1.00	0.76	0.99	0.98	1.00	0.99	0.96	0.99	0.99
Ventura	1998	0.93	0.95	0.95	0.96	0.99	-0.07	0.90	0.71	1.00	0.93	0.82	0.80	0.97
Ventura	1999	0.92	0.89	0.91	0.92	0.95	0.68	0.89	0.65	1.00	0.99	0.93	0.91	0.96
Waha	1994													
Waha	1995	0.94	0.96	0.96	0.72	1.00	0.94	0.92	0.71	0.97	0.93	0.73	0.63	0.98
Waha	1996	0.42	0.96	0.87	0.87	1.00	0.77	-0.28	0.87	0.81	0.28	-0.25	0.23	0.96
Waha	1997	0.99	0.97	0.98	0.98	1.00	0.77	0.99	0.98	1.00	0.99	0.96	0.99	0.99
Waha	1998	0.95	0.97	0.97	0.93	1.00	-0.04	0.91	0.68	0.99	0.91	0.79	0.82	0.96
Waha	1999	0.98	0.96	0.97	0.87	1.00	0.65	0.96	0.52	0.95	0.96	0.85	0.99	0.96
Panhandle	1994													
Panhandle	1995	0.94	0.99	0.99	0.86	0.98	0.95	0.94	0.87	0.95	0.94	0.64	0.61	1.00
Panhandle	1996	0.50	0.92	0.81	0.88	0.96	0.77	(0.25)	0.88	0.73	0.22	(0.21)	0.41	1.00
Panhandle	1997	0.99	0.99	0.99	0.96	0.99	0.77	0.98	0.97	0.99	0.99	0.94	0.98	1.00
Panhandle	1998	0.95	0.96	0.95	0.92	0.96	(0.18)	0.93	0.61	0.97	0.98	0.82	0.83	1.00
Panhandle	1999	0.95	0.94	0.96	0.94	0.96	0.78	0.96	0.71	0.96	0.95	0.86	0.94	1.00

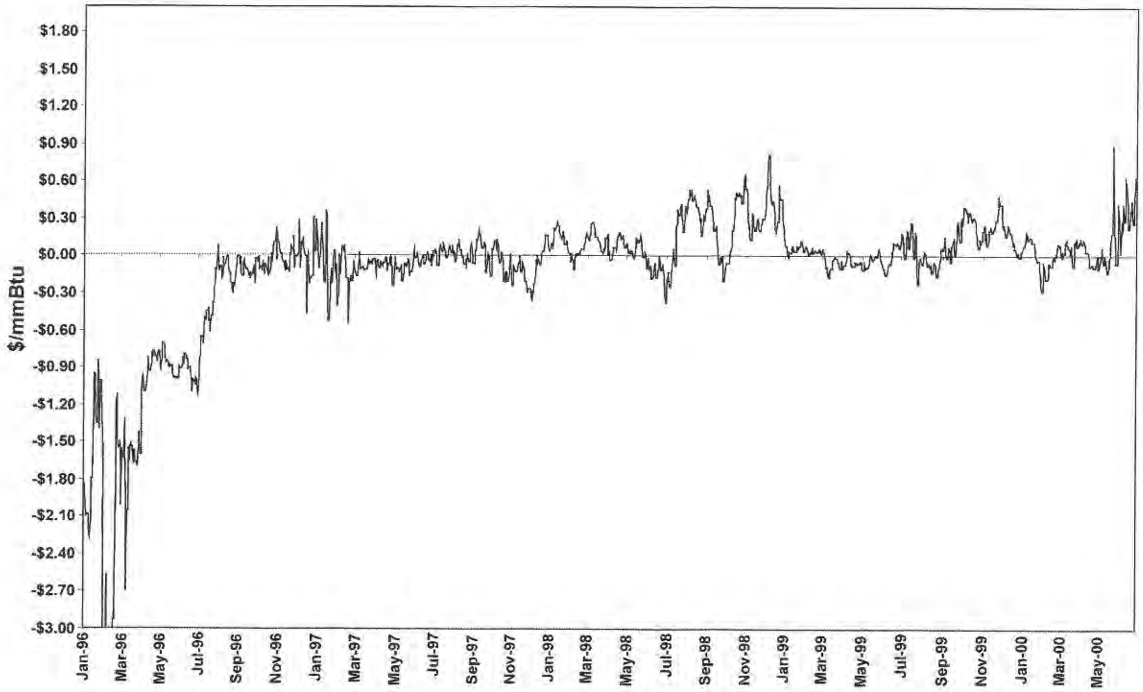
Natural Gas Price Basis Differentials

Just as regional prices are more consistent, natural gas price basis differentials are generally much more stable (and have become more so recently) for neighboring natural gas hubs when compared to basis differentials for power prices for neighboring regions. Figures 4-18a to 4-18d plot the basis differentials for Alberta, Topock, Katy and New York relative to Henry Hub. The graphs contain daily data as reported by *Gas Daily* from January 1996 to June 2000. Note that many of these location pairs are quite remote.



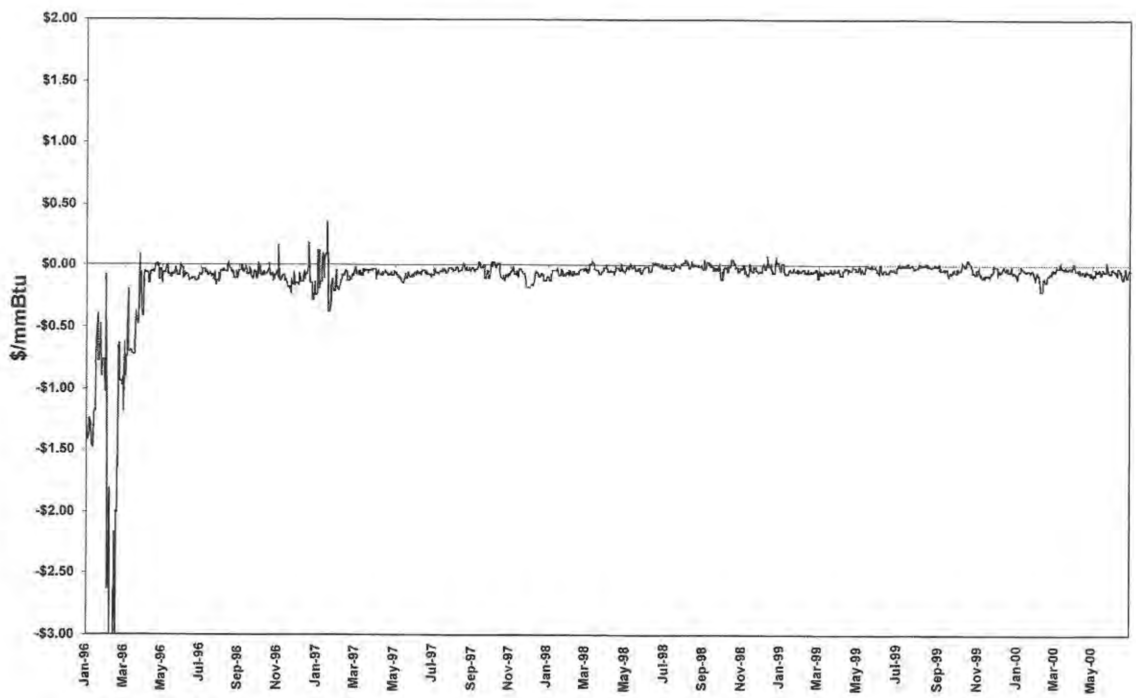
Source: *Gas Daily*

Figure 4-18a
Alberta (AECO-C)—Henry Hub Price Differentials: Daily



Source: *Gas Daily*

Figure 4-18b
Topock—Henry Hub Price Differentials: Daily



Source: *Gas Daily*

Figure 4-18c
Katy—Henry Hub Price Differentials: Daily

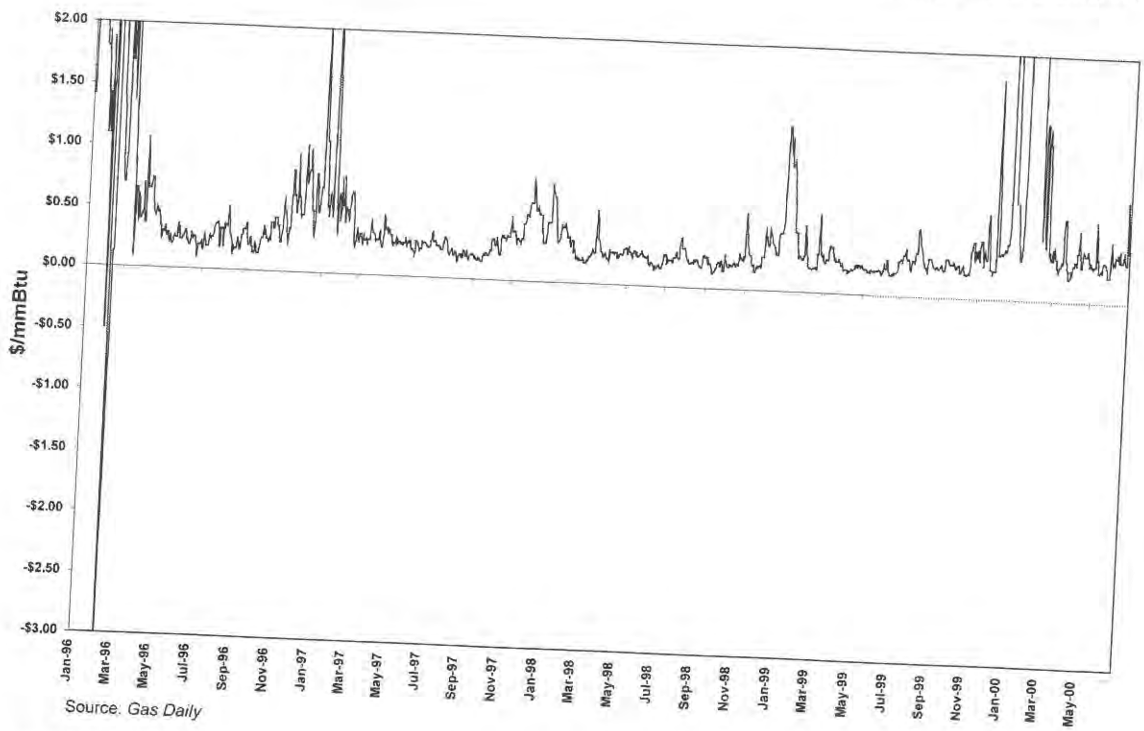


Figure 4-18d
New York—Henry Hub Price Differentials: Daily

The basis differential for Katy is minimal, averaging -$0.03 per MMBtu since January 1998. Moreover, the differential rarely wavers from this value. The basis differential for New York is considerably higher, on average $0.50 per MMBtu ($0.33/MMBtu if data for 2000, which included a severe winter price spike in January and February, are excluded). It also has more seasonality, increasing significantly in winter. The Alberta/Henry Hub basis differential has not shown comparable stability until recently, where it is on average $0.50/MMBtu since January 1999. The consistency of the basis differential since the end of 1998 is once again a reflection of the increasing homogeneity of natural gas prices that has taken place in the north since the addition of pipeline capacity connecting Northwest Canada to the Midwest. Topock-Henry Hub basis differentials oscillate around zero—and have some seasonality. However, relative to 1996, Topock prices now move with Henry Hub prices, despite being 2000 miles apart. The "explosion" in Southern California basis differentials in 2001/01 is an extreme but seemingly temporary exception to this observation reflecting infrastructure and possibly other circumstances unique to the California energy crisis.

Correlation of Electric and Natural Gas Prices

The discussion thus far has focused on how electric prices behave without consideration of gas prices, and similarly how natural gas prices behave without consideration of electric prices. In this section the interaction of electric and natural gas prices is considered. Table 4-11 summarizes correlation statistics between weekly spot prices of natural gas and peak power prices for the regions and hubs previously discussed in this report. This statistic is important to valuing gas-fired power plants, which essentially convert one form of energy to the other. The correlation statistic for the cells shaded gray is between 0.50 and 1.0.

Table 4-11
Correlation of Gas and Electricity Prices

Electricity Market	Season	Gas Market: San Juan	Carthage	Katy	Waha	Ventura	Atlanta	Alberta	Appalachia	Topock	Chicago	NY	Henry Hub
Cinergy	1995	.	.	.	.	.	.	.	.	.	.	.	.
Cinergy	1996	.	.	.	.	.	.	.	.	.	.	.	.
Cinergy	1997	0.06	0.05	0.05	0.04	0.03	0.03	0.01	0.03	0.08	0.04	0.02	0.03
Cinergy	1998	-0.02	0.24	0.24	0.23	0.16	0.24	0.00	0.21	0.02	0.20	0.19	0.20
Cinergy	1999*	0.44	0.49	0.46	0.34	0.46	**0.51**	0.46	0.44	0.41	0.45	0.41	0.48
Cinergy	Fall	0.07	0.21	0.18	0.17	0.14	0.16	-0.18	0.15	0.03	0.17	0.16	0.19
Cinergy	Spring	0.16	0.23	0.21	0.08	0.22	0.21	0.18	0.18	0.16	0.18	0.14	0.19
Cinergy	Summer	-0.16	0.10	0.09	0.06	0.06	0.09	0.35	0.06	-0.11	0.08	0.12	0.06
Cinergy	Winter	0.39	0.39	0.39	0.40	0.44	0.36	0.31	0.34	0.40	0.42	0.45	0.36
COB	1995	-0.02	0.00	-0.17	-0.13	-0.16	-0.29	-0.34	-0.38	0.23	-0.30	-0.33	-0.37
COB	1996	**0.91**	**0.56**	**0.54**	**0.67**	**0.54**	0.19	**0.64**	-0.06	**0.90**	0.03	-0.07	0.21
COB	1997	0.43	**0.51**	0.49	0.45	0.44	0.47	-0.04	0.47	0.49	0.43	0.34	0.48
COB	1998	-0.26	-0.48	-0.48	-0.42	-0.49	-0.49	0.28	-0.44	0.17	-0.55	-0.48	-0.49
COB	1999*	**0.84**	**0.78**	**0.79**	**0.85**	**0.79**	**0.81**	**0.79**	**0.79**	**0.87**	**0.79**	**0.62**	**0.78**
COB	Fall	0.42	0.16	0.29	0.34	0.37	0.27	**0.78**	0.34	**0.52**	0.28	0.23	0.26
COB	Spring	**0.80**	0.37	0.21	0.42	**0.53**	0.27	**0.88**	0.18	**0.78**	0.18	0.10	0.26
COB	Summer	0.11	-0.01	0.02	0.09	0.14	-0.02	0.48	-0.01	0.44	-0.02	-0.05	-0.03
COB	Winter	0.49	0.23	0.23	0.29	0.27	-0.11	**0.52**	-0.21	**0.56**	-0.12	-0.29	-0.05
ECAR	1995	0.18	-0.03	-0.09	-0.02	-0.02	-0.12	-0.10	-0.05	0.05	-0.09	-0.09	-0.06
ECAR	1996	0.12	0.28	0.24	0.20	0.15	0.20	0.00	0.05	0.12	0.13	0.06	0.21
ECAR	1997	0.04	0.05	0.05	0.03	0.02	0.02	0.01	0.03	0.06	0.03	0.00	0.03
ECAR	1998	-0.02	0.24	0.24	0.23	0.16	0.24	0.00	0.21	0.02	0.20	0.19	0.20
ECAR	1999*	**0.69**	**0.80**	**0.76**	**0.81**	**0.82**	**0.80**	**0.65**	**0.75**	**0.54**	**0.89**	**0.79**	**0.80**
ECAR	Fall	0.35	0.33	0.40	0.39	0.40	0.38	0.32	0.39	0.37	0.37	0.36	0.39
ECAR	Spring	0.19	0.16	0.05	0.16	0.18	0.11	0.04	0.11	0.22	0.12	0.06	0.12
ECAR	Summer	0.06	0.16	0.16	0.18	0.20	0.15	0.36	0.14	0.18	0.14	0.16	0.14
ECAR	Winter	0.23	0.47	0.43	0.42	0.41	0.42	0.19	0.32	0.23	0.38	0.35	0.46
Entergy	1995	.	.	.	.	.	.	.	.	.	.	.	.
Entergy	1996	.	.	.	.	.	.	.	.	.	.	.	.
Entergy	1997	0.14	0.11	0.10	0.11	0.09	0.09	-0.05	0.08	0.15	0.09	0.07	0.09
Entergy	1998	-0.02	0.20	0.20	0.19	0.12	0.20	-0.01	0.18	0.04	0.15	0.16	0.16
Entergy	1999*	**0.53**	**0.58**	**0.55**	0.44	**0.55**	**0.60**	**0.55**	**0.54**	**0.51**	**0.54**	0.47	**0.57**
Entergy	Fall	0.23	0.35	0.34	0.33	0.29	0.32	-0.38	0.29	0.16	0.31	0.32	0.35
Entergy	Spring	0.18	0.26	0.25	0.13	0.25	0.22	0.17	0.21	0.19	0.21	0.14	0.21
Entergy	Summer	-0.15	0.05	0.05	0.02	0.02	0.05	0.31	0.03	-0.07	0.03	0.09	0.02
Entergy	Winter	0.41	0.36	0.34	0.39	**0.53**	0.37	0.11	0.28	0.31	0.46	**0.55**	0.33

Table 4-11
Correlation of Gas and Electricity Prices (Continued)

Electricity Market	Season	Gas Market											
		San Juan	**Carthage**	**Katy**	**Waha**	**Ventura**	**Atlanta**	**Alberta**	**Appalachia**	**Topock**	**Chicago**	**NY**	**Henry Hub**
ERCOT	1995												
ERCOT	1996	**0.71**	**0.73**	**0.64**	**0.75**	**0.52**	0.32	0.37	0.02	**0.70**	0.11	0.00	0.34
ERCOT	1997	**0.56**	**0.62**	**0.61**	**0.59**	**0.56**	**0.55**	0.18	**0.57**	**0.61**	**0.54**	0.43	**0.57**
ERCOT	1998	-0.11	0.22	0.25	0.22	0.12	0.23	0.00	0.20	-0.03	0.15	0.13	0.18
ERCOT	1999*	**0.86**	**0.94**	**0.94**	**0.88**	**0.83**	**0.82**	**0.93**	**0.93**	**0.89**	**0.87**	**0.65**	**0.94**
ERCOT	Fall	**0.67**	**0.71**	**0.71**	**0.69**	**0.68**	**0.66**	-0.12	**0.63**	**0.64**	**0.63**	**0.60**	**0.67**
ERCOT	Spring	0.13	**0.52**	**0.54**	0.43	0.40	0.27	0.26	0.22	0.18	0.23	0.09	0.34
ERCOT	Summer	0.08	0.10	0.13	0.17	0.23	0.11	0.47	0.10	0.23	0.08	0.09	0.08
ERCOT	Winter	**0.81**	**0.87**	**0.81**	**0.91**	**0.75**	**0.61**	0.14	0.34	**0.81**	0.40	0.34	**0.62**
Florida	1995												
Florida	1996	-0.22	-0.02	-0.04	-0.10	-0.15	-0.04	-0.31	-0.04	-0.21	-0.10	-0.08	-0.04
Florida	1997	**0.53**	**0.74**	**0.73**	**0.64**	**0.63**	**0.61**	**0.64**	**0.61**	**0.60**	**0.68**	**0.58**	**0.69**
Florida	1998												
Florida	1999*												
Florida	Fall	0.38	0.37	0.38	0.37	0.42	0.36	0.40	0.47	0.40	0.39	0.49	0.38
Florida	Spring	-0.70	0.49	0.44	**0.60**	**0.52**	0.34	-0.58	0.39	-0.65	**0.56**	0.35	0.41
Florida	Summer	0.28	**0.59**	**0.61**	**0.68**	**0.69**	**0.65**	0.49	**0.67**	0.33	**0.61**	**0.71**	**0.64**
Florida	Winter	**0.58**	**0.73**	**0.71**	**0.66**	**0.64**	**0.60**	0.20	**0.63**	**0.61**	**0.67**	**0.59**	**0.69**
MAIN	1995												
MAIN	1996	0.30	0.46	0.43	0.40	0.38	0.25	0.25	0.10	0.31	0.25	0.11	0.31
MAIN	1997	0.06	0.09	0.08	0.06	0.05	0.05	0.04	0.06	0.09	0.07	0.03	0.06
MAIN	1998	0.01	0.19	0.20	0.19	0.12	0.19	-0.01	0.17	0.03	0.16	0.16	0.15
MAIN	1999*	**0.79**	**0.81**	**0.78**	**0.84**	**0.90**	**0.81**	**0.69**	**0.77**	**0.63**	**0.94**	**0.85**	**0.81**
MAIN	Fall	0.35	0.42	0.40	0.39	0.42	0.39	0.26	0.39	0.39	0.37	0.36	0.40
MAIN	Spring	0.25	0.02	0.02	0.03	0.12	-0.05	0.04	-0.08	0.28	-0.04	-0.11	-0.04
MAIN	Summer	-0.01	0.04	0.05	0.07	0.10	0.04	0.30	0.01	0.11	0.02	0.05	0.01
MAIN	Winter	0.37	**0.52**	**0.50**	0.48	0.50	0.28	0.17	0.12	0.37	0.31	0.16	0.35
NEPOOL	1995	0.34	-0.16	-0.10	-0.21	-0.28	-0.02	-0.22	0.09	-0.64	0.02	0.21	0.06
NEPOOL	1996	**0.64**	0.47	0.44	**0.56**	0.48	**0.58**	**0.69**	0.43	**0.66**	0.33	0.47	**0.54**
NEPOOL	1997	0.37	0.38	0.37	0.36	0.37	0.39	0.28	0.38	0.37	0.39	0.43	0.39
NEPOOL	1998	0.16	0.35	0.37	0.34	0.28	0.27	-0.48	0.27	0.13	0.25	0.39	0.35
NEPOOL	1999*	**0.65**	**0.69**	**0.67**	**0.55**	**0.67**	**0.63**	**0.70**	**0.65**	**0.66**	**0.64**	**0.57**	**0.68**
NEPOOL	Fall	**0.86**	**0.62**	**0.83**	**0.84**	**0.83**	**0.83**	0.04	**0.83**	**0.78**	**0.85**	**0.84**	**0.83**
NEPOOL	Spring	0.23	0.21	0.17	0.11	0.23	0.14	0.37	0.13	0.22	0.12	0.11	0.17
NEPOOL	Summer	0.41	0.15	0.16	0.22	0.23	0.16	0.33	0.17	0.29	0.17	0.26	0.16
NEPOOL	Winter	0.43	**0.60**	**0.56**	**0.60**	0.49	**0.63**	-0.30	0.49	0.40	0.40	**0.50**	**0.61**
Palo Verde	1995	0.10	-0.06	-0.19	-0.21	-0.24	-0.39	-0.42	-0.44	0.18	-0.38	-0.41	-0.45
Palo Verde	1996	**0.79**	0.36	0.35	0.44	0.32	0.00	0.36	-0.22	**0.78**	-0.14	-0.24	0.01
Palo Verde	1997	0.16	0.20	0.19	0.17	0.13	0.14	-0.31	0.14	0.23	0.09	-0.04	0.15
Palo Verde	1998	-0.29	-0.37	-0.36	-0.33	-0.45	-0.39	0.10	-0.36	0.09	-0.49	-0.40	-0.39
Palo Verde	1999*	**0.88**	**0.81**	**0.81**	**0.85**	**0.83**	**0.84**	**0.77**	**0.81**	**0.85**	**0.83**	**0.70**	**0.80**
Palo Verde	Fall	**0.64**	0.35	**0.56**	**0.58**	**0.59**	**0.50**	**0.67**	**0.54**	**0.70**	0.48	0.40	**0.50**
Palo Verde	Spring	**0.84**	0.39	0.22	0.43	**0.51**	0.29	**0.77**	0.18	**0.83**	0.17	0.10	0.27
Palo Verde	Summer	0.36	0.28	0.31	0.41	0.45	0.26	**0.67**	0.27	**0.71**	0.27	0.23	0.26
Palo Verde	Winter	0.50	0.21	0.21	0.26	0.25	-0.17	0.50	-0.26	**0.56**	-0.19	-0.36	-0.10
PJM	1995	0.34	-0.12	-0.13	-0.05	-0.15	0.08	-0.20	0.02	-0.15	-0.02	0.16	0.02
PJM	1996	0.01	0.18	0.16	0.11	0.16	**0.52**	0.12	0.48	0.03	0.34	**0.52**	0.49
PJM	1997	0.12	0.15	0.14	0.12	0.11	0.11	0.13	0.12	0.14	0.13	0.10	0.13
PJM	1998	-0.18	-0.08	-0.06	-0.05	-0.14	-0.04	0.11	-0.01	0.08	-0.13	-0.08	-0.13
PJM	1999*												
PJM	Fall	**0.55**	0.42	**0.58**	**0.55**	**0.59**	**0.59**	**0.67**	**0.57**	**0.57**	**0.57**	**0.58**	**0.59**
PJM	Spring	-0.02	0.00	-0.09	-0.03	-0.02	0.02	-0.17	0.03	-0.01	0.04	0.03	0.03
PJM	Summer	0.08	-0.01	0.00	0.02	0.04	-0.01	0.27	0.00	0.14	-0.02	0.05	-0.02
PJM	Winter	-0.10	0.26	0.24	0.20	0.19	**0.60**	0.10	**0.54**	-0.10	0.40	**0.64**	**0.55**

Table 4-11
Correlation of Gas and Electricity Prices (Continued)

Electricity Market	Season	San Juan	Carthage	Katy	Waha	Ventura	Atlanta	Alberta	Appalachia	Topock	Chicago	NY	Henry Hub
		Gas Market											
SERC	1995	.	.	.	.	.	.	.	.	.	.	.	.
SERC	1996	0.02	0.23	0.21	0.15	0.10	0.20	-0.09	0.20	0.03	0.15	0.18	0.21
SERC	1997	0.05	0.06	0.05	0.04	0.02	0.03	-0.05	0.03	0.07	0.03	-0.01	0.03
SERC	1998	-0.03	0.24	0.24	0.23	0.16	0.24	0.00	0.21	-0.01	0.20	0.18	0.20
SERC	1999*	**0.53**	**0.58**	**0.55**	0.44	**0.55**	**0.60**	**0.54**	**0.54**	**0.50**	**0.55**	0.48	**0.57**
SERC	Fall	0.15	0.23	0.22	0.20	0.21	0.19	0.27	0.18	0.20	0.15	0.14	0.20
SERC	Spring	0.14	0.19	0.19	0.09	0.23	0.16	0.17	0.13	0.17	0.13	0.06	0.14
SERC	Summer	-0.01	0.08	0.09	0.12	0.15	0.08	0.36	0.04	0.11	0.06	0.08	0.05
SERC	Winter	0.43	0.50	0.48	0.47	0.49	0.43	0.13	0.43	0.43	0.48	0.48	0.46
SPP	1995	.	.	.	.	.	.	.	.	.	.	.	.
SPP	1996	.	.	.	.	.	.	.	.	.	.	.	.
SPP	1997	.	.	.	.	.	.	.	.	.	.	.	.
SPP	1998	-0.02	0.23	0.24	0.23	0.16	0.24	-0.03	0.21	0.01	0.20	0.22	0.20
SPP	1999*	**0.52**	**0.57**	**0.54**	0.43	**0.55**	**0.60**	**0.54**	**0.53**	**0.50**	**0.54**	0.49	**0.56**
SPP	Fall	-0.15	**0.59**	**0.57**	0.47	0.25	0.44	-0.33	0.32	-0.47	0.48	**0.51**	**0.60**
SPP	Spring	0.10	0.17	0.14	0.02	0.12	0.18	-0.05	0.17	0.10	0.16	0.15	0.14
SPP	Summer	**0.54**	**0.59**	**0.60**	**0.57**	**0.57**	**0.60**	0.28	**0.60**	0.19	**0.62**	**0.63**	**0.58**
SPP	Winter	0.34	0.15	0.14	0.27	0.45	0.07	0.40	0.07	0.33	0.34	**0.53**	0.10
TVA	1995	.	.	.	.	.	.	.	.	.	.	.	.
TVA	1996	.	.	.	.	.	.	.	.	.	.	.	.
TVA	1997	-0.03	-0.16	-0.15	-0.13	-0.14	-0.21	-0.02	-0.22	-0.07	-0.16	-0.11	-0.20
TVA	1998	.	.	.	.	.	.	.	.	.	.	.	.
TVA	1999*	.	.	.	.	.	.	.	.	.	.	.	.
TVA	Fall	.	.	.	.	.	.	.	.	.	.	.	.
TVA	Spring	**0.53**	-0.38	0.13	0.14	-0.06	0.24	0.45	**0.61**	0.10	0.17	0.43	0.20
TVA	Summer	-0.30	-0.34	-0.35	-0.35	-0.36	-0.34	0.09	-0.37	-0.32	-0.31	-0.23	-0.37
TVA	Winter	.	.	.	.	.	.	.	.	.	.	.	.

Notes: 1999* January 1999 to June 1999.

Generally there is low correlation, especially relative to electric on electric or gas on gas correlation statistics for neighboring regions or neighboring hubs. The electric on gas correlation statistics for 1999 are generally higher than for any other year. However, because this is a statistic for only half a year of data, one cannot draw as definitive conclusions from it. Moreover, the value for 1998 for most of those regions was a sharp contrast. Electric regions that are close to the pipes, like ERCOT, or which rely on gas regularly, such as COB, Palo Verde, NEPOOL and SPP, or even seasonally, like Florida, tend to have higher correlation than those that do not. However, the correlation is fairly low, e.g., 0.6 rather than 0.9. This means those markets are directionally connected, but not so strongly in absolute terms. Note that these correlations are in the absolute value of gas and electric prices, not in the percent change in each from day to day. The latter are only slightly different overall than the correlation in prices themselves.

A more detailed examination of these electric on gas correlation statistics for specific pairs of natural gas hubs and electric regions, matched by proximity, further highlights that there is no semblance of steady convergence. Figures 4-19a to 4-19g on the next two pages are plots of seven-week rolling correlations of weekly spot prices starting in 1996. The natural gas hub/electric region pairings are as follows, Alberta and COB, Topock and Palo Verde, Henry Hub and ERCOT, Henry Hub and Entergy, Appalachia and NEPOOL, and Henry Hub and Florida. The correlation statistics plotted in Figures 4-19a to 4-19g bounce between almost the entire possible range of 1.0 and –1.0 without any recognizable pattern.

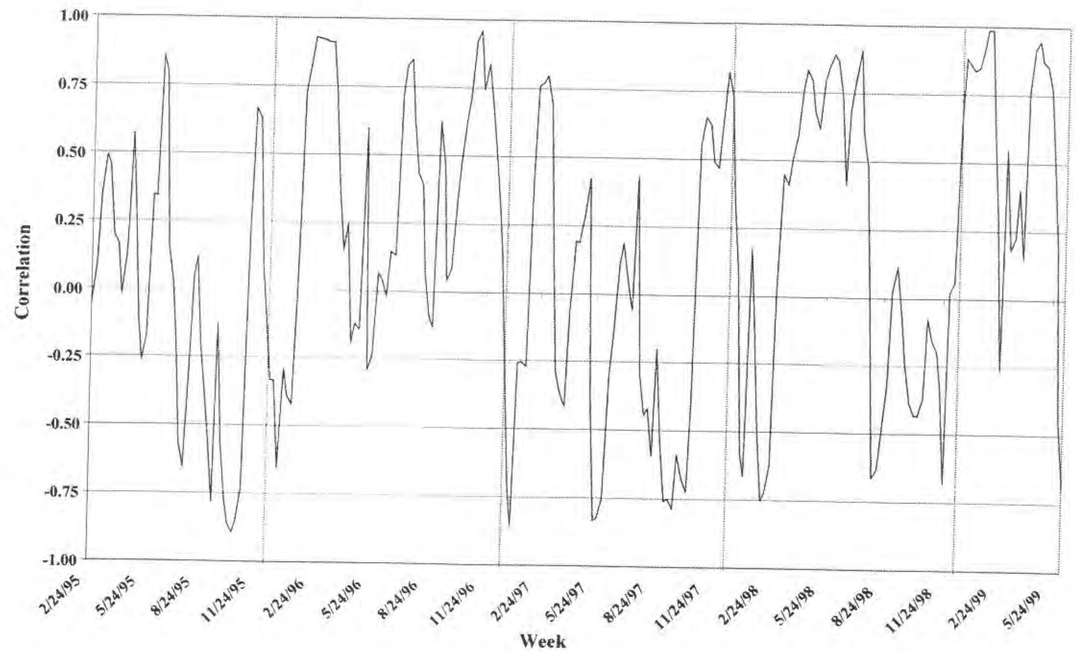


Figure 4-19a
Seven-Week Rolling Correlations of Gas and Electricity Spot Markets: Alberta vs. COB

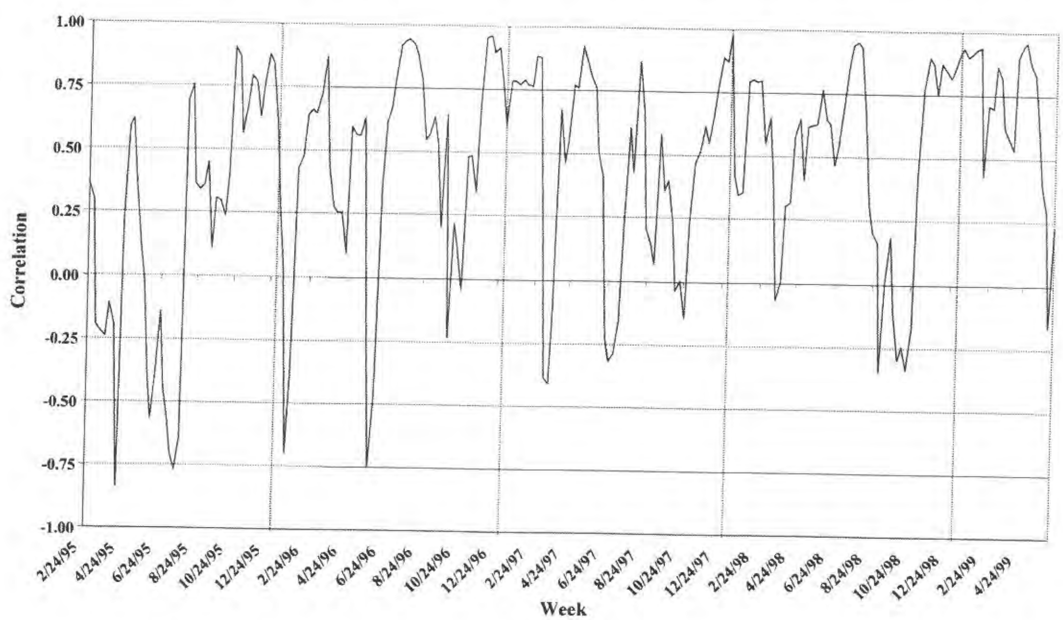


Figure 4-19b
Seven-Week Rolling Correlations of Gas and Electricity Spot Markets:
Topock vs. Palo Verde

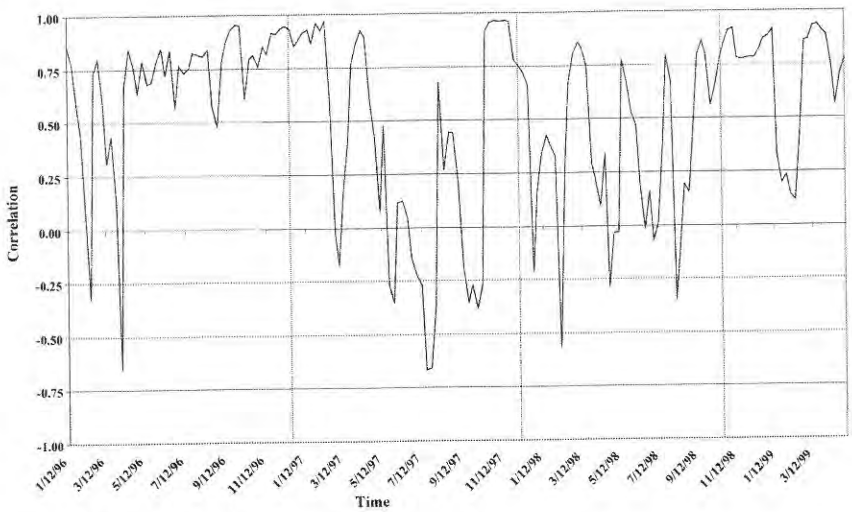


Figure 4-19c
Seven-Week Rolling Correlations of Gas and Electricity Spot Markets: Henry Hub vs. ERCOT

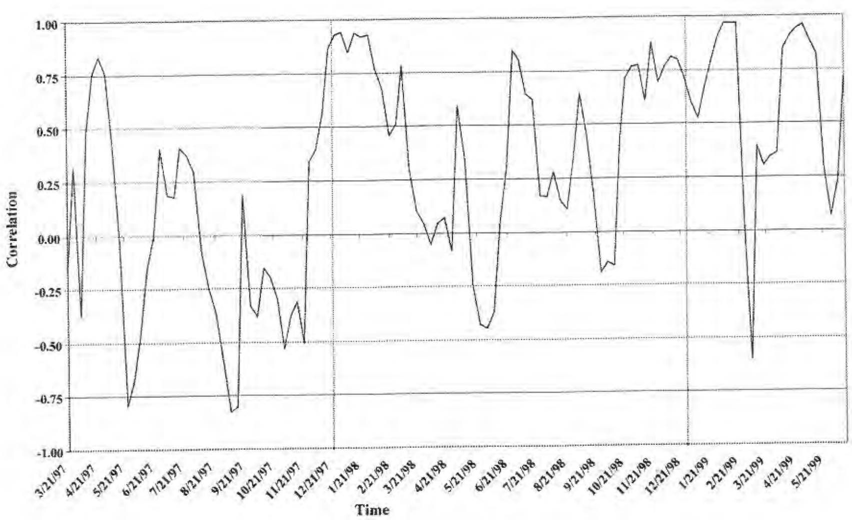


Figure 4-19d
Seven-Week Rolling Correlations of Gas and Electricity Spot Markets: Henry Hub vs. Entergy

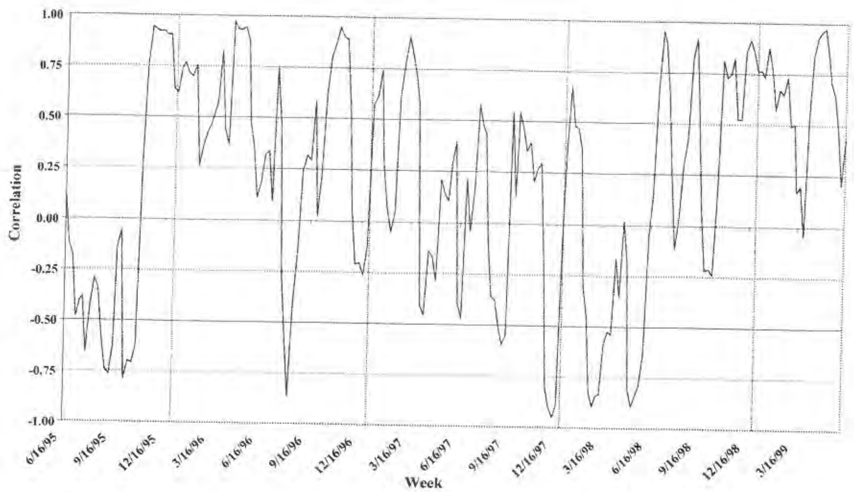


Figure 4-19e
Seven-Week Rolling Correlations of Gas and Electricity Spot Markets: Appalachia vs. NEPOOL

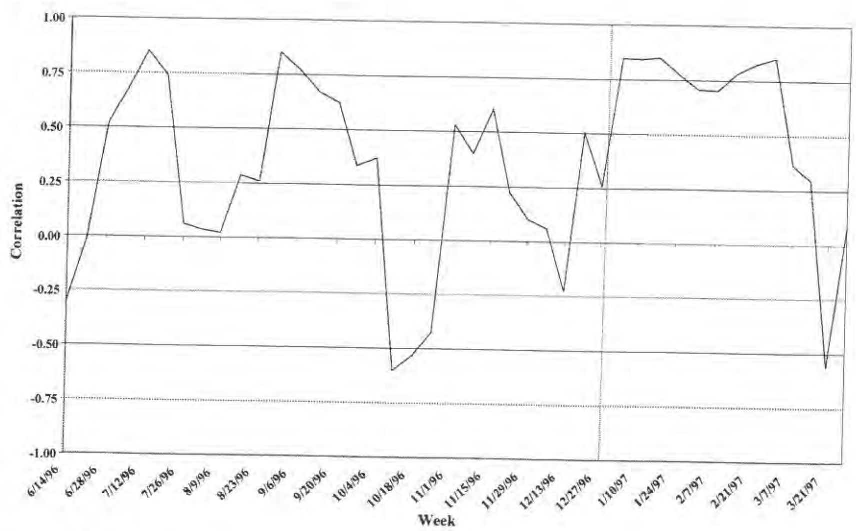


Figure 4-19f
Seven-Week Rolling Correlations of Gas and Electricity Spot Markets: Henry Hub vs. Florida

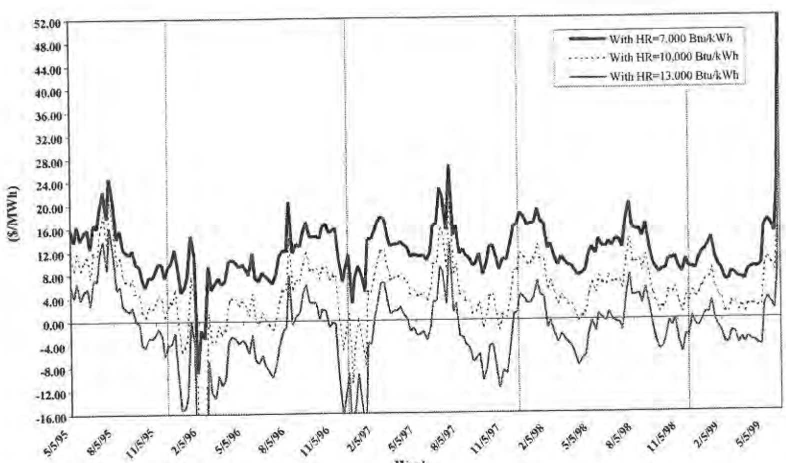
There are many reasons for this non-convergence/integration of wholesale gas and electric prices. Foremost is the fact that capacity scarcity and/or market power often determine electric prices rather than variable costs. These scarcity premiums can be very extreme, causing wide divergence from marginal fuel costs. However, gas-electric correlations remain fairly low, even when electric prices are truncated at, say $250/MWh. The lack of convergence then is due to the fact that even when gas is on the margin, units of very different heat rates can be deployed. Also, electric grid congestion can induce redispatch premiums that are not related to any single unit's marginal operating cost.

Spark Spreads

Analysts are concerned about the correlation between gas and electric prices in part because of what they imply about the stability of spark spreads. (They may also be interested in using the more liquid gas contracts as an imperfect hedge for electricity deals.) Spark spread is defined as the difference between the price of electricity less the cost of the gas used to produce the electricity. The spark spread shows the profit potential for a given natural gas technology. It can be measured in either dollars per MWh or dollars per MMBtu. The instability of the correlation statistics discussed above suggests that spark spreads are volatile—they have the same kind of troublesome personality we have seen throughout electric markets.

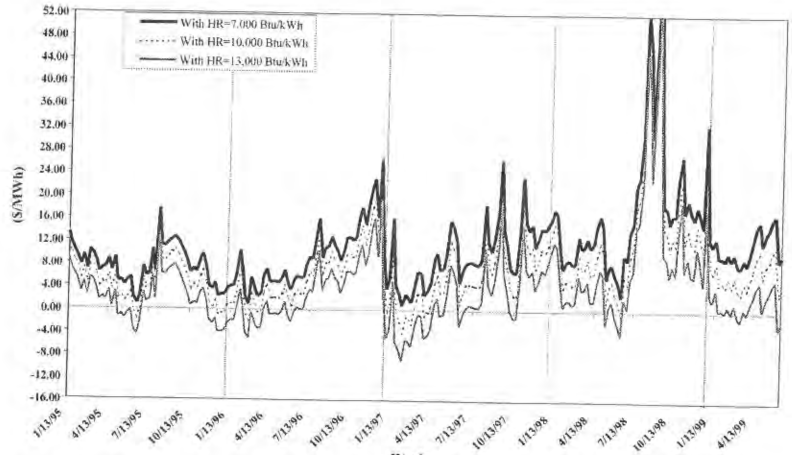
Figures 4-20a to 4-20d on the next page shows the trend of spark spreads for four pairs of electric and gas regions, NEPOOL and Henry Hub, COB and Alberta, ERCOT and Waha, and ERCOT and Katy. The spark spreads are calculated using weekly spot price data. The price of natural gas in MMBtu is converted to a cost per megawatt hour under three alternative assumptions about the gas plant's heat rate, 7,000 Btu/kWh, 10,000 Btu/kWh, and 13,000 Btu/kWh.

There is a strong seasonal component to the spark spread statistics. Profits rise in the summer when electricity prices are high and gas prices are low. In all cases, the highly efficient unit, 7,000 Btu/kWh heat rate case, has a positive spark spread. It is exceptionally high for ERCOT if Katy gas was used. At the other extreme is the peaking unit, or old gas unit with heat rates at 13,000 Btu/kWh. These units can turn a profit in a high price period and have been most profitable in the regions accessible to COB prices and Alberta natural gas.



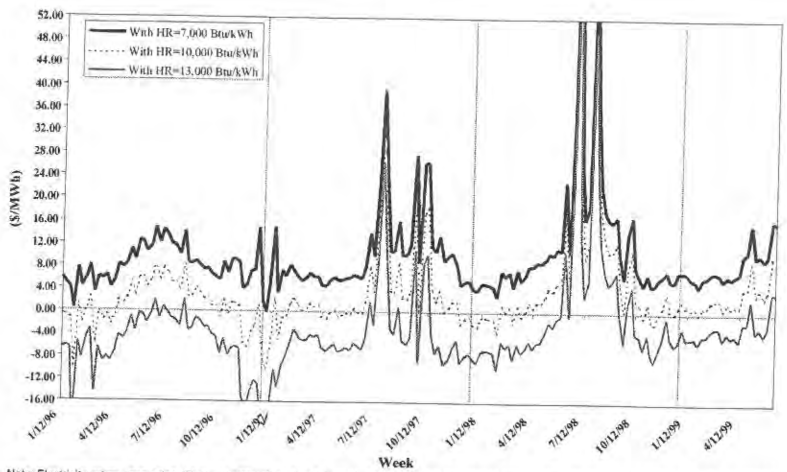
Note: Electricity price - gas price. There are 12 values that fall outside the scale of this graph, ranging from $-42.70 on 2/2/96 to $53.99 on 6/12/99.

Figure 4-20a
Spark-Spreads of Gas and Electricity Spot Prices:
NEPOOL vs. Henry Hub



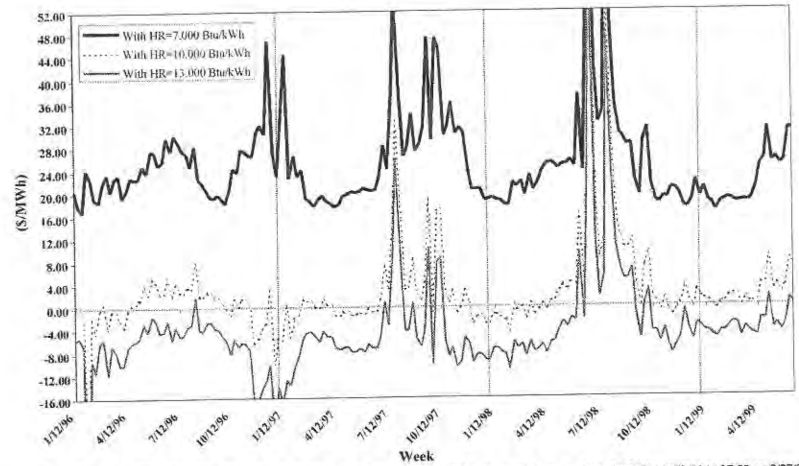
Note: Electricity price - gas price. There are 16 values that fall outside the scale of this graph, ranging from $30.54 on 8/22/98 to $65.14 on 9/5/98.

Figure 4-20b
Spark-Spreads of Gas and Electricity Spot Prices:
COB vs. Alberta



Note: Electricity price - gas price. There are 37 values that fall outside the scale on this graph, ranging from $-20.21 on 2/2/96 to $81.48 on 6/27/98.

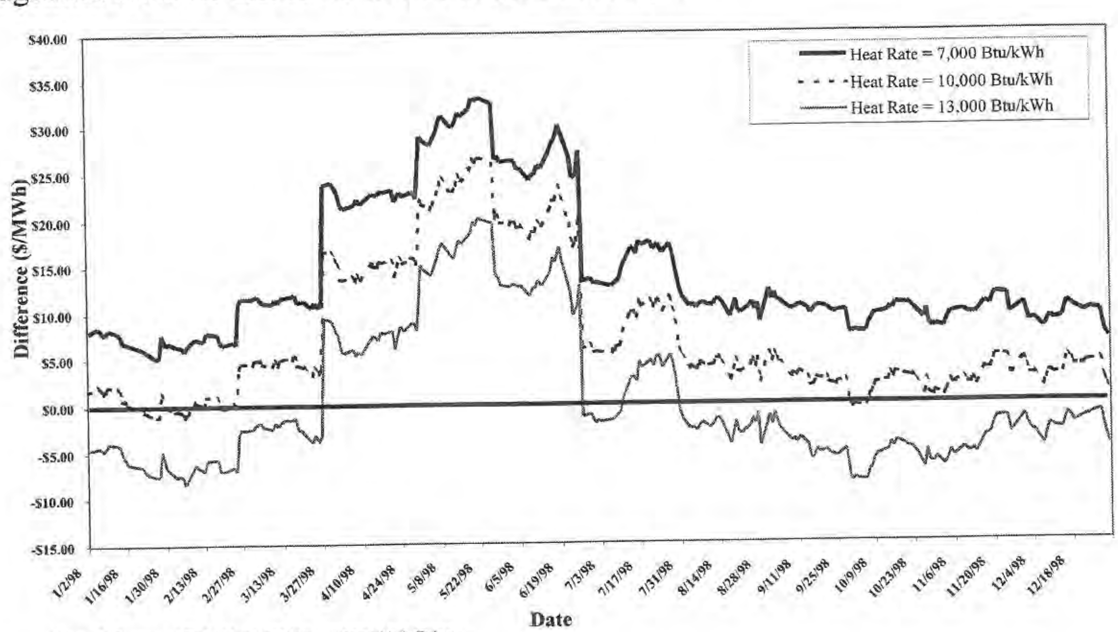
Figure 4-20c
Spark-Spreads of Gas and Electricity Spot Prices:
ERCOT vs. Waha



Note: Electricity price - gas price. There are 16 values that fall outside the scale of this graph, ranging from $-47.12 on 2/2/96 to 97.58 on 6/27/98.

Figure 4-20d
Spark-Spreads of Gas and Electricity Spot Prices: ERCOT vs. Katy

Of course, one can use forward contracts to try and lock in a spark spread. This is discussed further in the next chapter. However, spark spreads based on forward contract prices can experience the same highs and lows as the spot prices. For example, the spark spread for Palo Verde and Henry Hub for futures contracts 3 months to delivery is plotted in Figure 4-21. That is, if a firm bought a Henry Hub futures contract for natural gas to be delivered three months hence (summer), and sold a futures contract for power to be delivered at Palo Verde three months hence (summer), the firm could have locked in a profit of approximately $25/MWh if the unit producing the power had a heat rate of roughly 7,000 Btu/kWh. The shape of these spark spread curves is essential to knowing when to lock in the contract. This question and other risk management tools are discussed further in the next chapter.



Note: Difference=Palo Verde Price - Henry Hub Price

Figure 4-21
Spark Spread for Palo Verde and Henry Hub, 1998 Three-Month Forward Contracts

The magnitude of these spark spreads can be put into context by looking at what these measures yield on an annual basis. Specifically, a generation plant manager would like to lock in yields for a CC that exceed approximately $80/kW per year. This is the non-fuel cost per year of a new CC, a levelized number which includes recovery of and on capital. Table 4-12 presents capital recovery numbers for a representative CC that operates at a 70% capacity factor with a 7,000 Btu/kWh heat rate. Column 1 calculations are based on the average differential between NEPOOL electric prices and the natural gas price at Henry Hub index plus a $1.00/mmBtu charge for transportation to the Northeast. The second column, represents a similar calculation for COB electric prices less the natural gas price for Alberta, again including a $1.00/mmBtu charge for transportation. Thus, without even locking in a Futures contract, i.e., a guaranteed spark spread, generators were in some years recovering more than enough to break-even for a new plant. However, it also suggests that with some more risk management, higher profit margins could be obtained.

Table 4-12
Spark-Spreads of Electricity and Gas Spot Prices

Spark Spreads of Electricity and Gas Spot Prices ($/KW - year)		
Year	**NEPOOL-Henry Hub**	**COB-Alberta**
1996	59.97	56.76
1997	81.44	59.88
1998	72.76	110.83
1999	76.62	70.10

Note: Assuming 70% capacity factor, i.e., 6132 hours out of 8760 hours.

5

IMPLICATIONS OF FUEL AND POWER PRICE VOLATILITY FOR POWER PLANT OPERATIONS AND DEVELOPMENT

Overview

The previous chapters have described patterns of volatility and correlation in fuel and electric prices from a structural and statistical perspective. This chapter focuses on how such price risk affects the power plant or fuel manager's decisions regarding operation of an existing fleet of assets, adding new units through building or buying, sourcing of fuel, or similar decisions that affect the risk exposure of physical assets.

The chapter starts by discussing the context in which planning decisions must be made in this "New Age" of competitive power markets. Organizational aspects dictate how well strategies are developed and implemented. The cumulative decisions of all market players also have an impact on current day decision making and eventual market outcomes. Likewise, the time horizons for planning have also shifted in terms of scope and breadth (i.e., including time horizons, both long- and short-term, and further segmenting these into smaller increments of time).

Examples of the use of financial instruments to filter decisions and use them to secure hedged revenues are then examined. These examples are 1) use of futures in spark spreads, 2) comparing futures "lock-in" versus a daily "float," and 3) valuing the ability to access more than one market. Other examples are also described in a less detailed fashion. The bottom line for fuel and generation asset managers is that they must use statistical information from market trading to recognize and provide for risk in order to create and implement profit-making opportunities with physical assets and financial instruments.

Power Plant Decision-Making In Transition

The challenge facing fuel and generation asset managers as agents for the power plant owner in the transition to competitive markets for power and fuels can be appreciated by considering Figure 5-1.

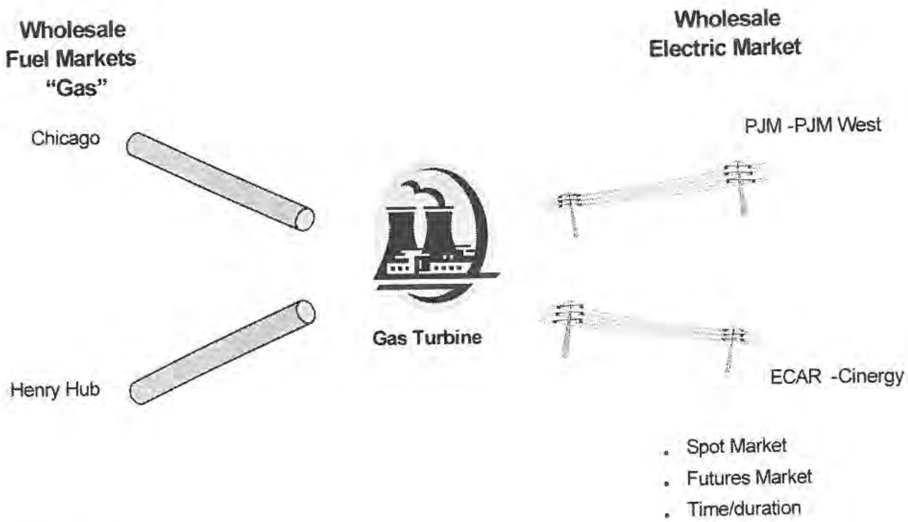


Figure 5-1
New Age Fuel Manager Responsibilities

By virtue of industry unbundling, a great deal of coordination must be achieved in order to capture value. A non-inclusive list of interdependent decisions to consider includes:

- Where and how much fuel to purchase from one or more locations
- What routes to use to deliver fuels to plants
- When to operate
- Where to place new assets
- Where to sell power, how to contract for any necessary electric transmission rights
- How far in advance to sell power and under what terms
- How far in advance to buy fuel
- How to adjust positions and commitments in light of changed circumstances

Greater detail of the financial and physical considerations involved is shown in Figure 5-2. This figure emphasizes the several segments in the value chain for delivery power. Each segment now has its own contracting opportunities and risks that, at the margin, determine the retail price. What can be seen is that the current state of competitive markets for power is stimulating a growth in the number of procurement and delivery strategies that may be employed for extracting value from generation assets. At one end of the spectrum, the generation owner can take market risks by buying and selling only in the wholesale markets for fuels and power. This strategy effectively "decouples" generation from the primary fuel suppliers and the ultimate consumer of electricity. This strategy is attractive in that it keeps fuel, scheduling, and sales, in synchrony—one aspect never forces an unmatched solution. On the other hand, it leaves the asset's long-lived capital recovery highly uncertain as the general spread between delivered fuel costs and power prices change over the years. At the other end of the spectrum, there can be merit to remaining partly or completely "vertically-integrated" by entering into long-term buy/sell agreements, thereby shifting market risk back out of the generation owner's hands. The difficulties here include making sure that all of the back-to-back contracts are compatible, as well as enforceable, in unstable market conditions.

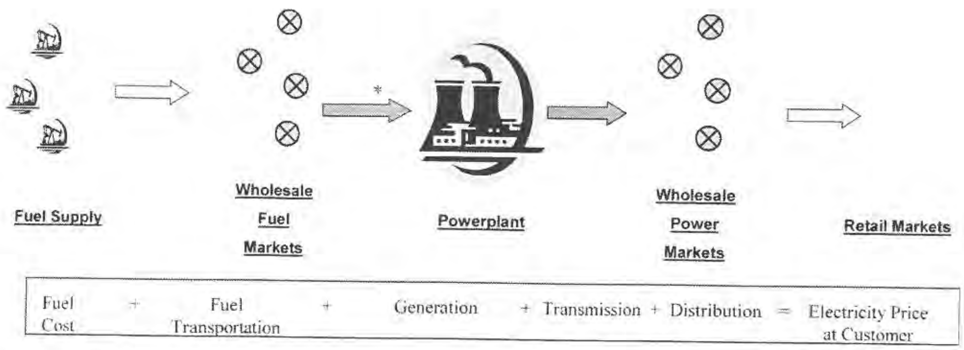


Figure 5-2
Post PURPA/888 Power plant Financial Model

The major observation to be gleaned from Figure 5-2 is that it is no longer necessary to go end-to-end to make profits. For instance, unequal valuation of substitute transmission paths creates a profit opportunity from selling rights over the higher priced path while buying them over the cheaper one. Valuation "errors" that result from conflicting assessments of market conditions by a limited number of market participants can create similar profit opportunities at any point in the chain, or between different time periods for future use of the chain.

Organizational Aspects of Coping with Fuel and Electric Price Volatility

The decisions of what contractual or ownership positions to take along the value chain are not the only problems to be resolved. An important question is whether to "outsource" fuel and power marketing and management in order to avoid risk. However, the downside is that so much potential profit may have to be given up to entice the necessary talent so as to make outsourcing infeasible. Deciding how to integrate the strategy within the organization and through contract outside the organization resemble a tug-of-war as illustrated in Figure 5-3. The risk reduction occurs in two ways. First, third party suppliers may be willing to take some or all of the risk for a price. Second, third party specialists may have the scale, expertise and liquidity to bear a specific risk move economically than a given fuel manager, power plant owner, or even utility.

Decision makers in the post PURPA/888 world—price disparities attract many different agents.

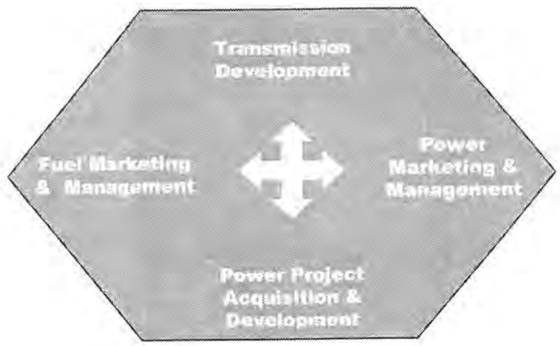


Figure 5-3
Organizational Aspects

Developing or selling physical assets involves consideration of another set of organizational functions. Up until the present time, the focus of most utilities has been on acquiring (or selling) existing or new generating capacity. Receiving less attention has been how for making fuel, power, or supply and delivery network investment decisions (i.e., pipelines, rail, storage, power lines, etc.) could go towards adding strength to the power plant owner's position. This results in both a lack of familiarity with the commodity alternatives in those other areas and, more seriously, a lack of organizational decision processes for empowering the managers of those areas to make and coordinate the necessary risk-bearing decisions.

Adding to the tension is that "price discovery" is exposing numerous arbitrage opportunities all along the different segments of the fuel-to-power supply chain. This brings numerous firms and individuals each with their own ideas of how to make profits. An important observation to make is that for a specific region these multiple "actors" or entities can work within a single firm or as independent entities depending upon the perceived needs and valuations of each entity. Most of these potential arbitrage opportunities are best realized by some combination of physical assets (i.e., generation, transmission, etc.) and financial instruments (i.e., long-term buy/sell contracts, transmission rights, lease agreements, etc.) all along the supply chain. The implication is that multiple entities acting on an arbitrage opportunities now carries with it future risk—the world of planning the future by command and control is no more and that dynamic planning and operations must be fused together.

Implications of Risk for the Firm

This new regime of increasing exposure to price volatility and market risk calls for an executive-level commitment to risk and return targets and limits for the individual firm. Even with the most sophisticated and expensive state-of-the-art risk analysis and planning tools, it is not possible to eliminate all risk for several reasons. First, despite the breadth of trading activity, most energy commodity markets are fairly illiquid, especially many months or years ahead. Thus, there may be no counter party available to "buy" the risk. Second, the rules of the market have not been finalized. As they change the value of positions will shift in uncompensated ways. Third, there is a lot of subjective judgment in using risk assessment parameters because they cannot be explained fully in terms of predictable, structural aspects of the industry. Accordingly, any single expectation of future value is likely to be wrong. This means that firms that choose to participate in the electric markets are making cultural judgments about their willingness to take the risk of losses in the pursuit of profits.

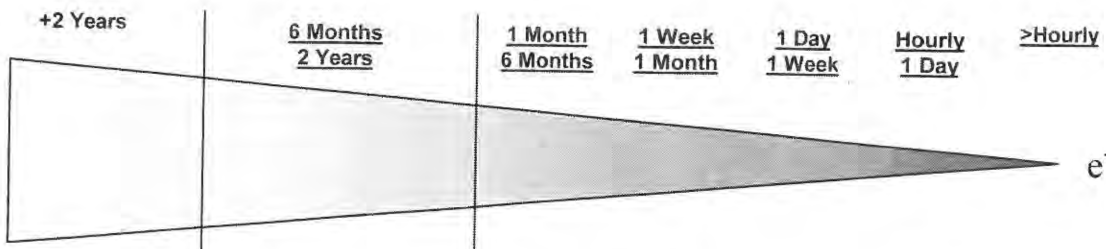
The multi-faceted nature of risk described above begs for simple and straightforward methods of quantifying total risk exposure that is being faced, and communicating that risk exposure preference throughout the firm. One such tool that has seen increasing use in boardrooms throughout the nation is Value at Risk (VAR). VAR provides an insight into how the many potential risks that the firm is facing combine in the profile of the possible range of losses or profits. The usefulness of tools such as VAR is providing a common language so that guidelines can be set at the highest levels in the firm, communicated throughout the organization and monitored on a daily basis. These guidelines can then be used by those within the firm for dealing with business operations on a day-to-day basis to use their best judgment to adapt to a dynamic market. Fuel and plant managers cannot be expected to set VAR targets, but they can play an important role in estimating VAR exposure and in implementing VAR-limiting strategies.

Planning Horizons in Electricity's Transitional Era

Up to this point, the discussion about the challenges presented by competitive markets for fuel and power has focused on the types of decisions that must be made and some of the organizational considerations in light of the transition to competition in electric power. An important combination to be made by the firm is the successful development and deployment of physical assets and the financial instruments used to extract value from those assets. One way to view the appropriate combinations of physical assets and financial instruments is shown in Figure 5-4. As mentioned above, planning and operational decisions must converge to capture value in a fashion that maps into the kind of information and opportunities available over different time horizons.

Figure 5-4 traces the types of decisions that are made for the production of power at any one point of time back through it antecedents. This is represented by the electron (e^-) on the right side of the figure. As decisions involving the production of that electron are traced further back in time, those decisions necessarily involve larger and larger quantities of production at a future time (represented by the widening triangle). The planning horizon can be broken down into three different eras:

- Long-Term (+2 years)
- Mid-Term (6 months to 2 years)
- Short-Term (6 months to hourly or less).



- Long-term ownership/investment in real assets (owning steel).
- Near-zero buying fuel and selling power forward possible.
- Unlikely to 'match' books.

- Long Term fuel & power long-term contracts.
  - Flexibility
  - Possible to match book
- Capacity Market
  - Market Commitment
  - Verification of fuel supply at peak
- Limited/illiquid forward/ futures market.
- Planned outage scheduling.

- 1 Month to 6 Months:
  - More liquid futures & forwards markets
  - Improve on spark spread position
  - "Volatility" trading in futures and forwards markets to generate revenues (measured risk)
  - Economic outage consideration/planning (month)
- 1 Day to 1 Week to 1 Month:
  - Forward/bilaterals still possible
  - Improve on spark spread position
  - Volatility trading
  - Economic outage consideration/planning (daily/weekly)
- Hourly:
  - Forward/bilaterals still possible
  - 'Residual' markets exist
  - Economic outages/turndown limited by technology
  - Less than hourly possible (i.e. regulation).

Figure 5-4
Planning Horizons in the Post PURPA/888 World

Long-Term Planning

Long-term planning is most often associated with decisions about owning or investing in real assets such as power plants (owning steel). During the regulated era of the power industry, the financial model that best suited the industry was to enter into long-term contracts for fuels (20 years or more) with "selling" guaranteed by the utility's monopoly franchise right. Transmission was implicit in the generation service, so its procurement was rarely an issue. In the current era, power plant construction is more often financed without all of its fuel requirements or its power production committed in advance. The latter is the distinguishing characteristic of merchant plants.

A power plant built as a merchant unit puts the power plant owner's in the financial state of being simultaneously short the fuels market (i.e., obligated to buy fuel) and long the power market (i.e., obligated to sell power) in order to generate revenues sufficient to cover debt requirements and provide the return of, and a return on, equity for the owners. The merchant plant investors (and debtors) are making the assumption that both fuels and power markets prices will be at levels necessary for positive revenues to be generated during the five to twenty year economic life of the plant.

Some or all of this future market risk can be alleviated by long-term lease or sale agreements. Long-term power deals can be anything over one to a few years in duration. In some cases these agreements might cover the entire life of the plant. It will likely be the case that less than the full capacity of the plant would be committed years ahead of time. This is often referred to as not "matching book" (i.e., not having sales contracts or short positions in place to offset the implicit long position), though this is quite rare in the U.S. Even recent Power Purchase Agreements (PPAs) for divested nuclear units are typically shorter than remaining asset life. Overseas, life-of-plant PPAs are more common, though not necessarily enforceable. The implication is that expectations of future prices, rather than the forward curves as determined by financial instruments, is expected to continue to drive decisions about buying, selling and building generation assets.

Mid-Term Planning

As the focus changes to an intermediate six month to two-year time horizon, the opportunities for committing to offsetting fuel and power deals increase. Through marketing and seasonal supply bidding it is possible for a merchant plant to book most, but probably not all, of its anticipated production capability, and cover that obligation with fuels contracts with like term, thereby locking in the anticipated spark spread for some portion of the plant's capability. As will be shown in the examples that follow, committing all production at any stage of the planning process sacrifices the potential for additional profits in exchange for a more certain, less risky profit at the current time. This decision of when to commit is neither a "good" or "bad" idea. No present value wealth is increased by trading one kind of risk for another at fair market prices, unless there is an arbitrage opportunity being captured. However, any given organization may have a strong preference for bearing risk one way or the other. This is where choices about acceptable value-at-risk (VAR) prevail. In addition, decisions made during this stage of planning greatly affect the level of flexibility that remains for short term planning.

Another issue to consider over the mid-term period is planning plant outages for necessary maintenance. In the past, outages were planned in response to anticipated supply and load conditions by the utility and for system logistic considerations. In deregulated markets, outage planning has shifted to individual firms responding to anticipated prices during the months of operation being considered. A potential problem is that individual owners might make plans to take units offline at the same time leading to capacity shortages.

Short-Term Planning

The implementation of Order 888 has breathed life into short-term power markets from time increments of a few days or weeks ahead down to one hour or less. Many of the new firms that have come into the electric industry since Order 888 in 1996 have come from trading financial derivatives and commodities instruments for which time horizons of six months are often a long time. The style of these new players in the electric industry has contrasted sharply with that of traditional utility practices and methods.

In time frames of six months or less, contracts for power can be traded in a variety of regional markets throughout the country. Focusing on closer-in time frames in just a few markets provides liquidity critically needed to fully "match books." Liquidity provides traders with certainty of being able to shift out of a position before having to make deliveries. Liquidity, therefore, makes it possible for speculators (i.e., those not intending to deliver or take electricity) to participate in the market. Speculators intend to make money on volatility, or changes in price in electricity. Those firms with assets or obligations are provided with opportunities to do better than the longer-term positions they had entered into. In addition, those positions could be improved upon to being even better than taking the spot pricing available at the time of production (how this can be achieved in just one way is illustrated later in the chapter). From the point of view of physical asset owners or managers, speculators are welcome participants in the market because they can, and will, participate much more extensively in risk-bearing than other industry players that can only take positions reflecting their own local situation. Speculators, therefore, are the "oil" that helps keep the market moving.

Trading occurs for monthly, weekly, daily, and sometimes hourly blocks of power. As seen, smaller units of time bring greater volatility, and hence increased risks and potential profits. Hourly markets can bring the highest price premiums of all the markets largely because short term supply and demand elasticity are both quite low and system balancing is obligatory. On hot days, this can result in enormous short-lived price spikes. However, several structural factors exist to limit hourly trading. Most of these limitations involve the difficulty of arranging and following through on production and delivery schedules covering such short time periods. The industry is currently working on means to improve the market structure to allow more hourly trading.

In the electric industry's transition to competition, it is the case that power plant operations will be greatly affected by the changes in power prices in the short-term. For example, low power prices for a particular month may call for planned outage. Later, power prices may change significantly enough to make it profitable to bring the unit online for all or some of the month. This flip-flopping of outages for economic reasons could continue all the way until the day of operation. Such "flip-flopping" is driven by continually changing expectations about the future market condition and the feedback from others' decisions as reflected in the price signals. Such uncertainty about plant operations creates additional challenges for power plant operators, particularly for those that have not had previous experience of operating "at-the-margin."

Using Financial Instruments with Physical Assets

This section presents three examples that illustrate the potential benefits, and risks, of using the "New Age" tools available to power plant owners to maximize the value of assets. The first example shows the use of futures to improve the returns on assets and extract trading revenues from the spark spread. The second example extends the first example by comparing a monthly futures contract versus the daily prices through the month, further illustrating the risks and benefits between the different business practices. The final example illustrates the potential benefit of being able to access multiple markets for power with an asset. We begin with a discussion of some principles about futures and forward market instruments.

Use of Futures in Spark Spreads

The concept of the spark spread was discussed in the previous chapter and has been discussed in numerous other EPRI reports.[40] In simple terms, the spark spread is the simple "operating profit" to be obtained from converting fuel at a specific price to electricity at a specific price. The prices are expressed in similar units (usually $/MWh or $/MMBtu) and the conversion of fuel to power is a function of the power plant technology and its specific operating characteristics. Other variable production costs can be included, such as emission costs, chemicals, etc., either directly or rolled into the heat rate. In the simple examples discussed here, only the cost of fuel is allowed to vary and the heat rate is fixed.

Whenever spark spreads are discussed, there often arises a number of questions about the applicability of using futures, forwards and spot pricing data in setting prices for fuel input and power output. Some of these questions include:

- What is the validity of using daily (or hourly) prices if the fuel or power prices are "locked-in" ahead of time by generation owners? (Sometimes called "marking to market")
- What is the validity of using prices for markets for which the liquidity is thin (i.e., unable to execute any trades at the prices quoted)?
- What is the validity of using monthly futures prices versus forwards contracts?

Marking to Market

The validity of using prices that reflect smaller units of time than the "actual" contracting position of the generation owner is founded upon the notion of the opportunity cost (or benefit) of the owner's position in the market. Even though a fuel manager that has entered into long term contracts for gas supply and transportation, he or she is presented daily with opportunities to either sell a portion of the longer term contract into the fuel market, if the market price is above the long term contract, or conversely, to buy incremental fuel at a price below the long term contract price level. Such opportunities are typically available whether the fuel manager acts upon them or not. Transaction costs, such as bid/ask spread, or uncertainty about being able to obtain any fuel at a later date to support power production obligations, often described as a convenience yield,[41] reduces, but does not eliminate, the feasibility of pricing existing fuel and

[40] EPRI, Fuel and Power Price Volatilities and Convergence (TR-111564, May 1999); EPRI, Fuel Management for Competitive Power Generation-A Guide for Managing Change (TR-107890, April 1997), Section 13, "Lessons from Similar Industries; and others."

[41] Convenience yield is a term used in commodity futures trading to describe the non-monetary return that is implied when owners of a commodity are unwilling to part with it, even for a short time, when shortages exist. One explanation of this behavior is to consider the "customer goodwill" the owner places on being able to supply long-term customers without interruption.

power contracts into smaller time increments. This continual re-evaluation of an existing position at current prices is called marking to market.

Liquidity

The liquidity question is based on the notion that a posted price may be "misleading" or "worse than useless" if only very few trades can be executed at the quoted price, or if any large trades would cause significant changes in the posted price. This means that anyone with a position in the market (whether speculator or hedger) may not be able to liquidate their position at that posted price. This argument does hold significant merit in evaluating whether or not a generation owner can actually take a position in the futures or forwards market and in evaluating the risk of being able to liquidate that position at a future time. It is still useful, however, to examine the spark spreads in futures and forward markets first and then evaluate the implications and risks associated with taking the particular position. Even for price signals generated in illiquid markets, if there exist persistent price signals for buying (i.e., low prices) or selling (i.e., high prices) relative to an industry "norm," then it can be expected that new or existing market participants will eventually organize to take advantage of the price disparity. The price signals are then a "flag" or indicator that an arbitrage opportunity exists that may require new physical assets or modifications to market rules. An example of market liquidity involves those utilities that have divested their generation but then need to buy enough supply to cover much of their distribution load under their transitional "standard offer" service. It is not possible to buy such large quantities of supplies ahead of time without radically driving up forward power prices.

Futures versus Forwards

Yet another question that is often asked is whether futures or forwards contract prices are preferable, particularly with regard to electricity. In principle, the advantage of a futures contract is that by standardizing as many contract issues as possible, liquidity can be built up and price transparency can be achieved (i.e., buyers and sellers both have access to "fair" prices). Unfortunately, there have been a number of issues that have beset the NYMEX-Style futures contracts for electricity causing them not to quite fulfill this promise. One issue is that traders have some difficulty in being able to determine a "fair" price for electricity to be delivered at a future time for an entire month's worth of on-peak days (the risks associated with taking or making delivery on a futures contract will be demonstrated with the second example). Over the counter (OTC) forwards markets have become more liquid as market participants themselves "learn by doing" and adopt forwards contracts to meet their needs.[42] Price transparency is also improving in forwards markets, mainly through the ease of information flow brought about by the internet. However, the price signals generated from such transactions are, almost by definition, for products that can vary widely in composition. Therefore, while the price signals from electricity futures may be suspect, it still represents the best single estimation available for a standard product, namely, a full month of on-peak power over a few months to a year or so forward.

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[42] Futures contracts, by definition, have limited flexibility in contract terms.

Futures Example: July 1999 Contract

The principles just discussed will now be illustrated through the use of a simple example. The first part of the example involves following the July 1999 Cinergy contract from seven months before delivery to contract close (i.e., from January to June 1999). The second part of the example involves comparing the July futures contract through the delivery period versus "day-ahead" spot market power.

Cinergy July 1999 Pre-Delivery Spark Spread Trading

Figure 5-5 illustrates the spark spread between the Cinergy electricity price and the Henry Hub gas price changes on a daily basis. The figure uses an 8,000 Btu/kWh heat rate and ignores other costs such as transportation and environmental costs. Generation owners are faced with an opportunity to alter their net position in the market on a daily basis through the use of financial instruments and thereby adjust the amount of future price risk being hedged. The basic premise of hedging is to lock in a price today for future generation. The generation owner, in this case, can seek a price for generation higher than that provided by either a long-term contract or by taking the estimated day-ahead prices for the month during the contract delivery period. Speculators (i.e., non-commercial traders) seek to profit from changes in futures prices over time such that the speculators initial positions can be liquidated at a profit. Some speculators attempt to predict futures market highs and lows and buy and sell accordingly. High volatility increases the probability that the futures price will move to a level that allows the speculator to liquidate the position before the futures or forwards markets expire.

Non-commercial traders such as generation owners have a built-in advantage in that they face less risk in engaging in some trading. This is because the generation owner can back up any particular position through operation of his power plant, up to the capability of that plant. That is, a generation owner that shorts, or sells, the spark spread (i.e., sells electricity futures contracts and buys gas futures contracts) can either lock-in a price spread today or, through the reverse process, buy back the spark spread and take future price risk in the remaining life of the futures contract. Further, price risk can be taken upon expiration of the futures contract, through participation in the day-ahead or hourly markets. This ability to back up a trading position with physical assets is the main reason that many firms engaged power marketing are seeking to become "asset based" or "asset backed."

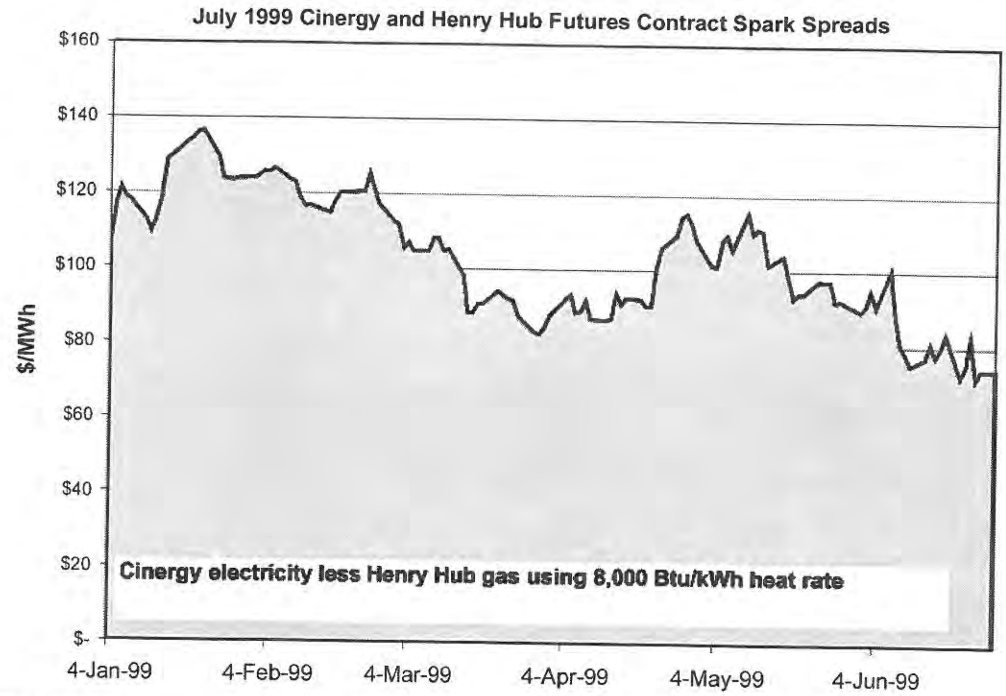


Figure 5-5
July 1999 Cinergy and Henry Hub Futures Contract Spark Spreads ($/MWh)

An example of how a generation owner can engage in non-speculative trading to increase returns on physical assets is illustrated in Table 5-1. Table 5-1 shows the same daily spark spreads for selected days of the July 1999 Cinergy contract, as shown in Figure 5-5. For simplicity, the amount of capacity in question is exactly 1MW. It is assumed that there is no initial position and that the transaction costs to sell or buy the spark spread is $0.20 per MWh.

Table 5-1
Example: Volatility Trading of 1-MW—Cinergy July 1999 Futures

Date	Cinergy Spark Spread $/MWh	Limit Order		Portfolio Summary				
		Track Price $/MWh	Delta $/MWh	Sell $/MWh	Buy $/MWh	Net Spark Spread $/MWh	Fee $/MWh	Net Cash Flow $/MWh
04-Jan-99	$106.92	$106.92	$0.0					
05-Jan-99	$117.08	$106.92	$10.16	$117.08	-	$117.08	$0.20	($0.20)
11-Jan-99	$112.84	$117.08	($4.24)	-	$112.84	-	$0.20	$4.04
13-Jan-99	$112.80	$109.64	$3.16	$112.80	-	$112.80	$0.20	($0.20)
03-Mar-99	$105.44	$112.80	($7.36)	-	$105.44	-	$0.20	$7.16
27-Apr-99	$114.16	$107.17	$6.99	$114.16	-	$114.16	$0.20	($0.20)
30-Apr-99	$107.85	$114.16	($6.31)	-	$107.85	-	$0.20	$6.11
05-May-99	$107.95	$101.40	$6.55	$107.95	-	$107.95	$0.20	($0.20)
Total at Contract Close						$107.95	$1.40	$16.51

Notes: 1. "Track Price" is the price level benchmark that the daily Cinergy Spark spread is compared to in order to generate the "Delta"which determines that trading should occur.
2. "Sell" means that the spark spread is sold (i.e., sell electricity and buy fuel), and the capacity is committed to operate in order to back up the position at a fixed operating profit.
3. "Buy" means that the spark spread is purchased (i.e. buy electricity and sell fuel), resulting in a zero net position, which means that the capacity is no longer committed to operate in exchange for a fixed operating profit.
4. In the example the decision to trade into or out of a position is based on theabsolute value of the delta exceeding $3/MWh.
5. Only the first day of trading the July 1999 contract and days that resulted in atrade are shown in the table.

A simplistic "limit order" trading program is implemented that does not rely upon perfect knowledge of what the spark spreads are going to be. Generally, the spark spread is sold when the price rises above the limit order to do so. In addition, a contract that is sold can be bought back if the price drops below the corresponding limit order. In this case, the limit order is a delta, or change, from a tracking price of $3 per MWh. The spark spread is sold when the delta goes above the limit order and bought back when it drops below the negative of the limit order. This example shows two sources of value for generation owners by engaging in the futures market. The first is in being able to lock-in a price at a level above the closing value of the futures contract ($107.95 - $73.90 = $34.05 per MWh). The second is that trading on the volatility of the spark spread future generated an additional $16.51 per MWh of cash revenues to the generation owner.

Table 5-2 summarizes the net benefit to the generation owner for participating in the market as opposed to simply being a price taker of the closing futures contract price. There are three important observations to make about the results. The first is that there exist two benefits to actively trading contracts for a power plant beyond that which is represented by the forecast of future price levels, namely market position and volatility trading. The second observation is that at no time during the example did the generation owner sell more contracts than the maximum capacity. Any additional sales above 1MW, or any buys, would constitute a speculative position that is not backed-up, or hedged, by the corresponding assets or obligations. The third observation to make is that this example covered a single month's operation for an asset that presumably will have a useful life of several years. The implication to be drawn by these observations is that revenues can be derived from an asset, at a low level of risk, that are above what the "traditional" revenue accounting models would predict (i.e., taking only the expected price for power and gas during each time frame).

Table 5-2
Summary of Benefits from Simple Volatility Trading Program for July 1999 Cinergy Spark Spread

	Typical Approach "Price Taking" $/MWh	*Simple Volatility Trading $/MWh*	*Net Benefit $/MWh*
Market Position	$73.90	$107.95	$34.05
Trading	$ 0.00	$ 16.51	$16.51
Total	**$73.90**	**$124.46**	**$50.56**

The simple trading program described here did not allow locking in the peak spark spread of $136 per MWh, or $63 per MWh above the close price. Yet, actively trading a position in the futures or forwards markets does allow a generation owner to do better than simply picking a single price, such as the contract closing price without having any special knowledge about the future. Trading expertise is key, however, in being able to accurately design and execute trading programs that allow for expected price uncertainty and eliminate, to the maximum extent, unnecessary risk.

Foregoing the Futures Hedge

Not opting to lock in the futures price is another option available to the generation owners. Instead of locking in a price for the month during the predelivery period, the generation owner could elect to sell generation on a day-to-day basis through the month. In the previous example, the generation owner might be tempted to buy back his right to sell into the market at a spark spread of $107.95 per MWh for the $73.90 per MWh closing price and pocket the difference of $34.05 per MWh. However, the generation owner that took that option would face the risk of having to take the price offered by the day-ahead markets. The example presented here follows through on the consequences of that particular decision on the electric side of the spark spread only (i.e., the July 1999 Cinergy contract that closed at $92 per MWh) and not the entire spark spread.

Figure 5-6 shows the daily net result of electing to sell power into the Cinergy market at a fixed price throughout a month, represented by the $92 per MWh line, compared to taking the day-ahead prices for the same market. The bars below the line represent "losses" relative to the closing price, while the bars above the line represent day-ahead prices above the futures contract delivery price.

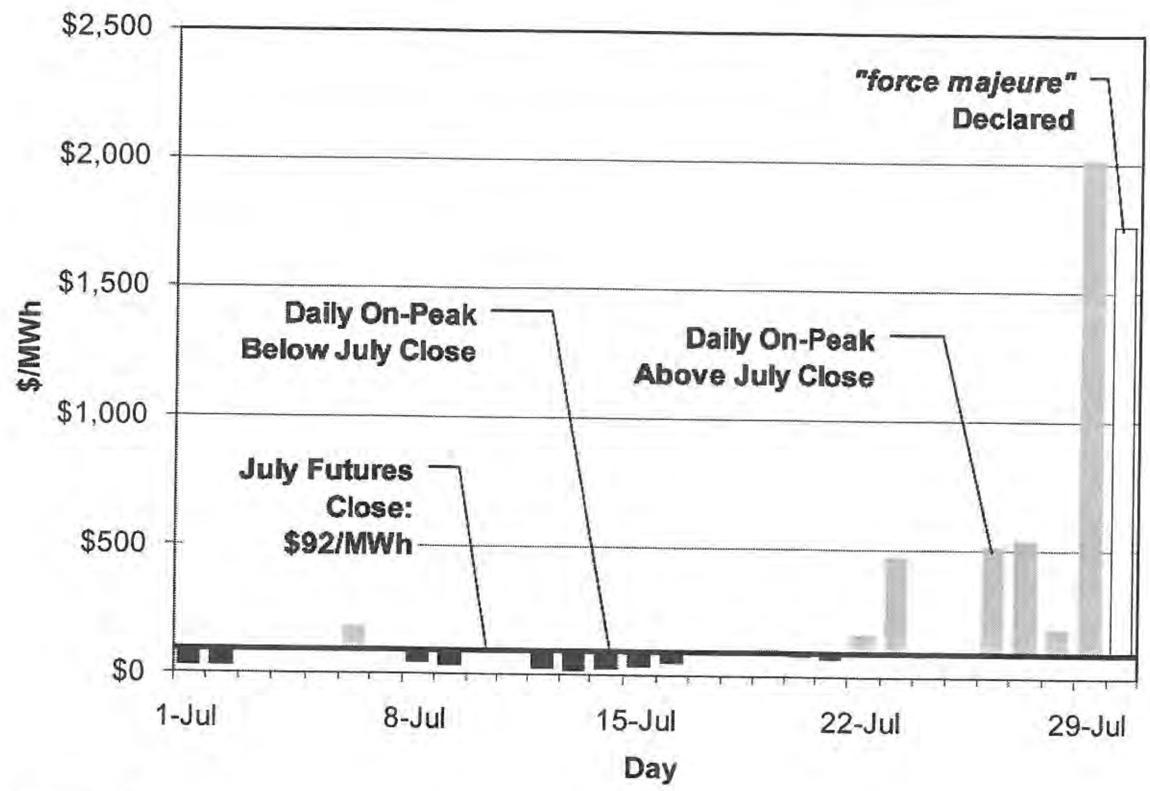


Figure 5-6
Comparison of Cinergy July Futures Close and Daily On-Peak Prices

There are a number of interesting observations to be made through inspecting Figure 5-6. First, the daily closing prices are greatly weighted by the prices realized during the latter part of the month. The result of these few high price days is sufficient to raise the average power price during the month of July to $358 per MWh as compared to the $92 per MWh that was set by the futures market at the beginning of the month. One implication of this result is the realization that the closing futures price, representing the best market information available at the time, can be a poor predictor of the actual market price. This is particularly true for a month such as July where the shift in season, and its severity, can be extremely difficult to predict. Another observation from Figure 5-6 involves the "force majeure" day that was declared on the last day of the month.

This "force majeure" call was made by Cinergy when it found itself unable to meet its own obligation from its own capacity and the generation it could purchase from the day-ahead market. Unable to find supplies "at any price" the utility declared a "force majeure." The result was that traders who had relied upon taking delivery from the utility to fulfill their own obligations were forced to scramble to find alternative supplies. Later, it was found that the utility had also "dragged"[43] the tie lines for 700 to 800 MW additional capacity it could not otherwise obtain.[44] Due to the fact that there were no blackouts reported as a result of these activities means that there were indeed supplies available. However, it is also apparent that prices at many multiples above cost were not sufficient to entice those owners of this capacity to sell into the market. An explanation of this apparent paradox, i.e., why can there be power market prices for thousands of dollars per MWh even though the capacity to meet demand exists, appears to lie more in motivations of fear (heightened sense of risk of insufficient supplies and distrust in market on part of both buyers and sellers, with resulting failure to capitalize on load diversity) than greed.[45]

Multiple Market Access For Fuel and Power

The previous chapter quantitatively reviewed the volatilities of, and correlations among, the many market power prices. This knowledge can be useful for valuing the capability of accessing multiple markets. Generators are often presented with opportunities to buy fuel from more than one supplier, or even market region, and can often likewise sell into more than just the regional market in which they are located. The effort and risk associated with attempting to capitalize on these opportunities can be quite high. However, the effort and risk may be well worth it.

Figure 5-7 illustrates the basic premise behind the value of being able to sell into more than one market. In the abstract, it can be seen that a generation owner that has the ability to sell into any of three markets can sell at the highest price line that "rides on top of" the three individual

[43] "Dragging" refers to the practice of a control area using the tie lines connecting it to the interconnection (i.e., WSCC, ERCOT, Eastern) as a supplemental resource to meet load without any contracts or notice given to the other control areas in its interconnection.

[44] A.R. Garfield, Chairman of ECAR Executive Board in a letter to James E. Rogers, Vice Chairman, President and CEO of Cinergy Corporation, December 6, 1999.

[45] EPRI, *Power Plant Profitability and Investment in the Central United States – Impact of New Gas Capacity on Generation and Repowering Economics*, 2000. 1000447. P. 1-5.

market prices. The result is that the generation owner ends up with an average price for power sold greater than any one of the average regional market prices for power.

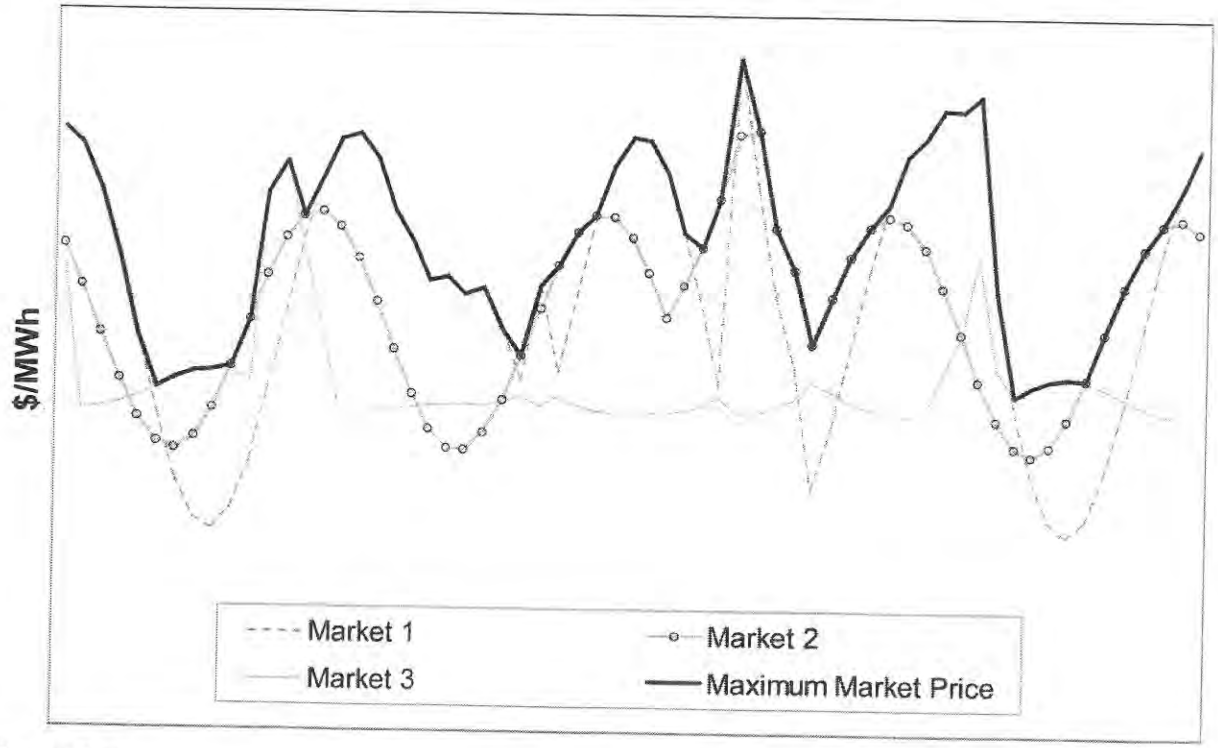


Figure 5-7
Example of Accessing Highest Value of Three Markets

The theoretical model that can be used to infer the value of multiple market access is referred to as the "Quality Option." This model has been developed for, and applied by, futures traders to explain premiums and discounts inherent in futures for wheat, bonds, and other commodities. An introduction to the theoretical basis behind valuing this ability to access multiple markets is presented in Appendix C. An examination of the key variables results in the following observations:

- **Correlation:** Correlation among the market price greatly affects the discount or premium associated with accessing multiple markets. Generally, high correlations imply that the prices move closely with one another, making it less likely that the "best" market would switch at frequent intervals. However, correlations of 0.95 or greater can still result in measurable market premiums or discounts.
- **Volatility:** Higher volatility increases the variability of prices about their means which also serves to increase the value of the premium of accessing multiple markets.
- **Price Differential:** The greatest value results from market prices that have the same average value. This improves the likelihood that switching between markets will occur. Increasing basis differentials decreases the value of the premium for being able to access multiple markets. This reflects the decreased probability that the market that is habitually "out-of-the-money" will be the premium market to sell into at any one time.

There are certainly practical considerations in whether the full benefits of the multiple access market premium can be achieved. Perhaps the largest impediment is obtaining adequate transmission, particularly when price divergences are the largest. Certainly, the lack of transmission is why the divergences occur in the first place. In circumstances where the divergences are non-periodic and large, the value probably cannot be realized, and instead represents an implied value for incremental transmission capability. However, the value of accessing more than one market is not tied to such wild price swings. Indeed, it has been shown that this ability to access more than one market has measurable value during time periods where market prices exhibit low volatility and high correlation.

The ability to realize these multiple market premiums are also highly dependent upon the location of the generation assets. Those generators that can sell into both ERCOT and the Eastern Interconnect, for example, are in much better position to reap multiple market premiums than a generator located in the middle of a market region.

Strategies for Physical Assets and Financial Instruments

The examples described in this chapter have concentrated on the generation owner's means for generating revenue. Price signals, however, motivate other market participants to interact with the market. The strategies sought by these other market participants will either indirectly affect existing generation owners through market price signals, or more directly affect the generation owner in affording more opportunities for additional revenues.

The different strategies can involve physical assets, such as new generating or transmission capacity, or come in the form of financial instruments. Other strategies can involve adapting or changing the market structure itself.

Physical Asset Strategies

The ongoing evolution of the power markets and their structure is changing the way in which existing assets are valued and deployed, and the strategies for deploying new assets.

As described earlier, existing assets have value to traders in term of capability to guarantee trading positions (i.e., being able to make physical delivery). In addition, each generating plant provides unique opportunities for value in terms of:

- Existing contract positions
- Location relative to fuel and power market access
- Capability to burn multiple fuels
- Repowering potential
- Stockpiling capability
- Cycling capability
- Ancillary services capability

The churning of the utility-owned capacity to non-utilities has sped the creation and execution of strategies to realize the greatest value from these existing assets. Further observations on this strategy can be found in EPRI, *Mastering the Markets—Generation in Transition* (TR-113998, December 1999). In addition, many of these assets are now under multi-year marketing agreements that combine the capability of the trading firm to concentrate on trading to extract value while the operating firm concentrates on operations to improve efficiency and availability.

New transmission and generating capacity projects will likewise benefit from consideration of the changing markets for power. Transmission expansion is suggested by regions that show high average basis differentials and low correlations. New generating projects that can be located to take advantage of multiple markets for power and fuel will likewise benefit from the ability to arbitrage between regions.

Financial Instruments

The growth of financial instruments directed at the power industry provides additional tools to pursue profit-making opportunities on the part of market participants. Some of these instruments have already been discussed, such as counter-party and risk insurance. Other financial instruments that have been used in the power markets include:

- Reverse spark spread
- Out-of-the-money call options
- Fuel netback pricing

Reverse Spark Spread

A reverse spark spread is when a generator sells an existing fuel supply contract in exchange for cash and replacement power. This financial arrangement has also been named and marketed as reverse tolling. This situation can be considered as a variant outcome of the volatility trading described earlier in this chapter. An example might be to consider a gas-fired steam generator with a poor heat rate that, through normal market fluctuations, was able to buy gas for a future time at a low price and sell the corresponding power at a higher than normal price (i.e., a positive spark spread). Now consider that as time goes by market conditions change such that gas for that same future period of time increases and/or the price of power goes down. In such situations, it is not unreasonable to expect that the spark spread for that generator might go substantially below zero. At that point, it would be wrong to assume that the generator's best strategy is to retain the spark spread contracts and generate to realize the profit guaranteed by those contracts. However, this is not the best strategy to pursue. In fact, the changed value of the fuel and power supply contracts may readily surpass the original spark spread margin. This means that the generation owner would be better off to idle his capacity, sell the fuel supply contract, and fulfill the power supply contract obligation by buying from other market sources.

Out-of-the-Money Call Options

Out-of-the-money call options represents opportunities for owner's of existing generation to pocket additional revenues in exchange for giving up the right to the low probability chances of extreme price spikes. Out-of-the-money refers to the fact that the strike price (or the "guaranteed" price) of power is set well above the expected, or at-the-money, level. The generation owner that has sold out-of-the-money call options on capacity still realizes all market revenues up to the pre-arranged strike price. In addition, the generation owner collects the option premiums. Another way of looking at the deal is that the generation owner is selling insurance to traders.

In the previous chapter, power prices were seen to exhibit occasional excursions well above the mean and standard deviation. Speculators and other traders of power as financial instruments are extremely reluctant to enter into any open positions that have any possibility of an astronomical payout. For that reason, traders are willing to pay an ongoing premium to a generator for the right to power from capacity.

Fuel Netback Pricing

This financial arrangement is a variant of tolling. Instead of going all the way to taking title to power, the fuel supplier provides fuel at a price determined as a function of the market price for power. In this case, the fuel supplier works with the power generator for their joint benefit that comes from improved dispatch. Often times, a "balancing" account is implemented that allows compensating the fuel supplier for those times when fuel was provided at a discount to a preset level from other times when infra-marginal returns are generated.

In the gas industry, such arrangements are often packaged with marketing agreements for the electricity and gas, as discussed previously. Pipeline companies and natural gas marketers have been the most active in developing this type of business. The coal industry has been less willing to price fuel on this basis, preferring to term such issues as "the customer's problem." This attitude is aggravated by corresponding lack of spot trading expertise and infrastructure.

Market Structure Strategies

There currently exists a major battle on how power markets are organized and how they operate. The New York Mercantile Exchange (NYMEX) has spent years in an attempt to create and grow futures contracts for power. Other exchanges followed suit with similar products. The goal of building liquidity around standard, one-month contract has run into problems, however, as illustrated by the examples in this chapter. Market participants face risk in using either futures or forwards markets.

A direct assault on the open outcry system has come from the online trading systems, such as Bloomberg, Altra, Houstonstreet.com and others. A built-in advantage is that they can adapt to the different time increments demanded by the market participants when circumstances warrant.

In this way, smaller time increments can be accommodated during periods of high volatility and longer time periods during "quiet" market conditions.

An emerging characteristic of the forwards market, as represented by the online exchanges, is that the connectivity provided by the Internet makes it easier for buyers and sellers to locate one another. This is a major benefit in improving liquidity in otherwise fragmented markets for power. In fact, the improved ability of online exchanges to operate as markets threaten even the traditional equity exchanges. Other initiatives at the market structure level include counter-party risk insurance and standardized contracting practices. In light of the experience gained from defaults by market participants on power contracts, firms have instituted much greater vigilance in establishing and protecting against counter-party risk. A few firms offer risk insurance services to power market participants as a way to allow trades to occur.

A

APPENDIX: REGIONAL COMPARISIONS OF POWER MARKETS

Introduction

This appendix provides detailed side-by-side comparisons of ten major electric regions in terms of capacity adequacy, fuel mix and costs, price levels, and regulatory restructuring activity.

Conversion Factors to S.I. Units

The following conversion factors apply to selected information in these tables. M used with English fuel (cubic feet of gas) and energy (British thermal units) units means thousands (10*3), and MM means millions (10*6). M applied to capacity (MW) and M used with metric fuel and energy units means millions (M tons).

Gas requirements (thousands of MMBtu)
Multiply by 1.055 to get thousands of gigajoules (GJ).

Gas requirements (MMcfd)
Divide by 35.3 to get cubic meters (14.73 psia and 60 degrees F). Note: Divide by 37.325 to get normal cubic meters (101.325 kilopascals at 0 degrees C).

Coal requirements (Thousands of tons)
Multiply (short) tons by 0.9072 to get metric tons.

Cost of fuel ($/MMBtu)
Multiply by 0.9478 to get $/GJ.

Heat rate (MMBtu/MWh)
Multiply by 1.0548 to get GJ/GWh.

Gas consumption (MMcf)
Divide by 35.3 to get cubic meters (see above).

Gas prices ($/Mcf) – not included in this appendix

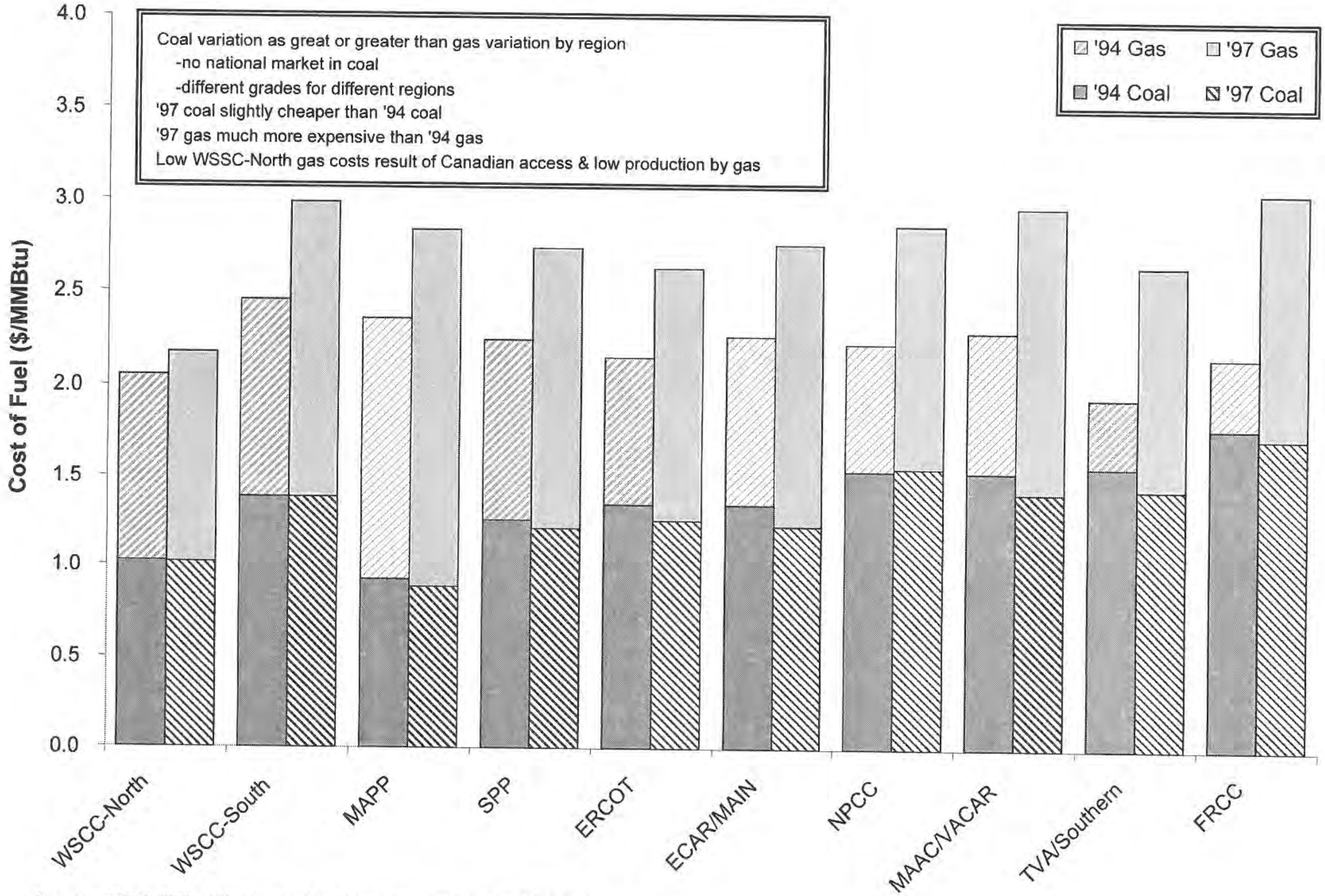
Table A-1
Capacity & Demand Statistics and Projections by Region

Region	Description	1994	1997	2002	'94-'97 AAGR	'97-'02 AAGR
WSCC-North	Summer Capacity (MW)	53,610	62,488	64,354	5.2%	0.6%
	Summer Peak Load (MW)	38,232	39,869	44,064	1.4%	2.0%
	Average Load (MW)	29,866	31,046	35,460	1.3%	2.7%
	Load Factor	78%	78%	80%		
	Reserve Margin	46%	47%	40%		
	Gas Requirements (Thousands of MMBtu)	63,207	39,789	190,587	-14.3%	36.8%
	Gas Requirements (MMcfd @ 100% LF)*	173	109	522	(64)	413
	Coal Requirements (Thousands of Tons)	68,853	66,353	71,166	-1.2%	1.4%
	Oil Requirements (Thousands of Barrels)	262	46	108	-44.0%	18.6%
WSCC-South	Summer Capacity (MW)	71,773	72,505	74,720	0.3%	0.6%
	Summer Peak Load (MW)	65,619	70,972	73,137	2.6%	0.6%
	Average Load (MW)	37,051	39,802	42,857	2.4%	1.5%
	Load Factor	56%	56%	59%		
	Reserve Margin	23%	23%	21%		
	Gas Requirements (Thousands of MMBtu)	672,417	450,064	685,507	-12.5%	8.8%
	Gas Requirements (MMcfd @ 100% LF)*	1,842	1,233	1,878	(609)	645
	Coal Requirements (Thousands of Tons)	44,502	44,149	43,537	-0.3%	-0.3%
	Oil Requirements (Thousands of Barrels)	2,859	609	737	-40.3%	3.9%
MAPP	Summer Capacity (MW)	30,975	31,462	32,652	0.5%	0.7%
	Summer Peak Load (MW)	27,000	29,787	32,611	3.3%	1.8%
	Average Load (MW)	15,582	17,313	19,155	3.6%	2.0%
	Load Factor	58%	58%	59%		
	Reserve Margin	20%	21%	14%		
	Gas Requirements (Thousands of MMBtu)	8,740	16,196	23,661	22.8%	7.9%
	Gas Requirements (MMcfd @ 100% LF)*	24	44	65	20	20
	Coal Requirements (Thousands of Tons)	72,548	76,165	82,165	1.6%	1.5%
	Oil Requirements (Thousands of Barrels)	310	566	2,941	22.2%	39.0%
SPP	Summer Capacity (MW)	69,540	68,992	70,434	-0.3%	0.4%
	Summer Peak Load (MW)	56,035	60,472	66,854	2.6%	2.0%
	Average Load (MW)	32,674	35,133	37,150	2.4%	1.1%
	Load Factor	58%	58%	56%		
	Reserve Margin	23%	18%	15%		
	Gas Requirements (Thousands of MMBtu)	733,924	662,599	746,191	-3.4%	2.4%
	Gas Requirements (MMcfd @ 100% LF)*	2,011	1,815	2,044	(195)	229
	Coal Requirements (Thousands of Tons)	94,758	108,468	114,160	4.6%	1.0%
	Oil Requirements (Thousands of Barrels)	2,547	7,472	1,695	43.2%	-25.7%
ERCOT	Summer Capacity (MW)	54,446	55,236	57,070	0.5%	0.7%
	Summer Peak Load (MW)	44,162	50,541	55,373	4.6%	1.8%
	Average Load (MW)	25,696	28,749	31,396	3.8%	1.8%
	Load Factor	58%	57%	57%		
	Reserve Margin	24%	17%	15%		
	Gas Requirements (Thousands of MMBtu)	791,551	947,521	978,845	6.2%	0.7%
	Gas Requirements (MMcfd @ 100% LF)*	2,169	2,596	2,682	427	86
	Coal Requirements (Thousands of Tons)	64,489	71,004	74,359	3.3%	0.9%
	Oil Requirements (Thousands of Barrels)	399	3,625	507	108.7%	-32.5%

Table A-1
Capacity & Demand Statistics and Projections by Region (Continued)

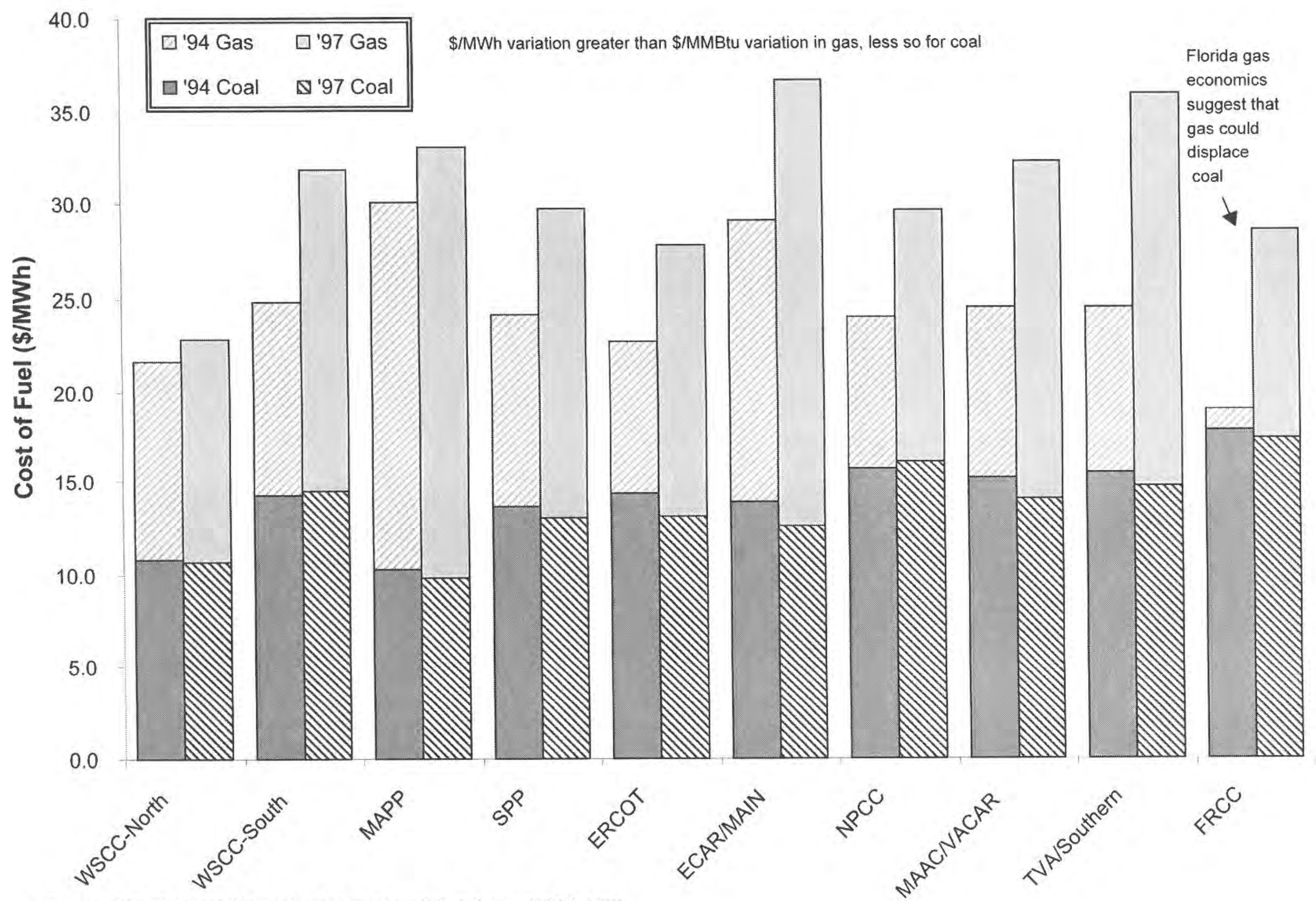
Region	Description	1994	1997	2002	'94-'97 AAGR	'97-'02 AAGR
ECAR/MAIN	Summer Capacity (MW)	152,563	156,173	161,332	0.8%	0.7%
	Summer Peak Load (MW)	129,727	139,379	152,236	2.4%	1.8%
	Average Load (MW)	80,056	86,822	94,734	2.7%	1.8%
	Load Factor	62%	62%	62%		
	Reserve Margin	20%	15%	14%		
	Gas Requirements (Thousands of MMBtu)	40,266	102,123	178,389	36.4%	11.8%
	Gas Requirements (MMcfd @ 100% LF)*	110	280	489	169	209
	Coal Requirements (Thousands of Tons)	253,733	288,248	308,860	4.3%	1.4%
	Oil Requirements (Thousands of Barrels)	5,395	4,091	7,862	-8.8%	14.0%
NPCC	Summer Capacity (MW)	59,120	59,803	60,048	0.4%	0.1%
	Summer Peak Load (MW)	47,581	49,269	53,085	1.2%	1.5%
	Average Load (MW)	29,674	30,190	32,222	0.6%	1.3%
	Load Factor	62%	61%	61%		
	Reserve Margin	30%	21%	14%		
	Gas Requirements (Thousands of MMBtu)	242,031	310,164	317,476	8.6%	0.5%
	Gas Requirements (MMcfd @ 100% LF)*	663	850	870	187	20
	Coal Requirements (Thousands of Tons)	16,335	18,642	15,560	4.5%	-3.5%
	Oil Requirements (Thousands of Barrels)	43,115	57,079	38,698	9.8%	-7.5%
MAAC/VACAR	Summer Capacity (MW)	107,012	111,592	115,797	1.4%	0.7%
	Summer Peak Load (MW)	89,705	98,726	107,805	3.2%	1.8%
	Average Load (MW)	54,394	57,391	62,409	1.8%	1.7%
	Load Factor	61%	58%	58%		
	Reserve Margin	23%	18%	13%		
	Gas Requirements (Thousands of MMBtu)	108,695	78,690	233,735	-10.2%	24.3%
	Gas Requirements (MMcfd @ 100% LF)*	298	216	640	(82)	425
	Coal Requirements (Thousands of Tons)	77,886	86,986	101,234	3.8%	3.1%
	Oil Requirements (Thousands of Barrels)	27,178	10,416	17,031	-27.4%	10.3%
TVA/Southern	Summer Capacity (MW)	67,599	70,372	76,990	1.3%	1.8%
	Summer Peak Load (MW)	55,994	64,127	74,032	4.6%	2.9%
	Average Load (MW)	35,027	38,782	43,877	3.5%	2.5%
	Load Factor	63%	60%	59%		
	Reserve Margin	16%	14%	11%		
	Gas Requirements (Thousands of MMBtu)	17,001	31,619	158,939	23.0%	38.1%
	Gas Requirements (MMcfd @ 100% LF)*	47	87	435	40	349
	Coal Requirements (Thousands of Tons)	94,712	107,813	109,654	4.4%	0.3%
	Oil Requirements (Thousands of Barrels)	1,172	1,203	1,144	0.9%	-1.0%
FRCC	Summer Capacity (MW)	35,528	37,607	40,912	1.9%	1.7%
	Summer Peak Load (MW)	32,904	35,375	38,844	2.4%	1.9%
	Average Load (MW)	18,249	20,041	23,142	3.2%	2.9%
	Load Factor	55%	57%	60%		
	Reserve Margin	23%	20%	20%		
	Gas Requirements (Thousands of MMBtu)	179,531	291,086	337,376	17.5%	3.0%
	Gas Requirements (MMcfd @ 100% LF)*	492	797	924	306	127
	Coal Requirements (Thousands of Tons)	23,998	26,045	26,339	2.8%	0.2%
	Oil Requirements (Thousands of Barrels)	54,305	39,097	27,261	-10.4%	-7.0%

Source: NERC Electricity Supply and Demand Database, 1998.
Average Load = Annual Net Energy for Load/8760
Load Factor = Average Load/Summer Peak Load
Reserve Margin** = (Planned Capacity Resources - Net Internal Demand)/Net Internal Demand
*AAGR columns for Gas Requirements in MMcfd shows absolute difference between years, not average annual growth rate.
**1994 & 1997 reserve margins are calculated using the following years' projections



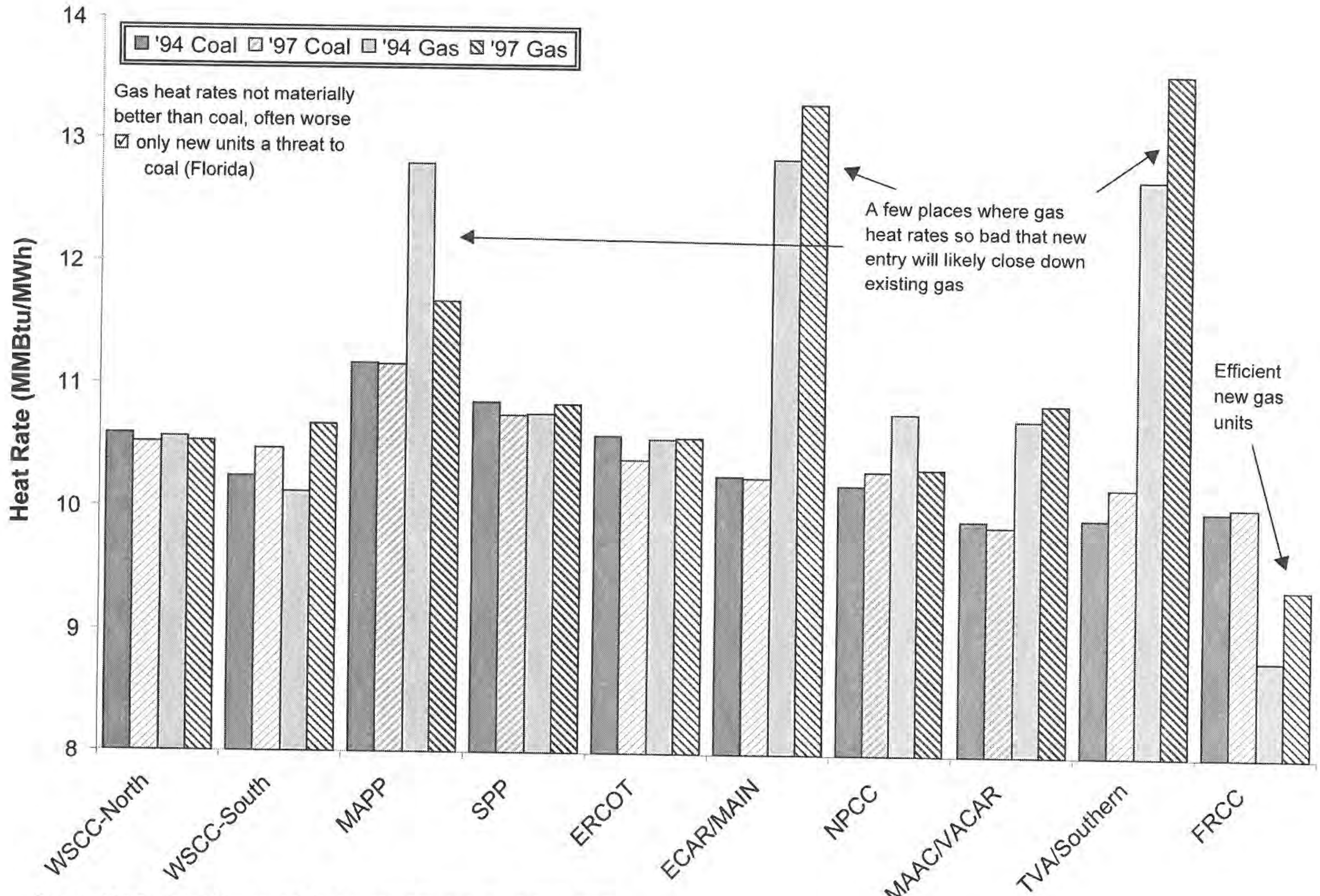
Source: EEI *Statistical Yearbook of the Electric Utility Industry*, 1994 & 1997.

Figure A-1
Average Delivered Cost of Fuel by Region



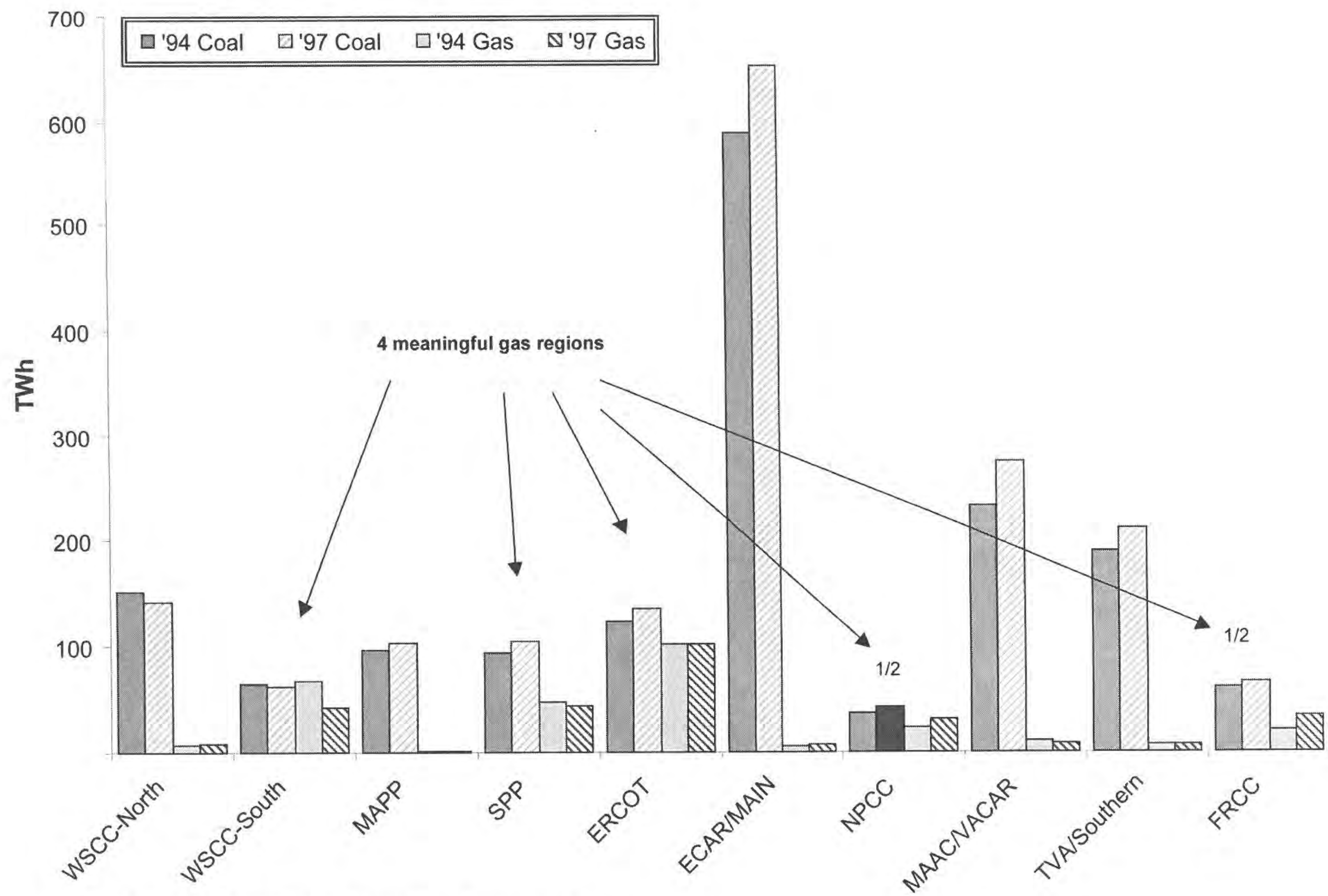
Source: EEI *Statistical Yearbook of the Electric Utility Industry*, 1994 & 1997.

Figure A-2
Average Cost of Electricity Produced by Region



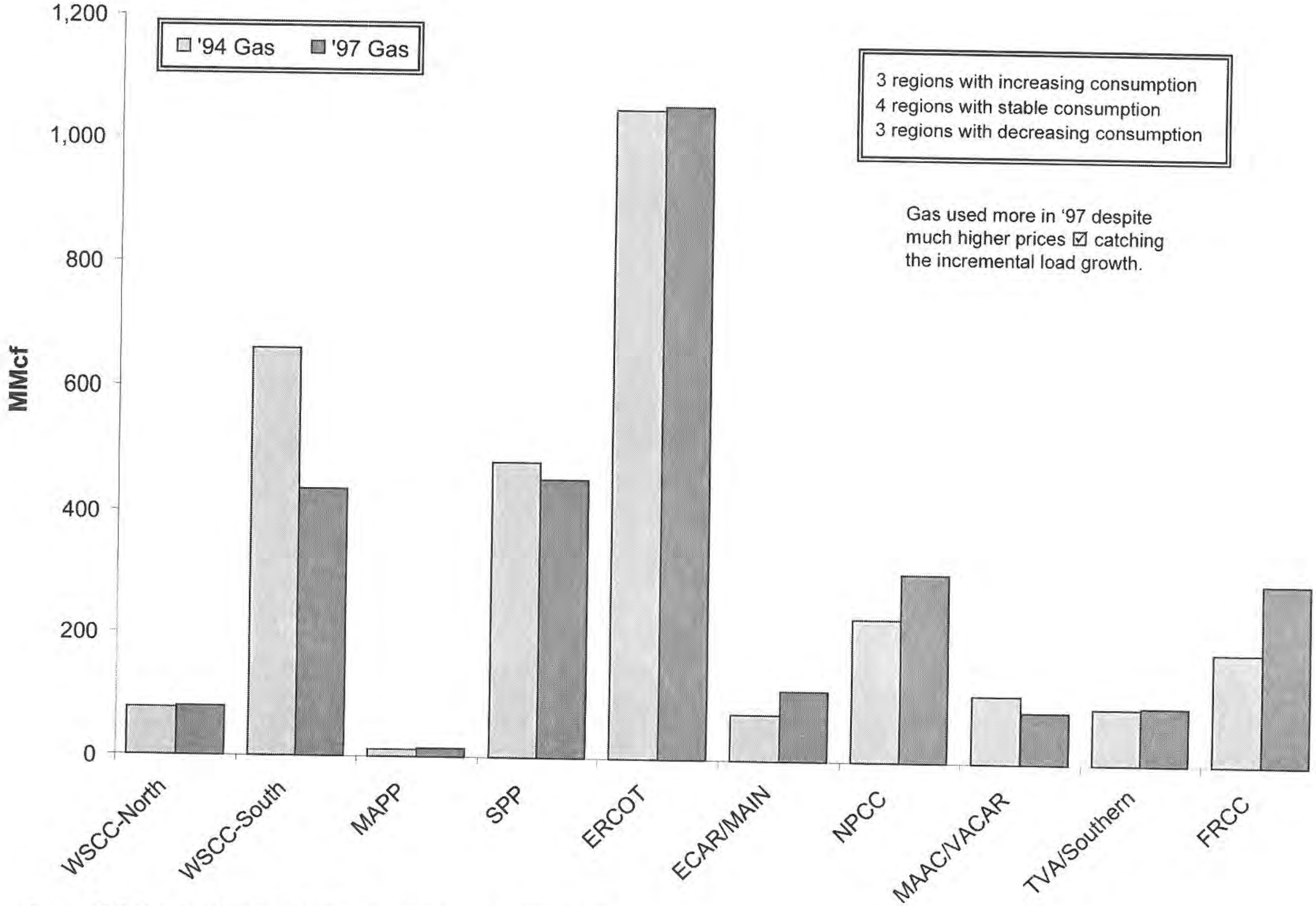
Source: EEI *Statistical Yearbook of the Electric Utility Industry*, 1994 & 1997.

Figure A-3
Average Heat Rate by Region (MWh – average, as burned)



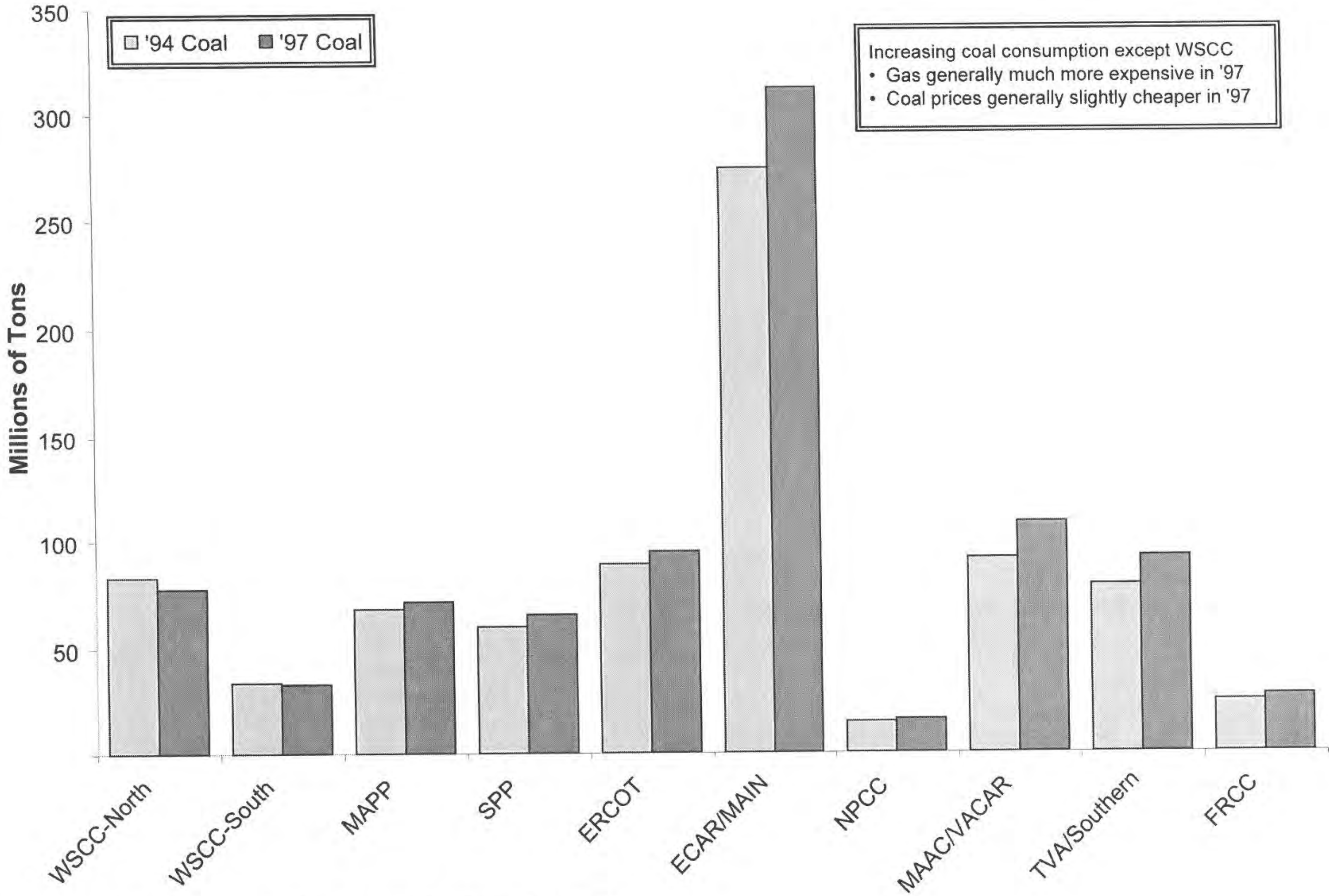
Source: EEI *Statistical Yearbook of the Electric Utility Industry*, 1994 & 1997.

Figure A-4
Electricity Produced by Fuel Type and Region



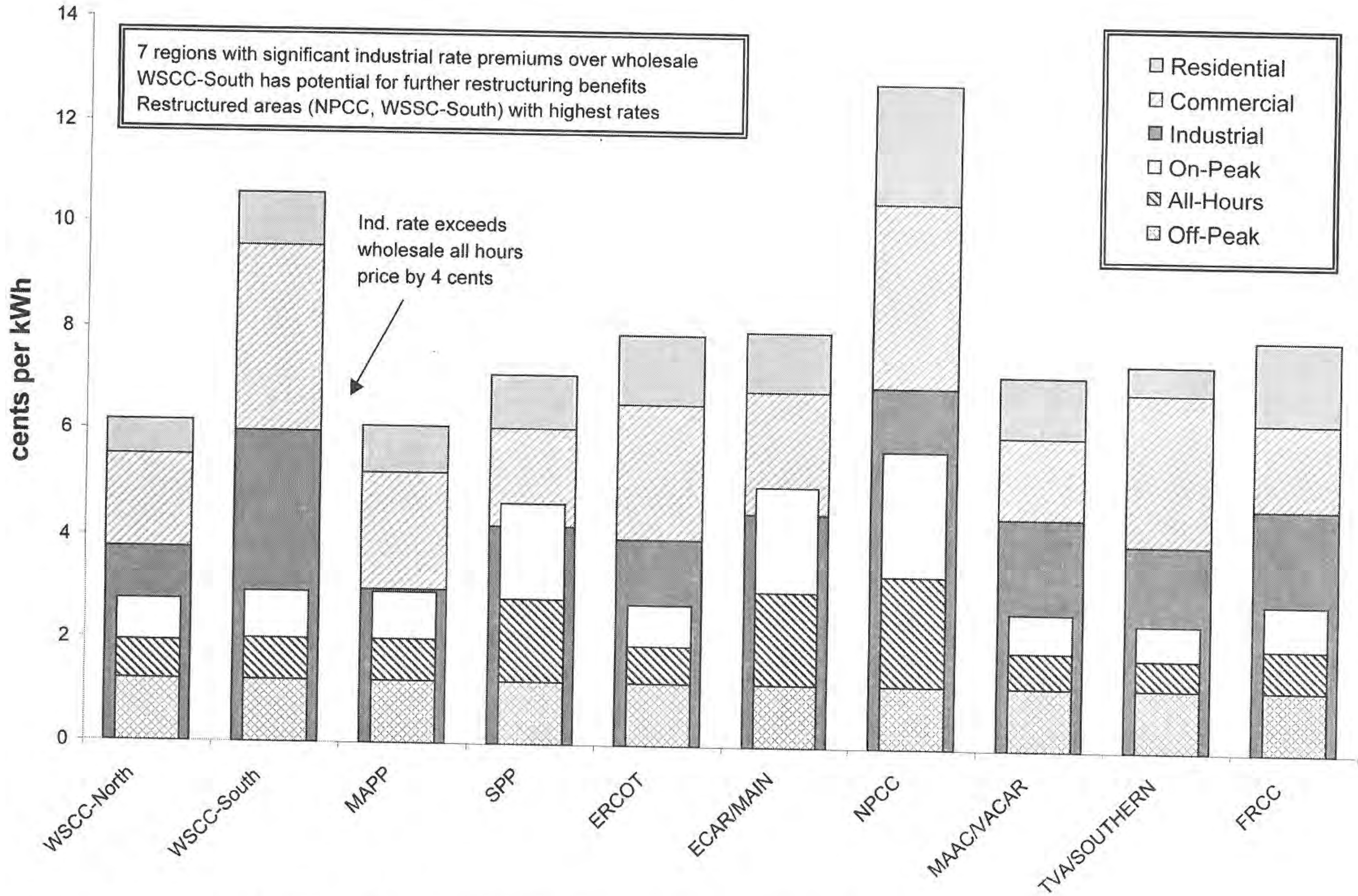
Source: EEI *Statistical Yearbook of the Electric Utility Industry*, 1994 & 1997.

Figure A-5
Gas Consumption by Region



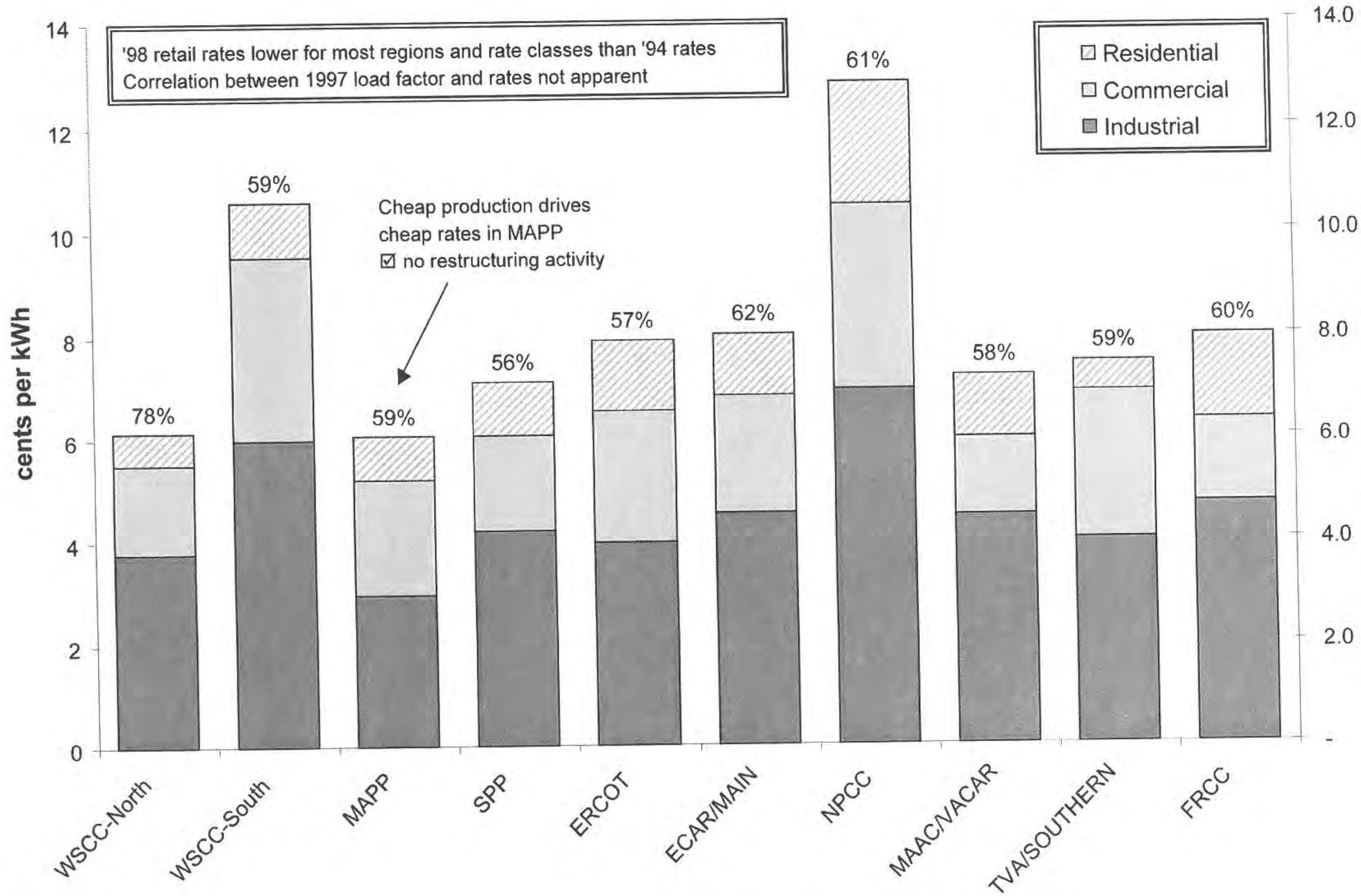
Source: EEI *Statistical Yearbook of the Electric Utility Industry*, 1994 & 1997.

Figure A-6
Coal Consumption by Region



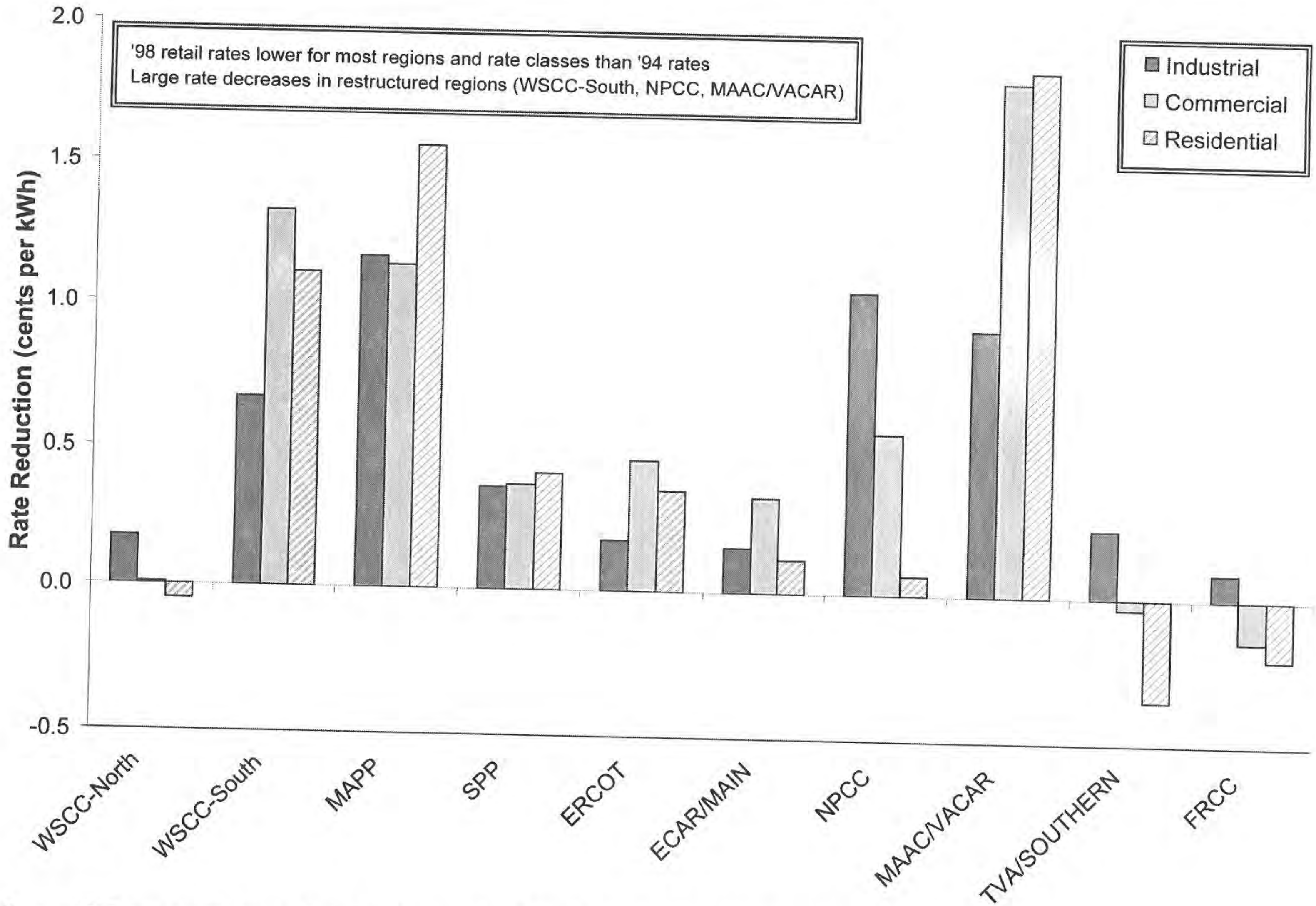
Source: EEI Typical Bills and Average Rates Report, Winter 1999. Rates based on data of listed utilities.
Off-Peak assumed to be $12/MWh where not available from Power Markets Weekly.

Figure A-7
1998 Regional IOU Retail Rates



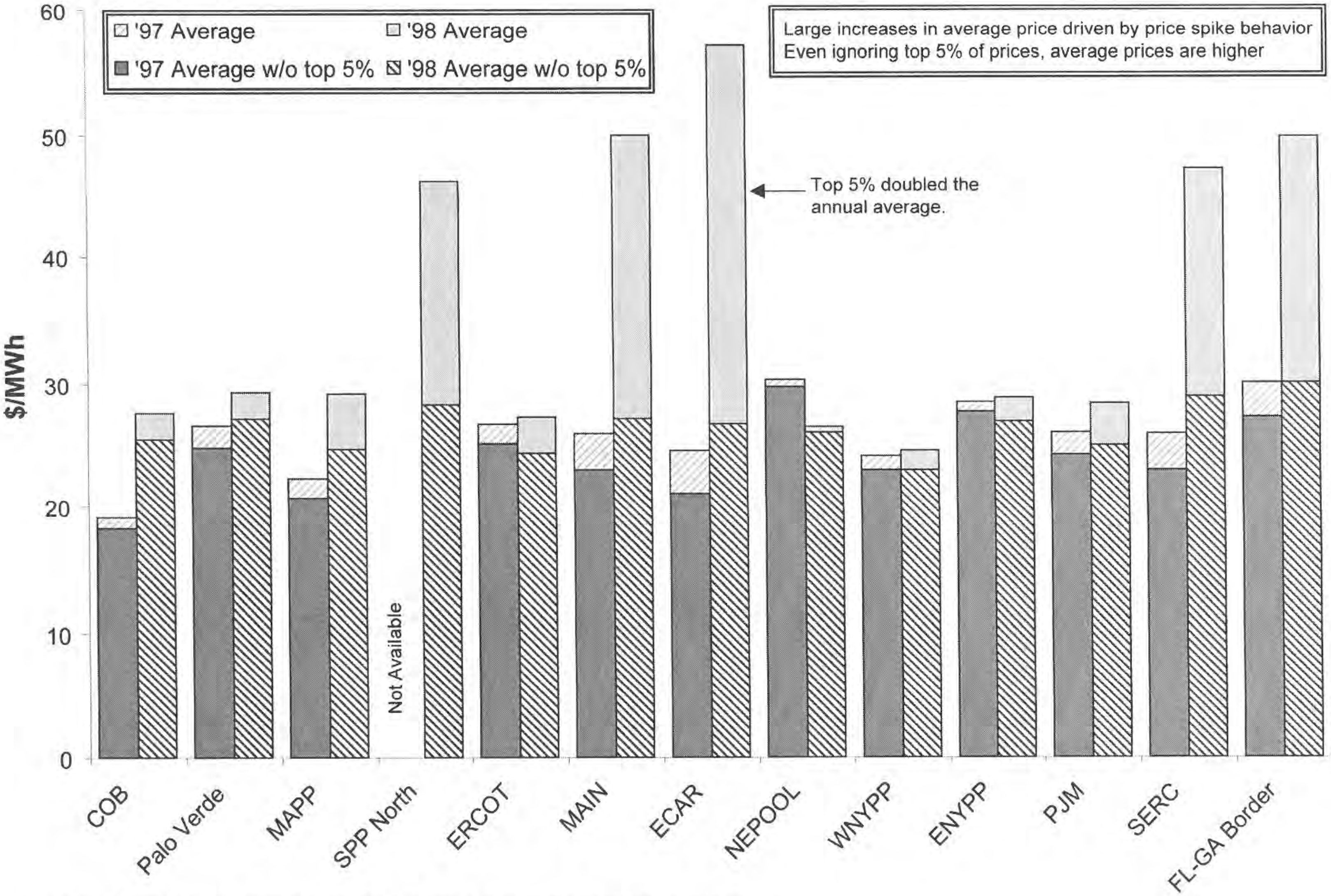
Source: EEI Typical Bills and Average Rates Report, Winter 1999. Rates based on data of listed utilities. Percentages are load factors.

Figure A-8
1998 Regional IOU Retail Rates vs. Load Factor



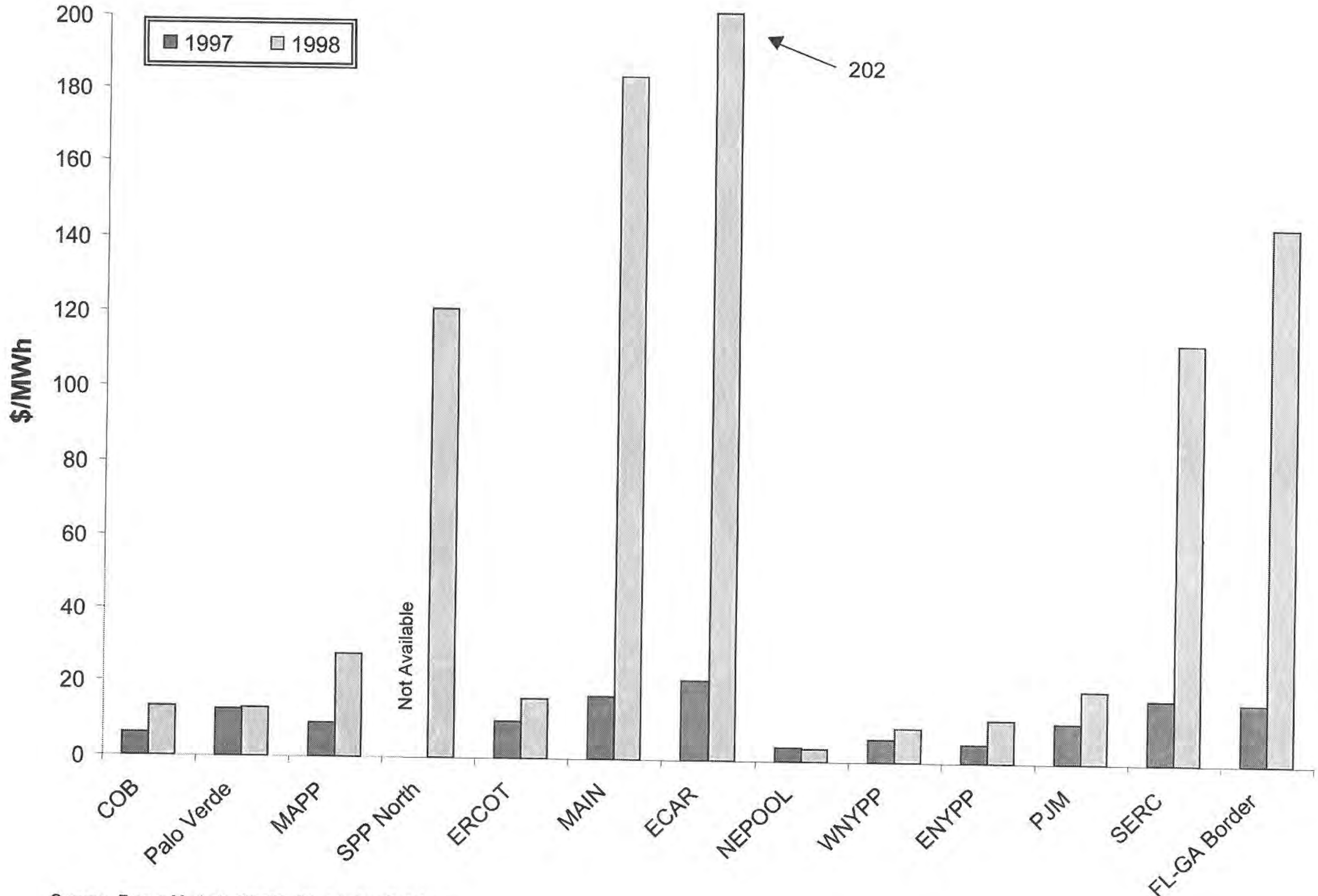
Source: EEI *Typical Bills and Average Rates Report* , Winter 1995 & 1999. Rates based on data of listed utilities.

Figure A-9
Change in Regional IOU Retail Rates 1994vs. 1998



Source: Power Markets Week's Price Index Database. Values reported are yearly averages.

Figure A-10
On-Peak Power Prices by Region



Source: Power Markets Week's Price Index Database.

Figure A-11
Standard Deviation of On-Peak Power Prices by Region

B

APPENDIX: VOLATILITY AND CORRELATION ANALYSIS METHODOLOGY

Introduction

This appendix describes how price volatility and correlation statistics presented in this report were calculated. It also includes the power price and natural gas price distributions as discussed in Chapter 4 as well as the electric on electric price correlations by month.

Volatility Calculation

The method used to calculate the price volatility in this report is the historic volatility method. It is estimated as the standard deviation of the return calculated from the particular commodity's historical prices.

The historic volatility method is calculated by first calculating the return on price, i.e., the logarithm of the ending price less the logarithm of the beginning price,

$$R_t = Ln(P_t)-Ln(P_{t-1})$$

where P is price, Ln is a natural logarithm, and t is some period of time such as daily prices for a month, weekly prices for a season, or monthly prices for a year. The second step is to calculate the standard deviation of R_t.[46] It is conventional to annualize the standard deviation or volatility to demonstrate how much the price could be expected to vary over a year given the same probability. The annualized volatility is estimated by multiplying the standard deviation calculated in the first step by the square root of T. For statistics using weekly data, T = 52. For statistics using daily data, T = 250.

Table B-1 presents an example of how historic volatility is calculated for daily Into Cinergy prices for May 1999. Column 2 shows electricity spot prices Into Cinergy over 20 trading days in May 1999. The logarithms of the ending price less the logarithms of the beginning price were calculated and are shown in column 3. For example, if the price of electricity at the close on Monday is \$26.83, and at the close on Tuesday is \$25.49, then the close-to-close price return is

[46] Standard Deviation is the standard statistical calculation, square root of the sum of the squared deviations divided by (n-1), where n is the number of observations.

log 26.83 – log 25.49 = -0.0512. The standard deviation of the values in column 3 is 0.0708. This yields the average annualized daily volatility of 1.19 or 119% [sqrt(250) × 0.0708 = 1.19].

Table B-1
Volatility Calculation Example using Spot Price Data

Day [1]	Price ($/MWh) [2]	$Ln(P_t)-Ln(P_{t-1})$ [3]
0	26.83	.
1	25.49	-0.0512
2	25.90	0.0160
3	25.06	-0.0330
4	27.01	0.0749
5	27.74	0.0267
6	29.38	0.0574
7	25.78	-0.1307
8	24.27	-0.0604
9	23.28	-0.0416
10	26.23	0.1193
11	25.01	-0.0476
12	24.71	-0.0121
13	23.88	-0.0342
14	23.78	-0.0042
15	19.74	-0.1862
16	18.81	-0.0483
17	19.07	0.0137
18	18.33	-0.0396
19	19.38	0.0557
Standard Deviation		*0.0708*

In our report two types of price data were used in our volatility calculations: 1) spot price data; and 2) forward price data.

Volatility Calculation using Spot Price Data

Historical spot prices for electricity and gas were obtained from *Power Markets Week* (PMW) and *Natural Gas Week* (NGW), respectively. PMW reports a daily electricity price for a 16-hour block transaction in $/MWh. The price is considered to be an on-peak price, and is the price for all 16 hours delivered on that day. The off-peak price data are also available but not complete, therefore only peak-price data were examined. On the other hand, NGW reports a weekly gas price in $/mmBtu. To be consistent with and comparable to the gas data, a weekly electricity price was calculated by taking an average across the 5 days in the week. Daily gas data were obtained from *Gas Daily*.

Volatility Calculation using Forward Price Data

Bridge/CRB, a global financial and commodity markets database firm, reports daily future electricity and gas prices traded at the New York Mercantile Exchange from July 10, 1998 to present. These prices include electricity forward prices at/into Cinergy, California-Oregon Border, Palo Verde, and gas forward prices at Henry Hub. In the report, price volatility of contracts executed in August were calculated for the 6-month, 3-month, and 1-month nearby deliveries. The calculations were based on the historical volatility methodology.

Table B-2 provides an example of how price volatility was estimated as of June 1999 for various nearby delivery months using futures contract price data. The data in Table 2 are natural log price differences in June for power to be delivered one to seven months from June at the California-Oregon Border (COB). For example, CFNB07 is the futures contract for delivery seven months from June, or January 2000 in this case. In this example, a 1-month nearby contract executed in June 1999 (delivery month is July 1999) has an annualized volatility of 78 percent (see column for CFNB01).

Table B-2
Volatility Calculation Example using Futures Contract Data

	% Change in Price By Delivery Month						
Date	**CFNB01 Jul-99**	**CFNB02 Aug-99**	**CFNB03 Sep-99**	**CFNB04 Oct-99**	**CFNB05 Nov-99**	**CFNB06 Dec-99**	**CFNB07 Jan-00**
6/1/99	.	.	.	.	.	.	.
6/2/99	0.097	0.402	0.037	(0.280)	0.016	0.067	(0.084)
6/3/99	0.053	0.022	0.018	0.016	0.011	0.005	0.008
6/4/99	0.018	0.030	0.024	0.008	0.008	0.007	0.008
6/7/99	0.050	0.030	0.028	0.016	0.012	0.013	0.010
6/8/99	0.045	0.027	0.024	0.008	0.008	0.007	0.006
6/9/99	(0.015)	(0.005)	(0.007)	0.000	0.000	0.000	(0.008)
6/10/99	(0.029)	(0.017)	(0.010)	0.000	0.000	0.000	0.000
6/11/99	0.044	0.035	0.021	0.000	0.000	0.000	0.000
6/14/99	0.011	(0.020)	(0.029)	(0.008)	(0.008)	(0.007)	0.000
6/15/99	(0.020)	(0.014)	(0.015)	(0.003)	(0.003)	(0.003)	(0.003)
6/16/99	(0.005)	0.008	0.008	0.000	0.000	0.000	0.000
6/17/99	0.091	0.036	0.032	0.011	0.008	0.007	0.000
6/18/99	0.052	0.022	0.022	0.000	0.000	0.000	0.000
6/21/99	(0.092)	(0.059)	(0.059)	0.000	0.000	0.000	0.000
6/22/99	(0.058)	(0.017)	(0.023)	(0.008)	0.000	0.000	(0.016)
6/23/99	(0.003)	0.026	0.017	0.000	0.000	0.000	0.000
6/24/99	0.058	0.022	0.021	0.000	0.000	0.000	0.008
6/25/99	0.030	0.009	0.004	(0.005)	(0.005)	(0.004)	0.008
Standard deviation [A]	0.049	0.096	0.025	0.067	0.006	0.016	0.021
Sqrt(250) [B]	15.811	15.811	15.811	15.811	15.811	15.811	15.811
Volatility [C]	0.782	1.524	0.400	1.055	0.100	0.256	0.334

Note: [C] = [A] x[B]

Correlation Calculation

Correlation is defined as the tendency for time series of data to move together. The correlation statistic is bound between –1.0 and 1.0. If two sets of numbers have a positive correlation, it means that they move together—as one moves up, the other one moves up. If the correlation statistic is negative, the two time series are said to have an adverse relationship—as one moves up, the other moves down. If the correlation is close to zero, they are said to be uncorrelated. If the correlation has a value of 1.0 (-1.0), they are perfectly positively correlated (perfectly negatively correlated).

As with volatility, correlation between two price series can be measured using historical price data. As with the variance, the correlation of two time series is the standard statistical definition that is available in any spreadsheet program or statistical package.

Rolling correlations were also calculated in this report—15-day and 7-week rolling calculations.

For example, for the 15-day rolling correlations, the methodology employed was as follows.

Correlation between X & Y:

$Corr(X,Y) = Cov(X,Y) / (\sigma(X) \cong \sigma(Y))$

where $Cov(X,Y)_t = E((X-Xbar)(Y-Ybar))$,

Xbar = the mean of time series X

Ybar = the mean of time series Y

$\sigma(x)$ is the standard deviation of time series X as described above.

Table B-3 presents an example of how the15-day rolling correlations are calculated for successive days. The 15-day correlation for a given day t, includes data for that day and the 14 days prior to it. For example, the 15-day rolling correlation over the periods 4/29/96 through 5/17/96, 4/30/96 through 5/18/96, and 5/1/96 through 5/19/96 are 0.28, 0.20, and 0.07, respectively.

Table B-3
15-Day Rolling Correlation Calculation Example

Date	PMW Daily Peak Prices ($/MWh)		15-Day Rolling Correlation Between PJM and Palo Verde
	PJM	Palo Verde	
4/29/96	19.50	15.00	.
4/30/96	19.25	15.00	.
5/1/96	19.25	15.00	.
5/2/96	20.00	14.00	.
5/3/96	18.25	14.00	.
5/6/96	19.40	13.00	.
5/7/96	18.90	14.00	.
5/8/96	18.75	15.00	.
5/9/96	18.45	15.00	.
5/10/96	20.00	15.00	.
5/13/96	18.30	15.00	.
5/14/96	20.00	15.00	.
5/15/96	19.15	16.00	.
5/16/96	19.75	16.00	.
5/17/96	20.75	16.00	0.2791
5/20/96	23.00	15.00	0.2008
5/21/96	49.00	15.00	0.0753
5/22/96	24.50	14.00	0.0521

Price Distribution Charts

The charts that follow are plots of price distributions discussed in Chapter 4 of the report. The first series of figures are descriptive statistics of spot power prices for the following regions: Cinergy (Into), COB, Entergy, ERCOT, Florida/Georgia Border, MAIN, MAPP, NEPOOL, Palo Verde, PJM West, SERC, and Into TVA. The plots use weekly spot price data through December 1999 as reported by PMW.

The second series of figures are descriptive statistics of spot natural gas prices for the following hubs: Alberta, Appalachia, Atlanta, Carthage, Henry Hub, Katy, New York, San Juan, Topock, Ventura and Waha. The plots employ weekly spot price data from 1994 to 1998 as reported by Natural Gas Week.

Summaries of the results just for the winter price distributions follow for the following natural gas hubs: Henry Hub, Katy, New York, San Juan, and Ventura.

Electric on Electric Price Correlation Results by Month

The last piece of analysis included in this appendix is the summary of correlation statistics for spot power prices by month for 1998 and 1999. These statistics use daily spot price data as reported by PMW.

Weekly Spot Power Price Distribution Charts

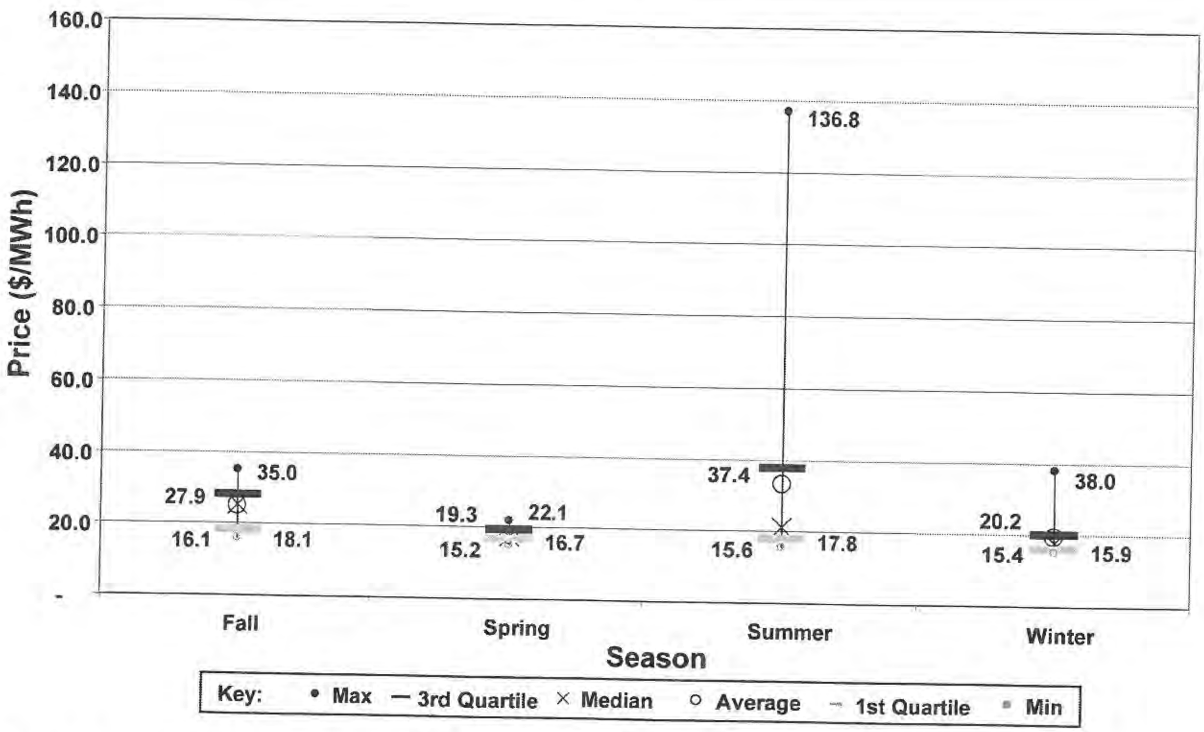


Figure B-1
CINERGY, 1997 Weekly Peak Price Distribution

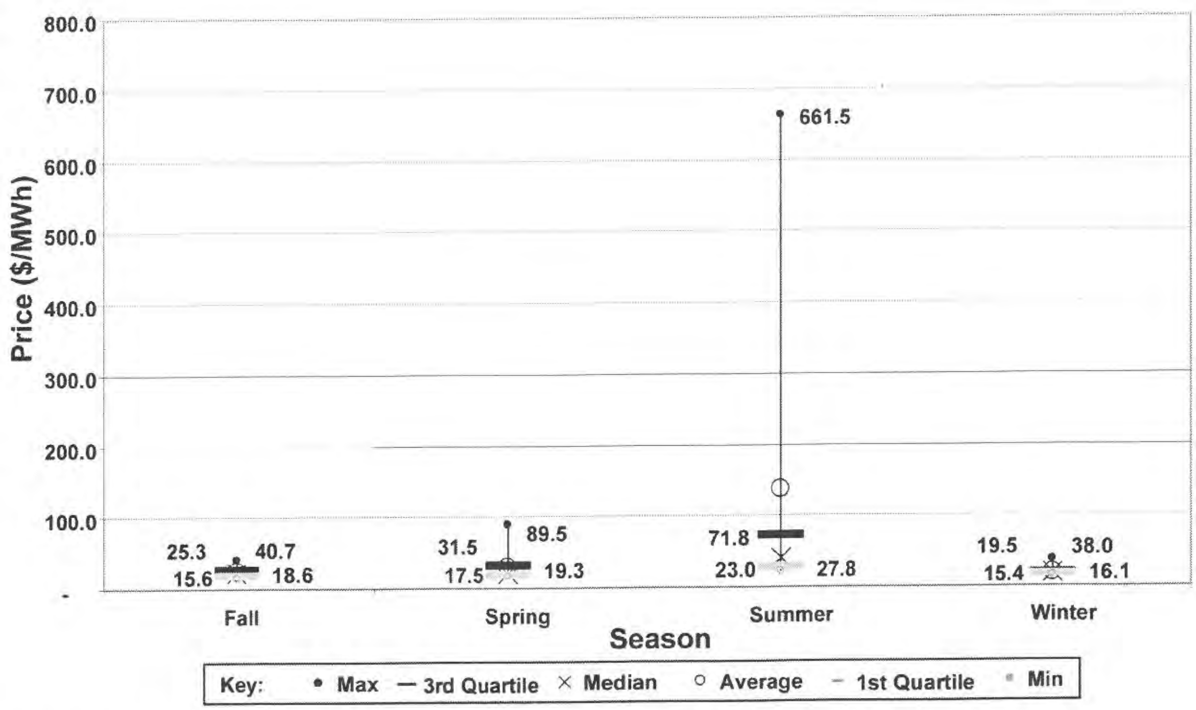


Figure B-2
CINERGY, 1998 Weekly Peak Price Distribution

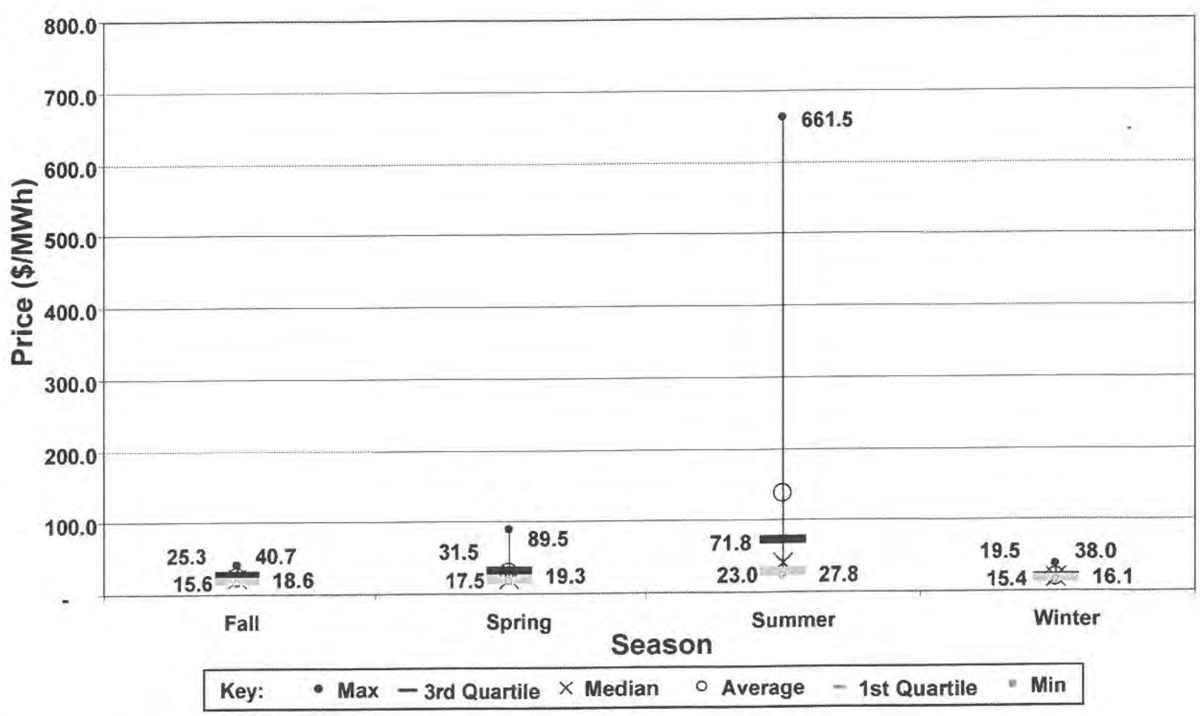


Figure B-3
CINERGY, 1999 Weekly Peak Price Distribution

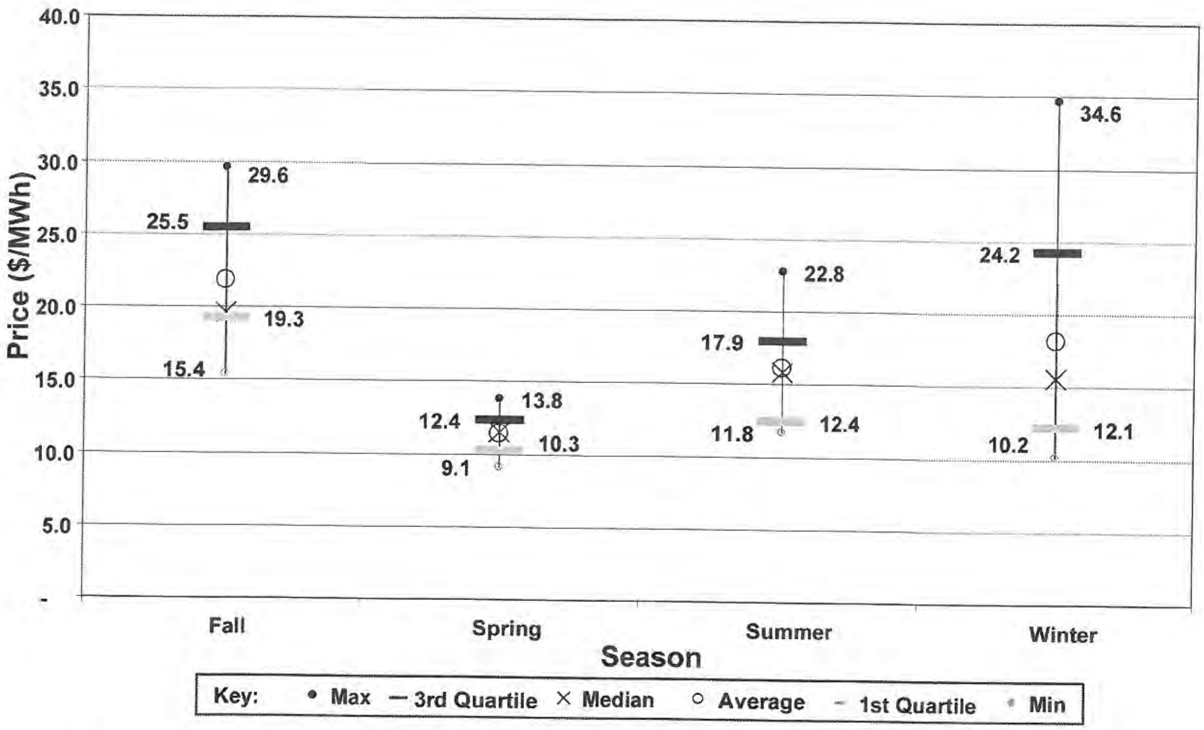


Figure B-4
COB, 1996 Weekly Peak Price Distribution

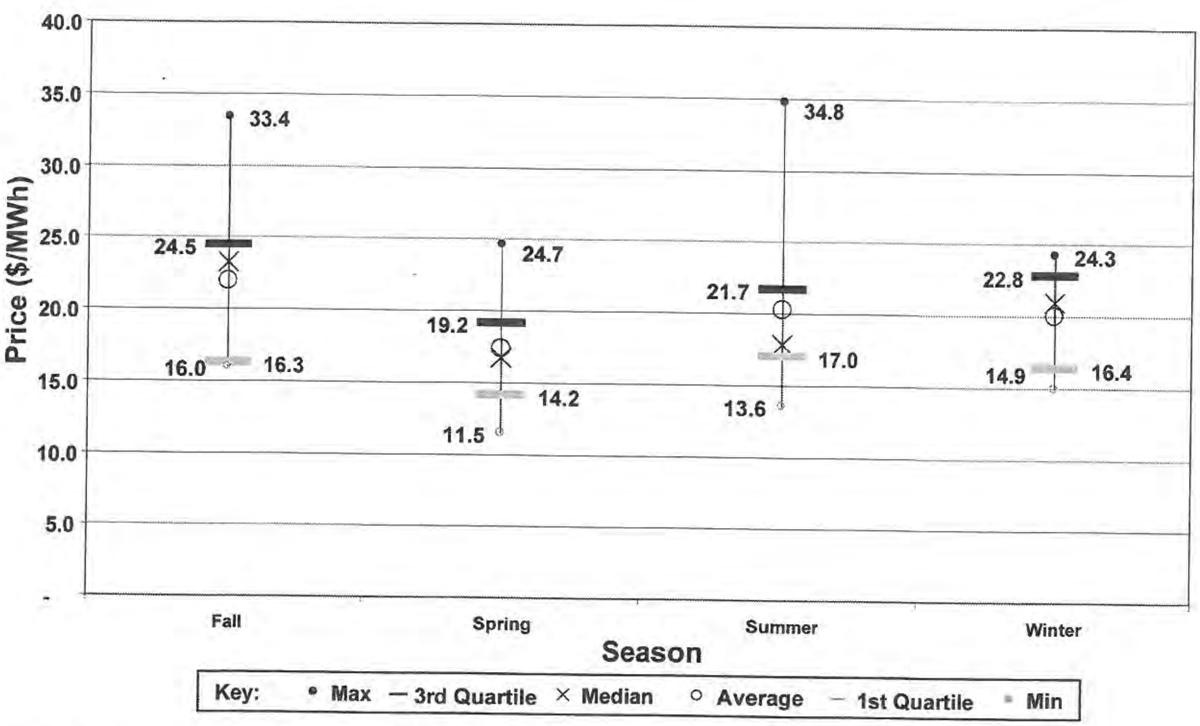


Figure B-5
COB, 1997 Weekly Peak Price Distribution

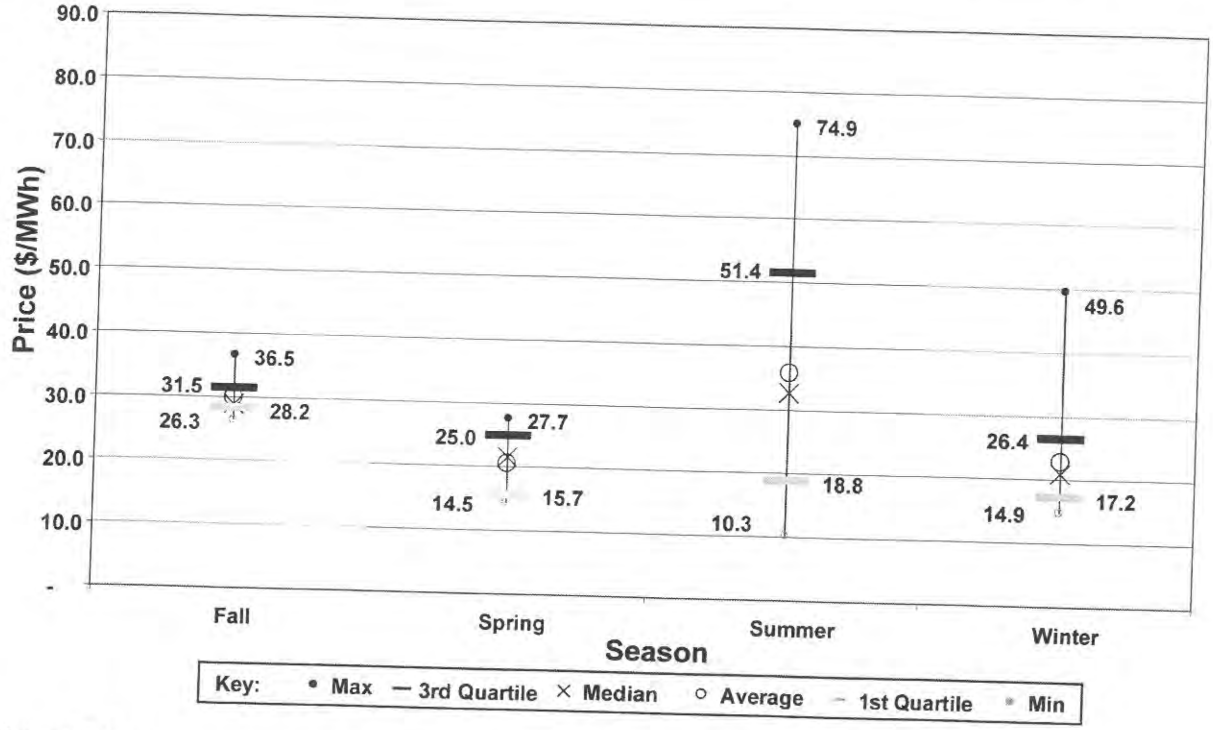


Figure B-6
COB, 1998 Weekly Peak Price Distribution

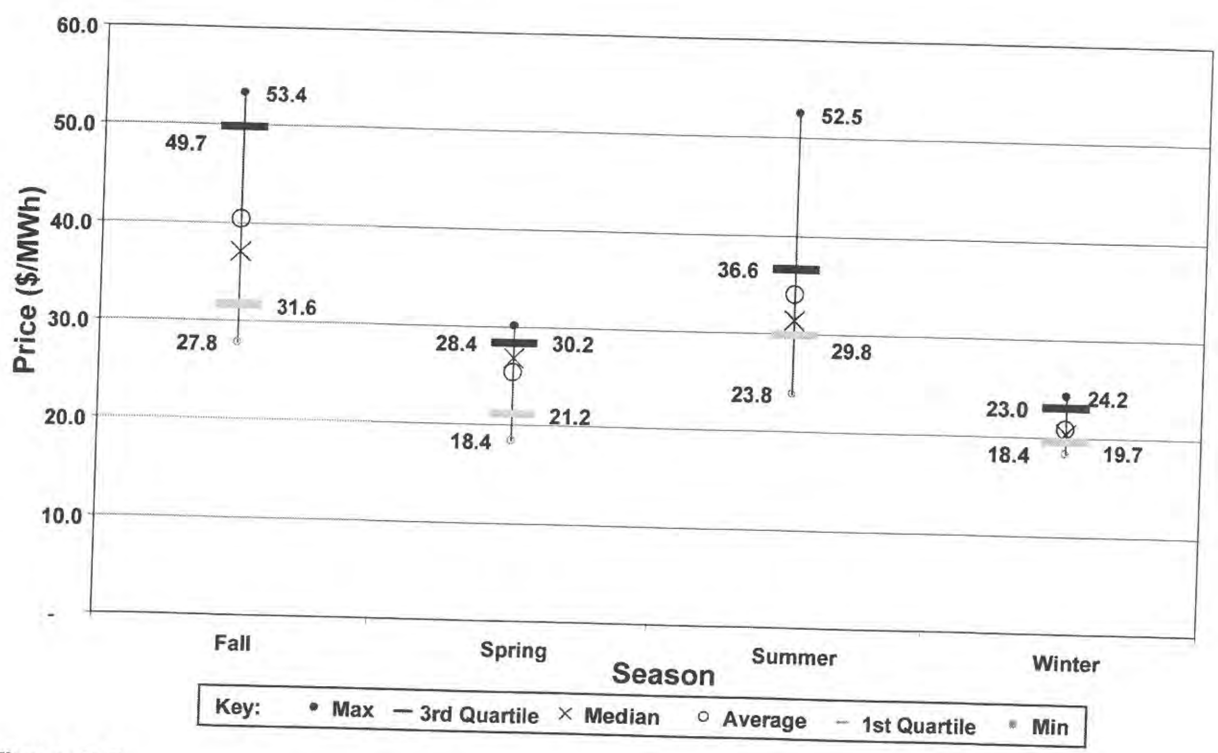


Figure B-7
COB, 1999 Weekly Peak Price Distribution

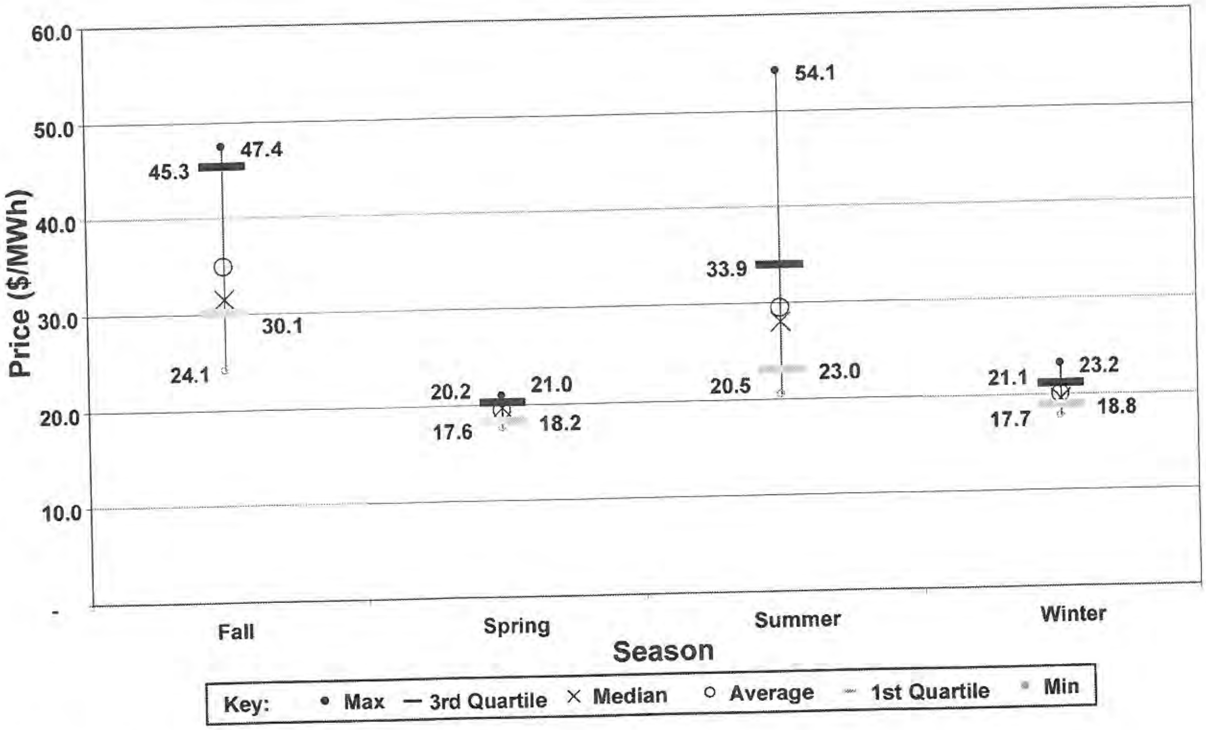


Figure B-12
ERCOT, 1997 Weekly Peak Price Distribution

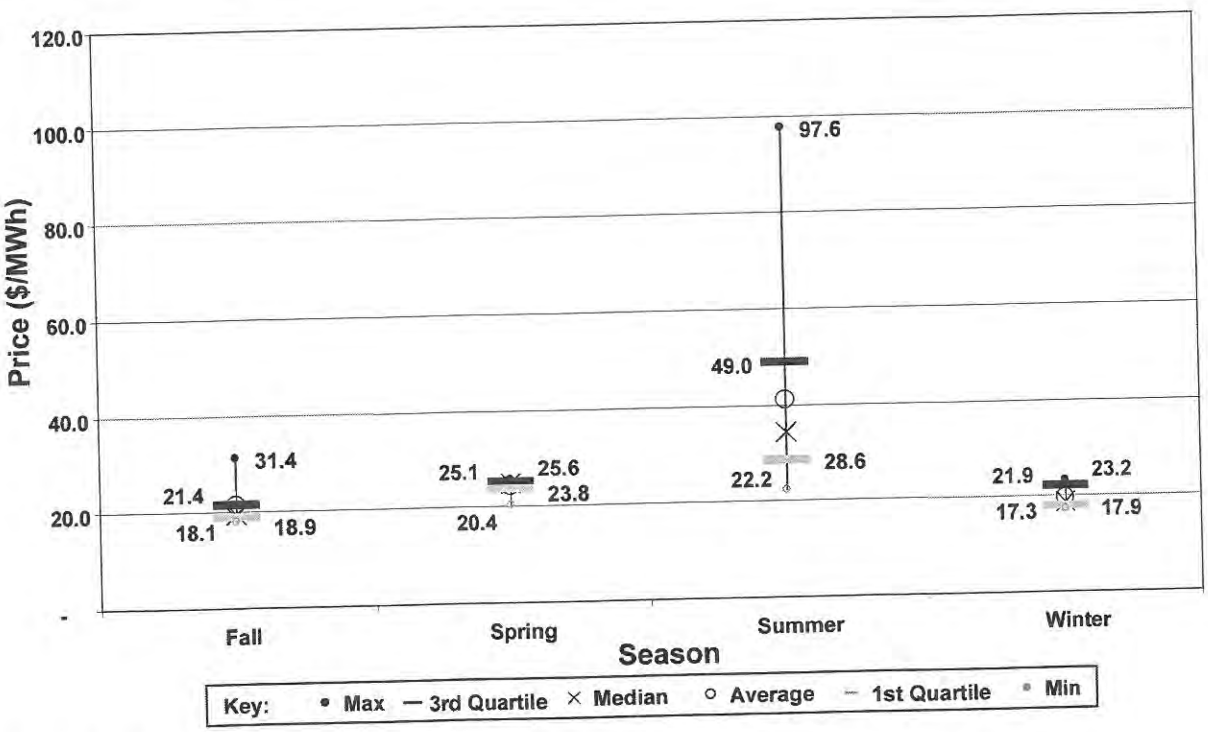


Figure B-13
ERCOT, 1998 Weekly Peak Price Distribution

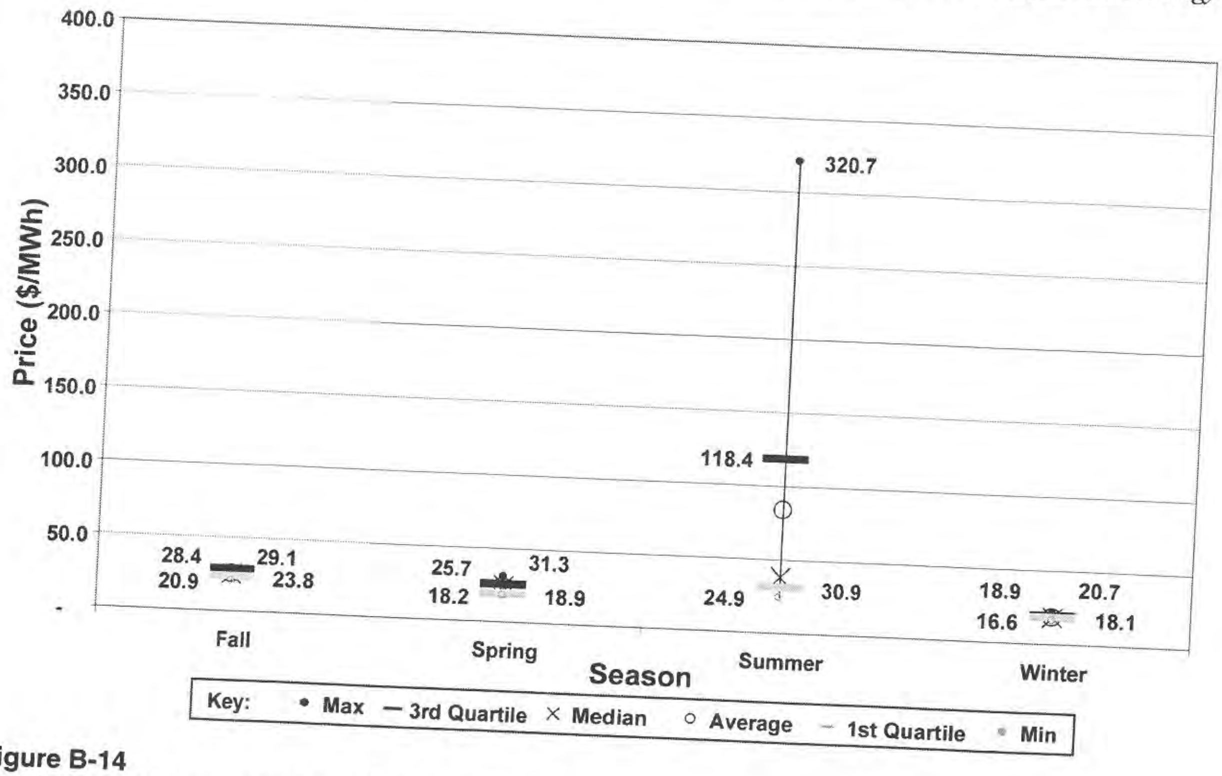


Figure B-14
ERCOT, 1999 Weekly Peak Price Distribution

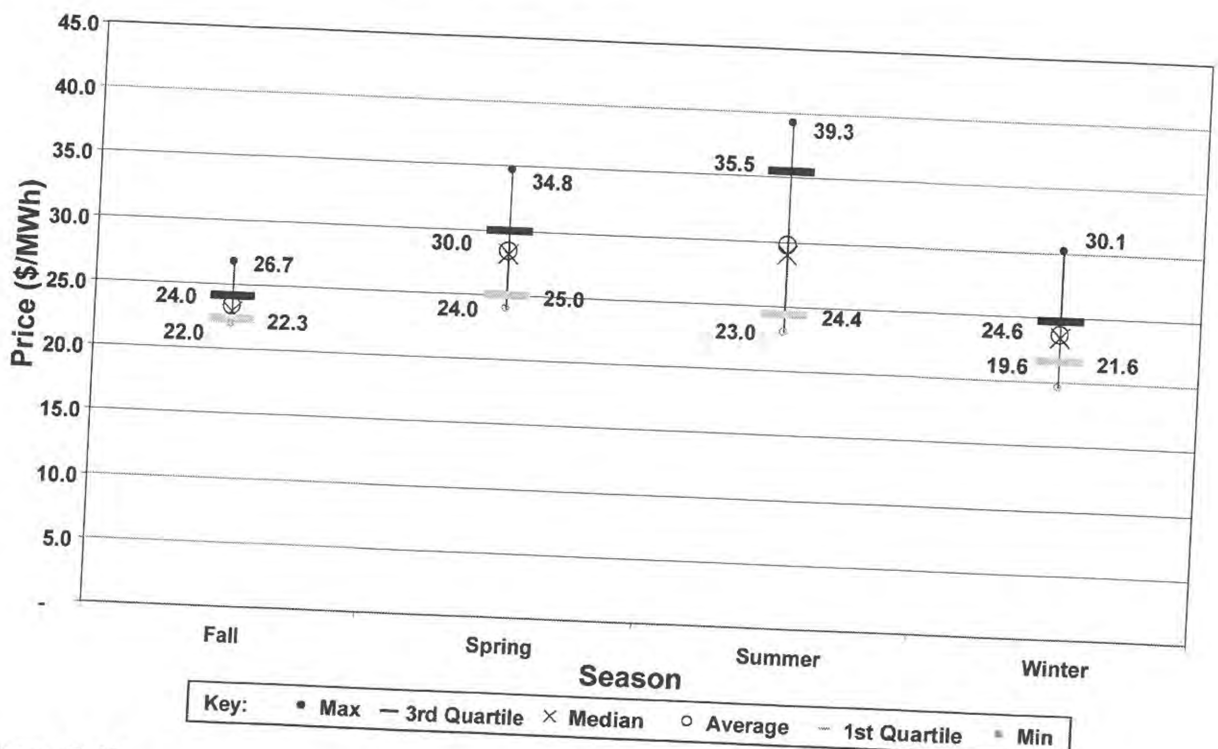


Figure B-15
FLORIDA, 1996 Weekly Peak Price Distribution

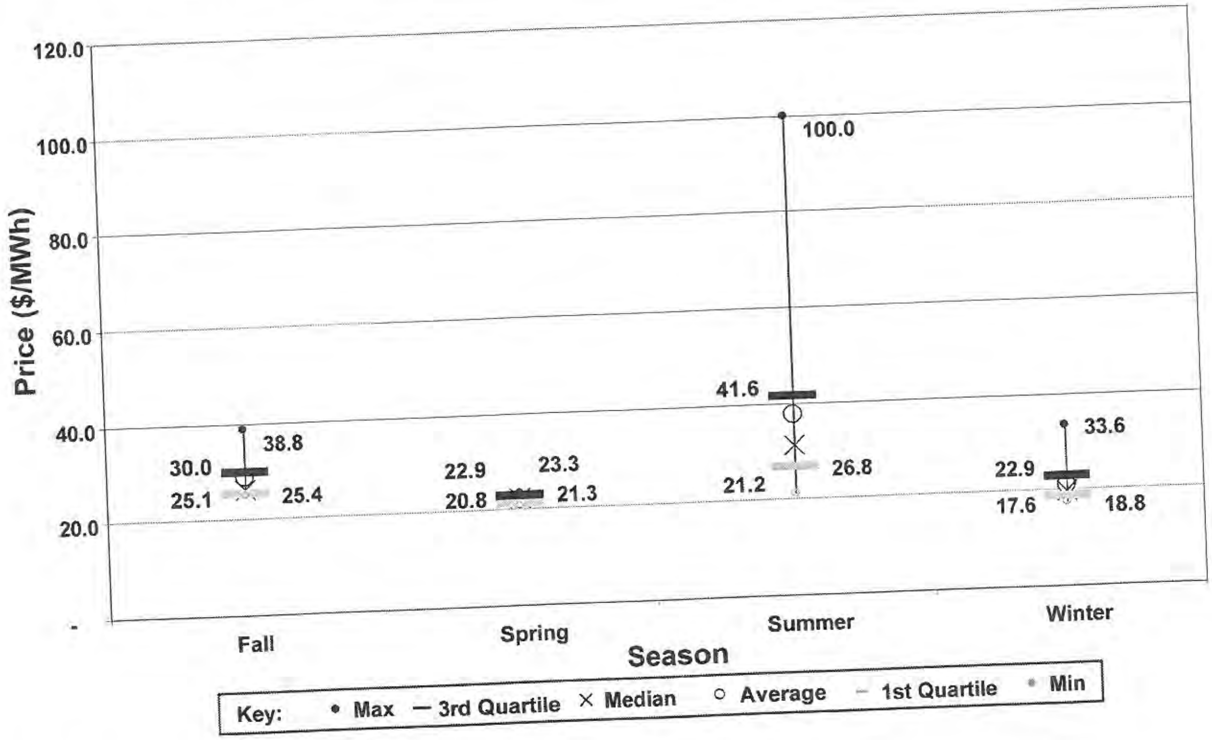


Figure B-16
FLORIDA/GEORGIA BORDER, 1997 Weekly Peak Price Distribution

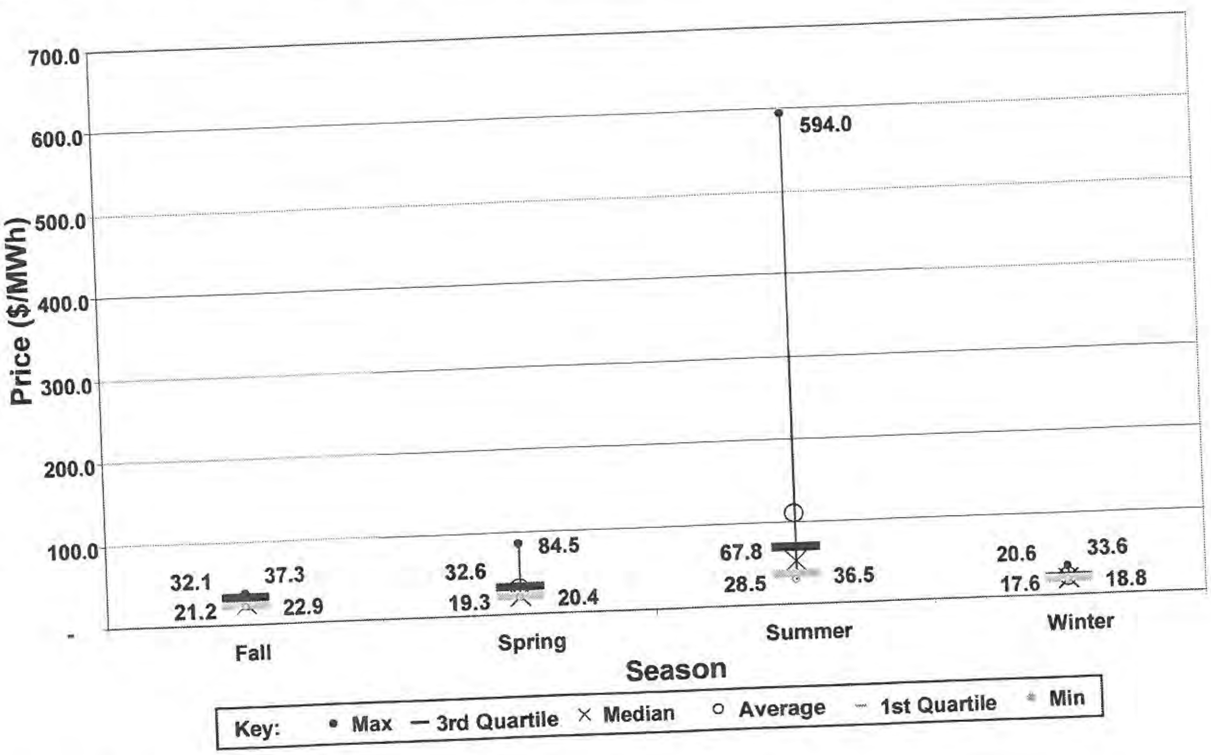


Figure B-17
FLORIDA/GEORGIA BORDER, 1998 Weekly Peak Price Distribution

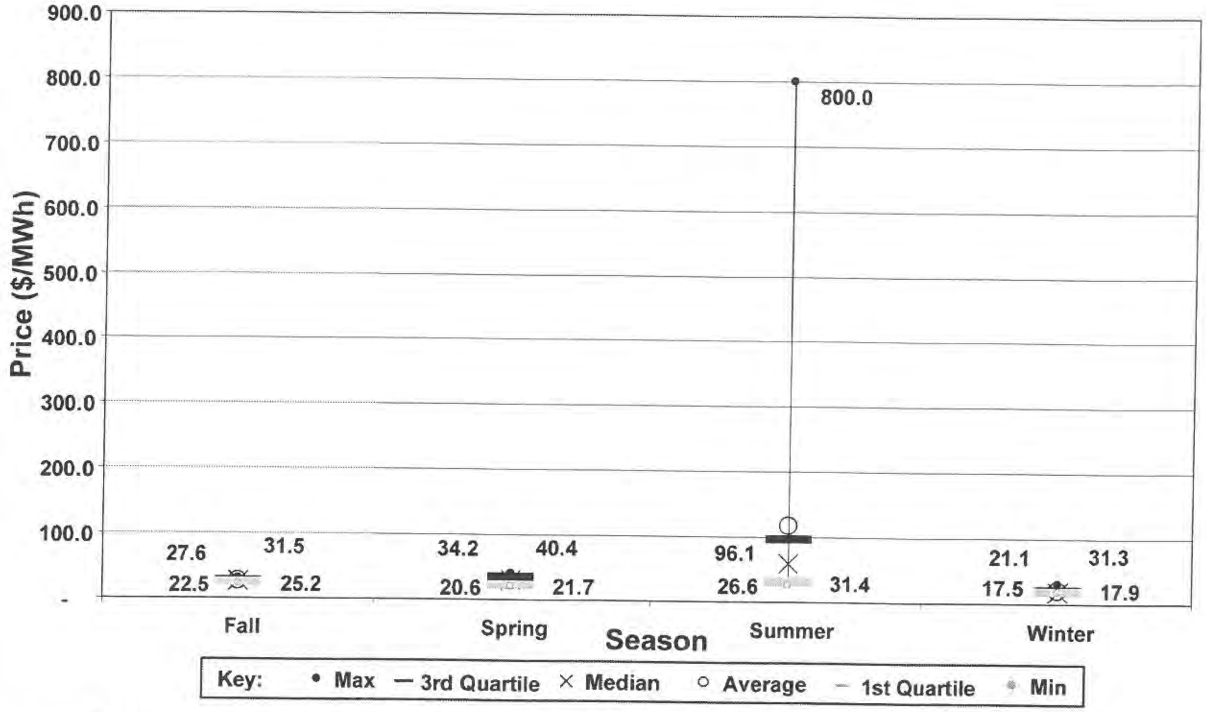


Figure B-18
FLORIDA/GEORGIA BORDER, 1999 Weekly Peak Price Distribution

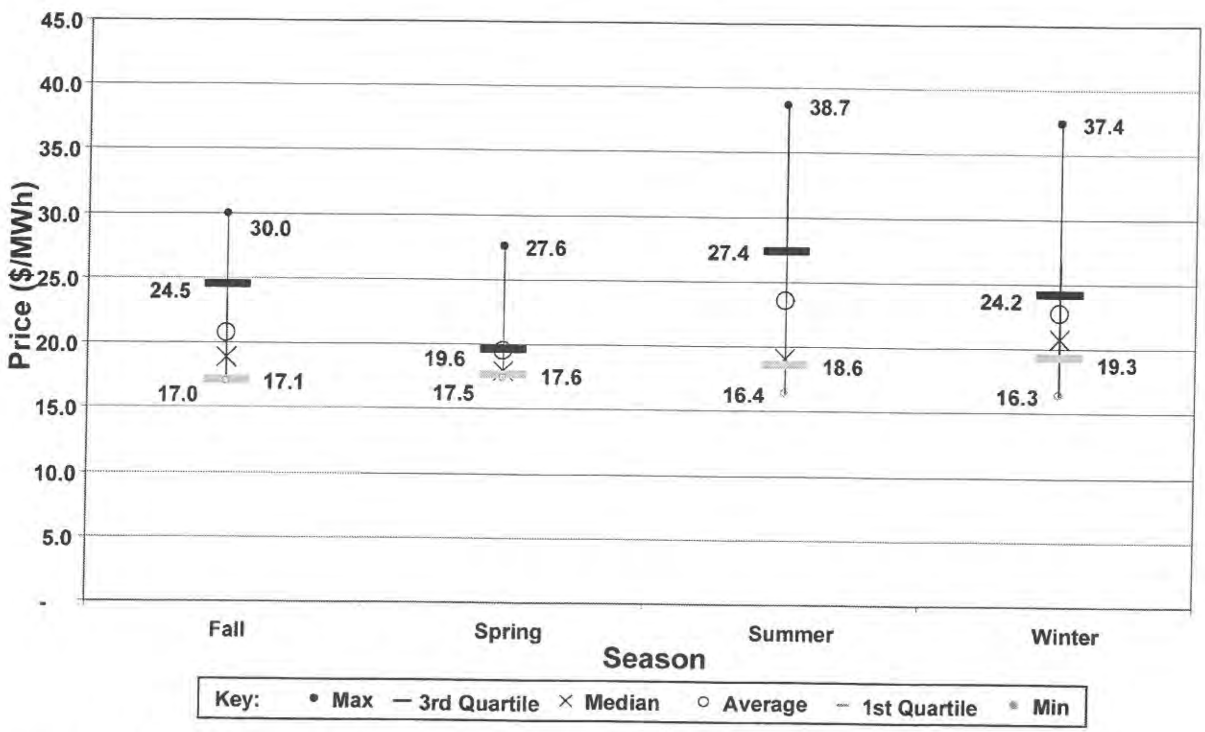


Figure B-19
MAIN, 1996 Weekly Peak Price Distribution

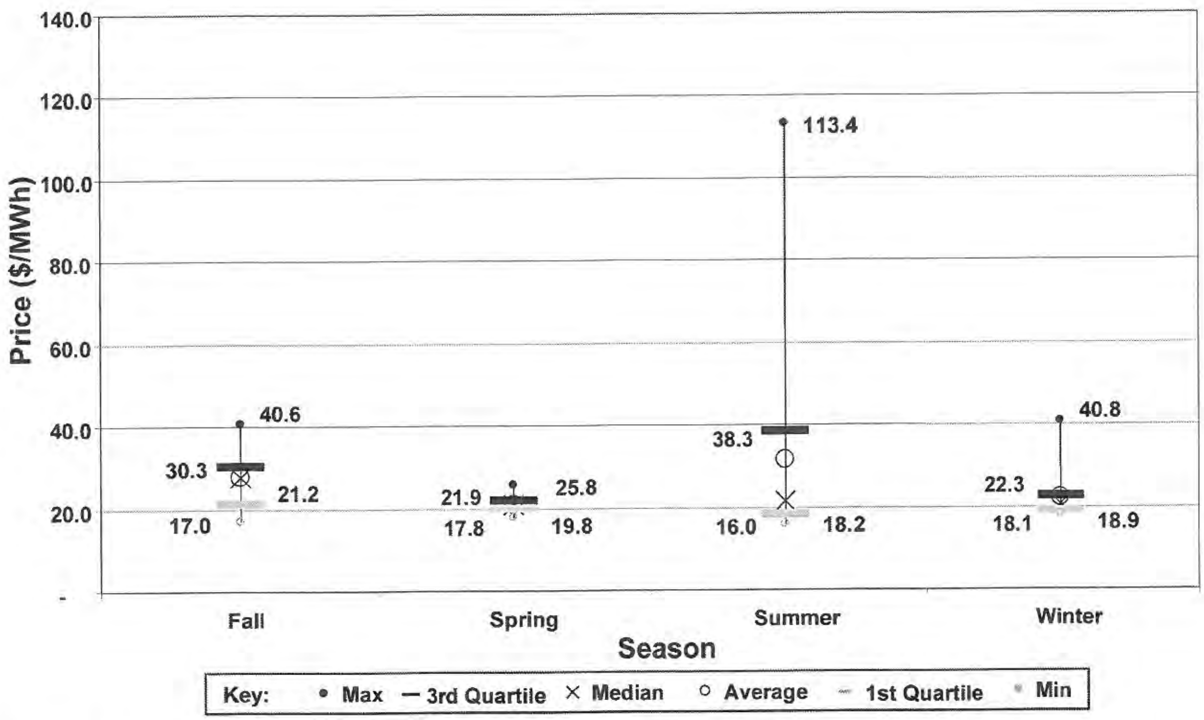


Figure B-20
MAIN, 1997 Weekly Peak Price Distribution

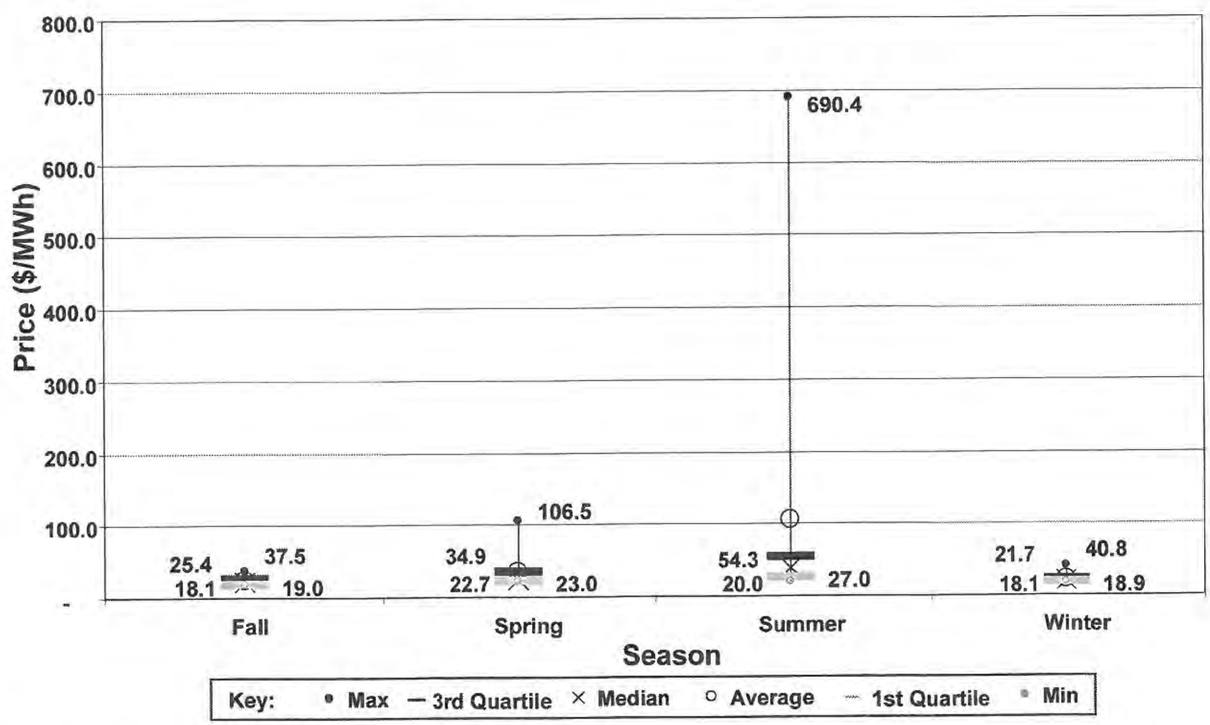


Figure B-21
MAIN, 1998 Weekly Peak Price Distribution

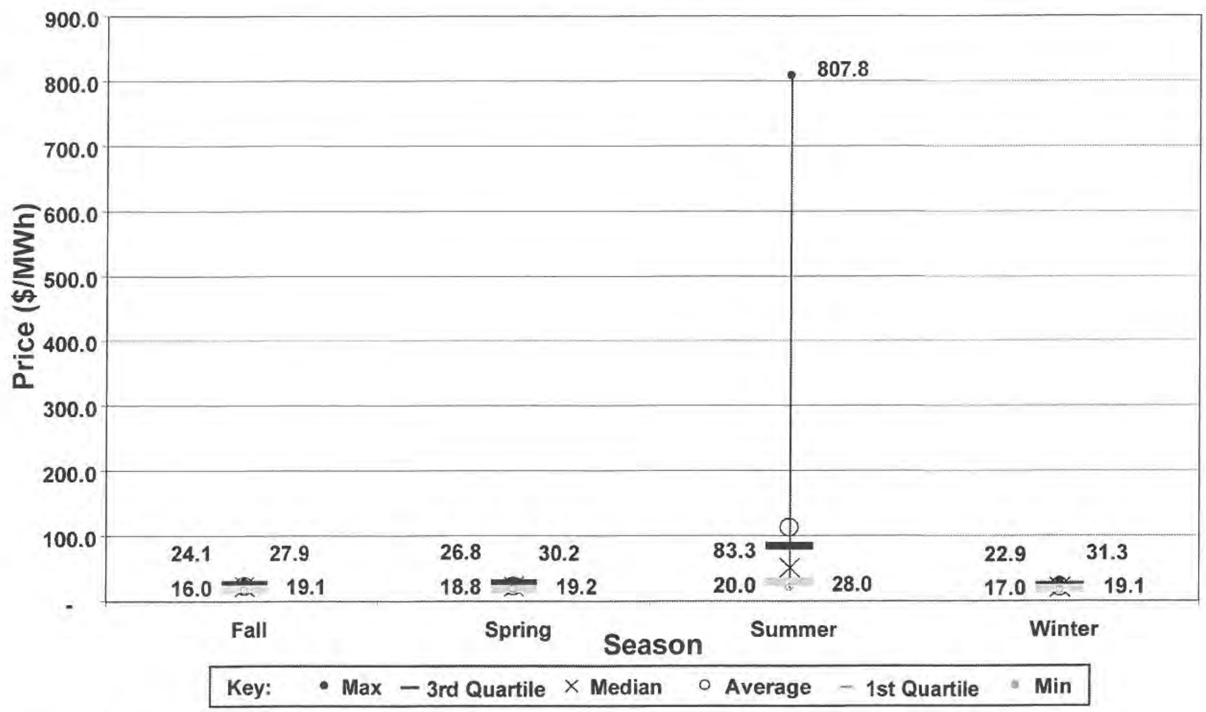


Figure B-22
MAIN, 1999 Weekly Peak Price Distribution

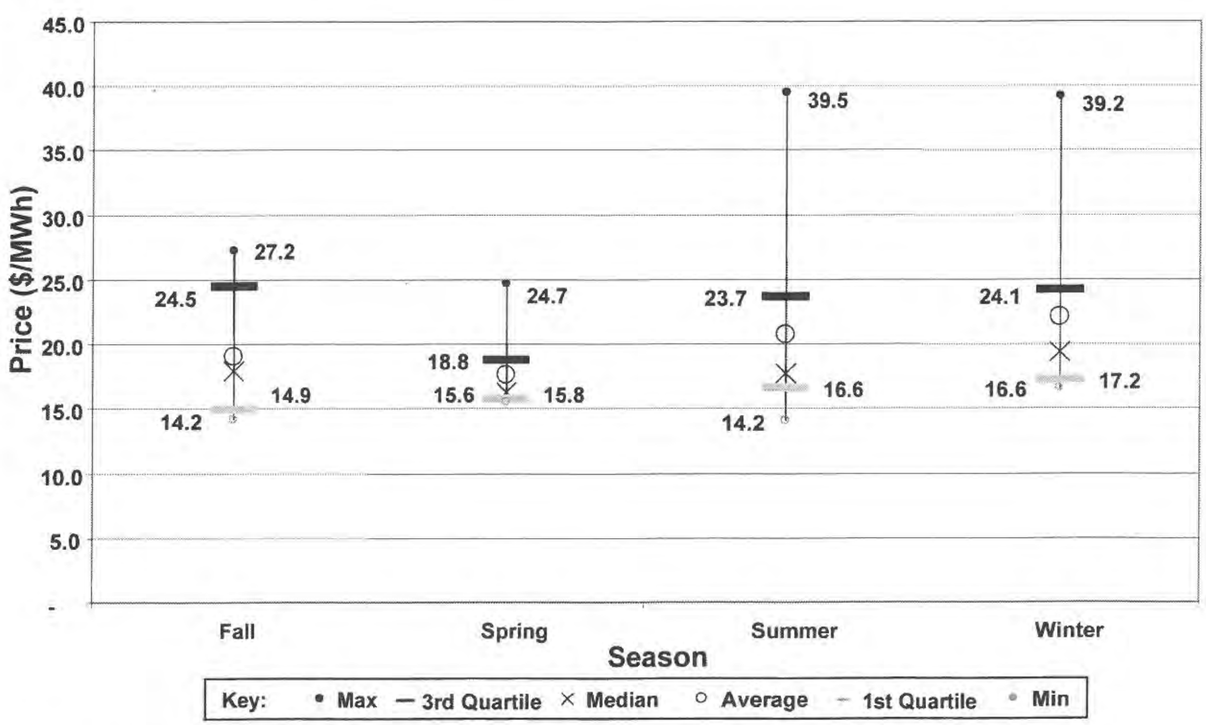


Figure B-23
MAPP, 1996 Weekly Peak Price Distribution

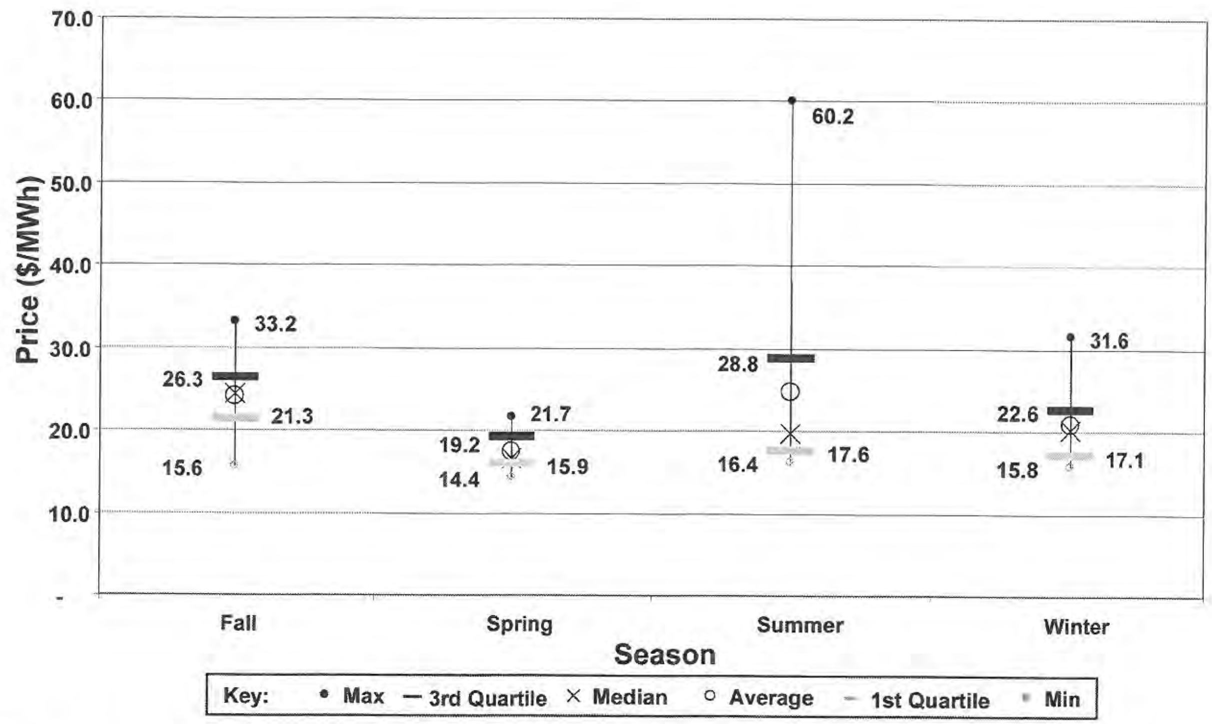


Figure B-24
MAPP, 1997 Weekly Peak Price Distribution

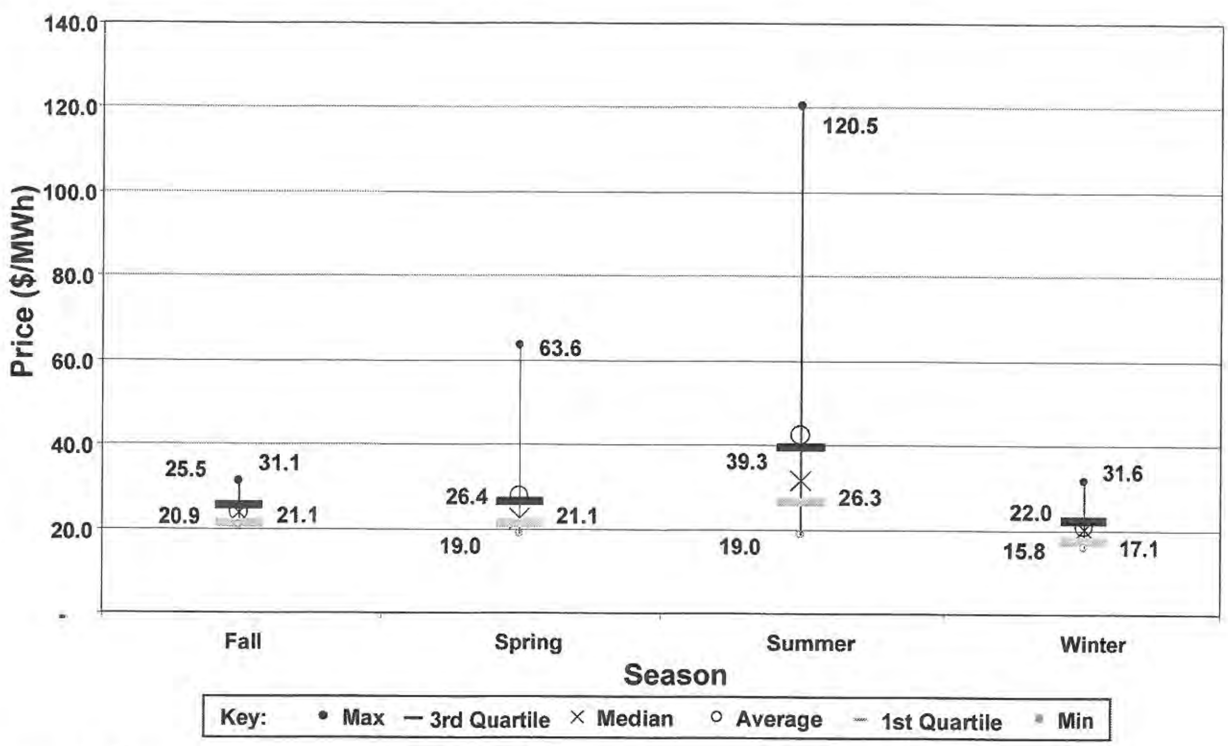


Figure B-25
MAPP, 1998 Weekly Peak Price Distribution

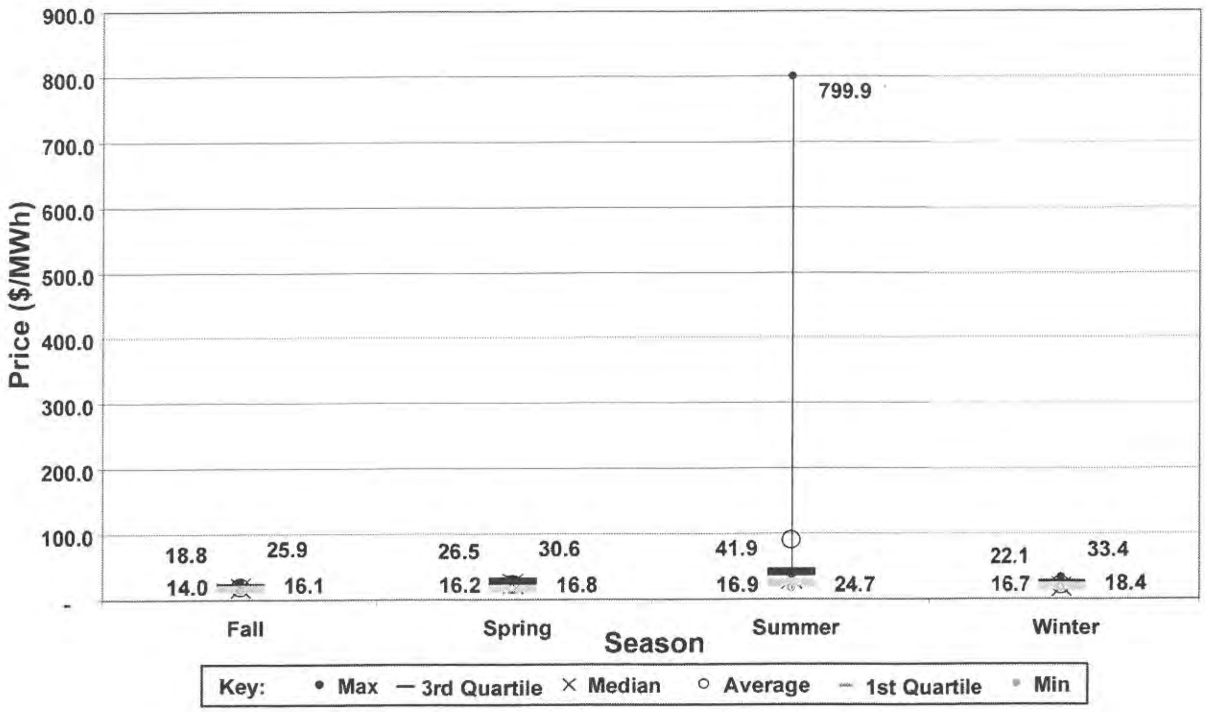


Figure B-26
MAPP, 1999 Weekly Peak Price Distribution

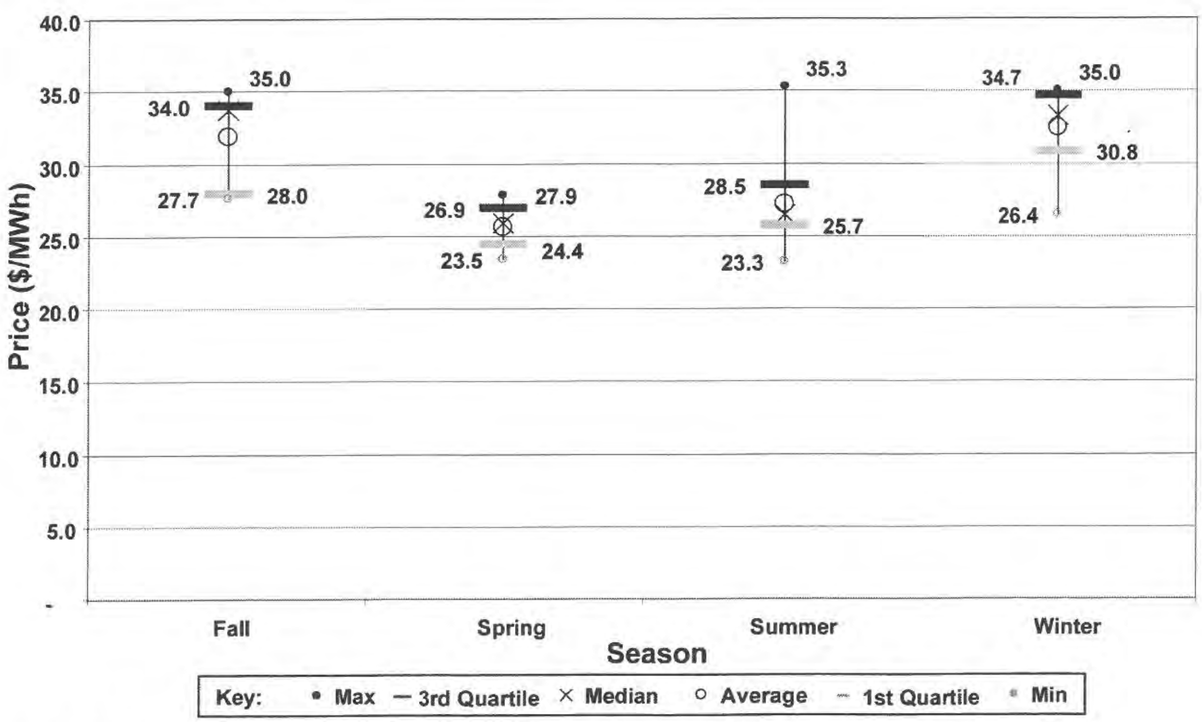


Figure B-27
NEPOOL, 1996 Weekly Peak Price Distribution

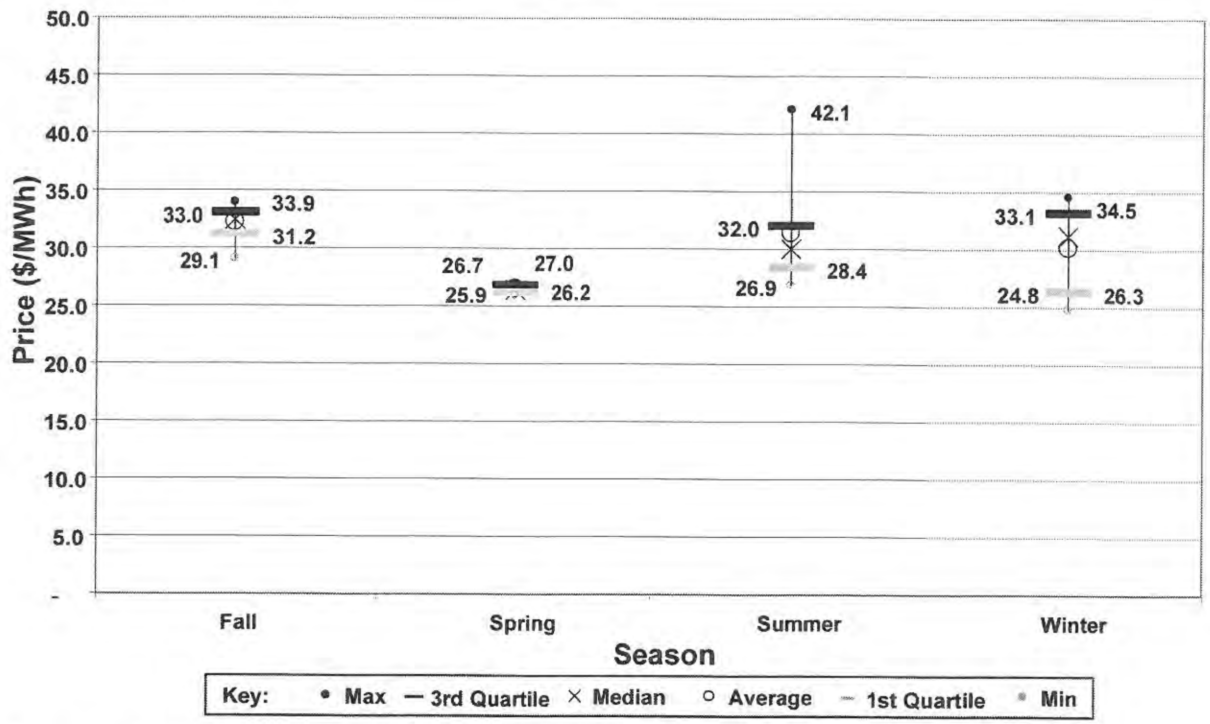


Figure B-28
NEPOOL, 1997 Weekly Peak Price Distribution

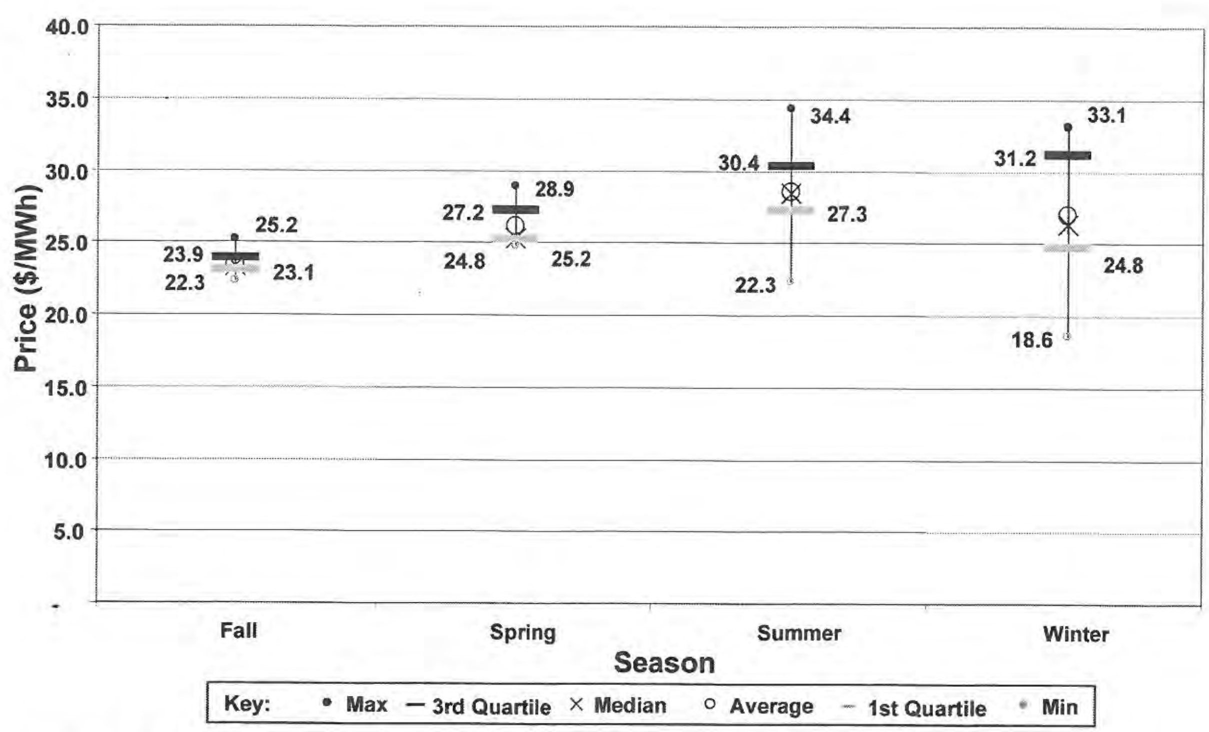


Figure B-29
NEPOOL, 1998 Weekly Peak Price Distribution

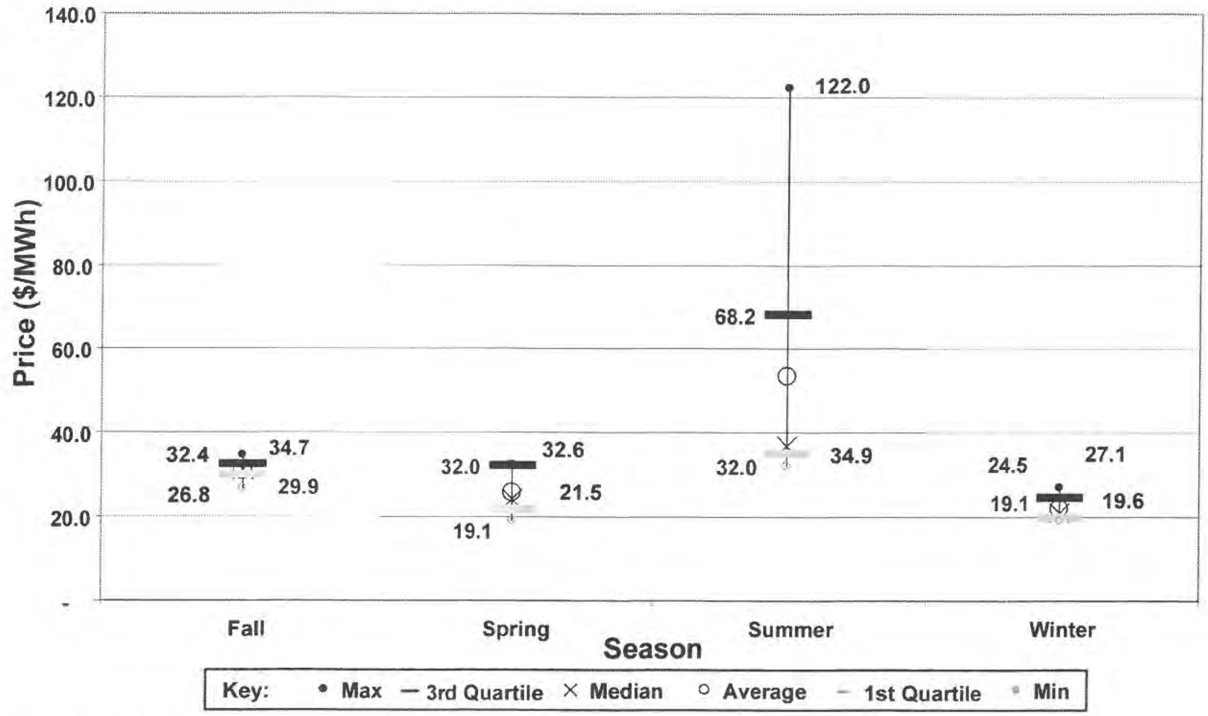


Figure B-30
NEPOOL, 1999 Weekly Peak Price Distribution

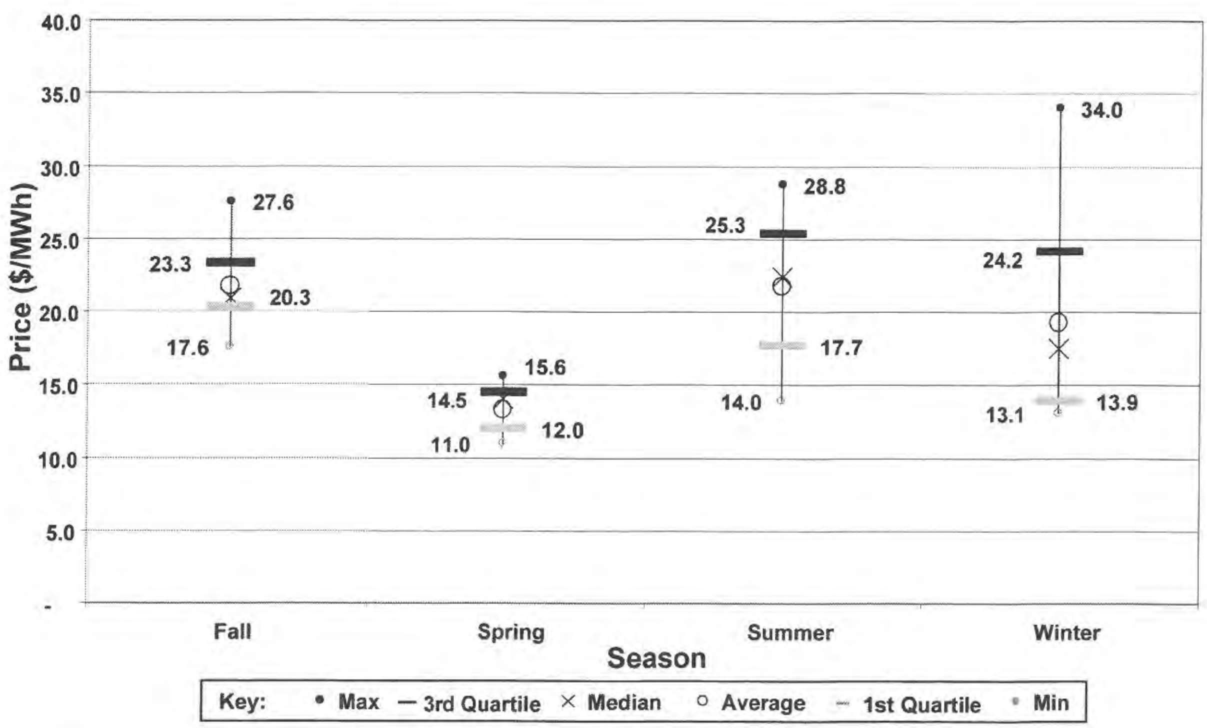


Figure B-31
PALO VERDE, 1996 Weekly Peak Price Distribution

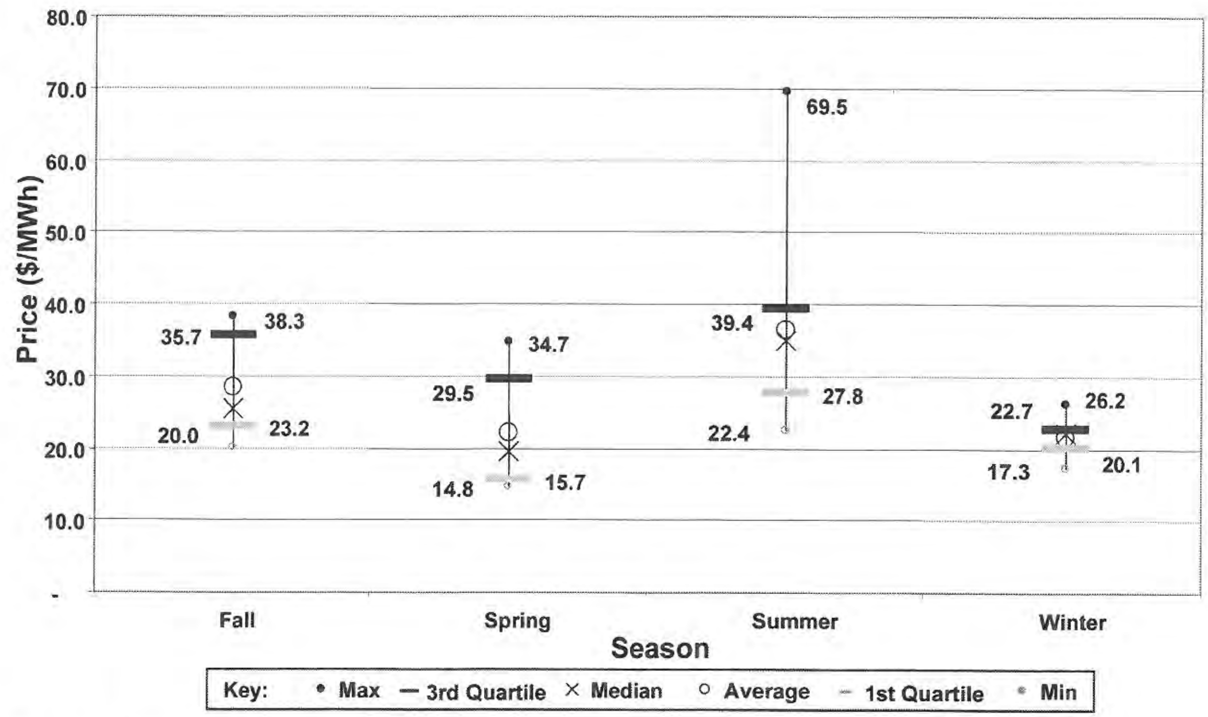


Figure B-32
PALO VERDE, 1997 Weekly Peak Price Distribution

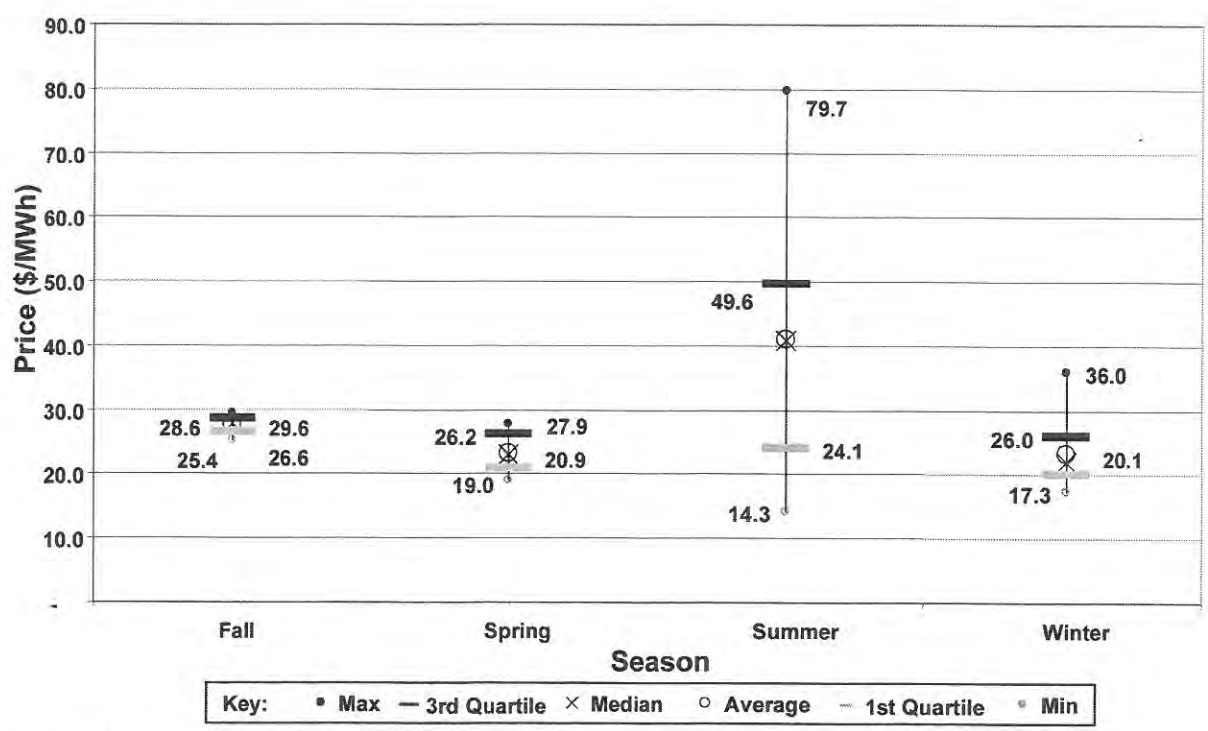


Figure B-33
PALO VERDE, 1998 Weekly Peak Price Distribution

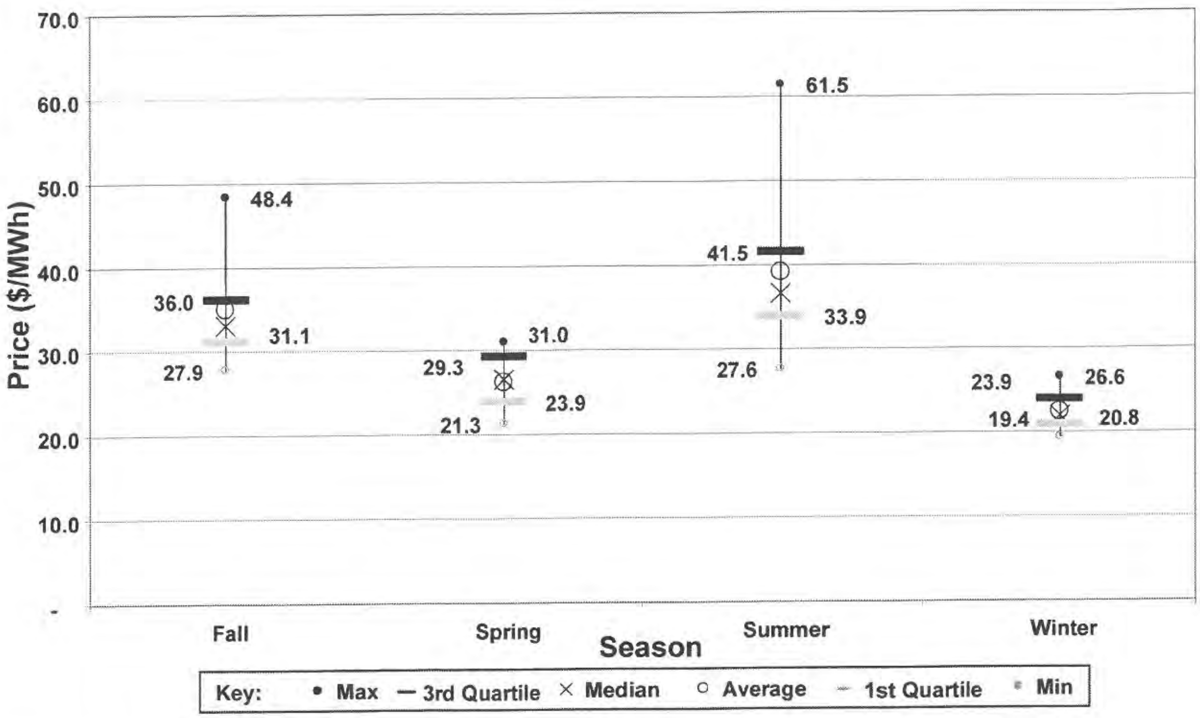


Figure B-34
PALO VERDE, 1999 Weekly Peak Price Distribution

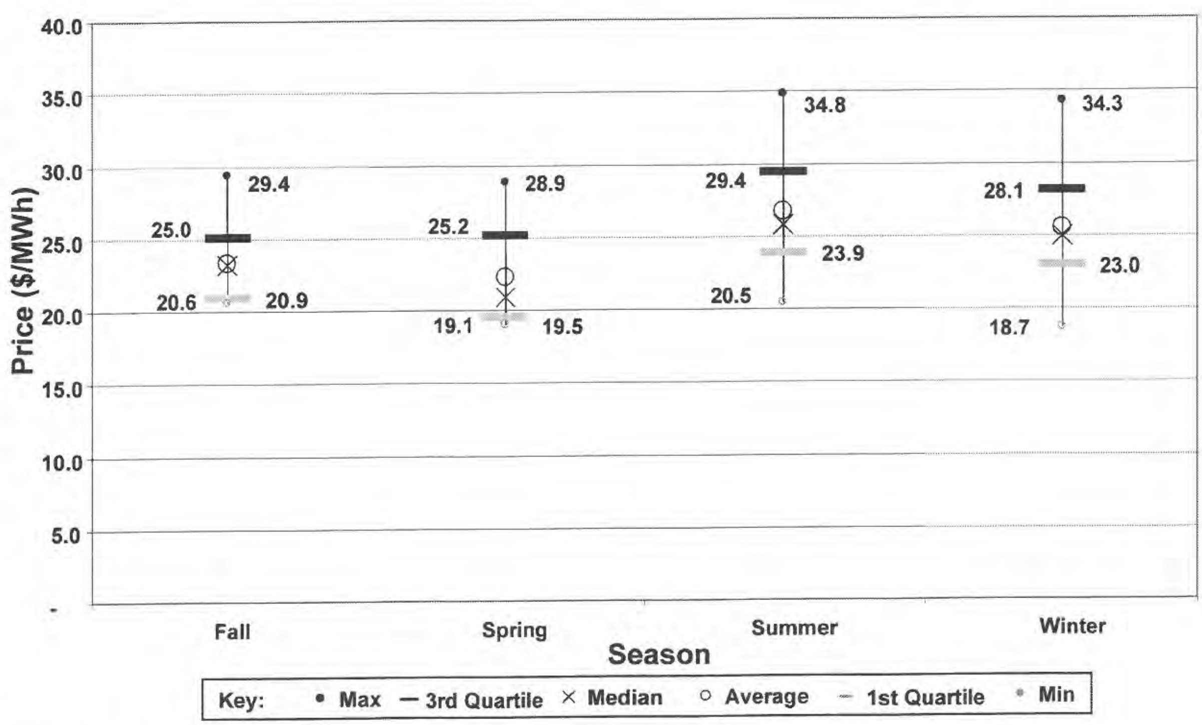


Figure B-35
PJM, 1996 Weekly Peak Price Distribution

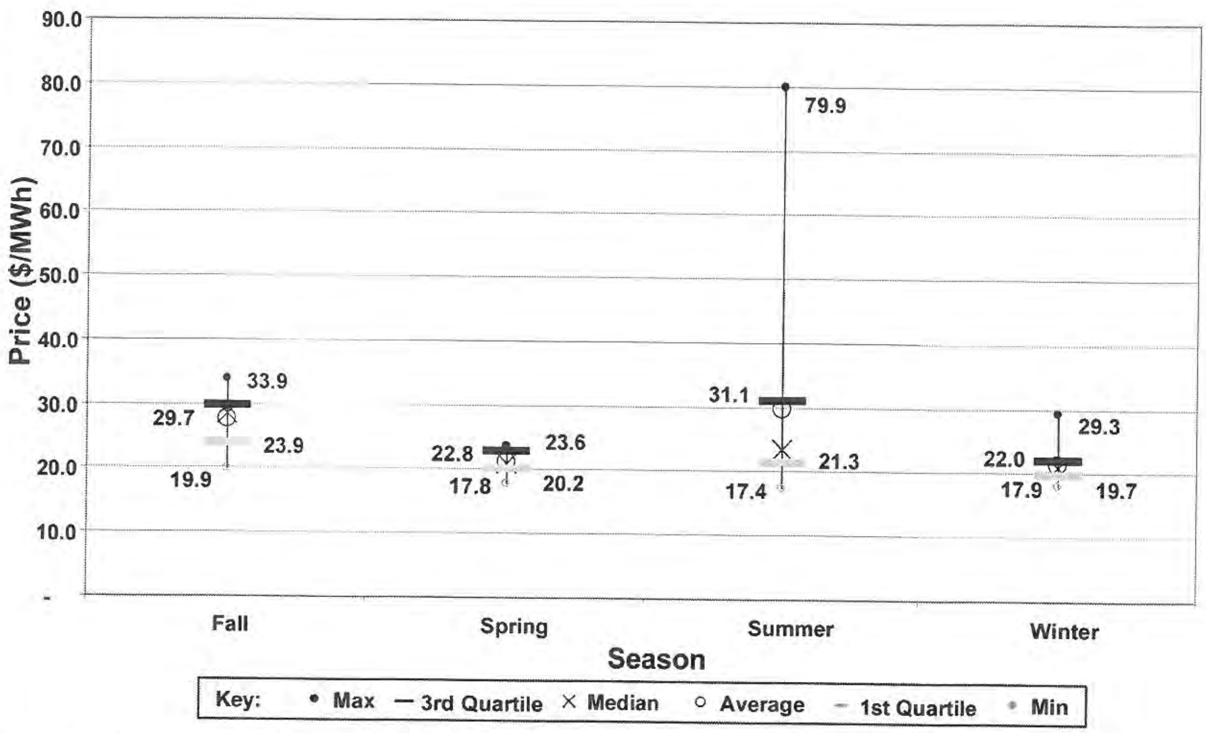


Figure B-36
PJM, 1997 Weekly Peak Price Distribution

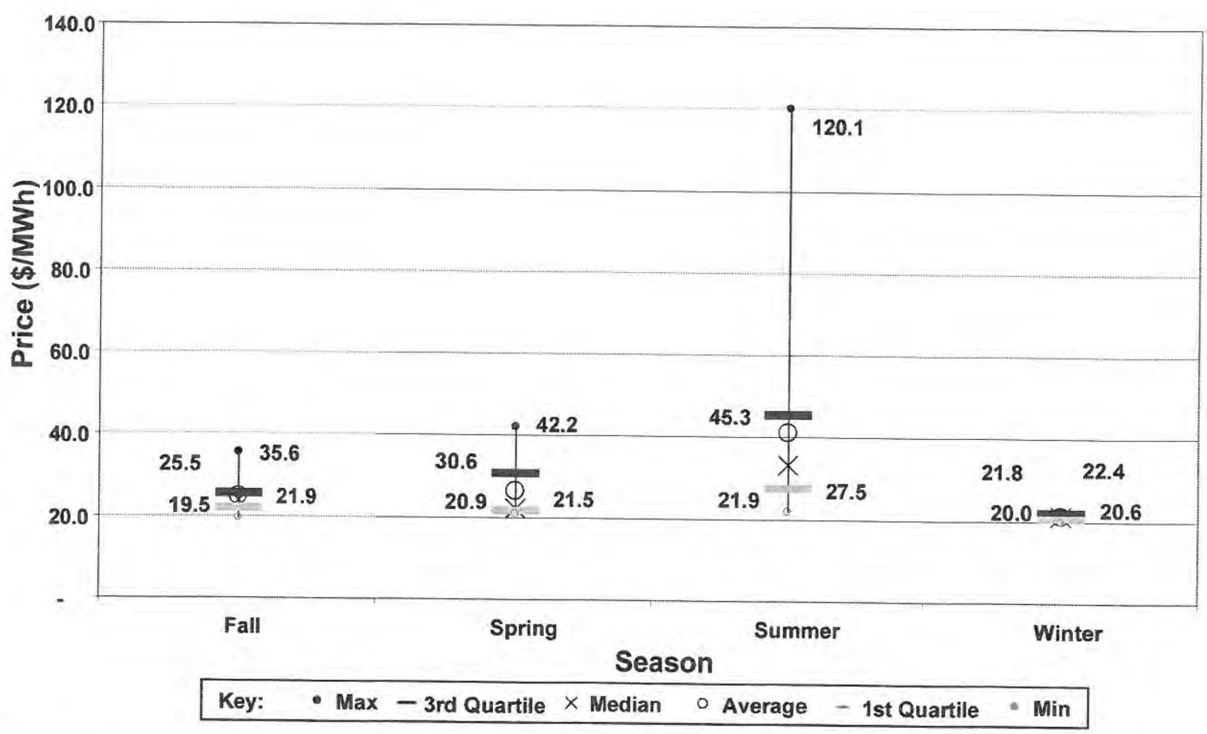


Figure B-37
PJM WEST, 1998 Weekly Peak Price Distribution

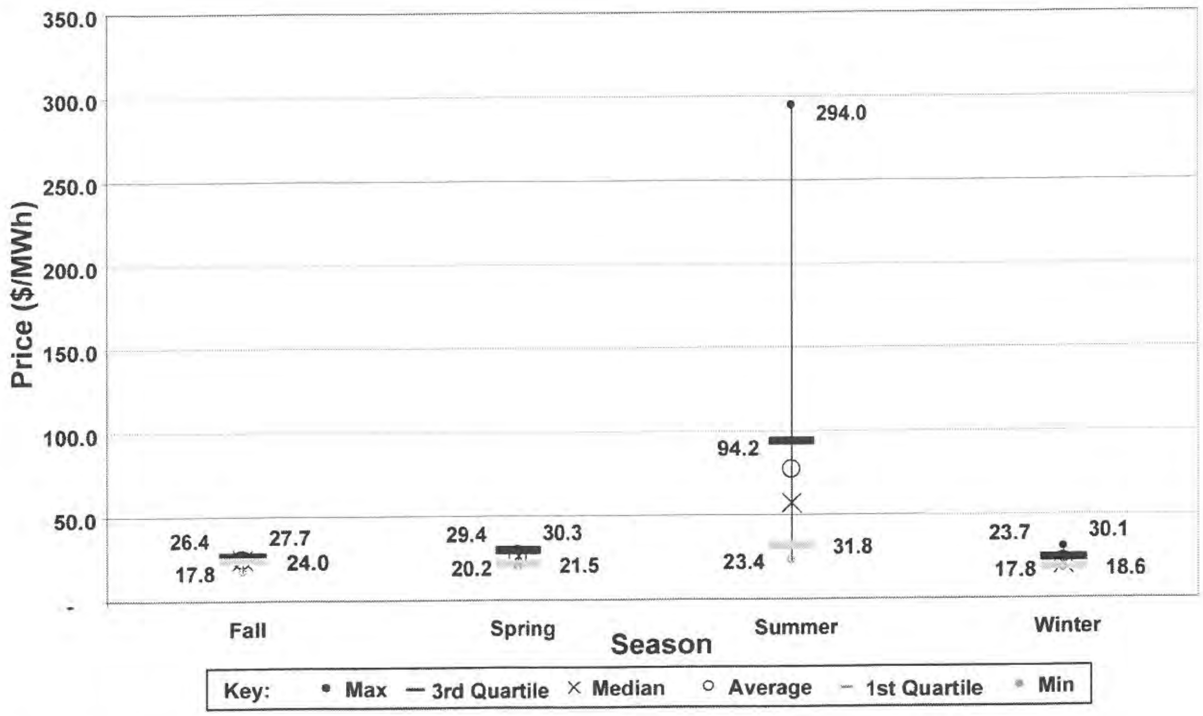


Figure B-38
PJM WEST, 1999 Weekly Peak Price Distribution

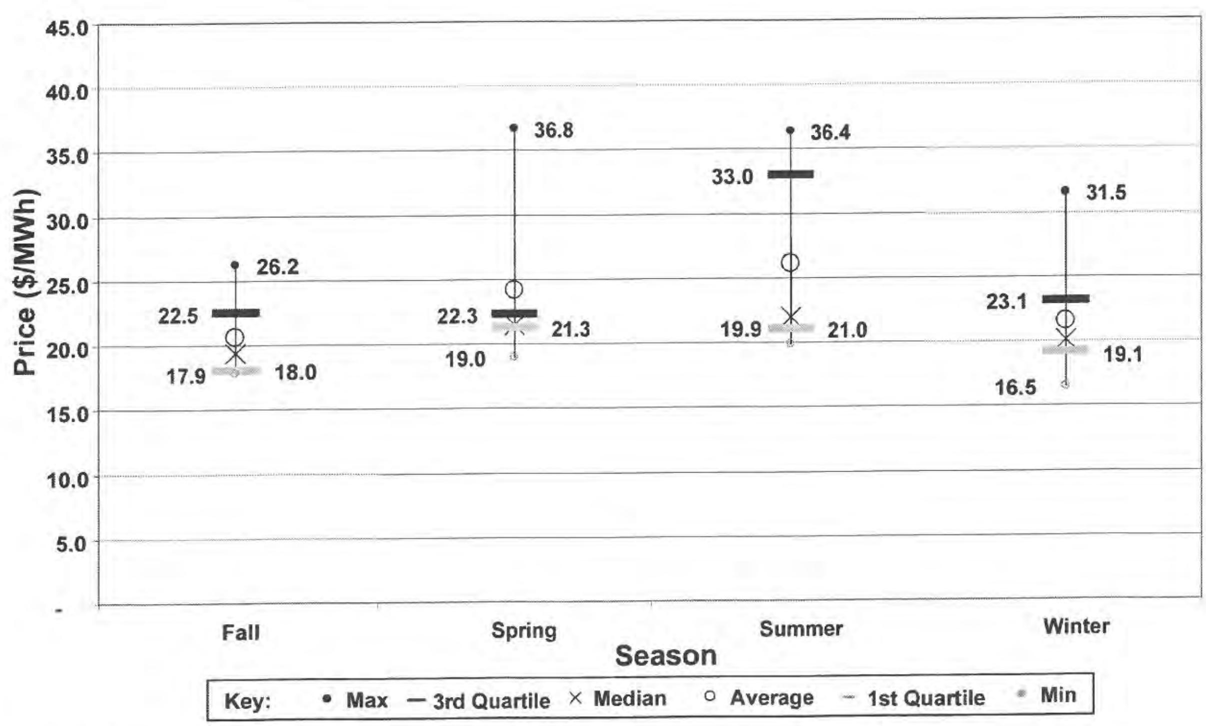


Figure B-39
SERC, 1996 Weekly Peak Price Distribution

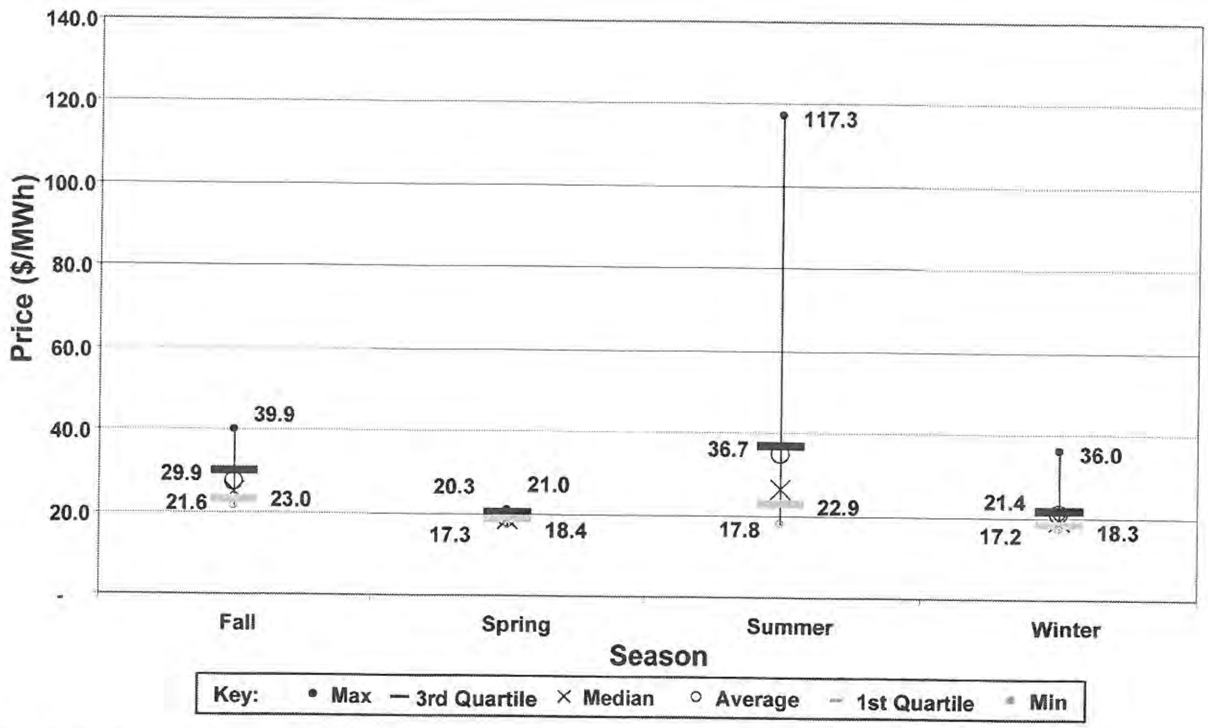


Figure B-40
SERC, 1997 Weekly Peak Price Distribution

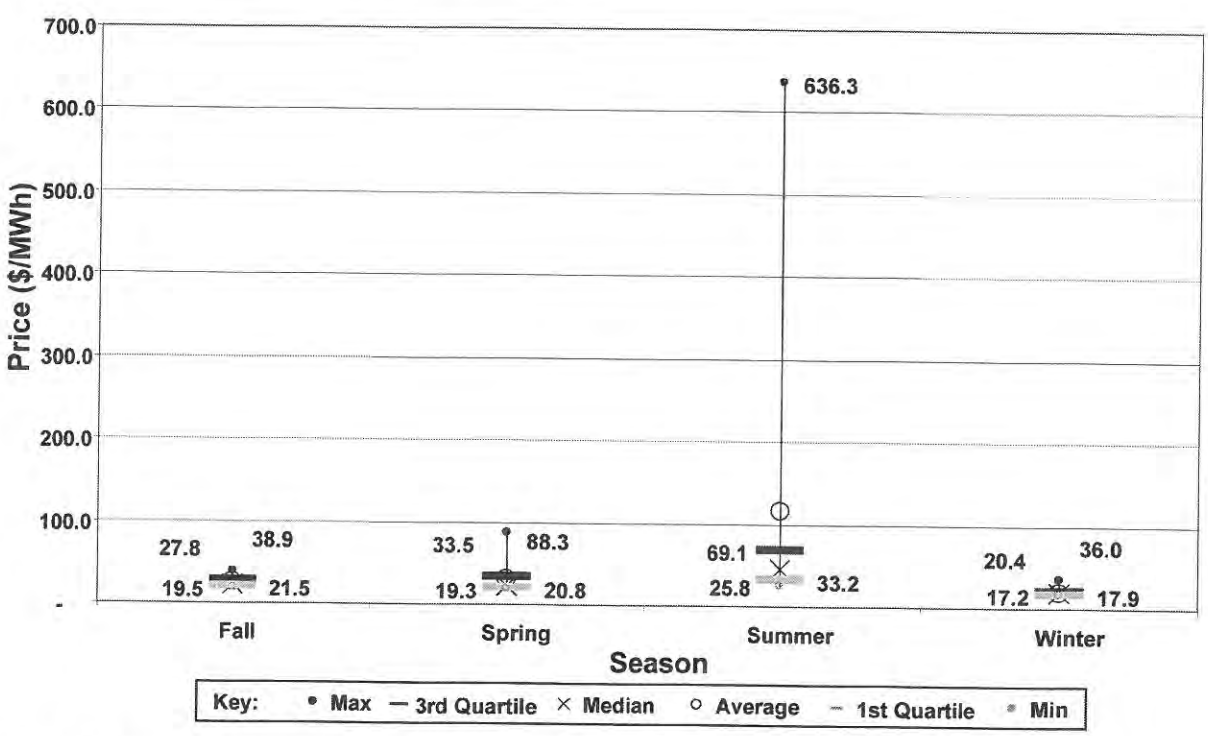


Figure B-41
SERC, 1998 Weekly Peak Price Distribution

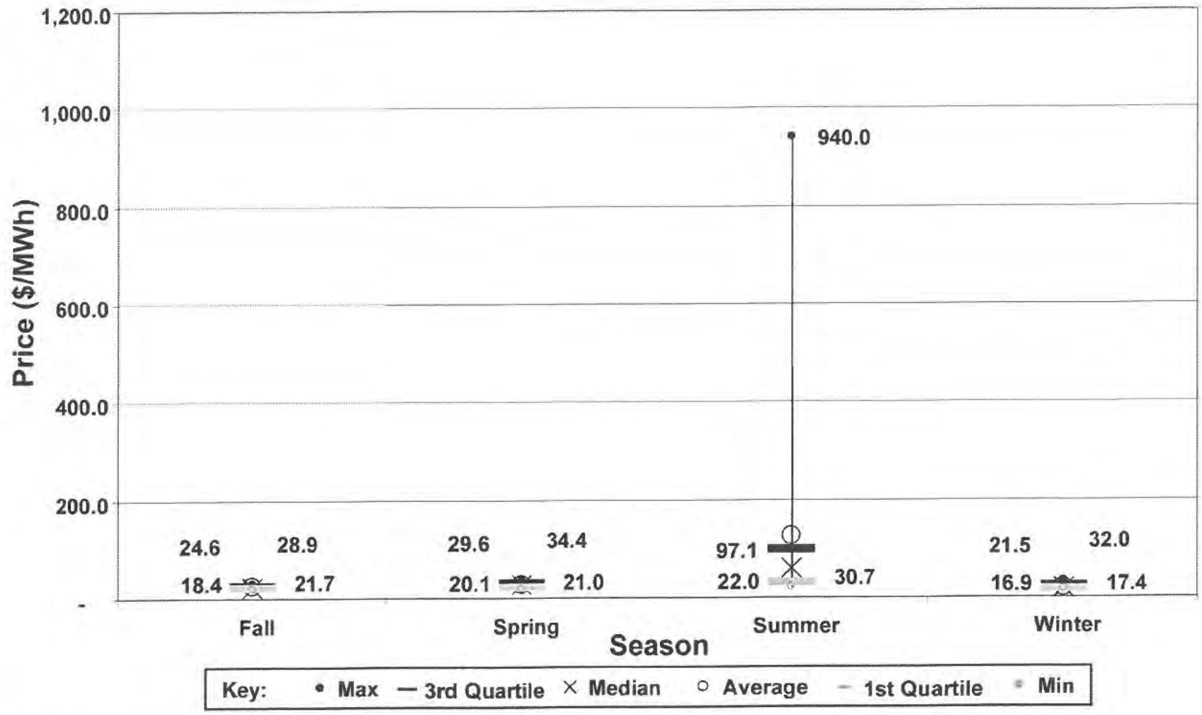


Figure B-42
SERC, 1999 Weekly Peak Price Distribution

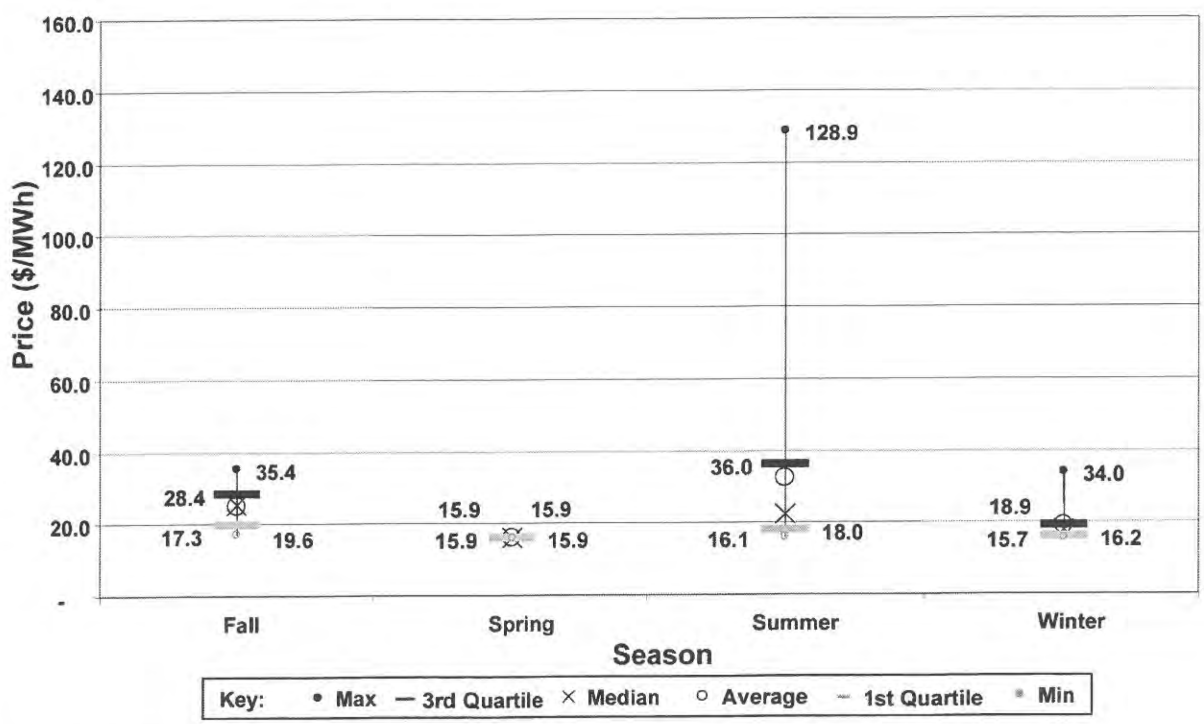


Figure B-43
INTO TVA, 1997 Weekly Peak Price Distribution

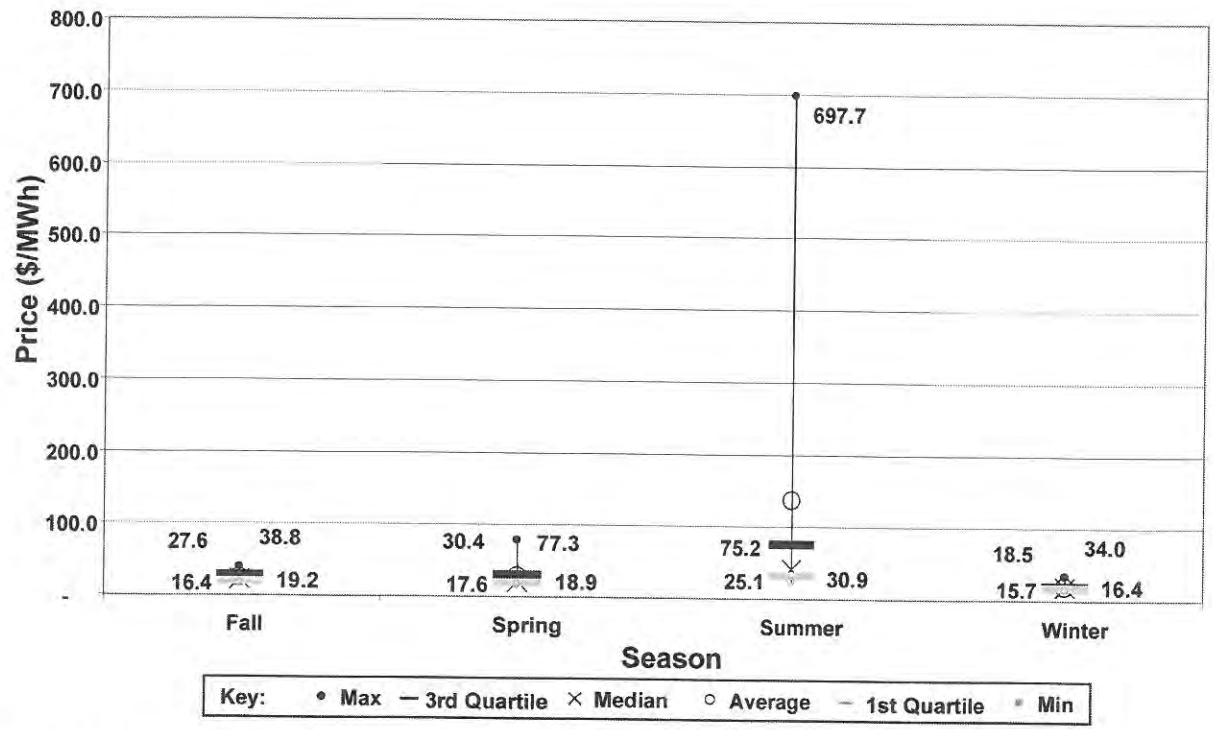


Figure B-44
INTO TVA, 1998 Weekly Peak Price Distribution

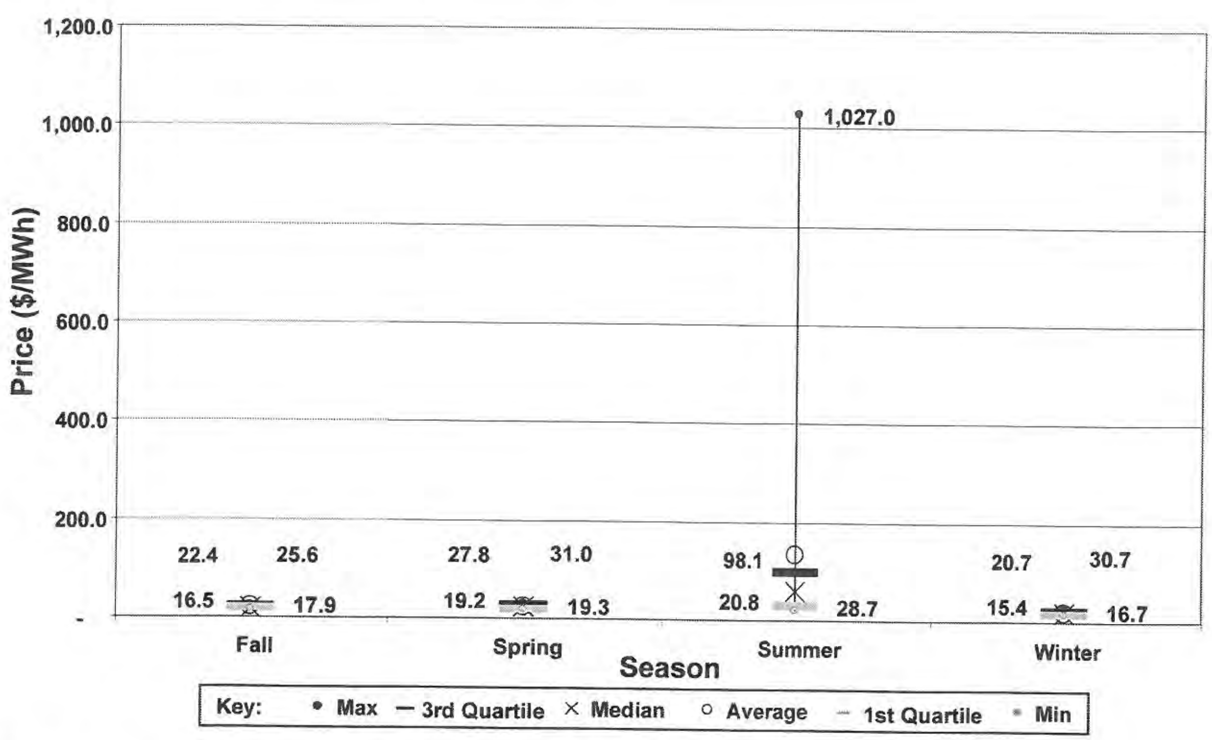


Figure B-45
INTO TVA, 1999 Weekly Peak Price Distribution

Weekly Spot Natural Gas Price Distribution Charts

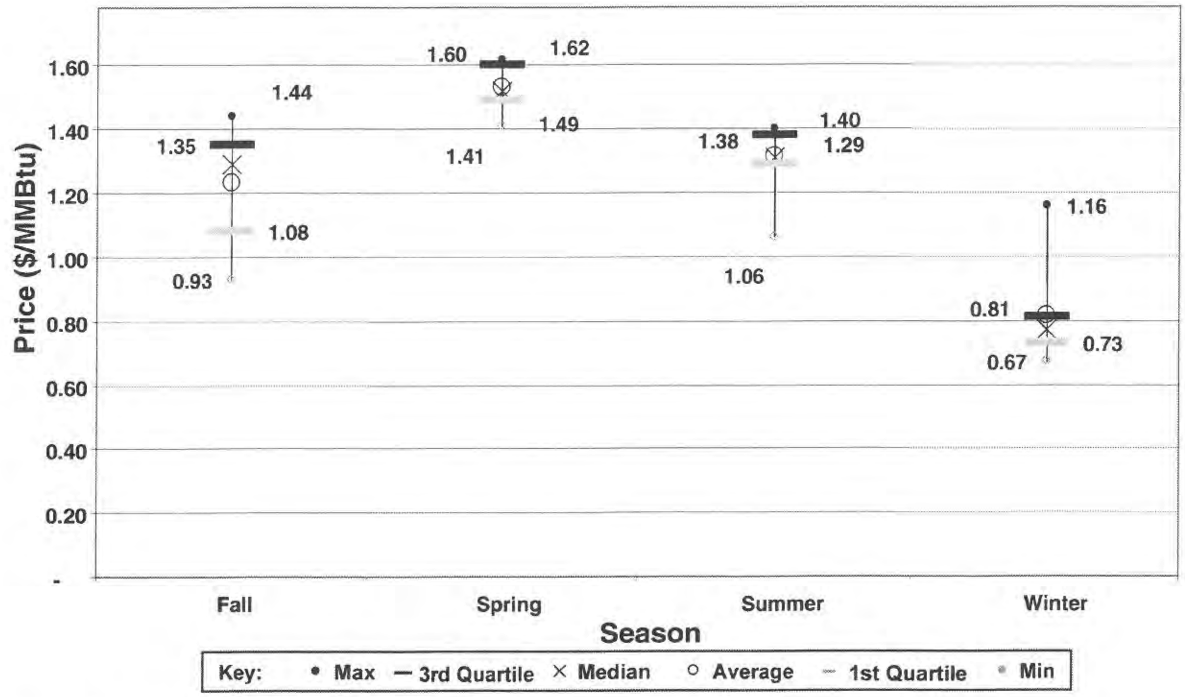


Figure B-46
Alberta, 1994 Weekly Peak Price Distribution

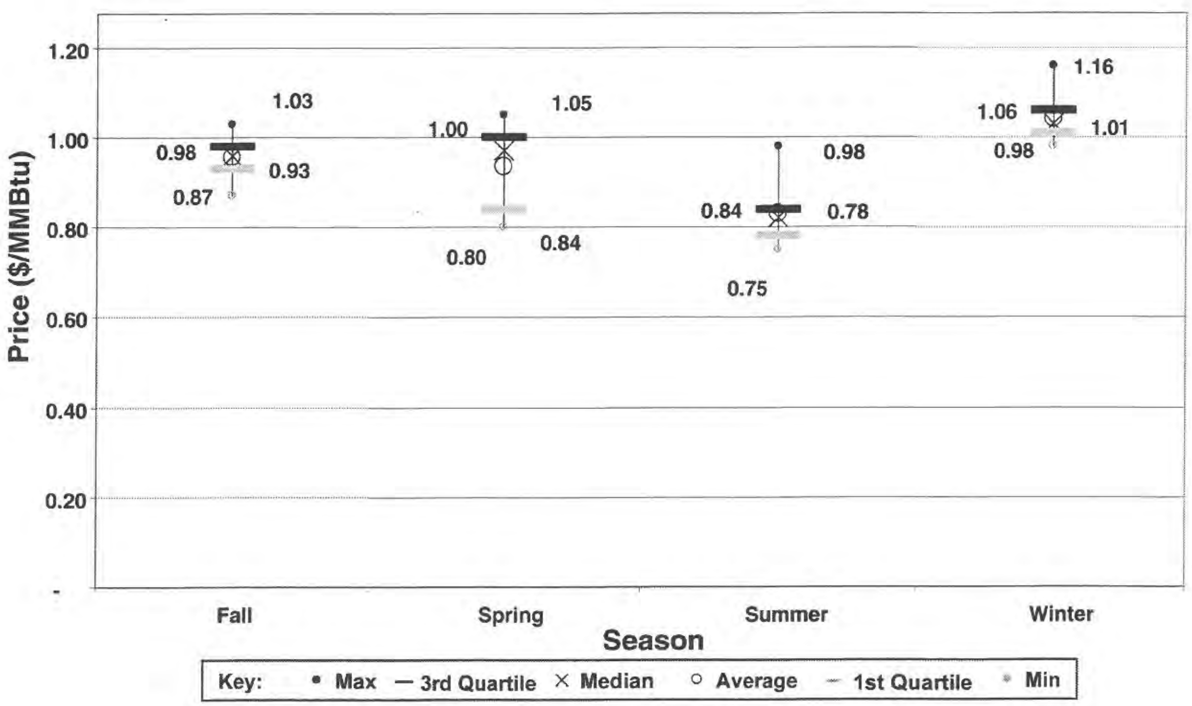


Figure B-47
Alberta, 1995 Weekly Peak Price Distribution

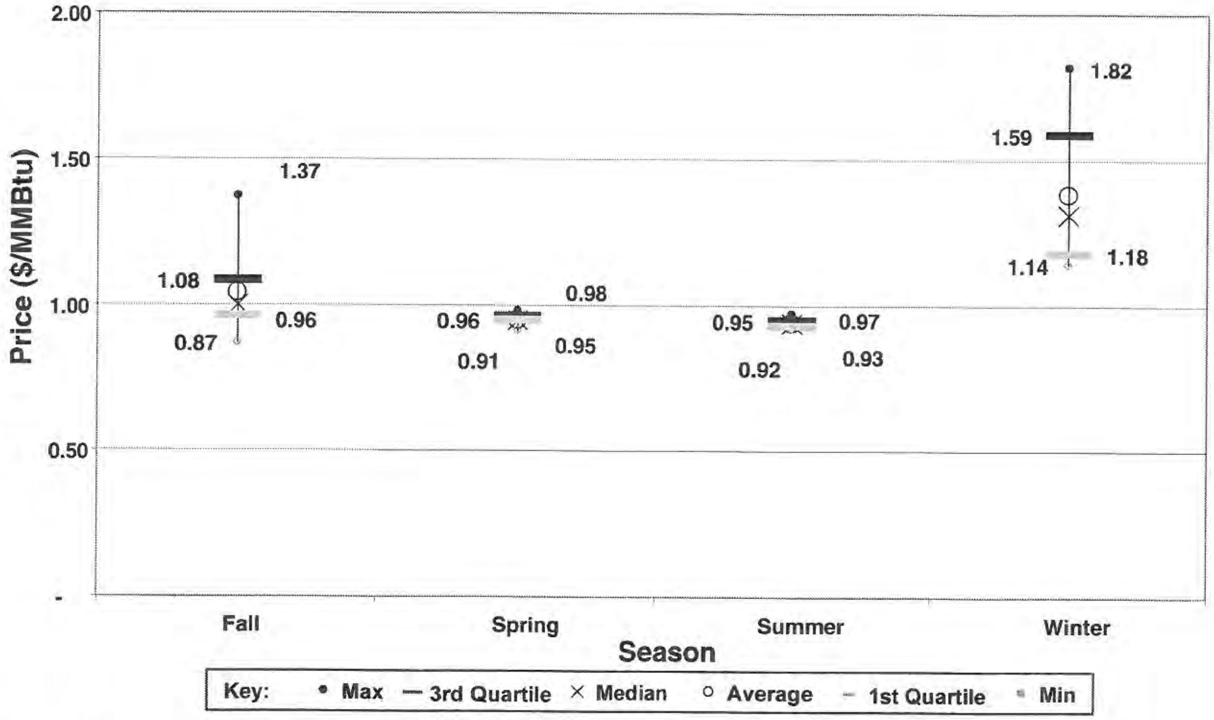


Figure B-48
Alberta, 1996 Weekly Peak Price Distribution

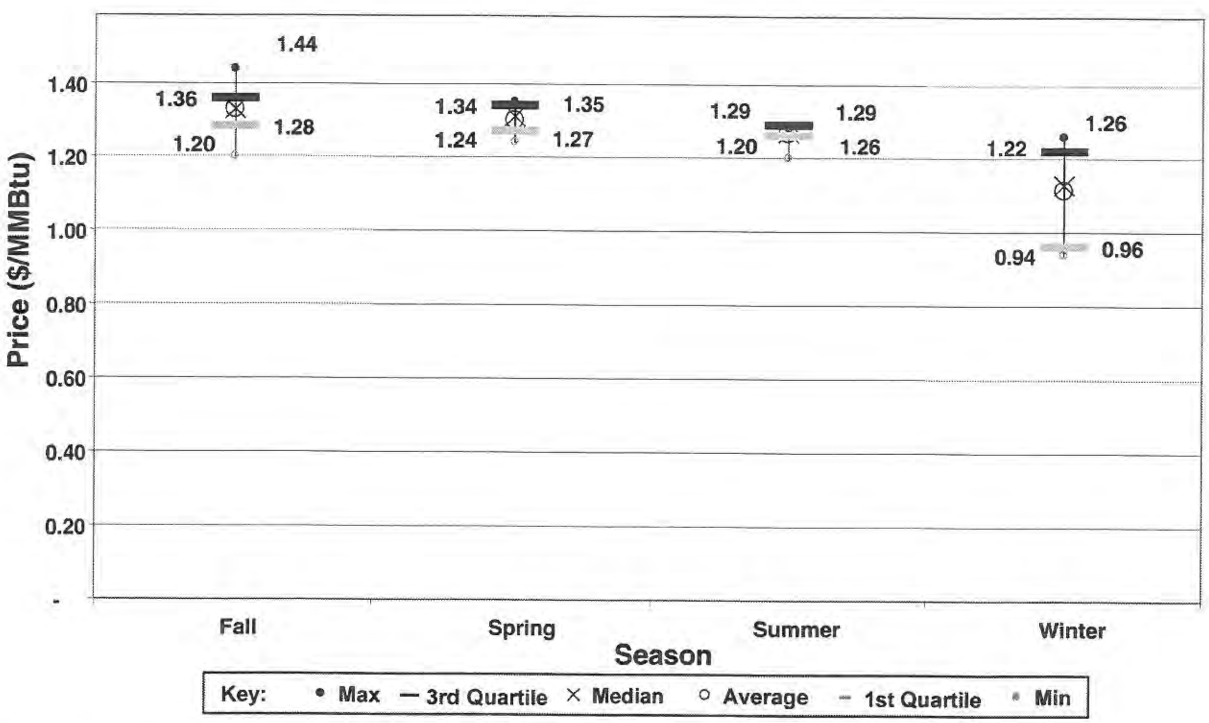


Figure B-49
Alberta, 1997 Weekly Peak Price Distribution

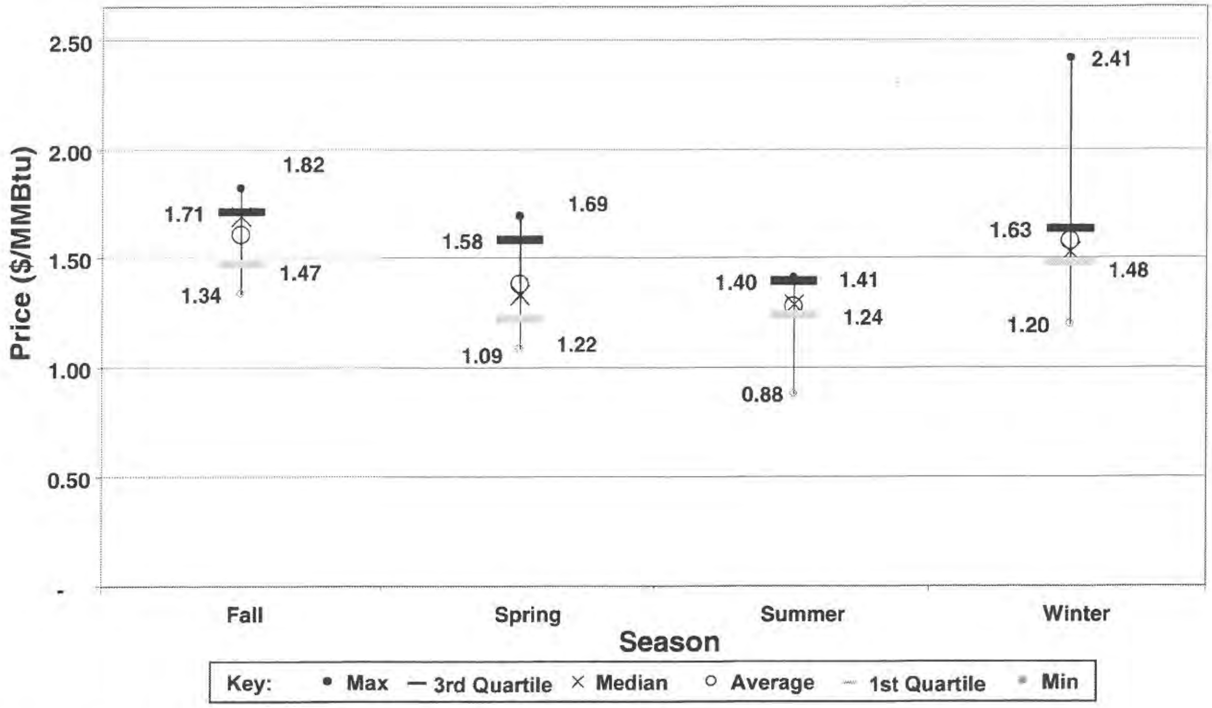


Figure B-50
Alberta, 1998 Weekly Peak Price Distribution

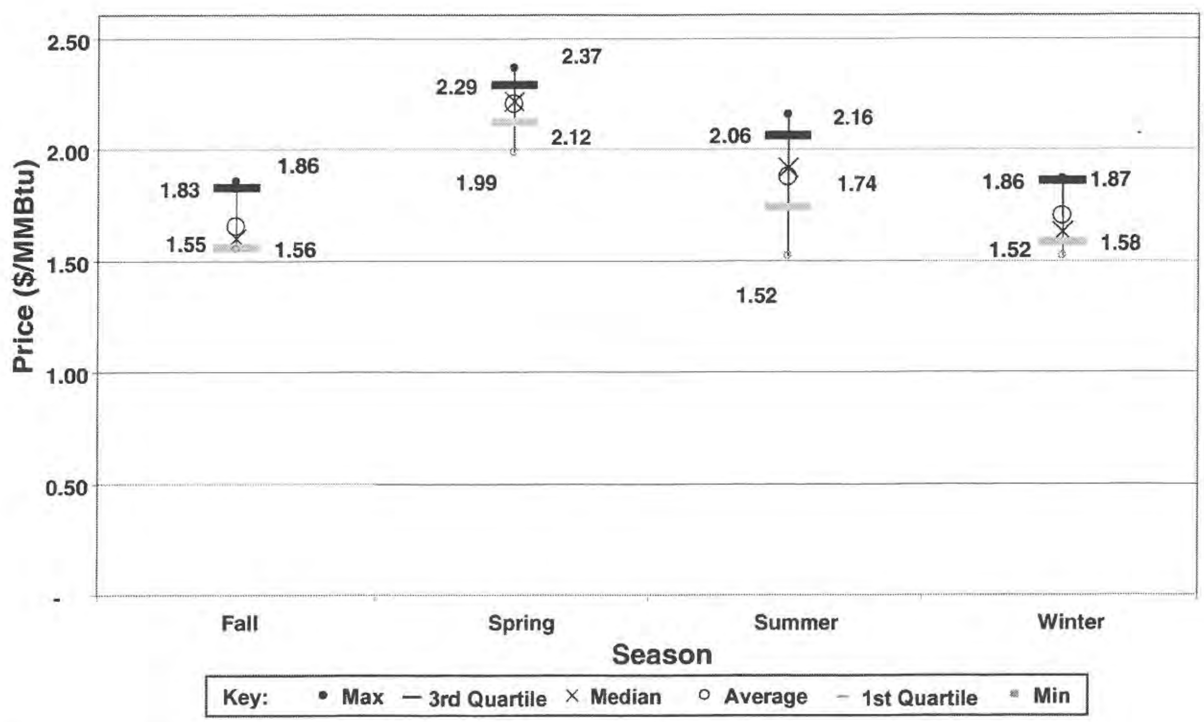


Figure B-51
Appalachia, 1994 Weekly Peak Price Distribution

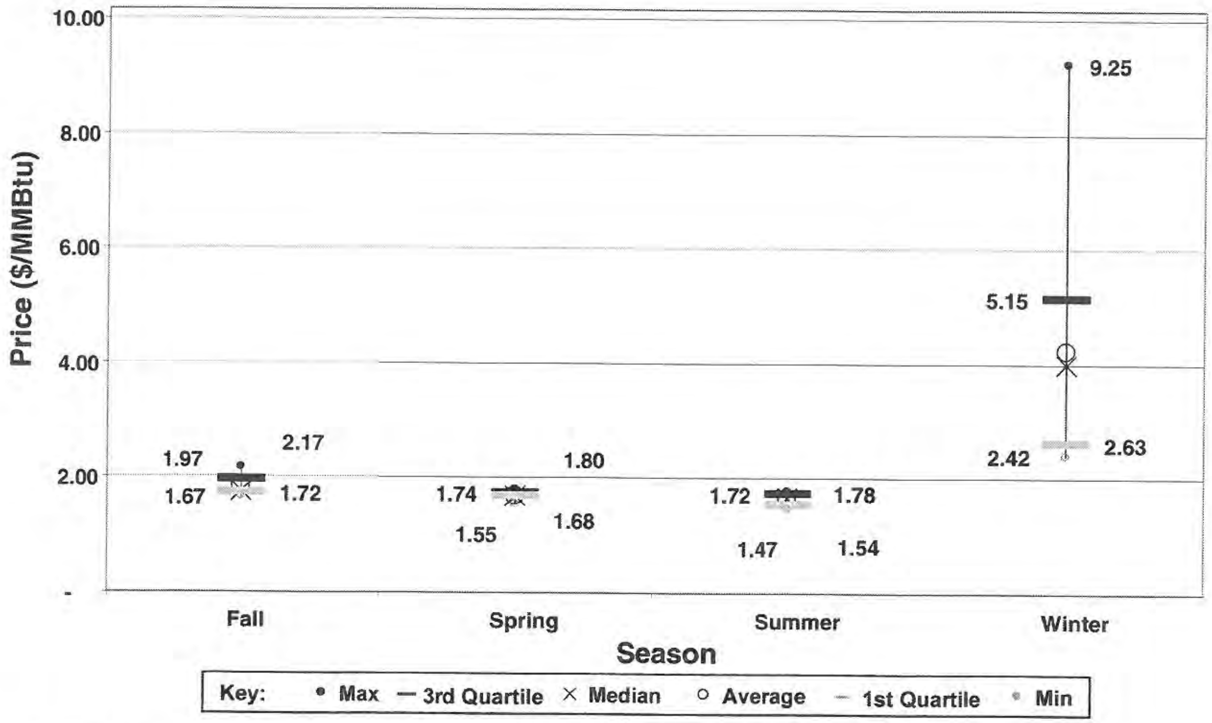


Figure B-52
Appalachia, 1995 Weekly Peak Price Distribution

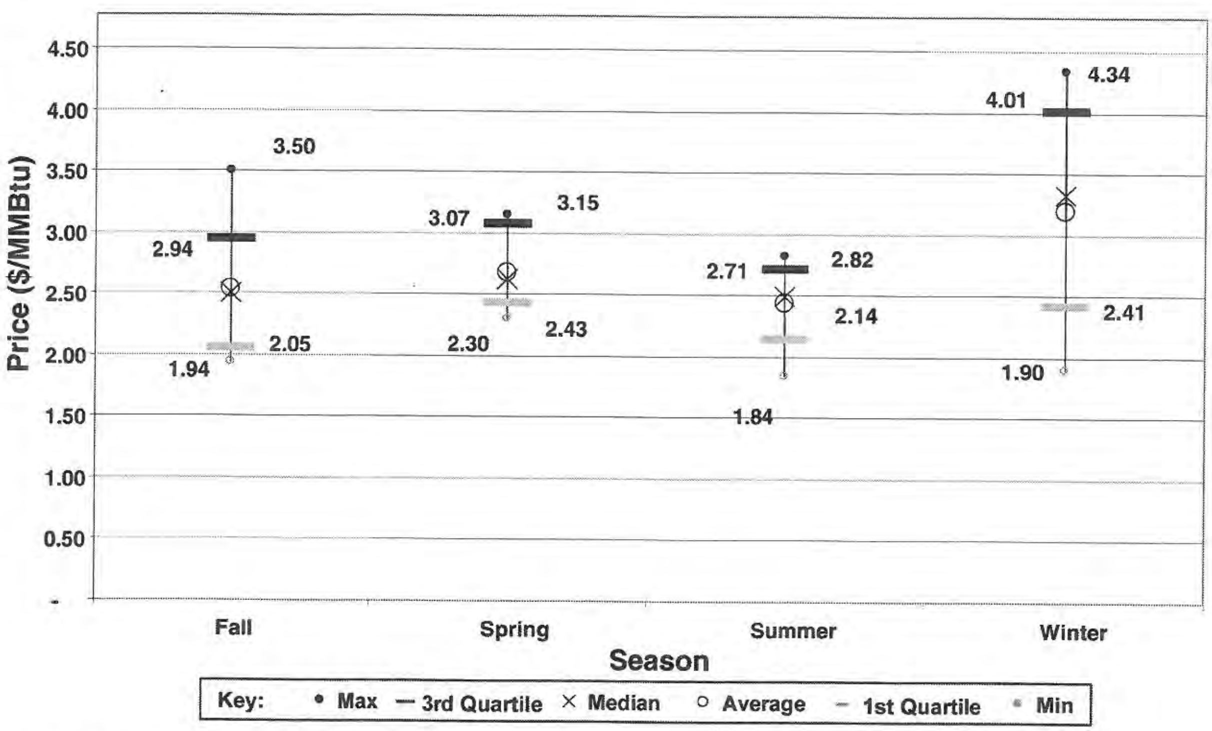


Figure B-53
Appalachia, 1996 Weekly Peak Price Distribution

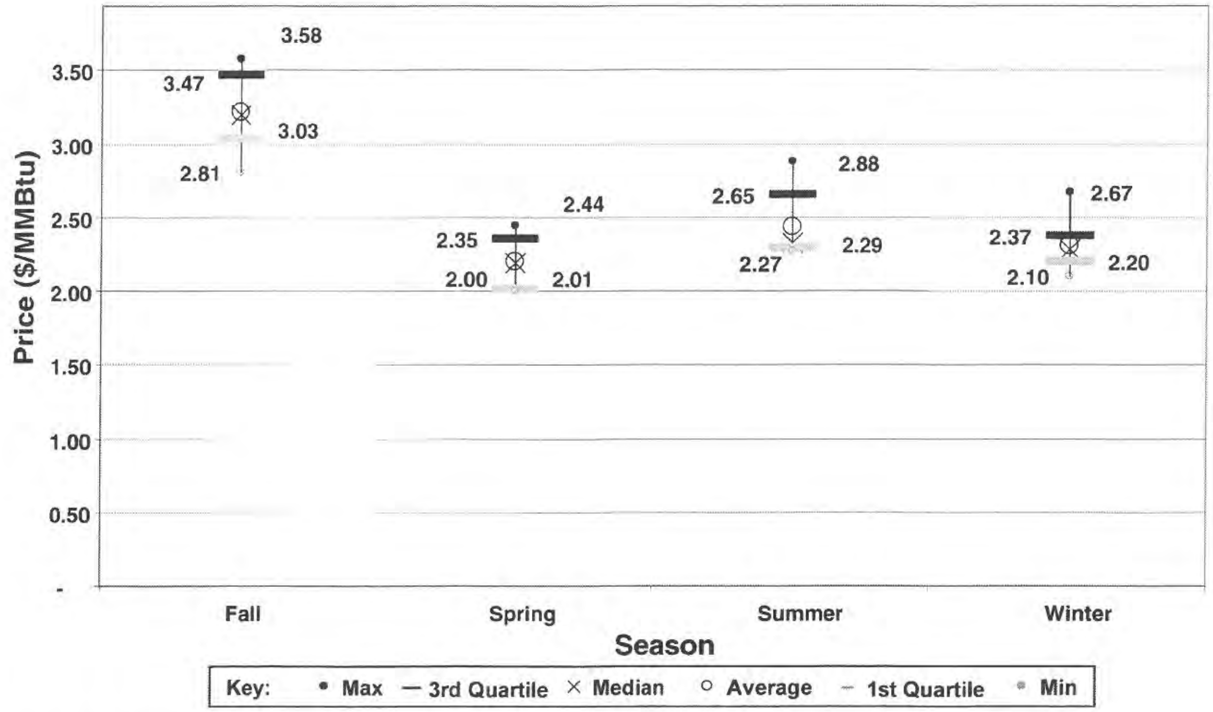


Figure B-54
Appalachia, 1997 Weekly Peak Price Distribution

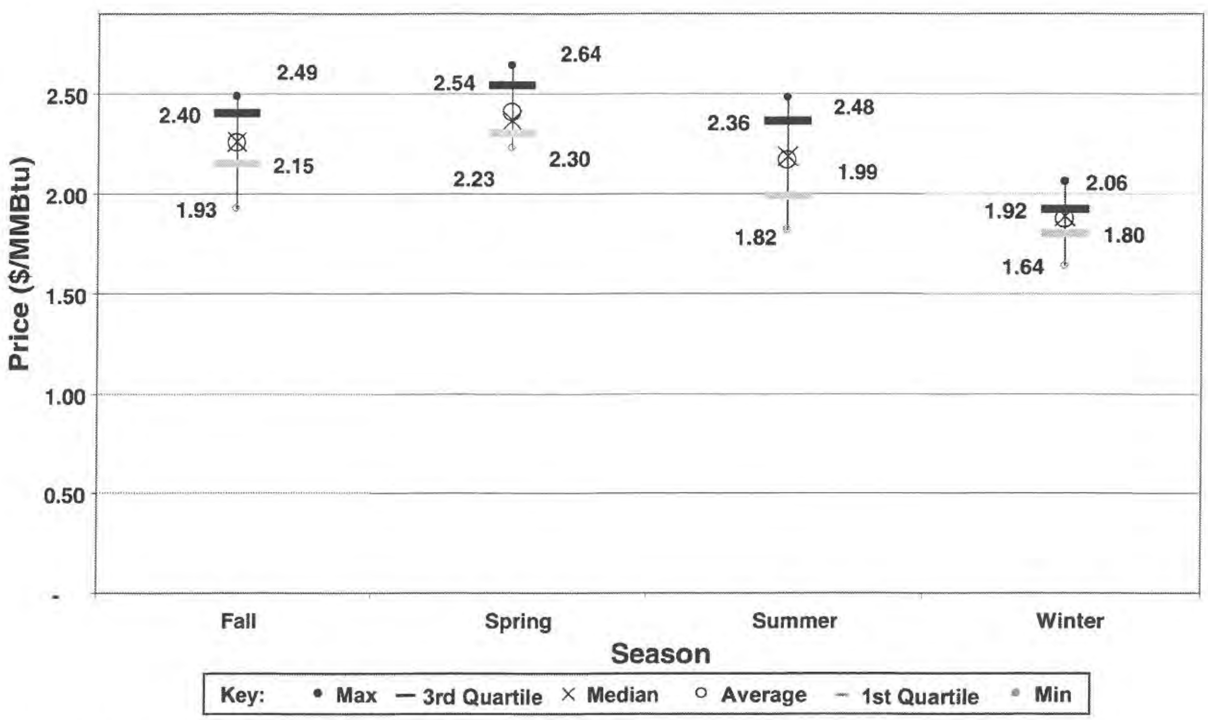


Figure B-55
Appalachia, 1998 Weekly Peak Price Distribution

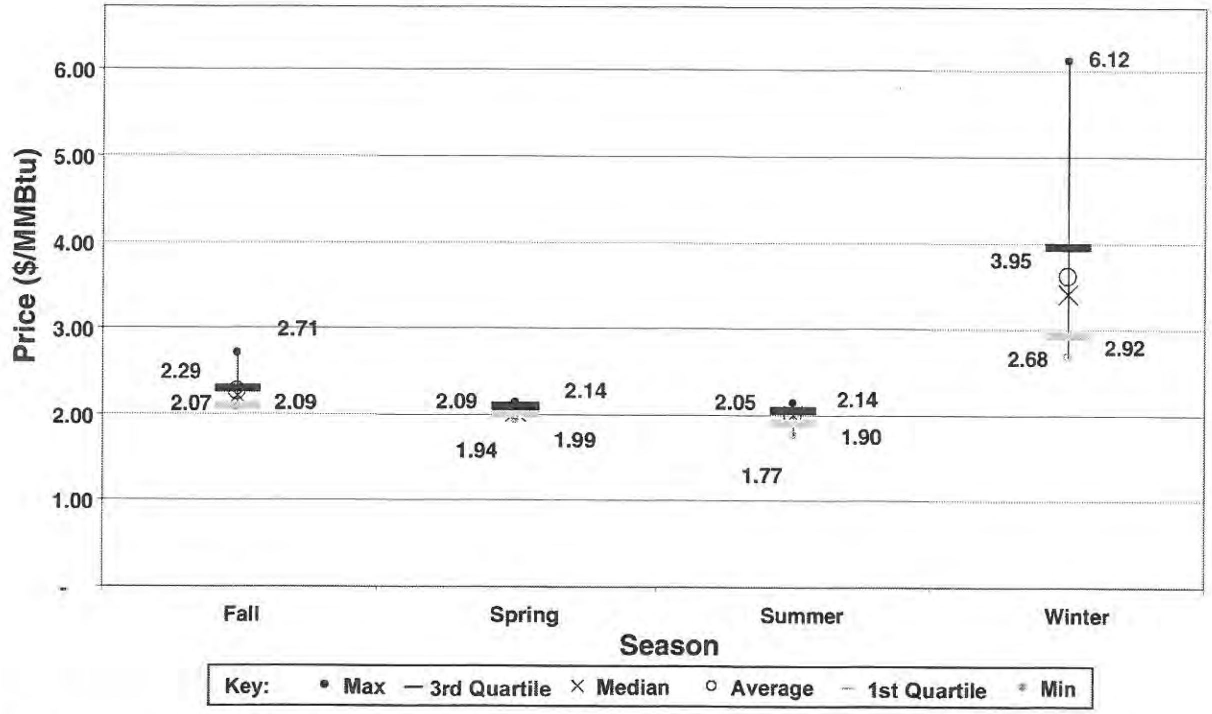


Figure B-56
Atlanta, 1995 Weekly Peak Price Distribution

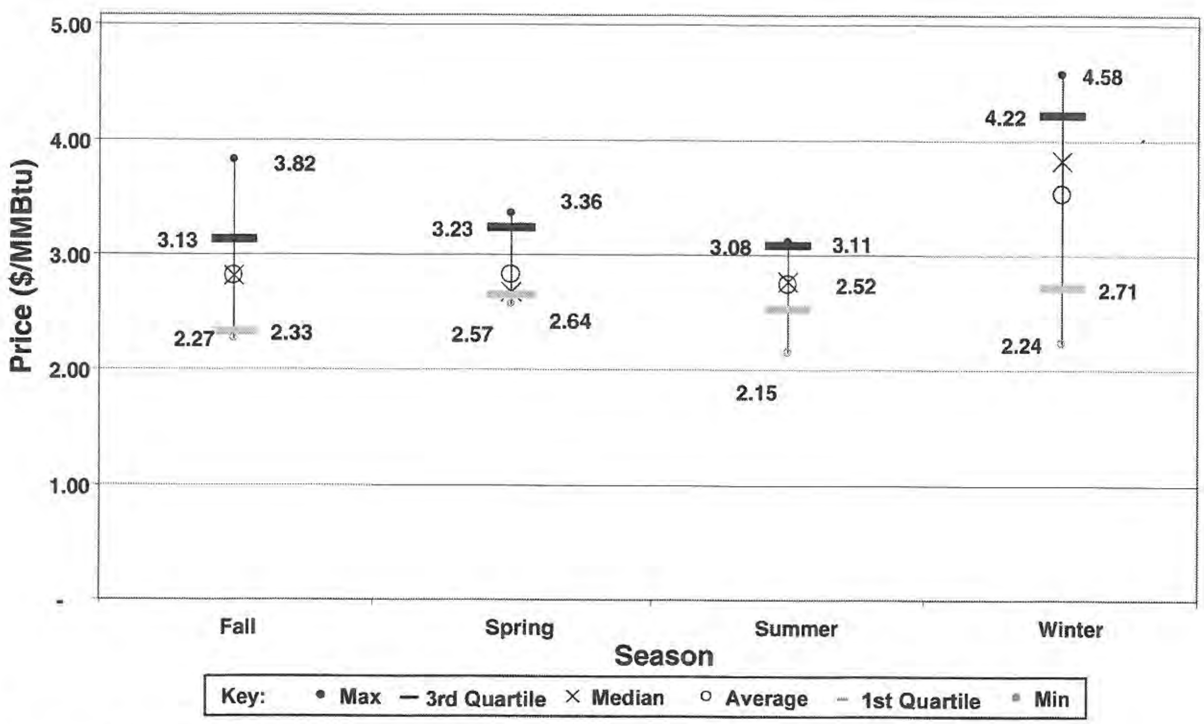


Figure B-57
Atlanta, 1996 Weekly Peak Price Distribution

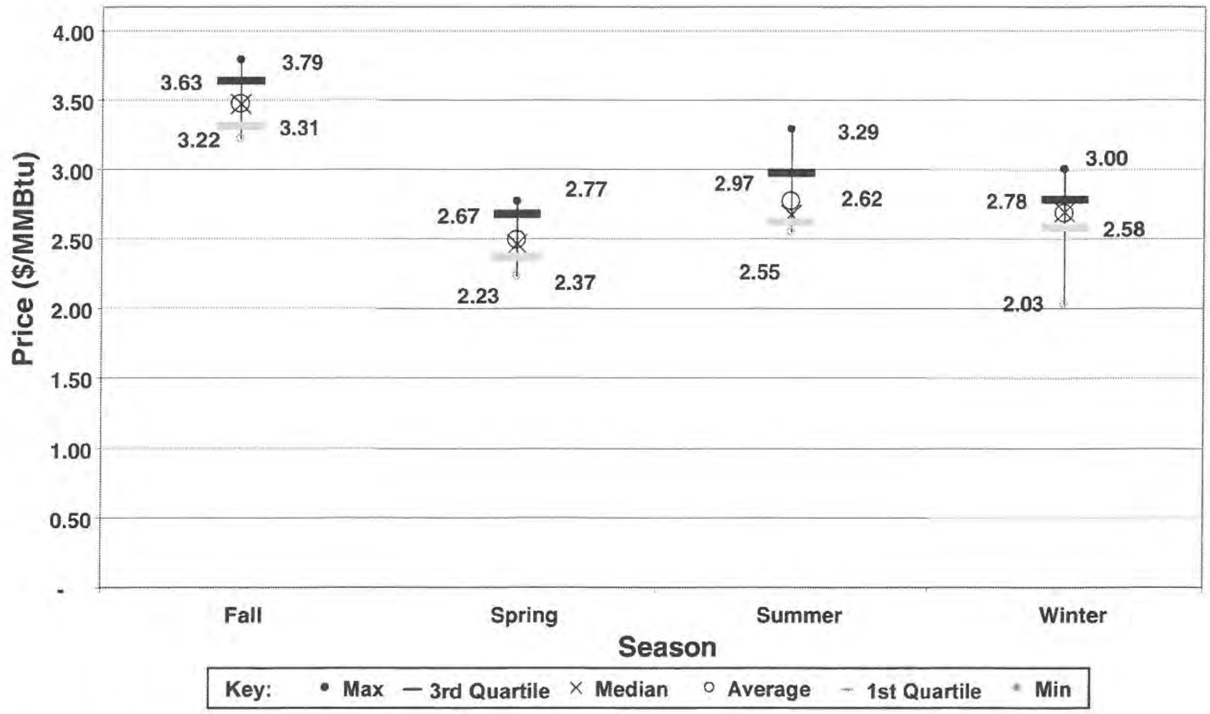


Figure B-58
Atlanta, 1997 Weekly Peak Price Distribution

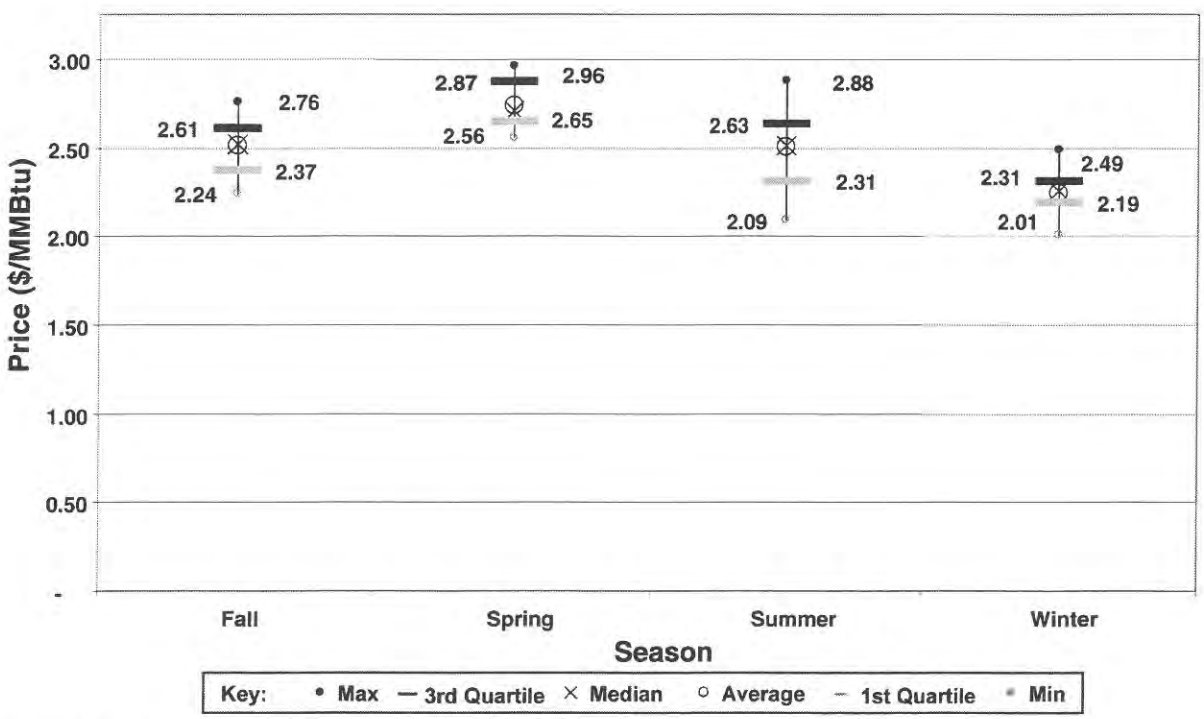


Figure B-59
Atlanta, 1998 Weekly Peak Price Distribution

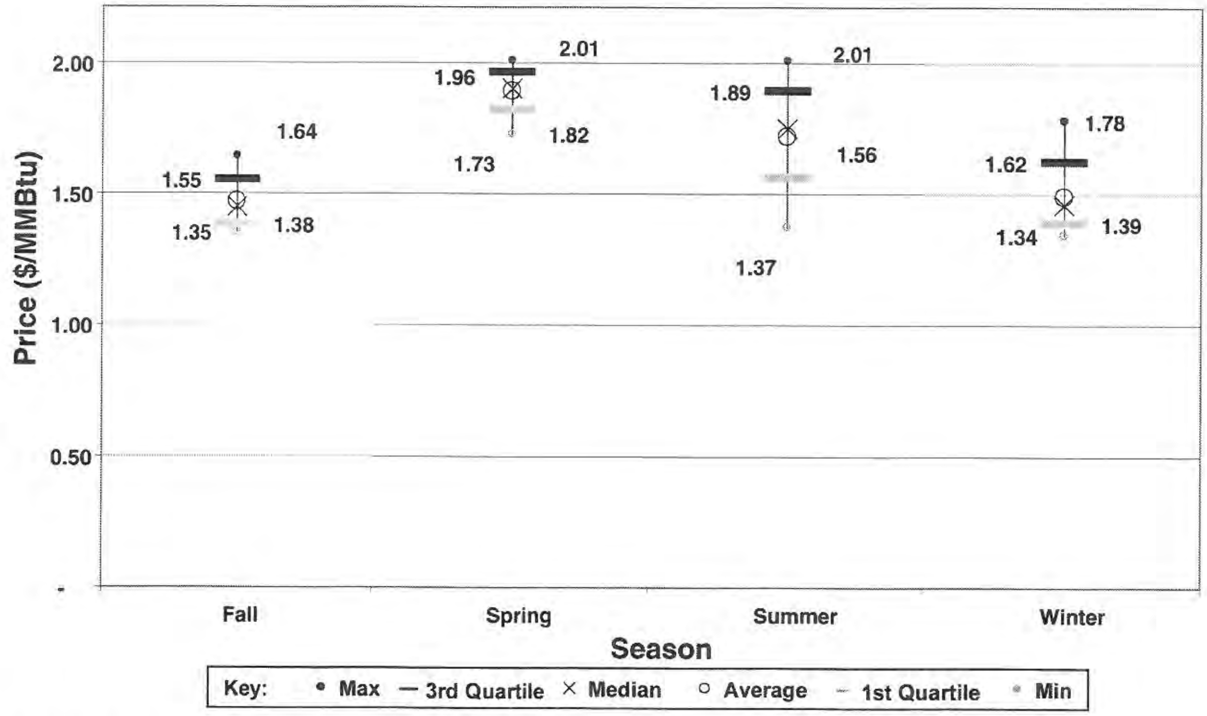


Figure B-60
Carthage, 1994 Weekly Peak Price Distribution

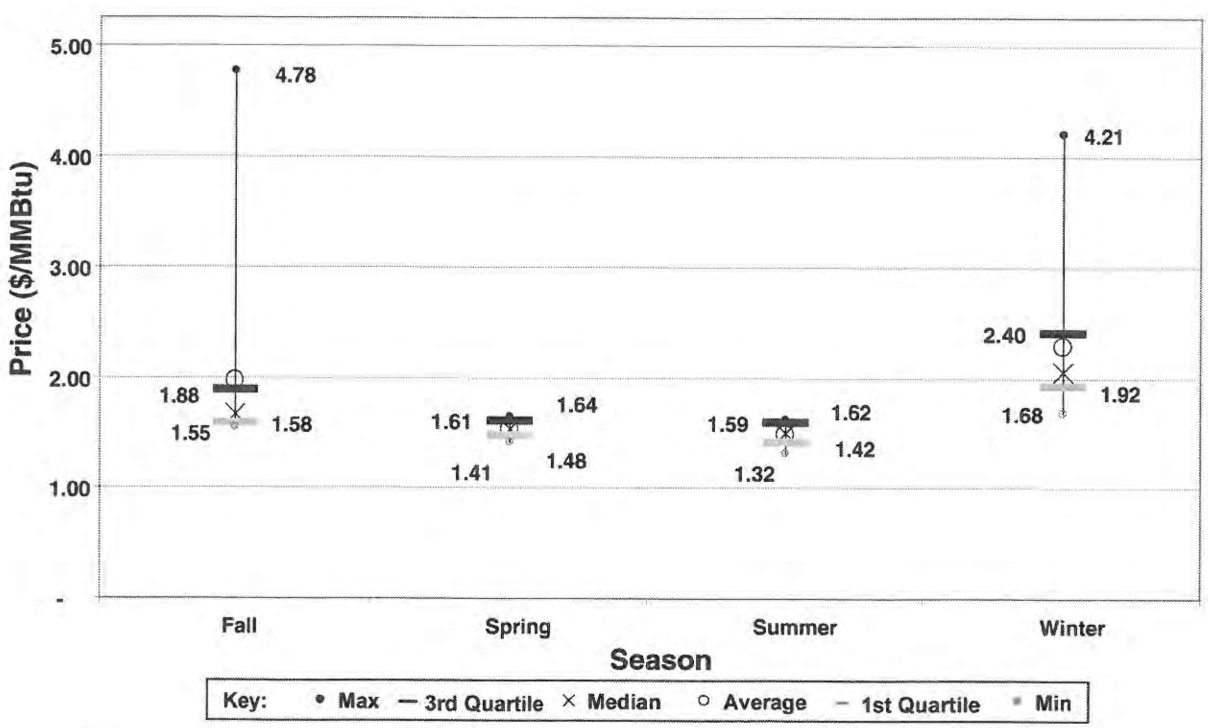


Figure B-61
Carthage, 1995 Weekly Peak Price Distribution

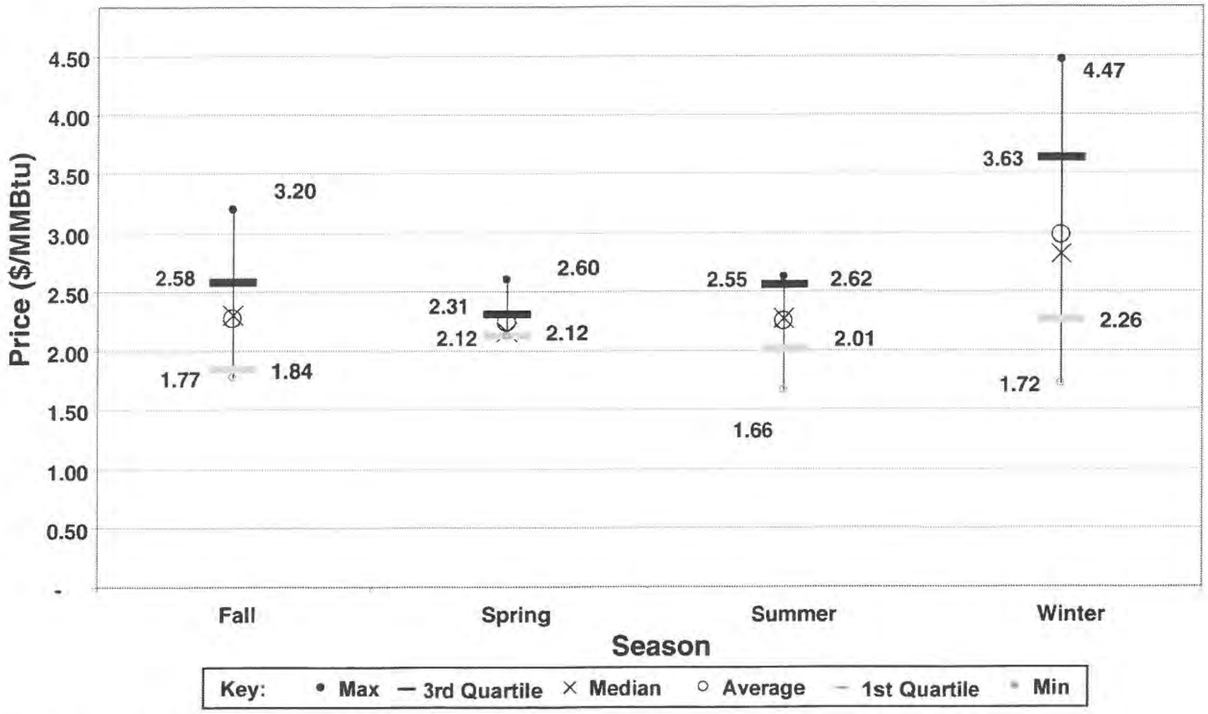


Figure B-62
Carthage, 1996 Weekly Peak Price Distribution

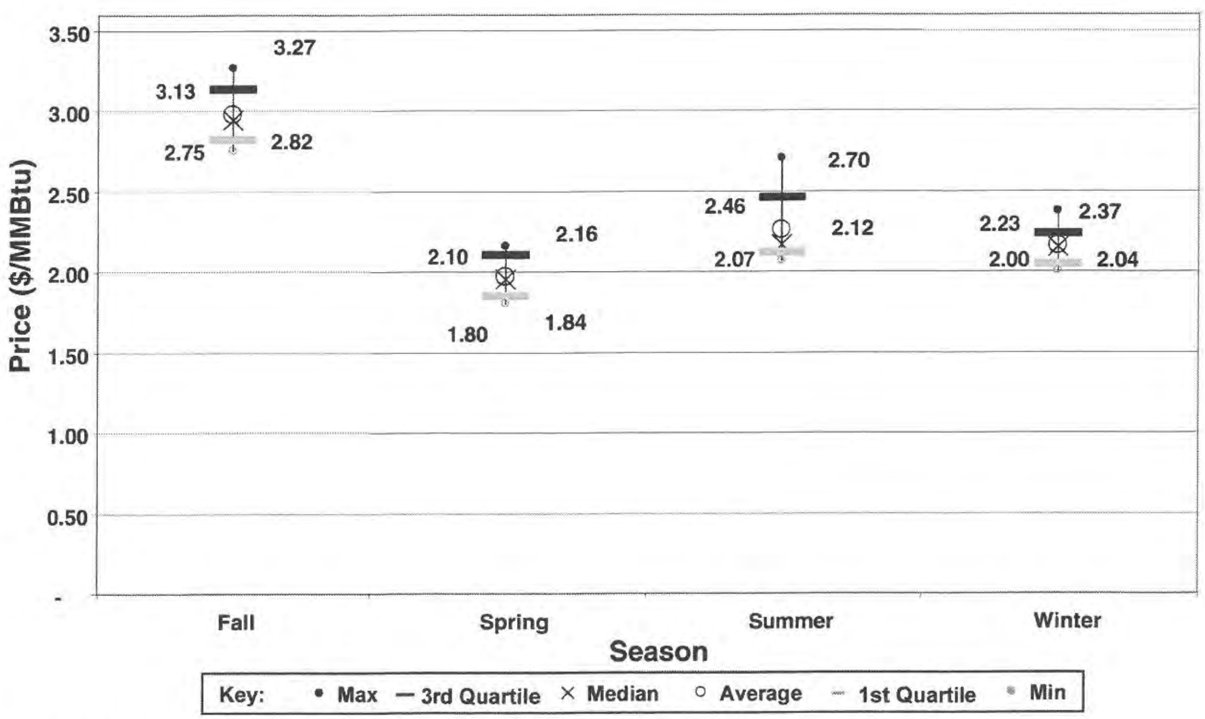


Figure B-63
Carthage, 1997 Weekly Peak Price Distribution

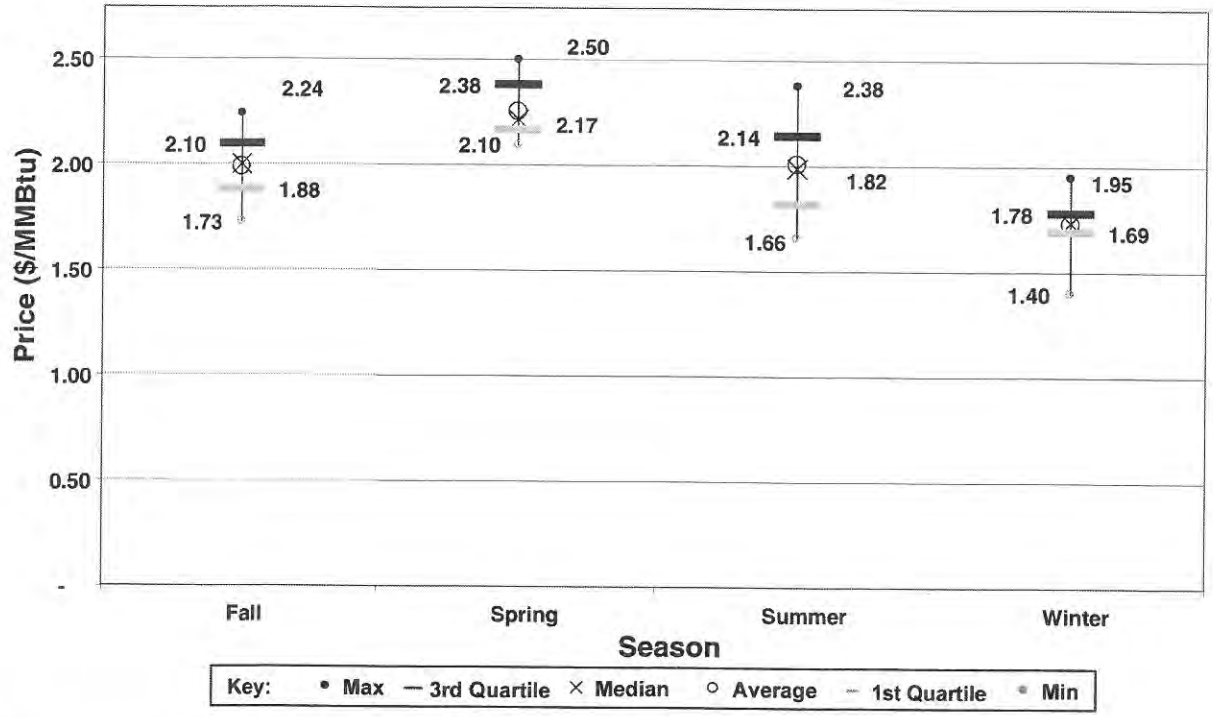


Figure B-64
Carthage, 1998 Weekly Peak Price Distribution

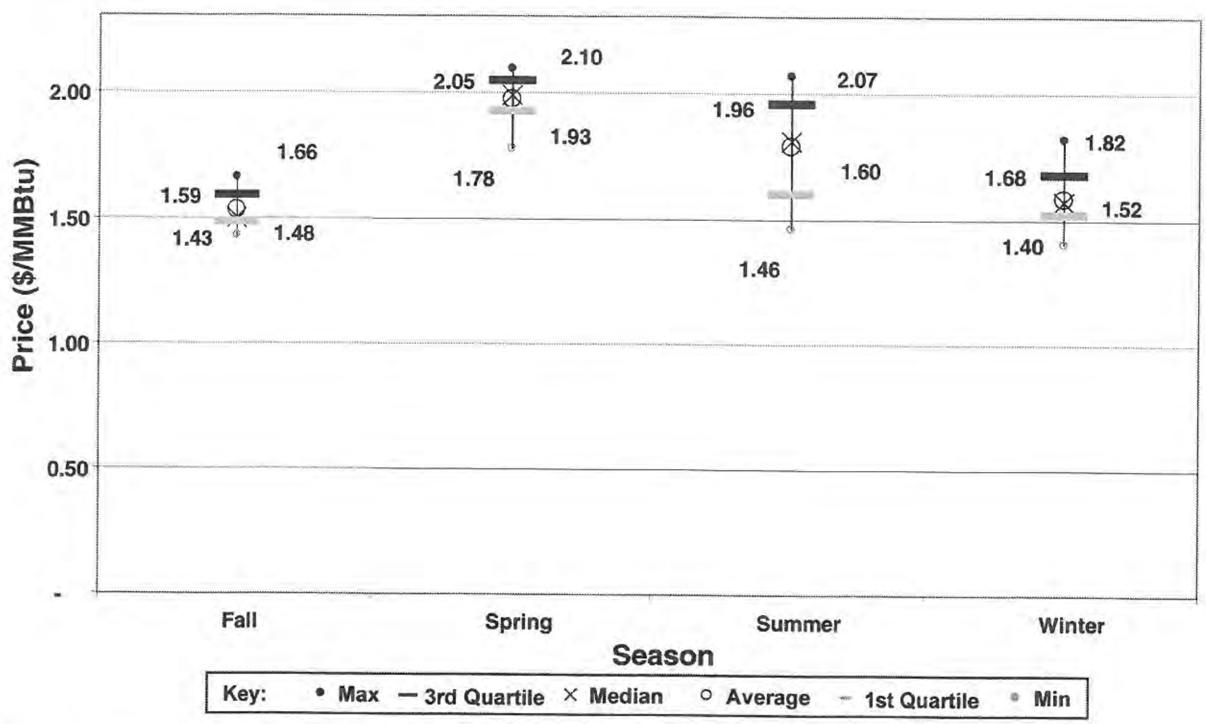


Figure B-65
Henry Hub, 1994 Weekly Peak Price Distribution

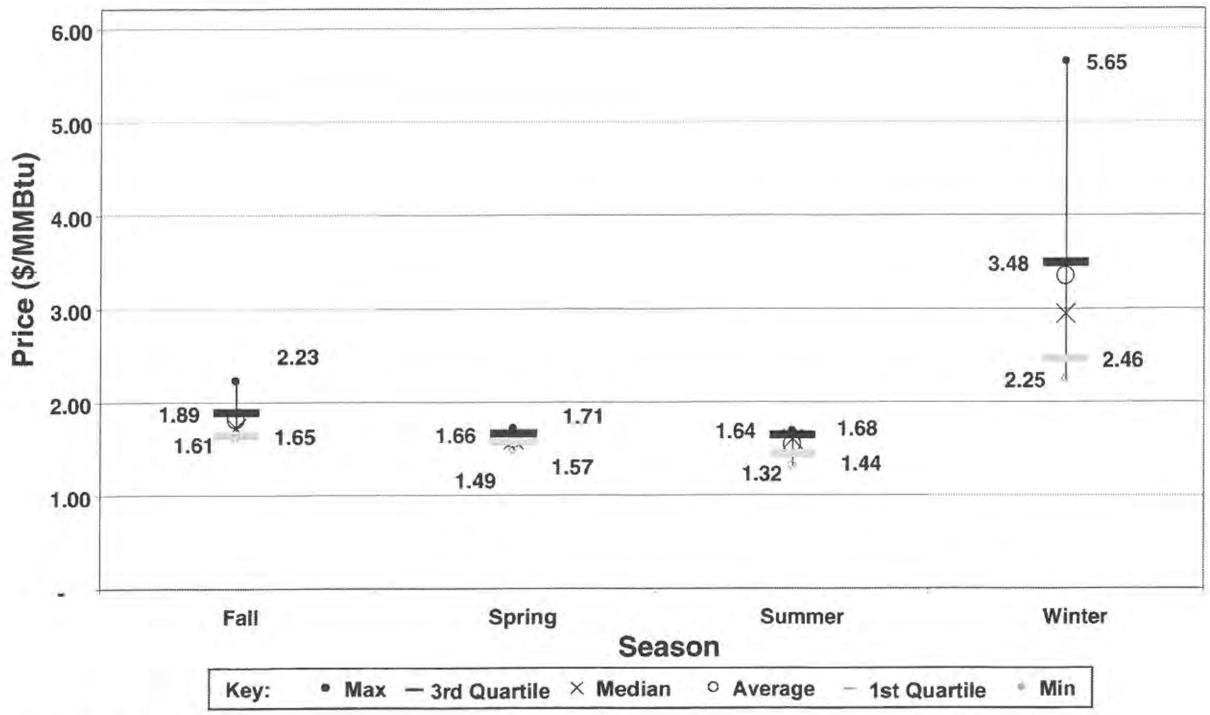


Figure B-66
Henry Hub, 1995 Weekly Peak Price Distribution

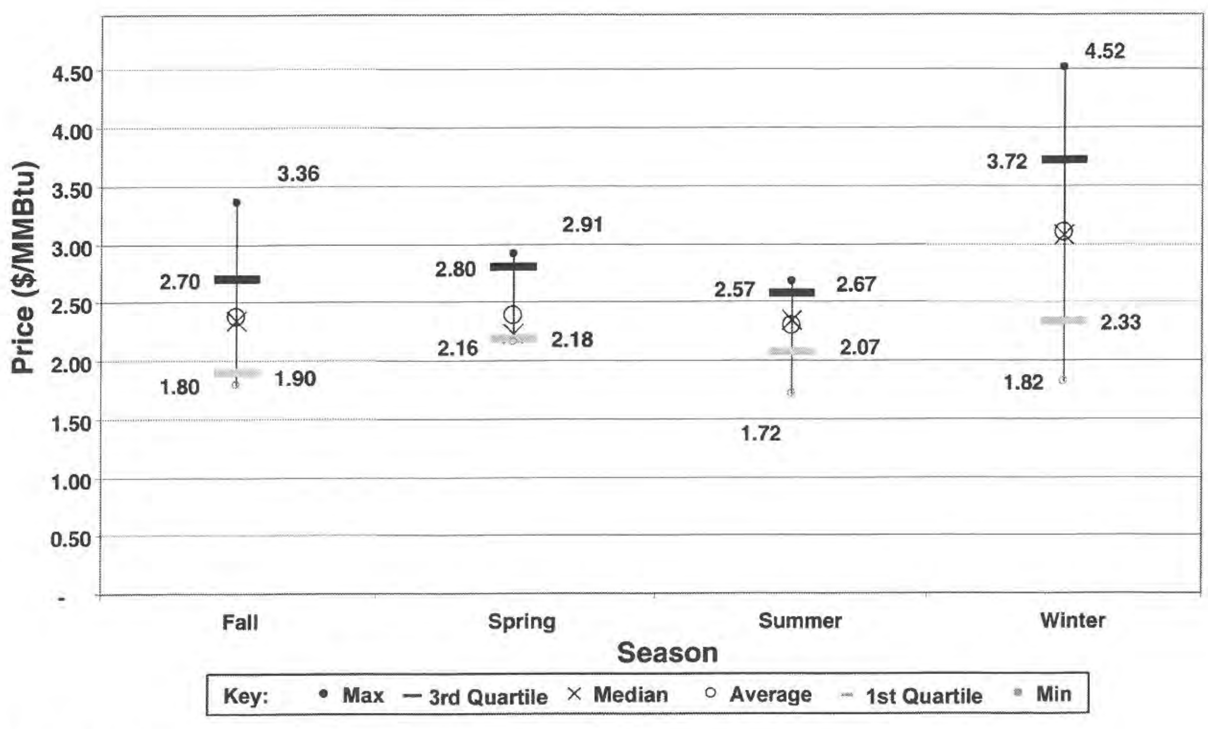


Figure B-67
Henry Hub, 1996 Weekly Peak Price Distribution

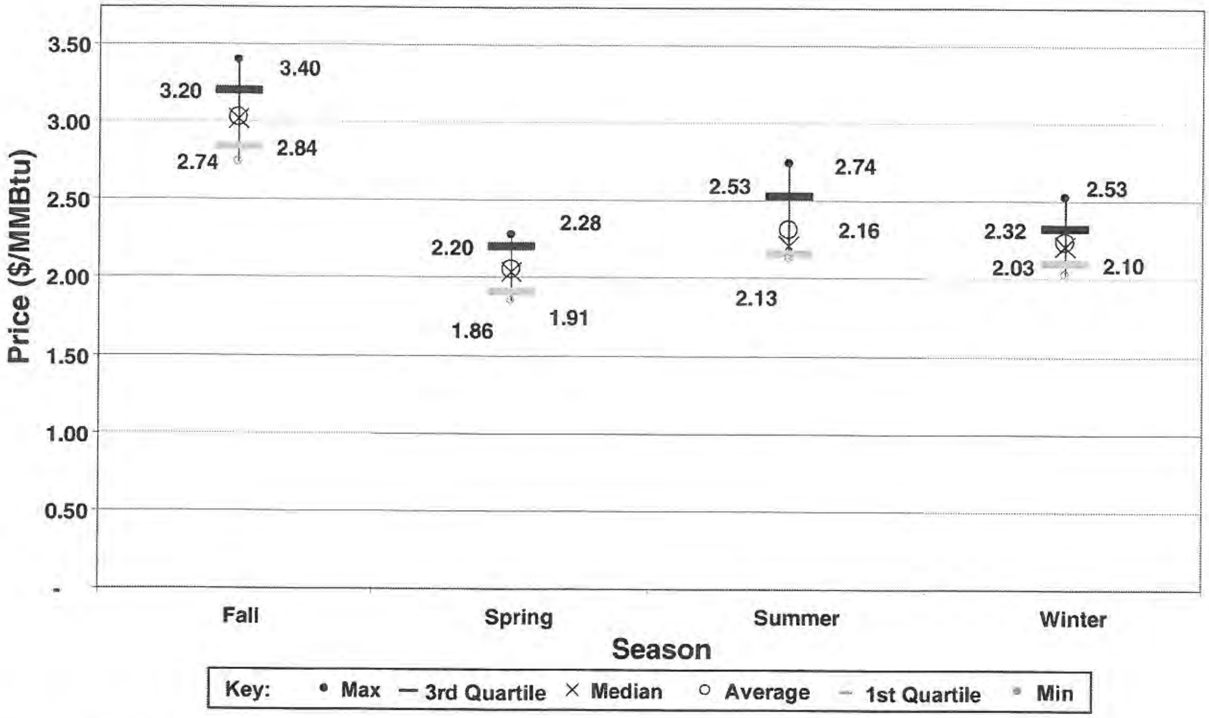


Figure B-68
Henry Hub, 1997 Weekly Peak Price Distribution

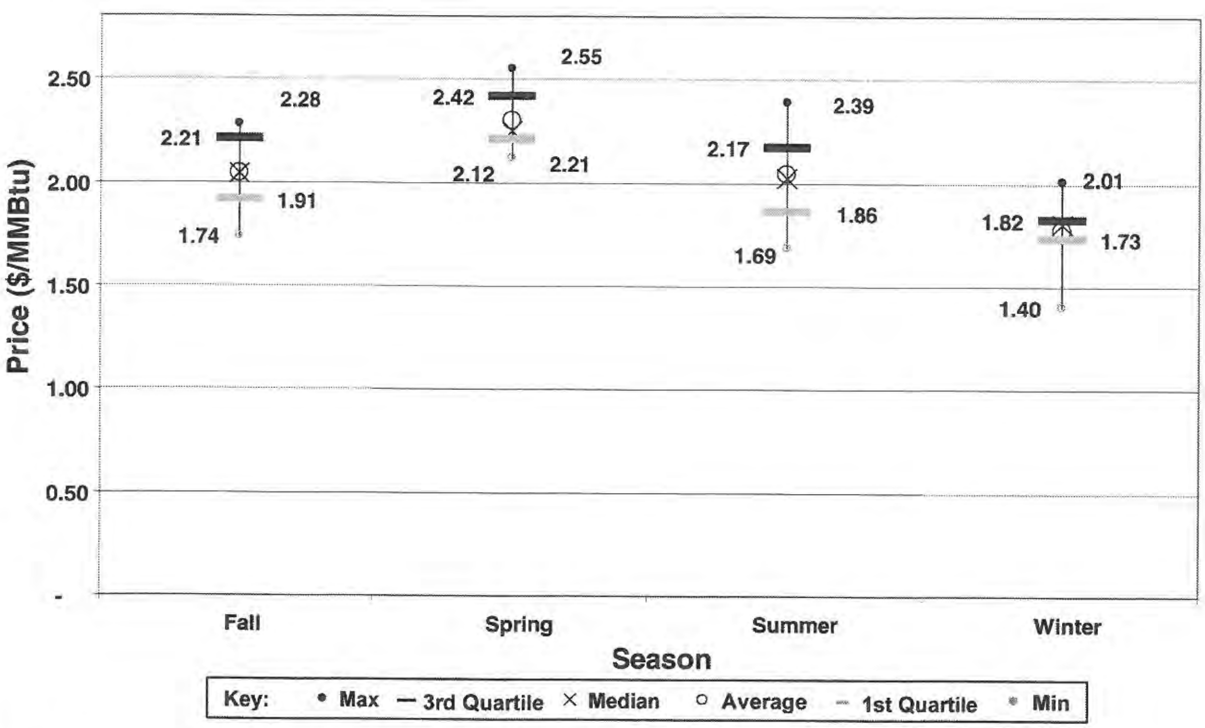


Figure B-69
Henry Hub, 1998 Weekly Peak Price Distribution

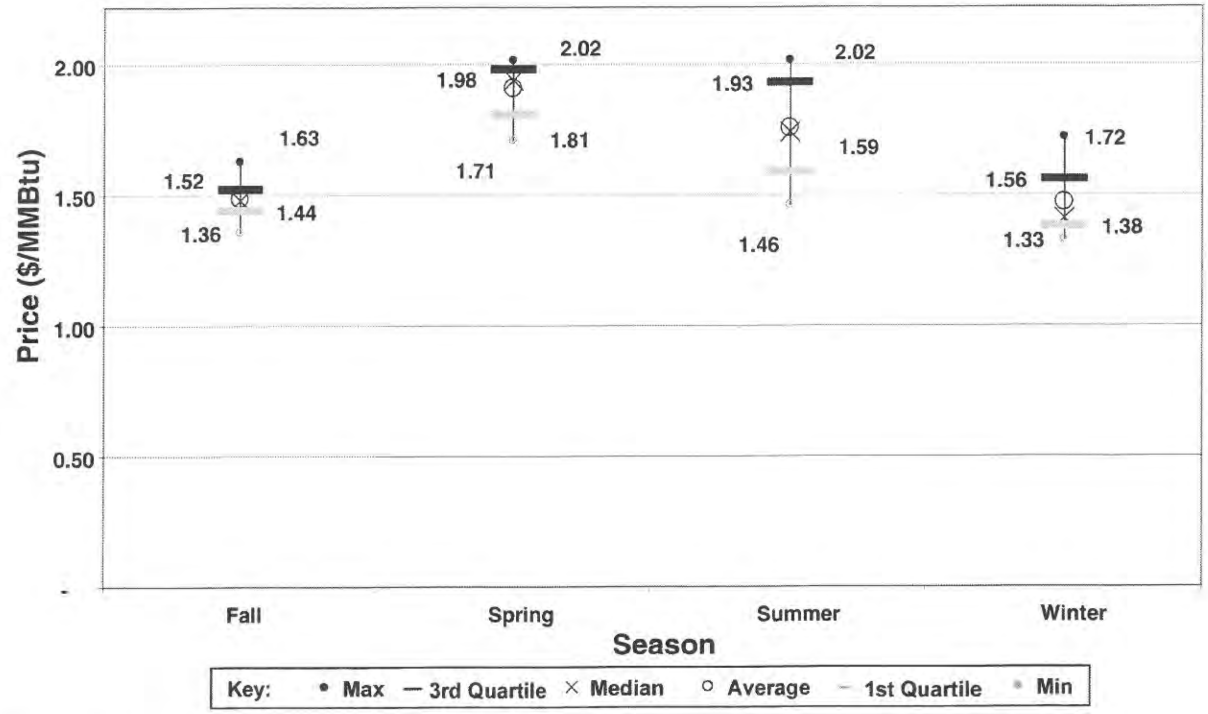


Figure B-70
Katy, 1994 Weekly Peak Price Distribution

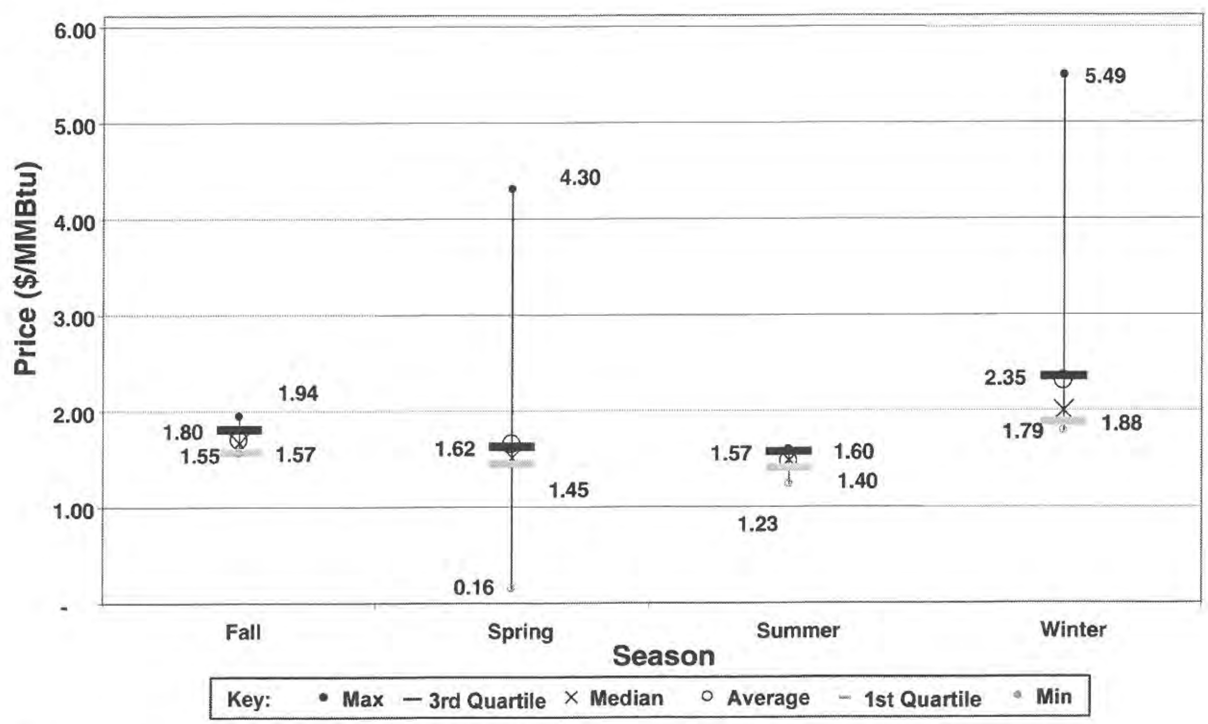


Figure B-71
Katy, 1995 Weekly Peak Price Distribution

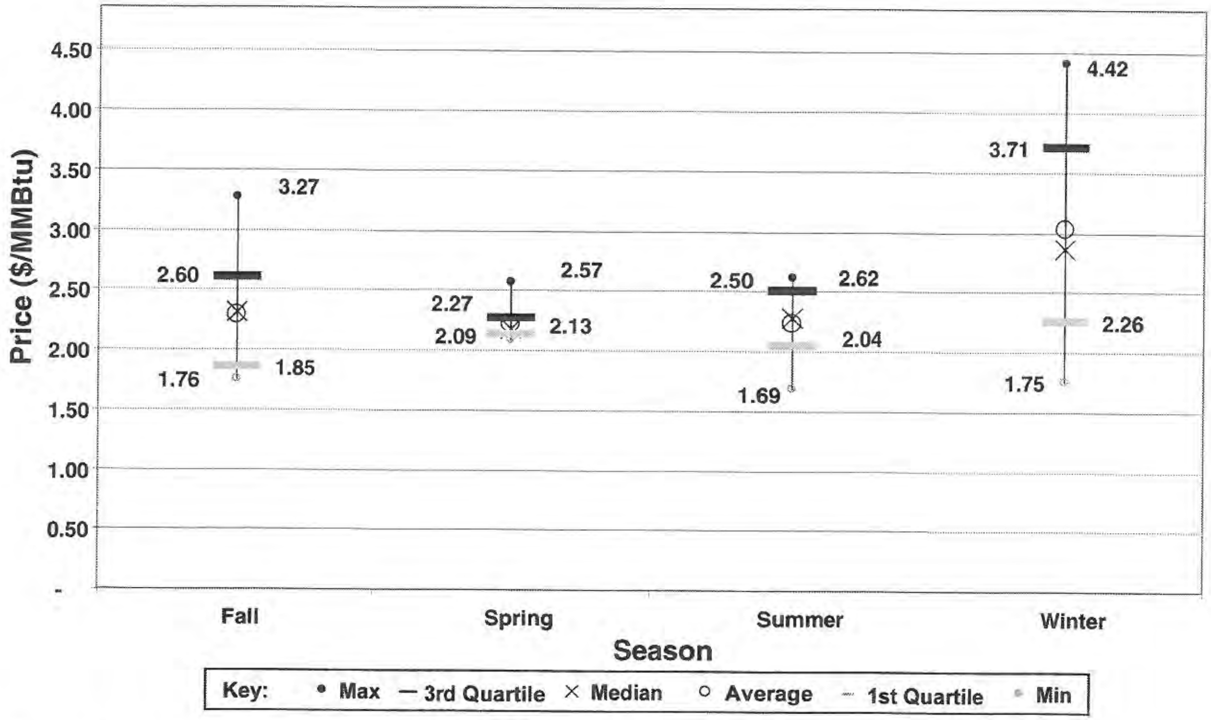


Figure B-72
Katy, 1996 Weekly Peak Price Distribution

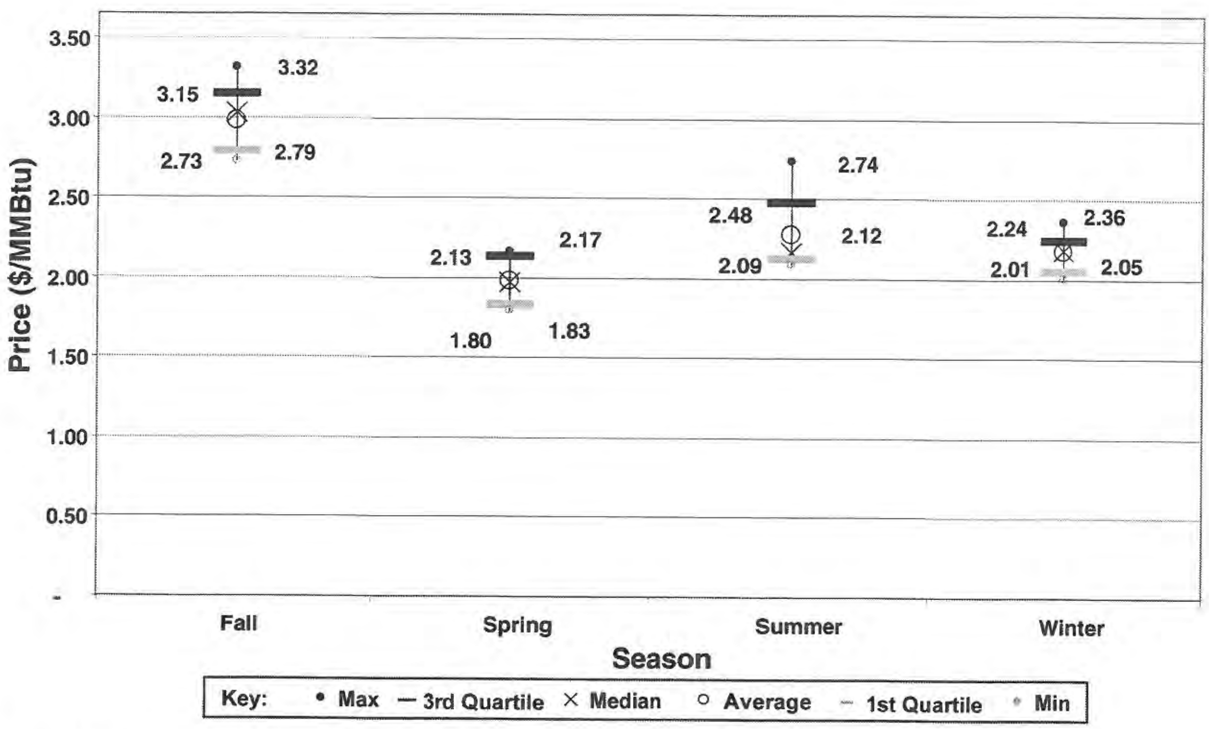


Figure B-73
Katy, 1997 Weekly Peak Price Distribution

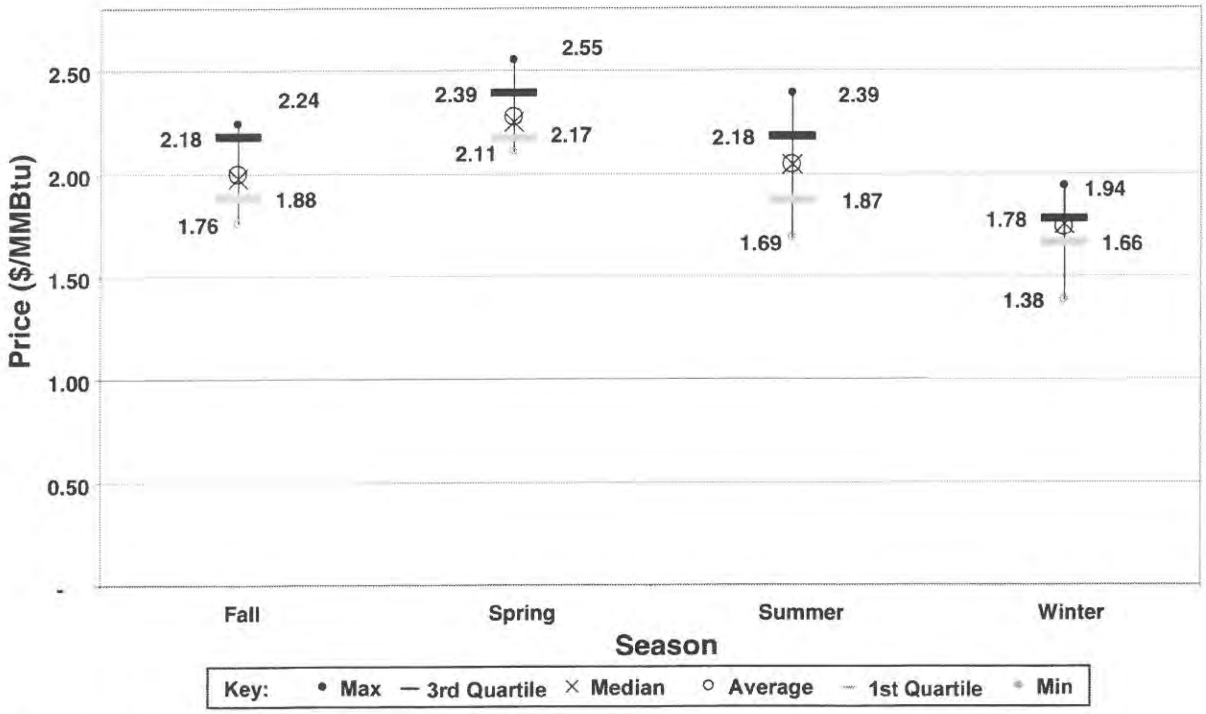


Figure B-74
Katy, 1998 Weekly Peak Price Distribution

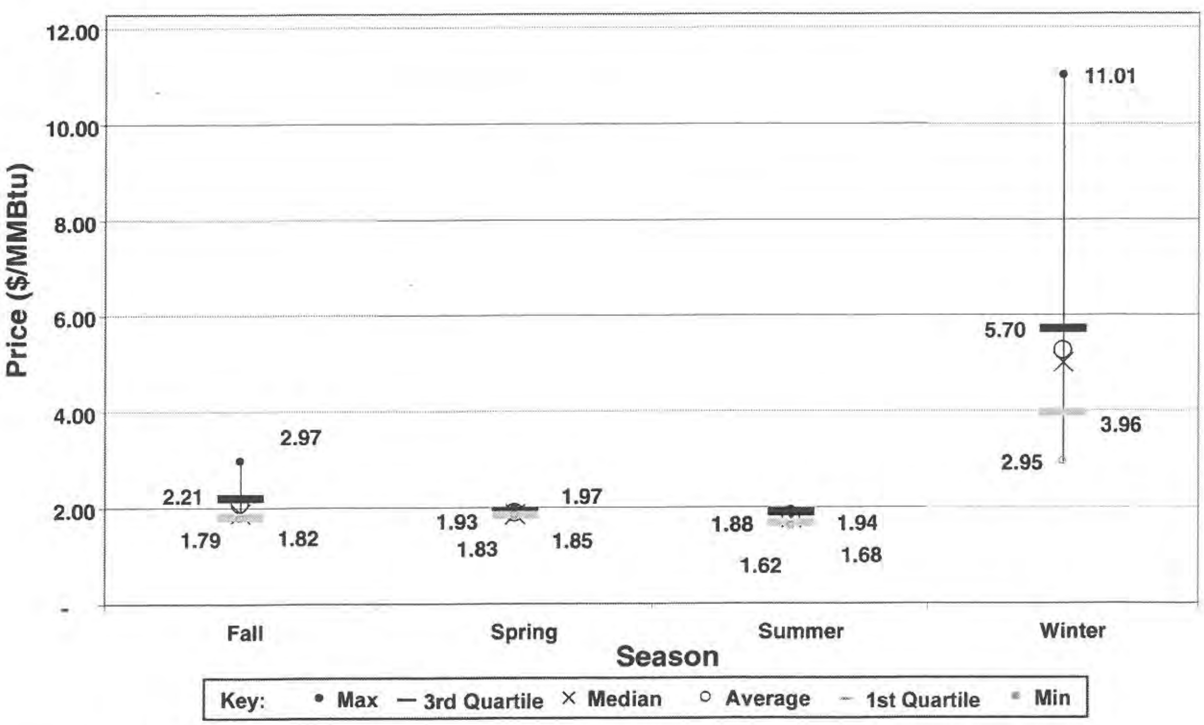


Figure B-75
New York, 1995 Weekly Peak Price Distribution

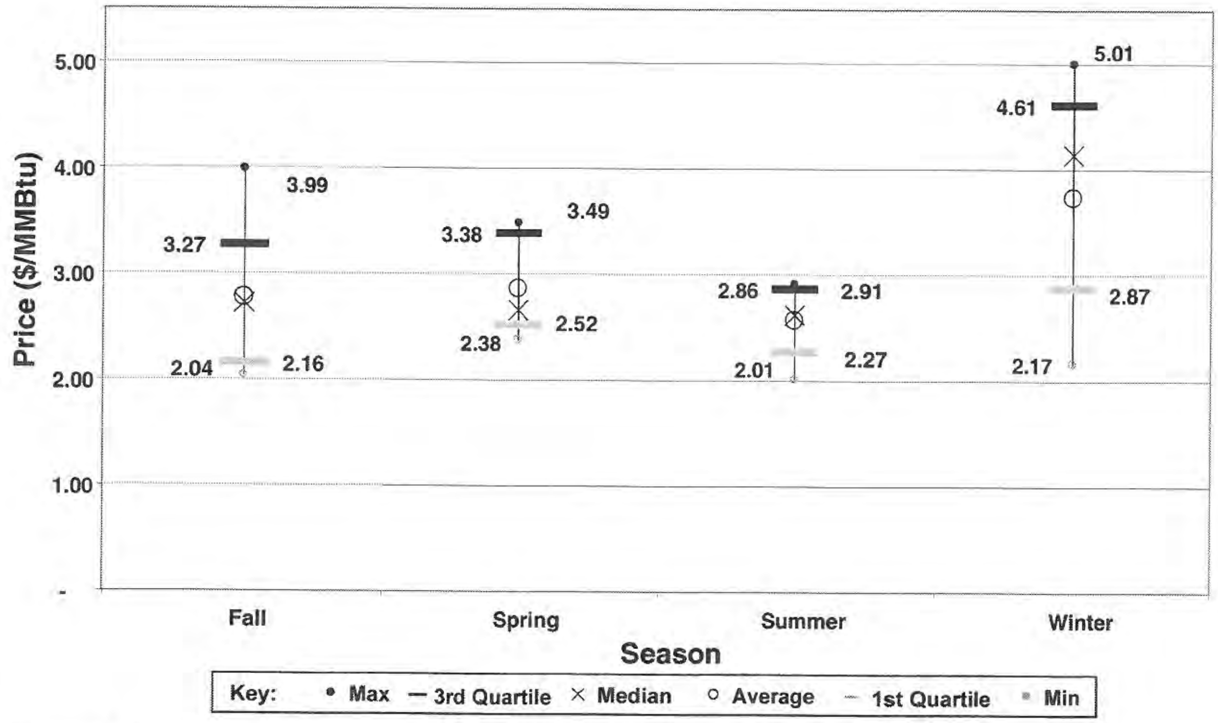


Figure B-76
New York, 1996 Weekly Peak Price Distribution

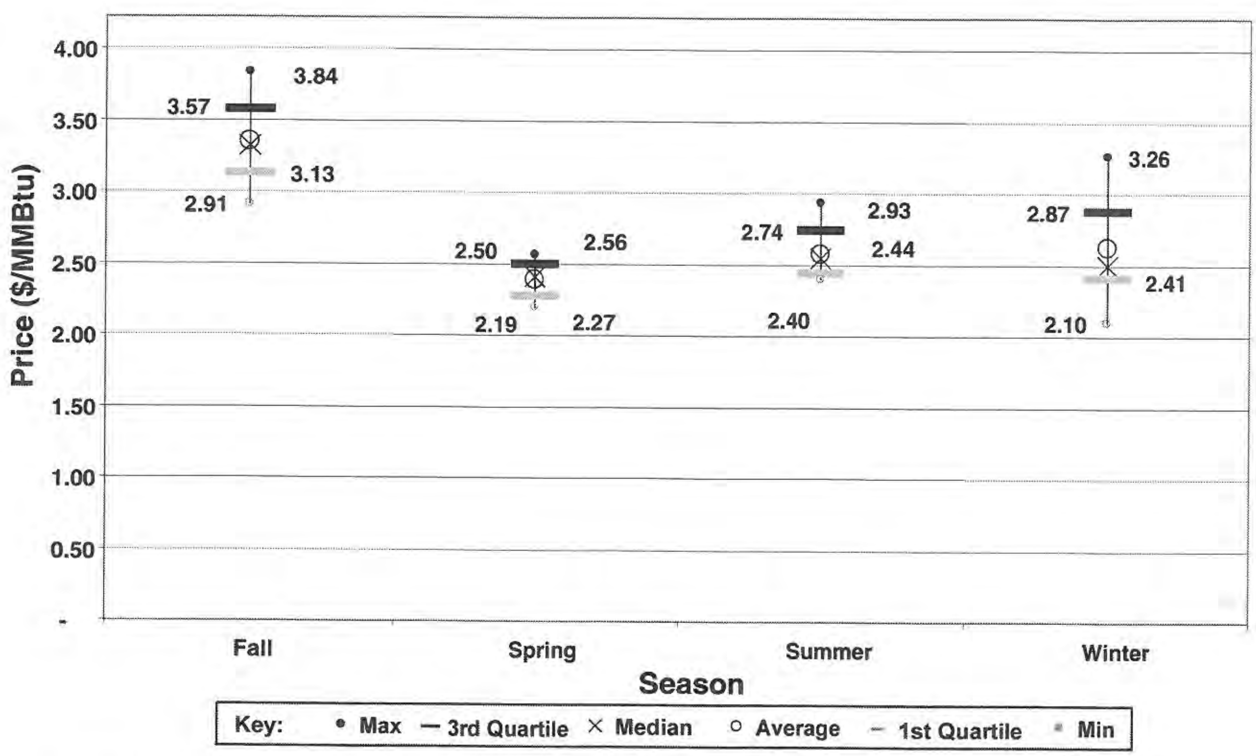


Figure B-77
New York, 1997 Weekly Peak Price Distribution

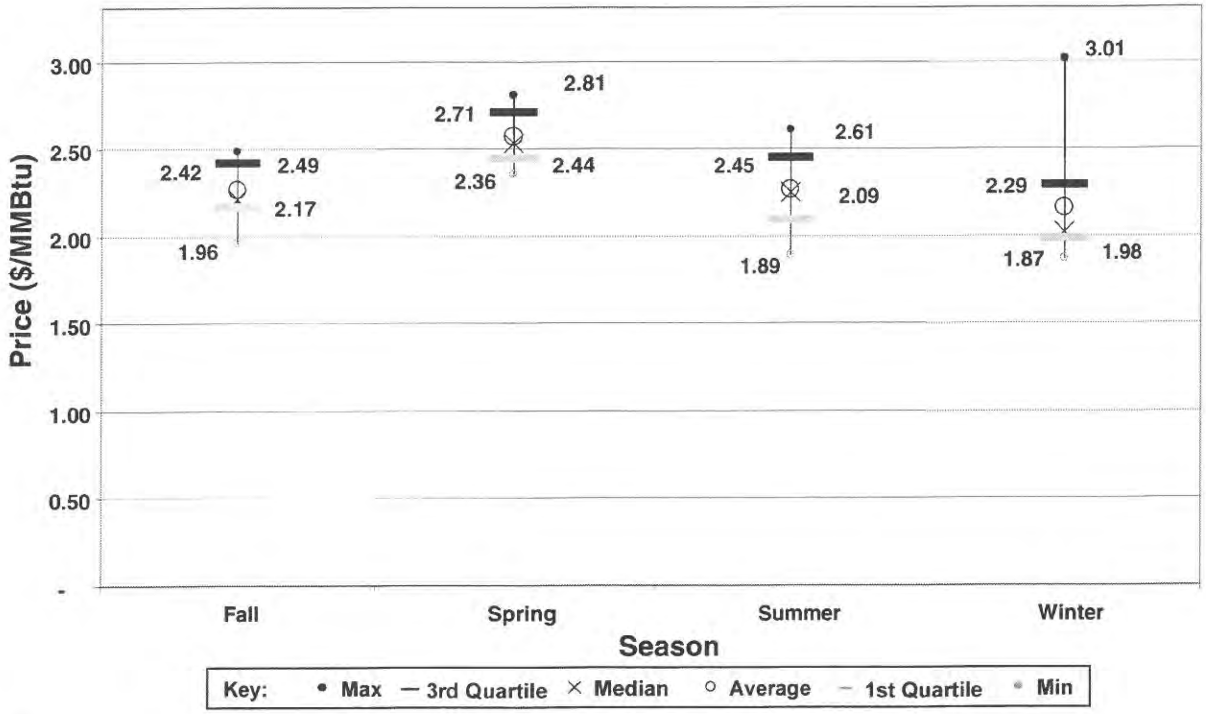


Figure B-78
New York, 1998 Weekly Peak Price Distribution

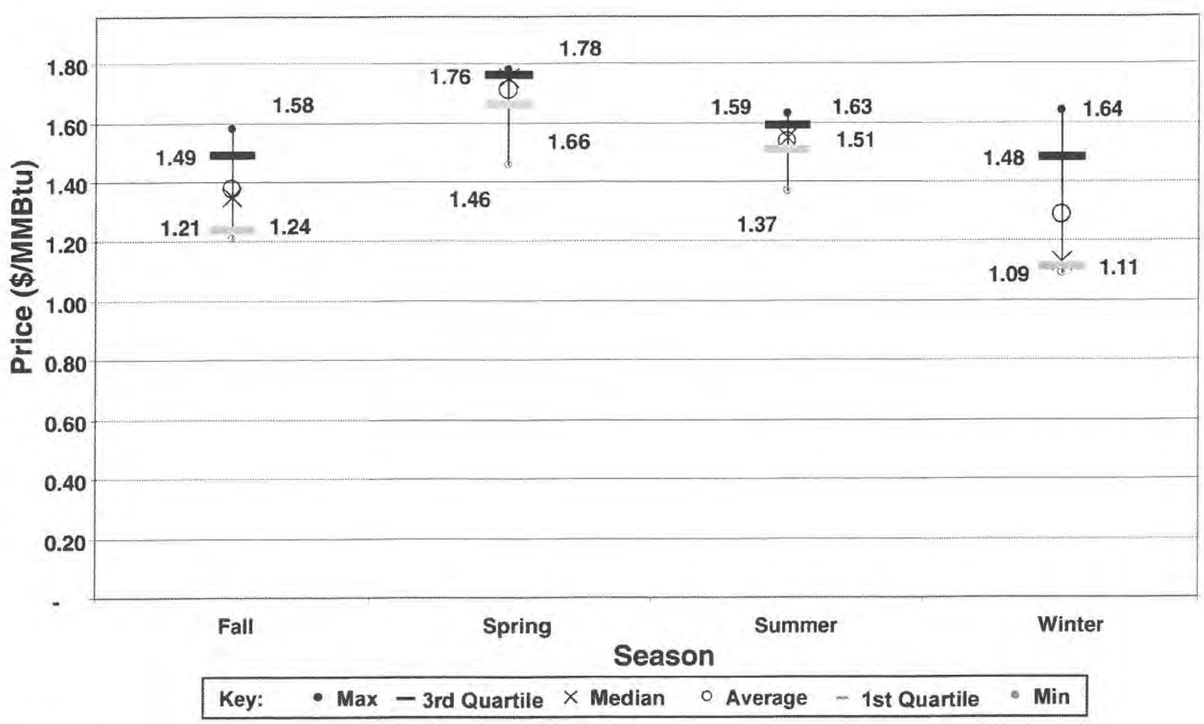


Figure B-79
San Juan, 1994 Weekly Peak Price Distribution

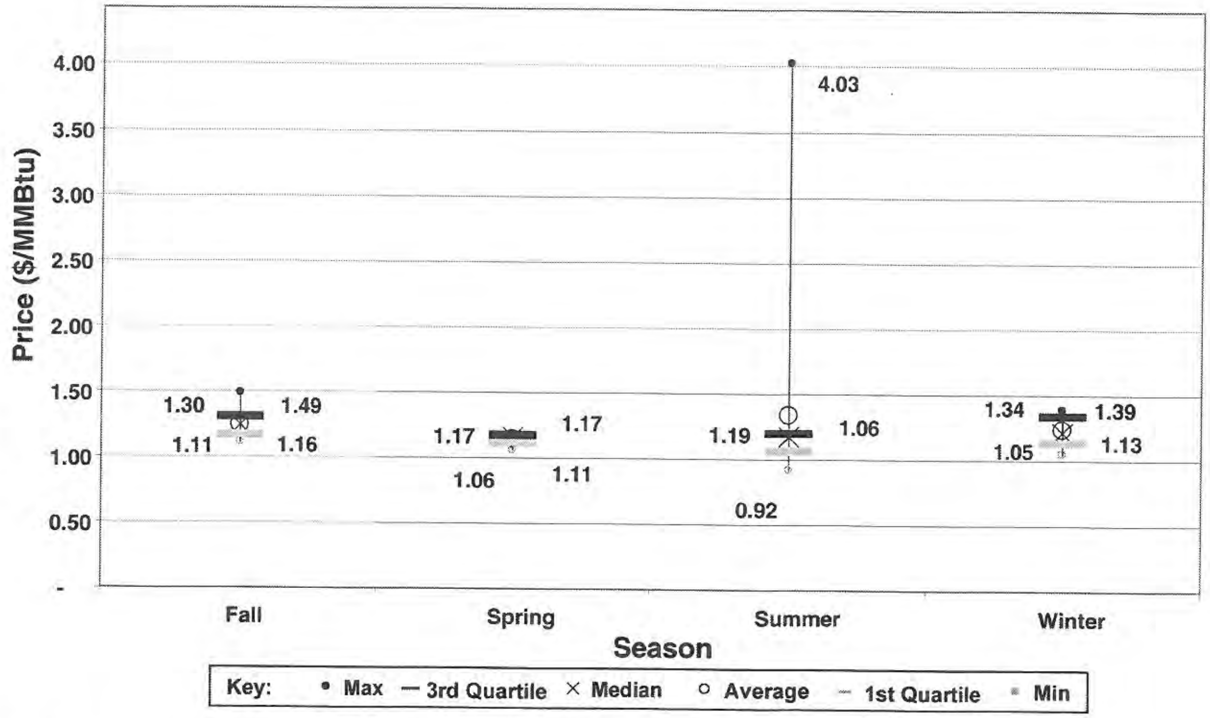


Figure B-80
San Juan, 1995 Weekly Peak Price Distribution

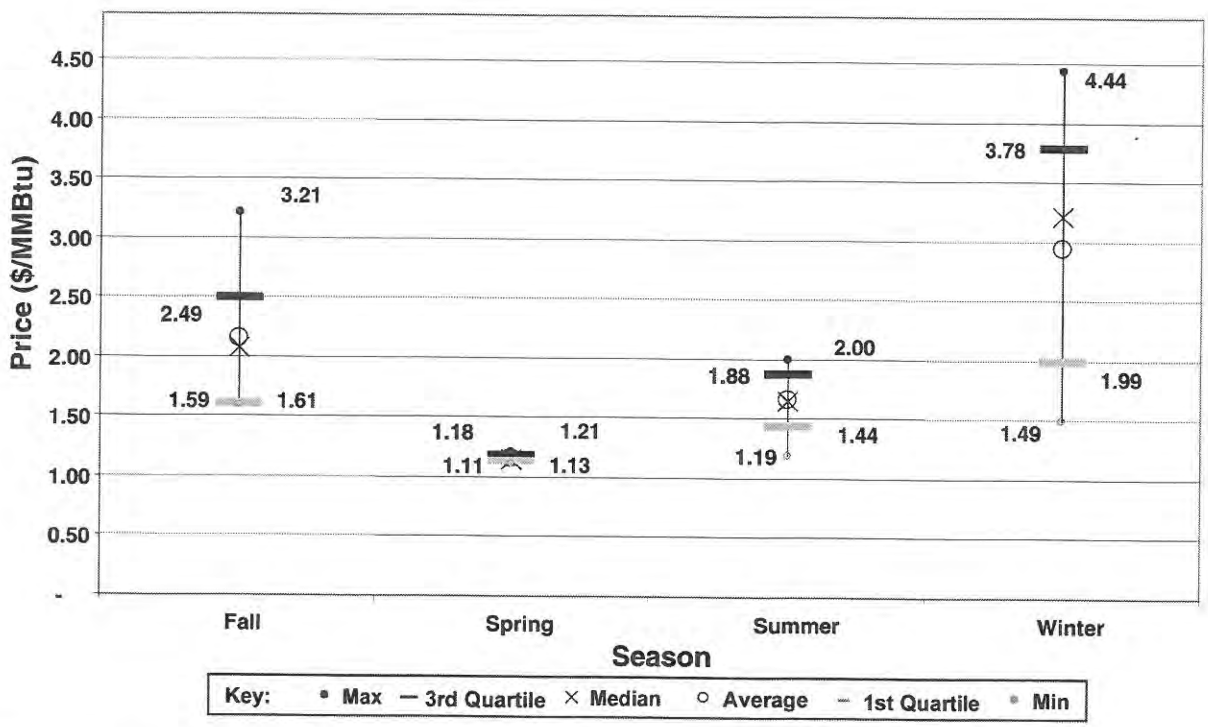


Figure B-81
San Juan, 1996 Weekly Peak Price Distribution

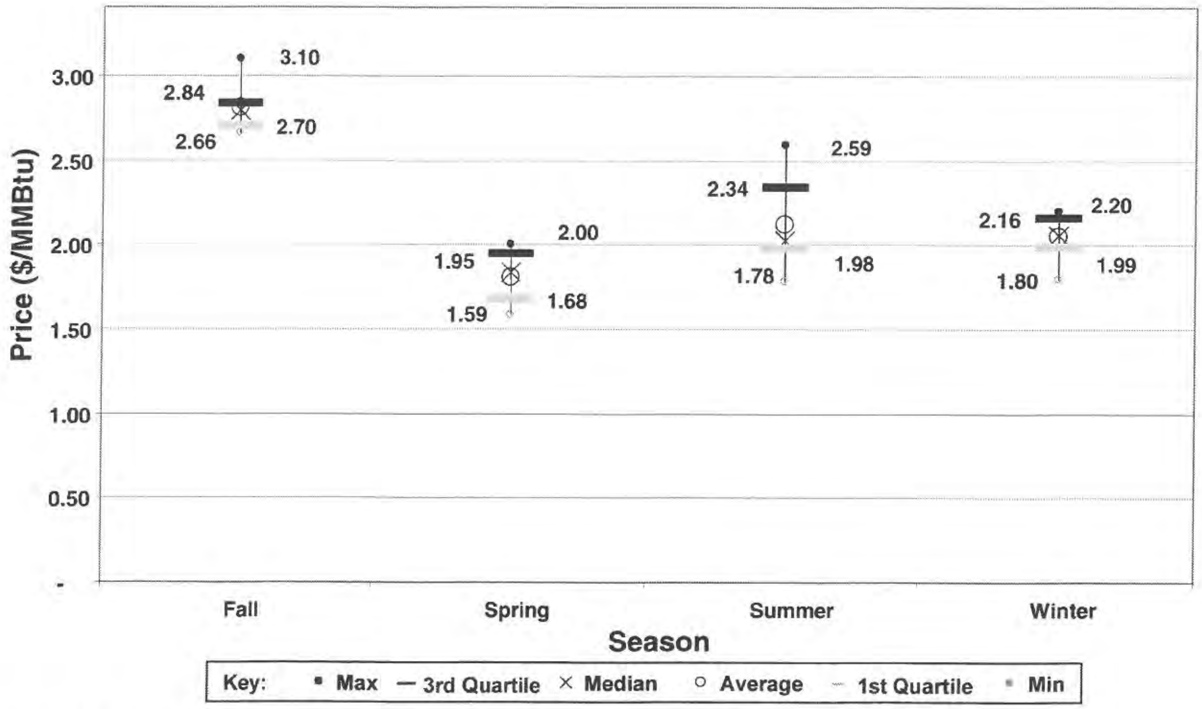


Figure B-82
San Juan, 1997 Weekly Peak Price Distribution

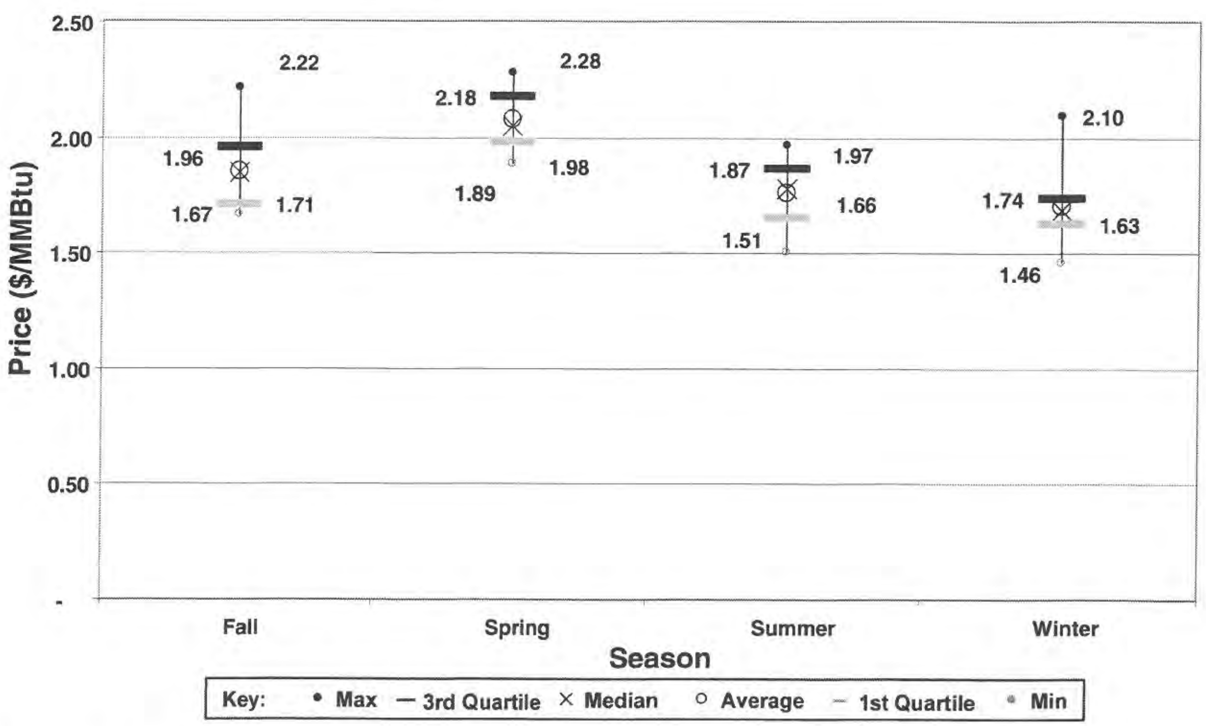


Figure B-83
San Juan, 1998 Weekly Peak Price Distribution

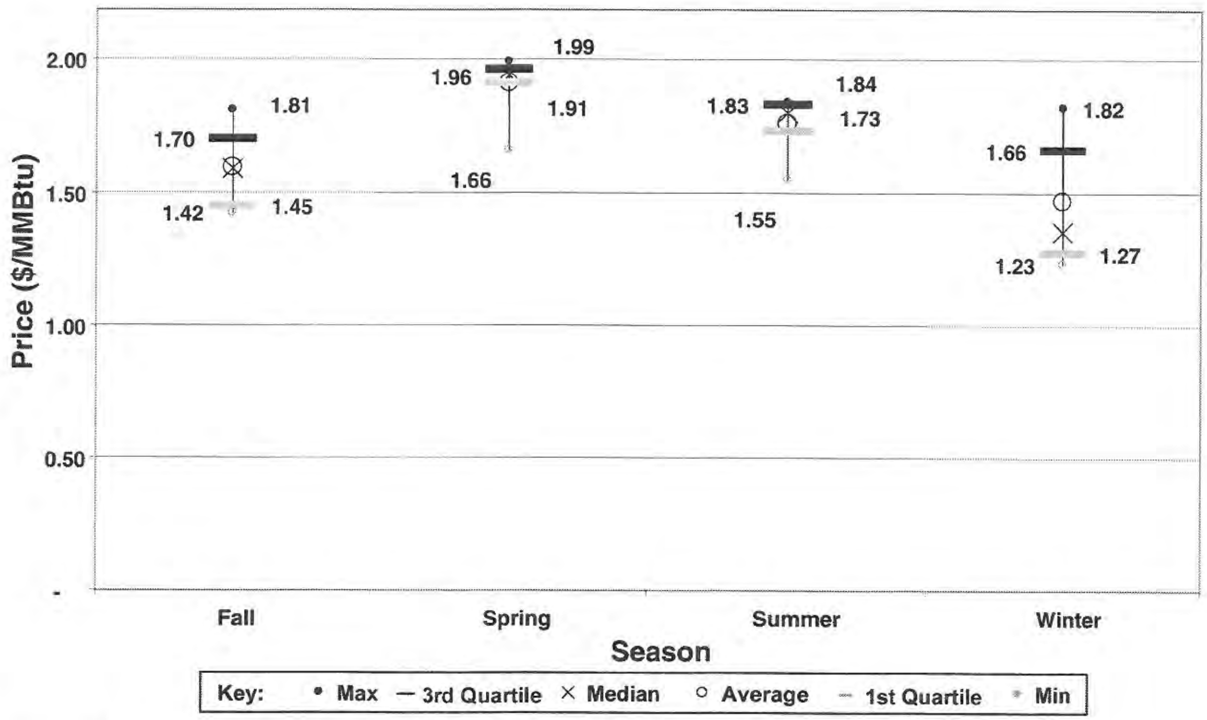


Figure B-84
Topock, 1994 Weekly Peak Price Distribution

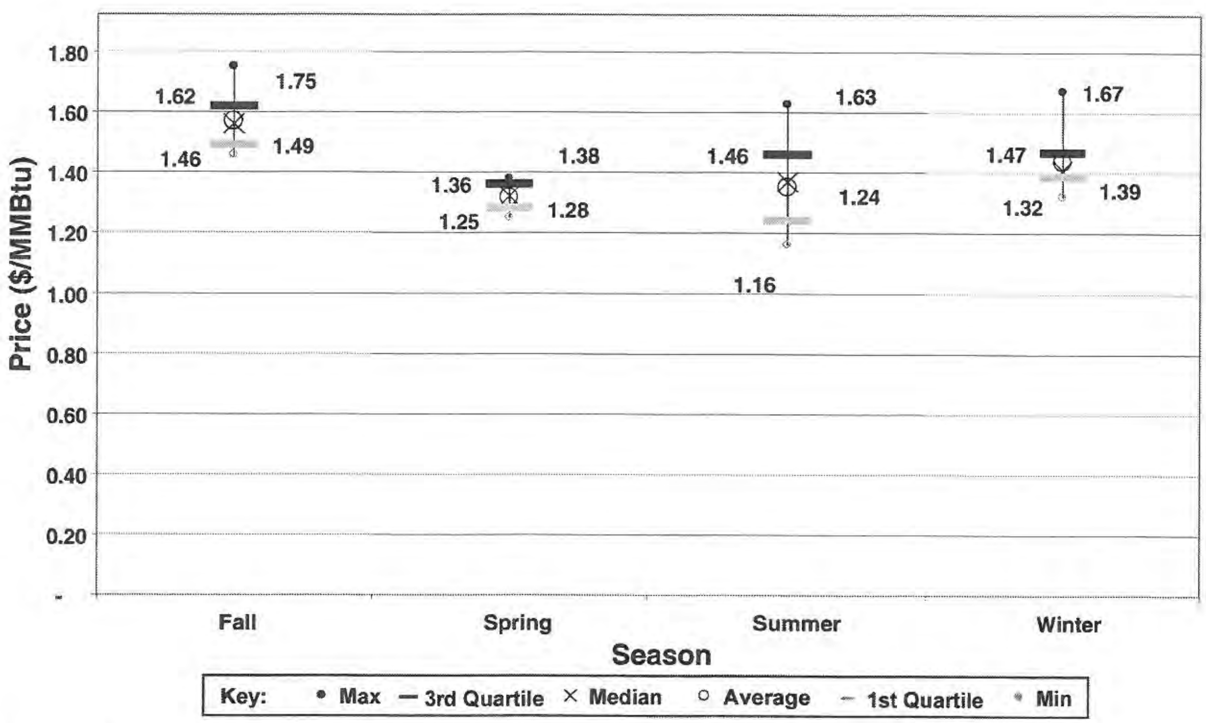


Figure B-85
Topock, 1995 Weekly Peak Price Distribution

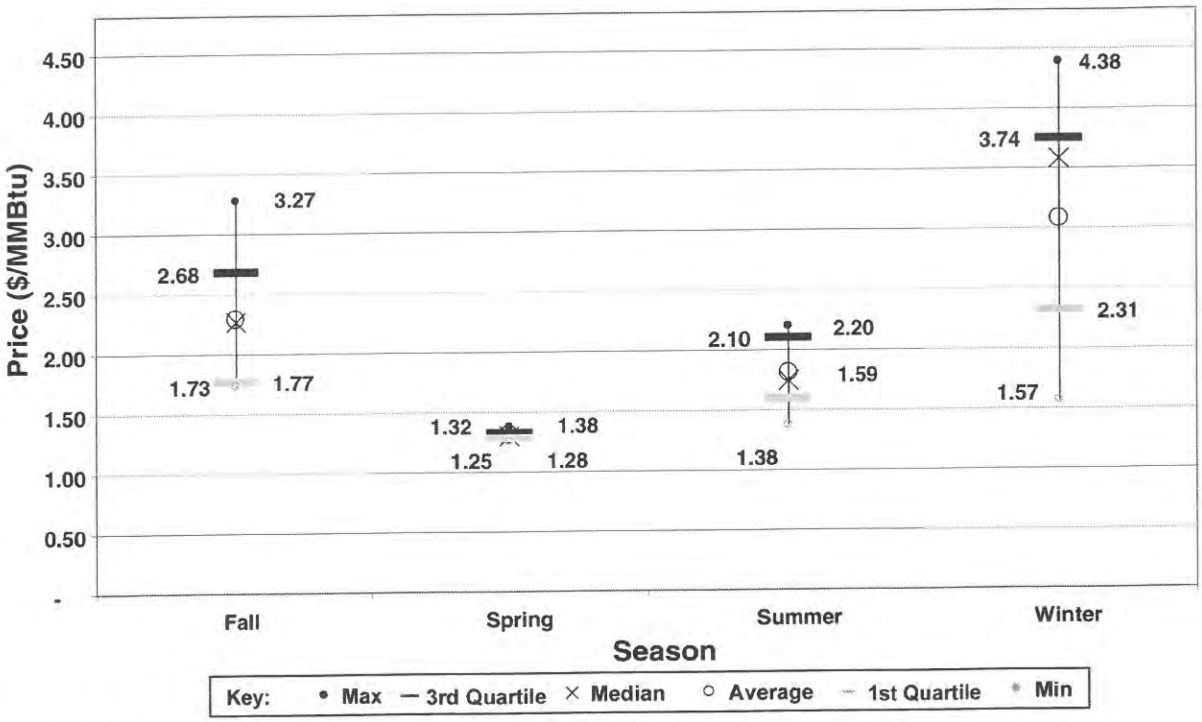


Figure B-86
Topock, 1996 Weekly Peak Price Distribution

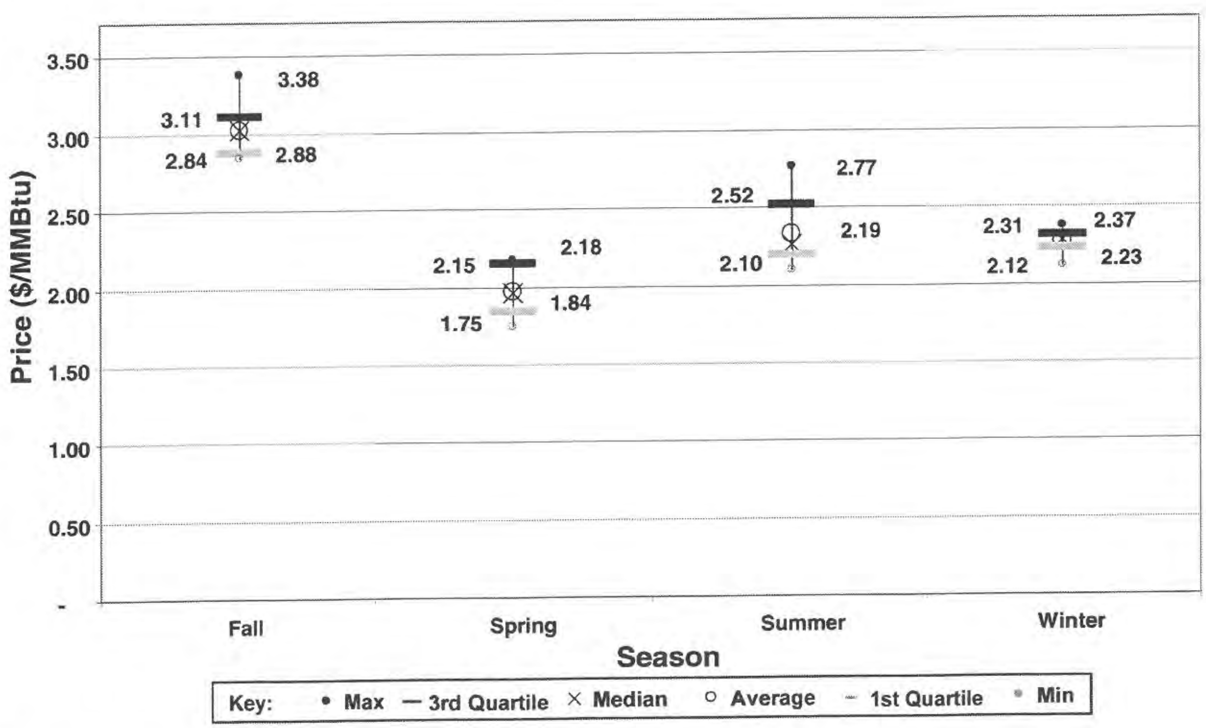


Figure B-87
Topock, 1997 Weekly Peak Price Distribution

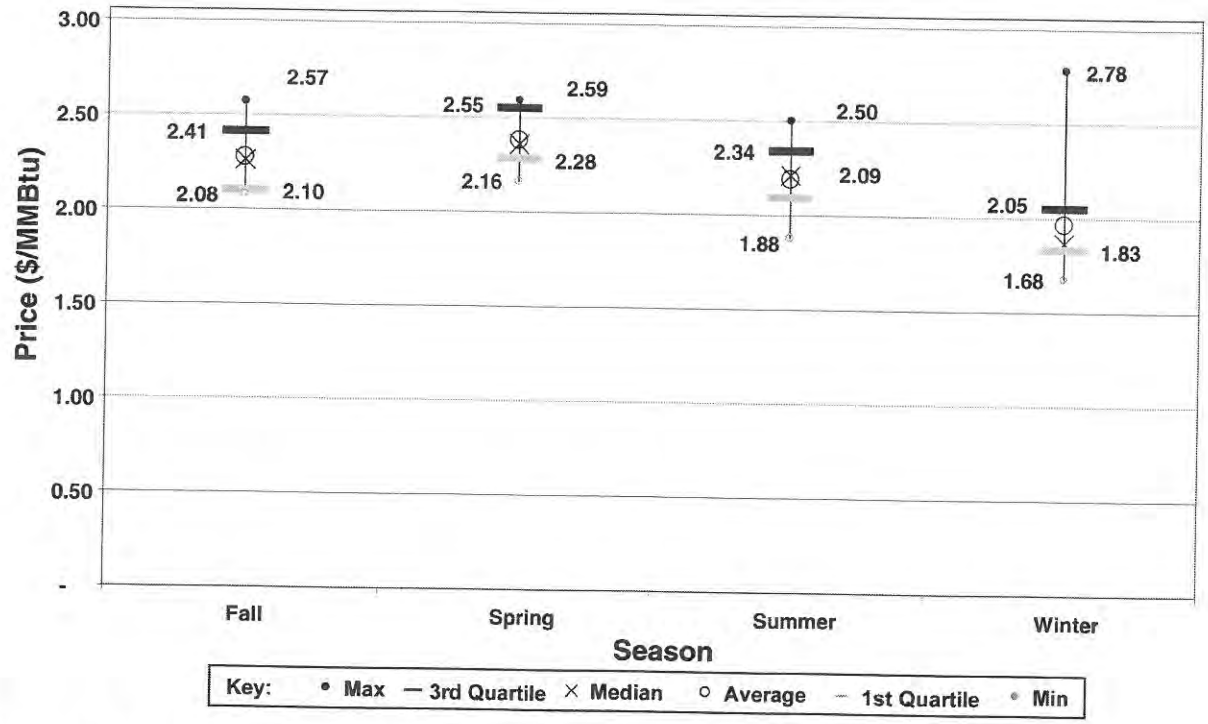


Figure B-88
Topock, 1998 Weekly Peak Price Distribution

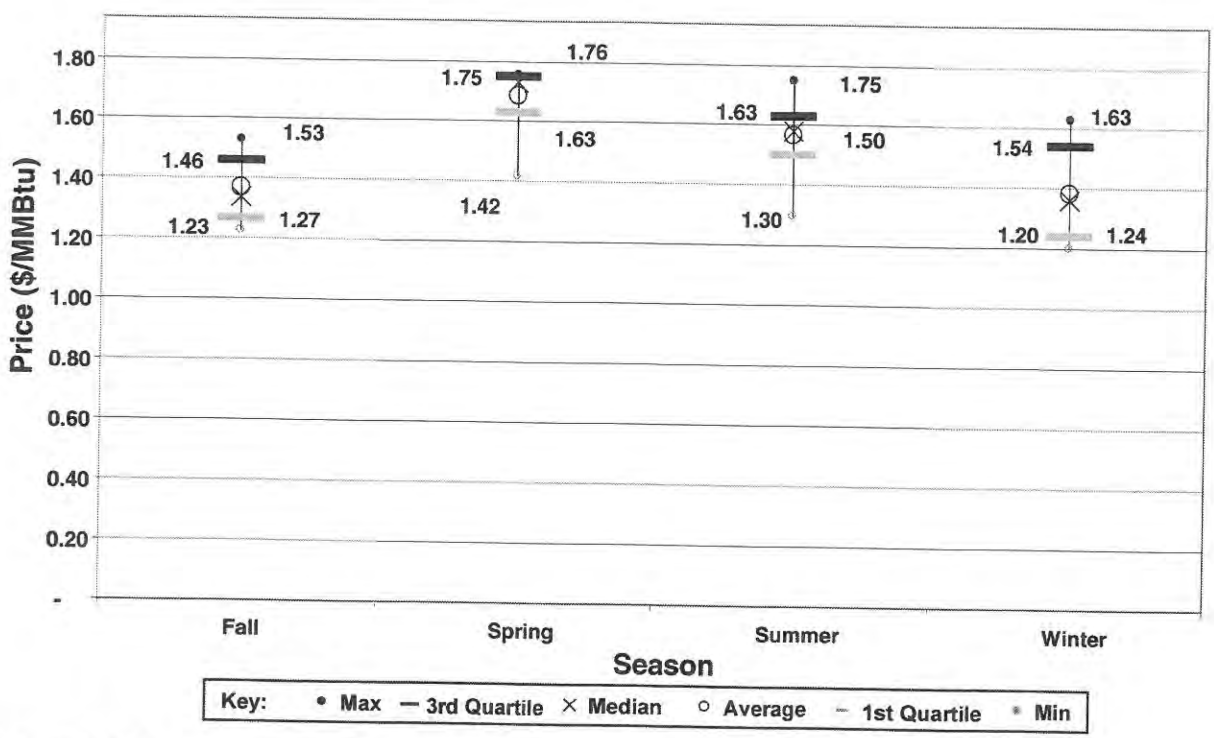


Figure B-89
Ventura, 1994 Weekly Peak Price Distribution

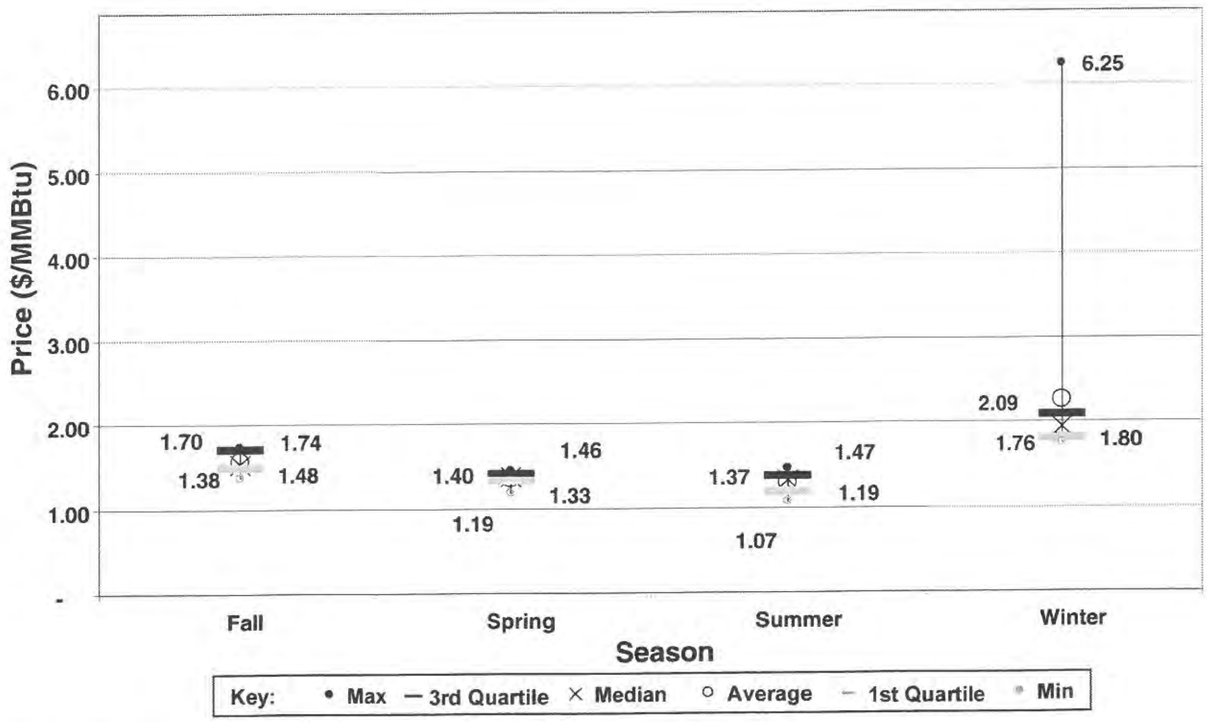


Figure B-90
Ventura, 1995 Weekly Peak Price Distribution

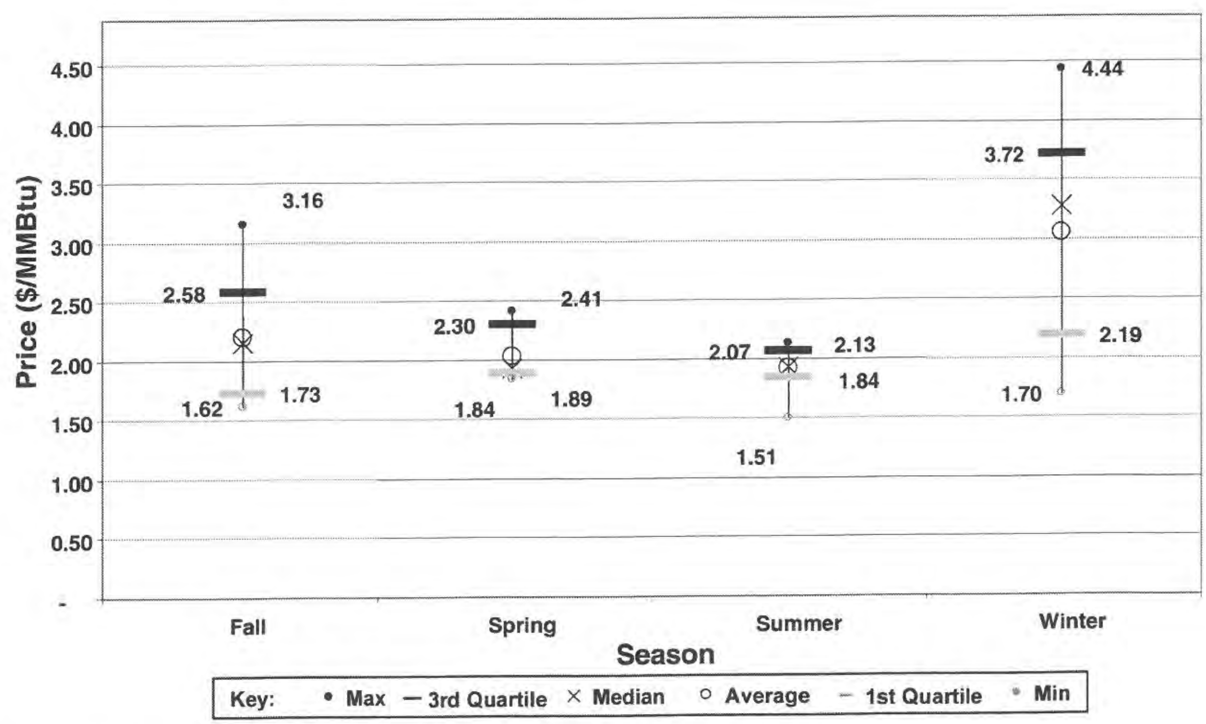


Figure B-91
Ventura, 1996 Weekly Peak Price Distribution

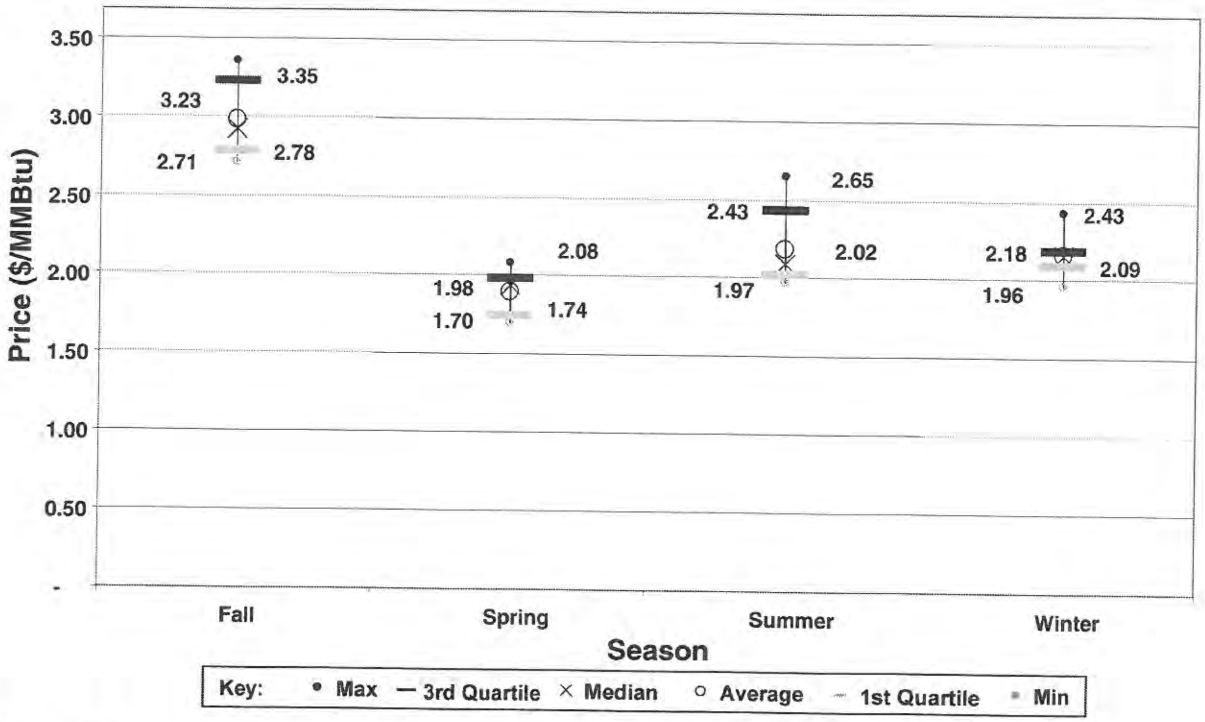


Figure B-92
Ventura, 1997 Weekly Peak Price Distribution

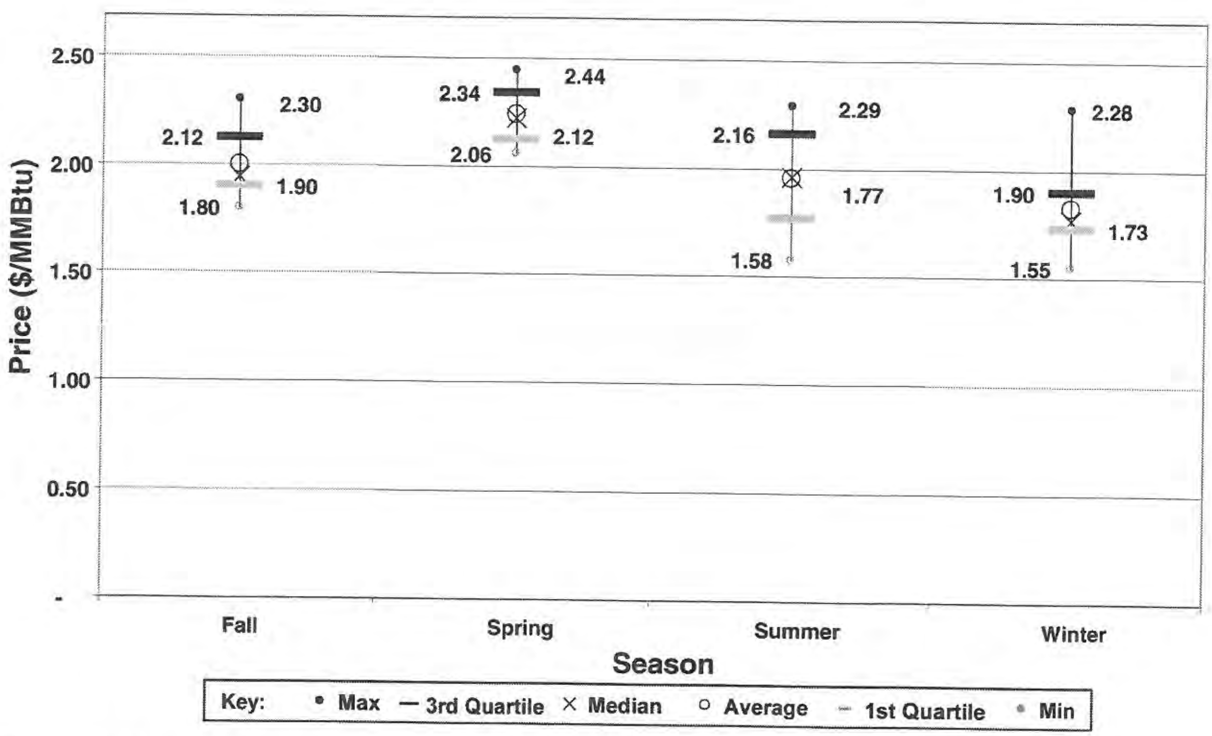


Figure B-93
Ventura, 1998 Weekly Peak Price Distribution

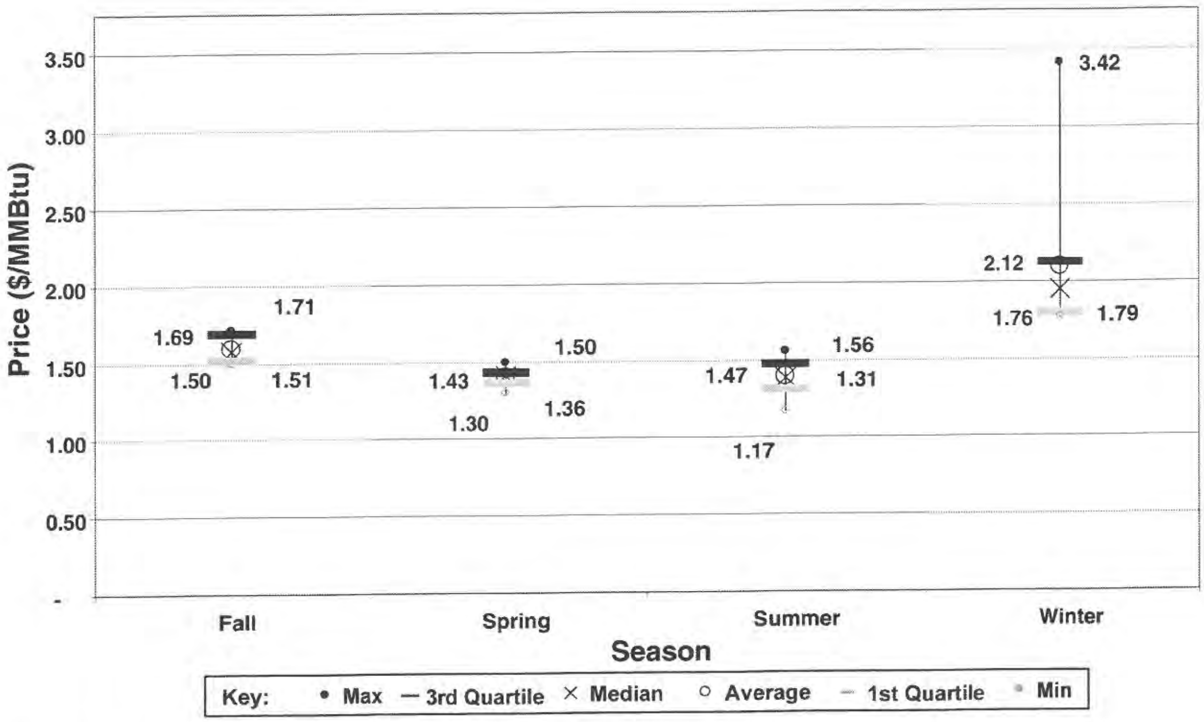


Figure B-94
Waha, 1995 Weekly Peak Price Distribution

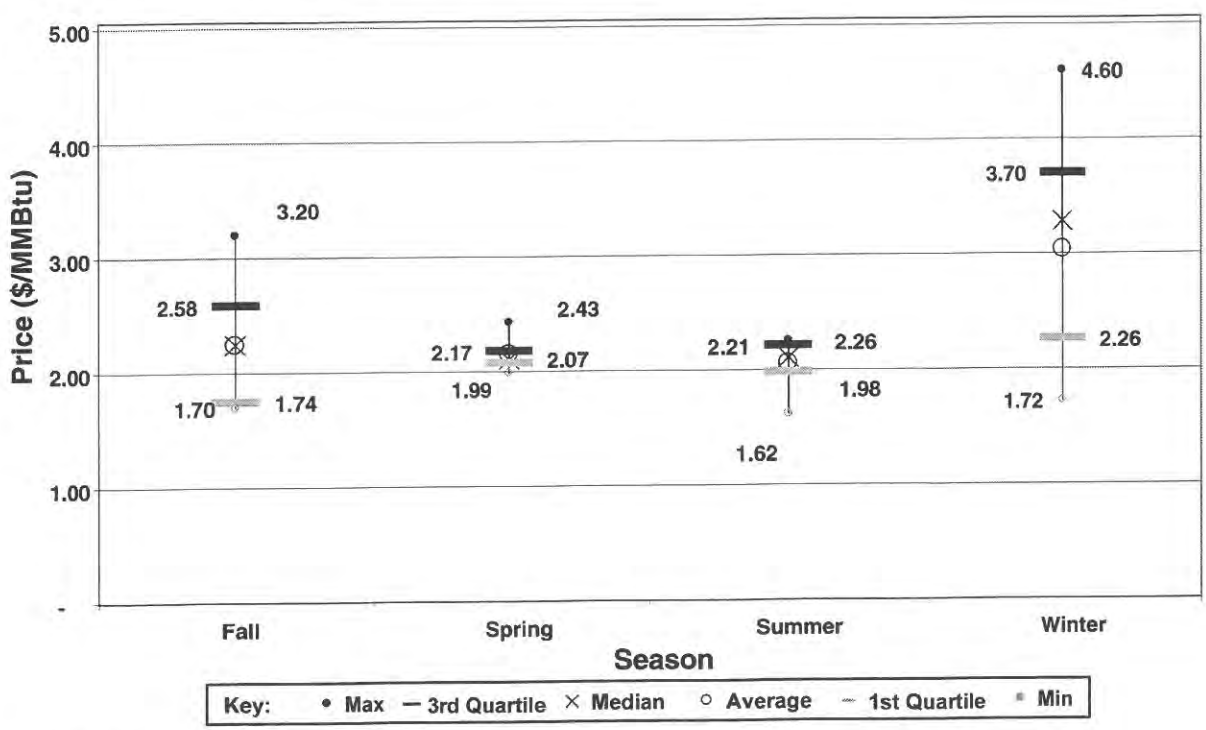


Figure B-95
Waha, 1996 Weekly Peak Price Distribution

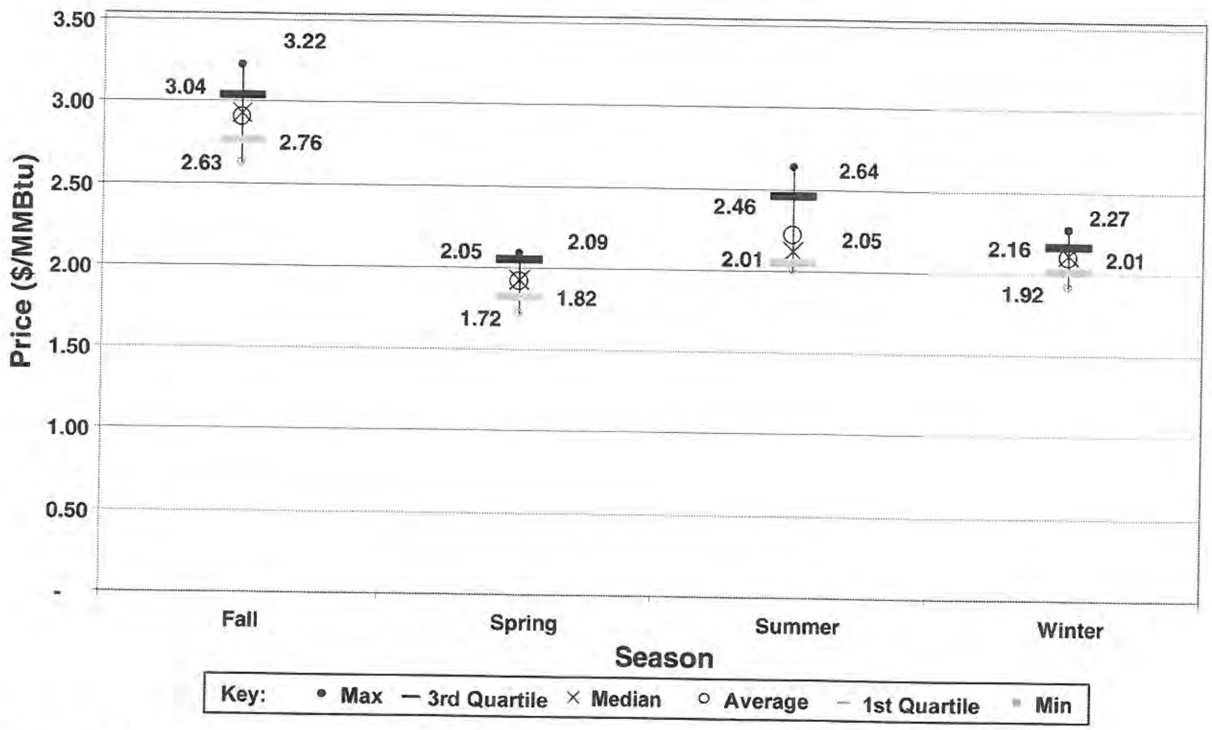


Figure B-96
Waha, 1997 Weekly Peak Price Distribution

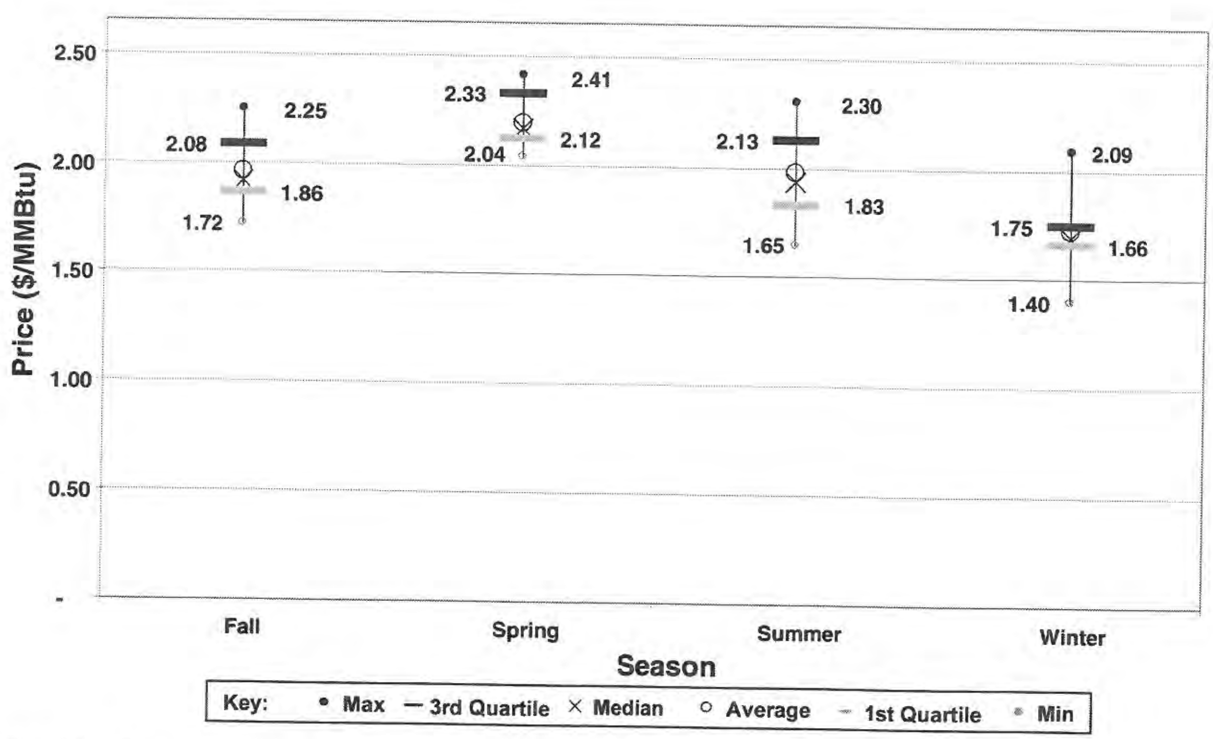


Figure B-97
Waha, 1998 Weekly Peak Price Distribution

Weekly Spot Natural Gas Price Distribution Charts, "Winter Only"

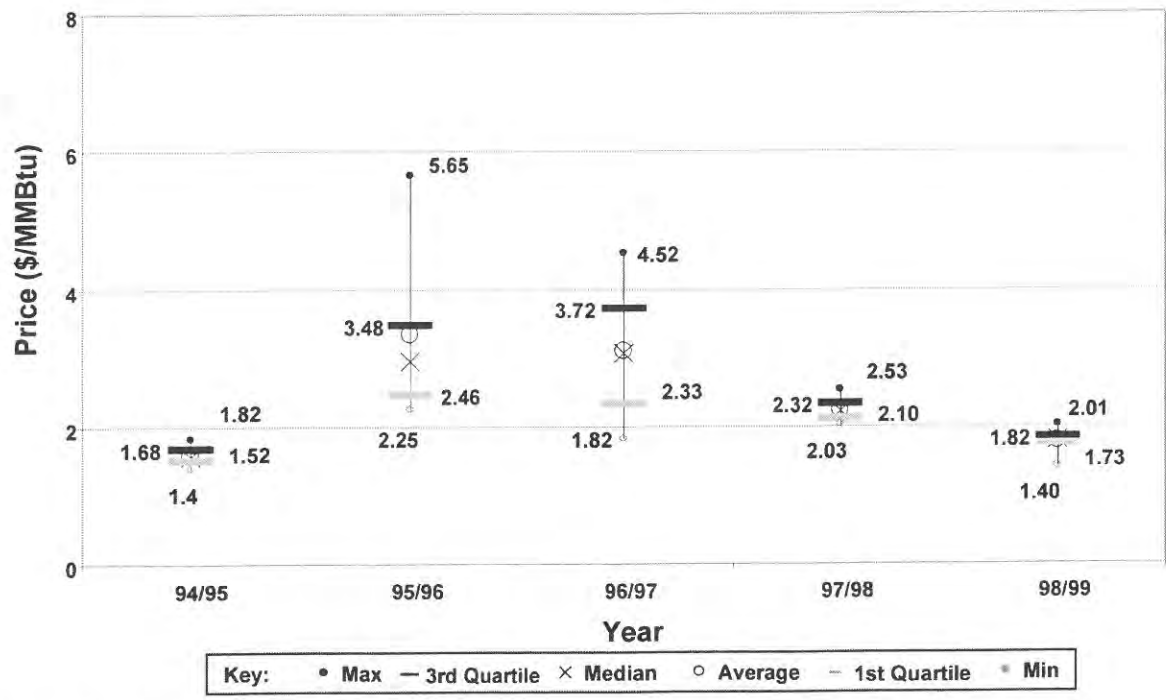


Figure B-98
Henry Hub, Winter Natural Gas Price Distributions

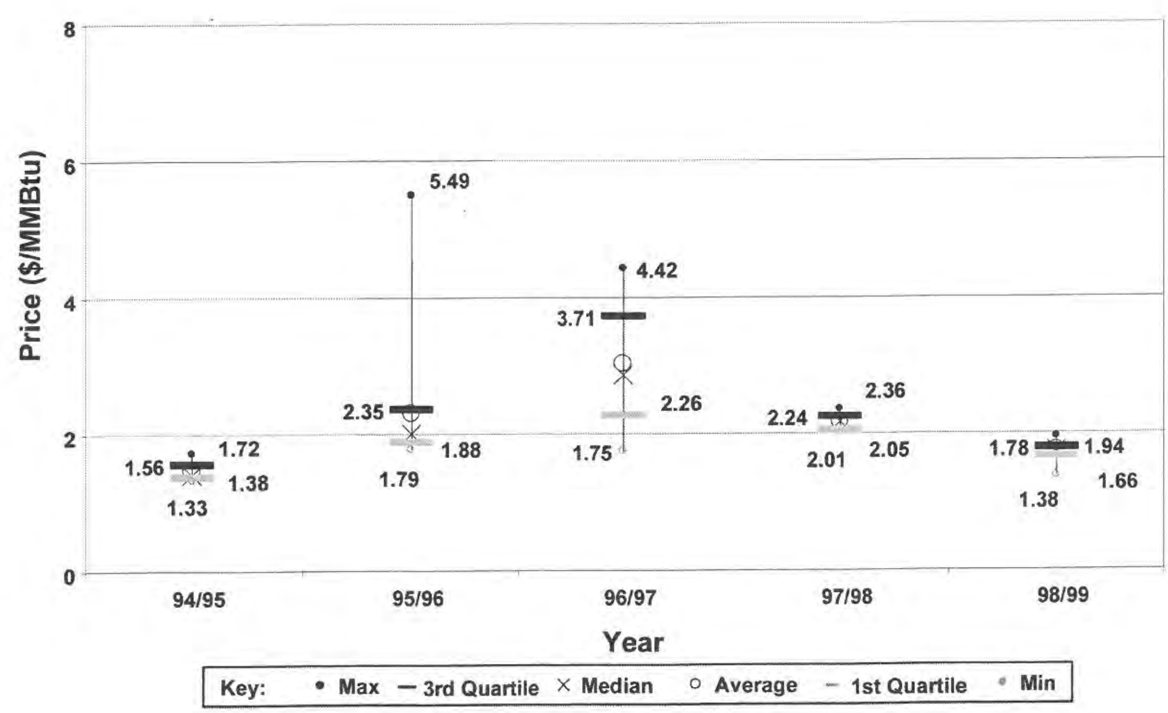


Figure B-99
Katy, Winter Natural Gas Price Distributions

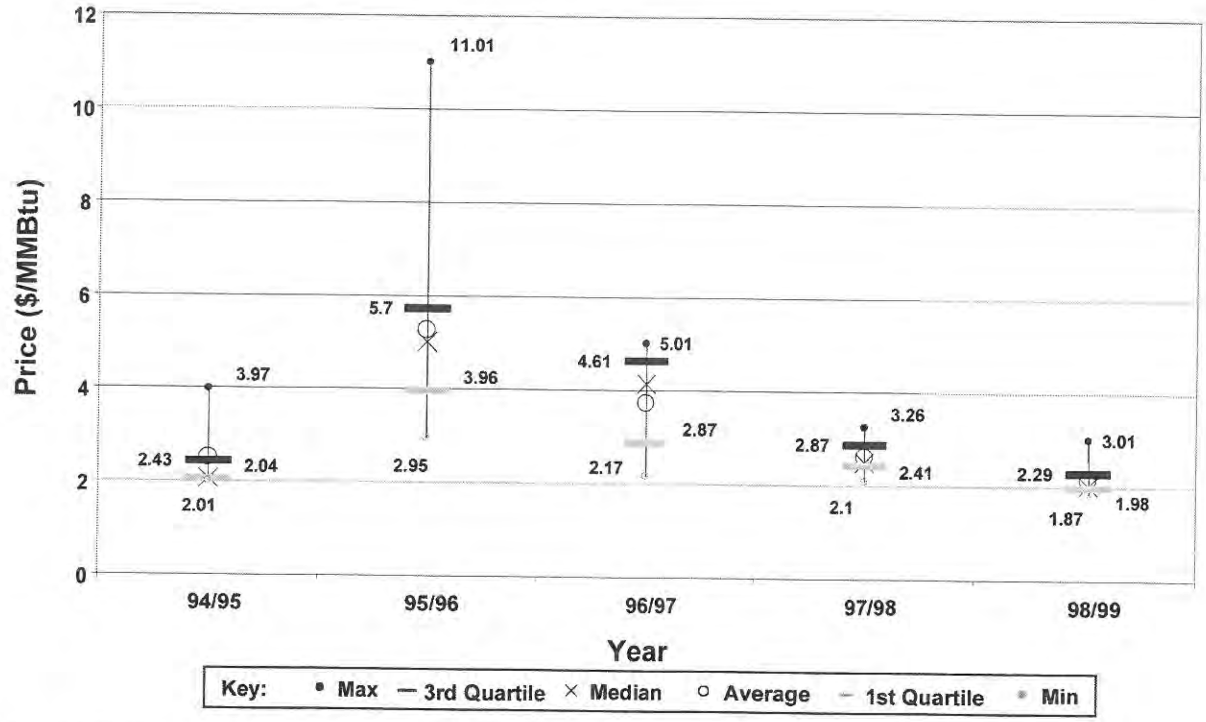


Figure B-100
New York, Winter Natural Gas Price Distributions

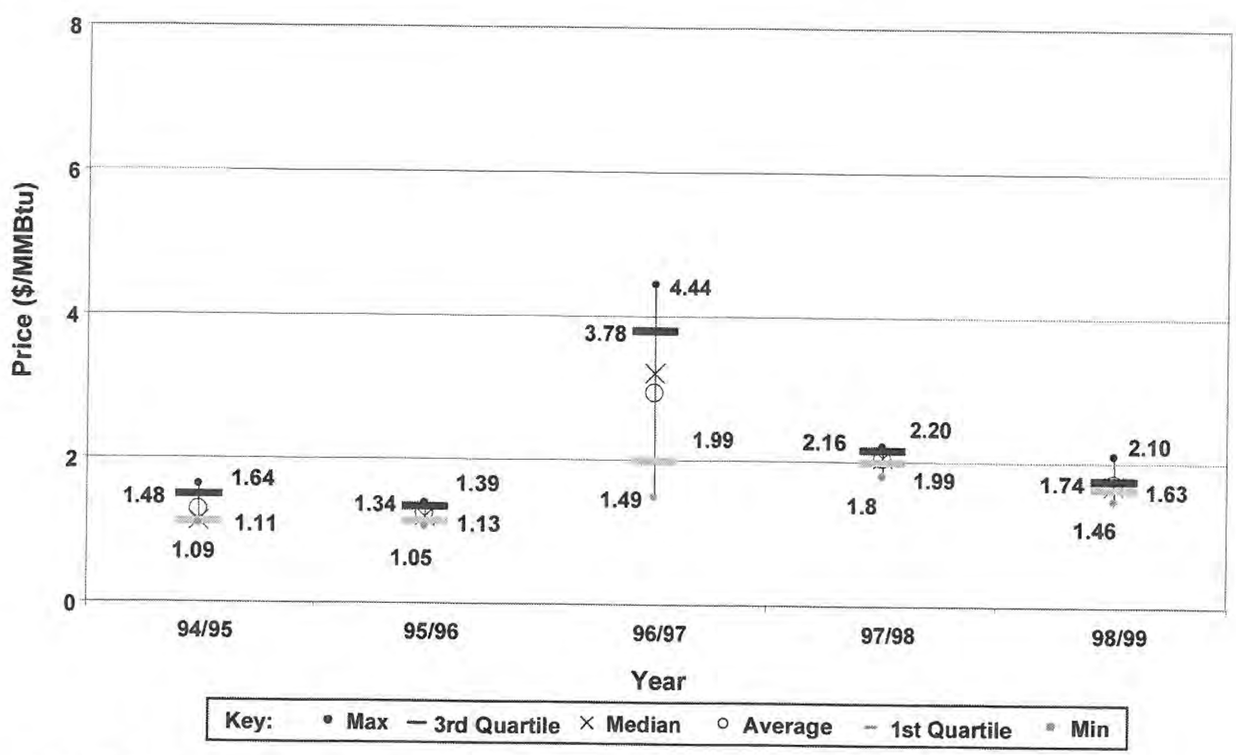


Figure B-101
San Juan, Winter Natural Gas Price Distributions

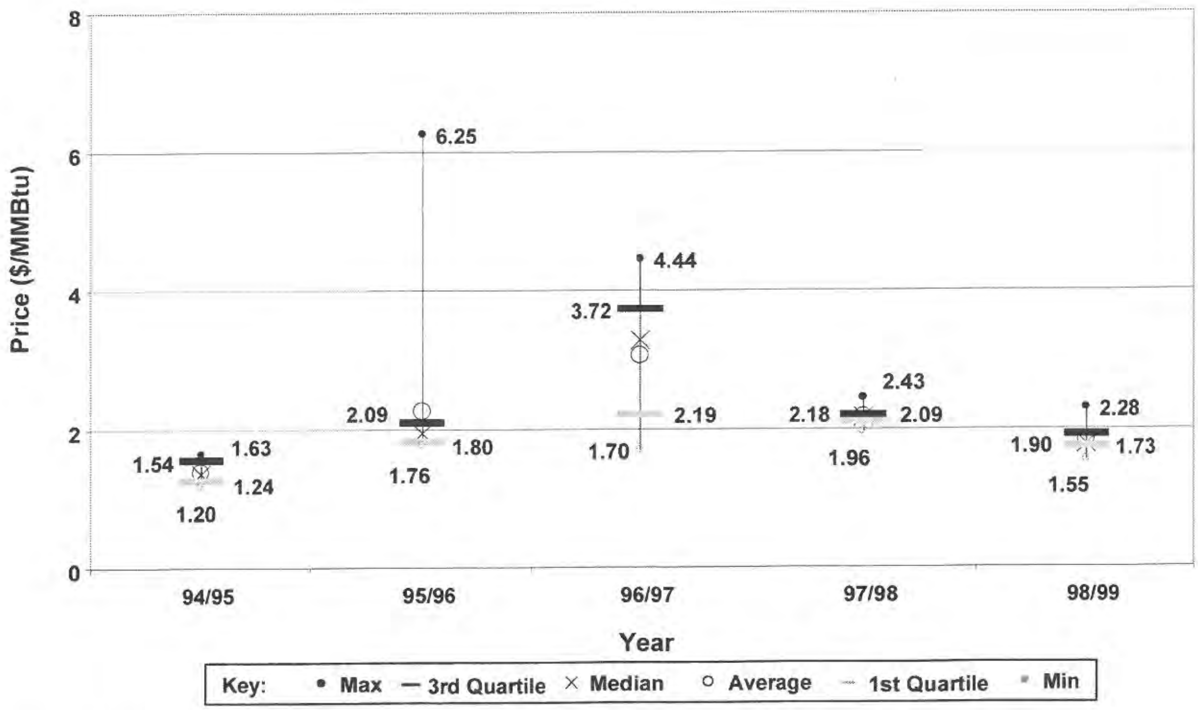


Figure B-102
Ventura, Winter Natural Gas Price Distributions

Daily Spot Electric on Electric Price Correlation Results by Month

Table B-4
Monthly & Annual Correlation of Daily Regional On-Peak Power Prices

Week	COB	Palo Verde	Into Entergy	ERCOT	Into Cinergy	PJM Western Hub	West New York	East New York	New England	MAPP	Into TVA	SERC	Florida/ Georgia Border
California-Oregon Border													
Jan-98	1.00	0.84	0.20	(0.28)	0.27	0.35	0.36	0.06	0.04	0.62	0.19	0.20	0.35
Feb-98	1.00	0.90	(0.07)	0.40	(0.18)	(0.17)	0.16	(0.18)	0.09	0.16	(0.31)	0.11	(0.11)
Mar-98	1.00	0.59	0.16	0.13	0.21	0.22	0.26	0.34	0.24	0.20	0.15	0.06	0.14
Apr-98	1.00	0.84	0.30	(0.24)	0.33	0.05	(0.10)	0.04	(0.11)	0.12	0.35	0.21	0.11
May-98	1.00	0.52	0.11	(0.16)	(0.08)	0.02	0.14	(0.12)	(0.02)	0.05	(0.04)	(0.12)	(0.02)
Jun-98	1.00	0.88	(0.13)	0.17	(0.12)	(0.15)	(0.21)	(0.40)	(0.29)	(0.18)	(0.12)	(0.19)	(0.11)
Jul-98	1.00	0.81	0.20	0.12	0.22	0.35	0.34	0.30	(0.13)	0.42	0.22	0.23	0.25
Aug-98	1.00	0.92	0.08	(0.06)	0.05	0.13	0.25	0.20	0.34	(0.23)	0.14	0.00	0.03
Sep-98	1.00	0.97	(0.16)	0.24	(0.21)	(0.05)	0.02	0.27	0.15	(0.13)	(0.17)	(0.18)	(0.25)
Oct-98	1.00	0.23	(0.24)	(0.15)	(0.18)	(0.39)	0.15	(0.25)	0.18	0.10	(0.24)	(0.23)	(0.38)
Nov-98	1.00	0.82	(0.17)	(0.36)	(0.27)	(0.16)	(0.30)	0.29	(0.08)	0.23	(0.24)	0.11	(0.46)
Dec-98	1.00	0.91	0.61	0.53	0.56	0.28	(0.27)	0.08	(0.04)	0.74	0.50	0.45	0.26
Jan-99	1.00	0.81	0.18	0.18	0.29	0.20	0.32	(0.08)	0.30	0.29	0.24	0.29	0.29
Feb-99	1.00	0.82	0.18	(0.20)	0.10	0.40	0.44	0.55	0.45	0.39	0.02	0.08	0.19
Mar-99	1.00	0.81	0.31	0.30	0.33	0.04	(0.07)	(0.13)	0.23	0.07	0.37	0.16	0.10
Apr-99	1.00	0.90	0.03	0.18	(0.13)	0.06	0.10	(0.24)	0.02	(0.66)	(0.00)	0.11	0.28
May-99	1.00	0.93	(0.17)	0.13	(0.09)	0.03	(0.03)	0.12	(0.17)	(0.30)	(0.03)	(0.10)	(0.09)
Jun-99	1.00	0.93	0.05	0.23	0.08	0.16	0.19	0.10	0.04	0.13	0.08	0.08	0.00
Jul-99	1.00	0.97	(0.05)	0.03	(0.09)	(0.22)	(0.11)	(0.15)	(0.23)	(0.08)	(0.05)	(0.06)	(0.03)
Aug-99	1.00	0.90	(0.19)	0.01	(0.20)	(0.14)	(0.16)	(0.13)	(0.19)	0.01	(0.20)	(0.16)	(0.26)
Sep-99	1.00	(0.18)	(0.05)	0.10	(0.17)	(0.22)	(0.17)	0.17	(0.12)	0.42	(0.11)	0.10	(0.17)
Oct-99	1.00	0.60	0.29	0.20	0.25	0.11	0.22	(0.11)	0.09	(0.16)	0.28	0.16	0.14
Nov-99	1.00	0.85	0.07	0.09	0.24	0.25	0.13		0.38	0.27	0.10	0.07	(0.12)
Dec-99	1.00	0.94	0.00	0.02	0.17	0.44	0.39		0.30	(0.15)	0.06	(0.03)	(0.06)
1998	1.00	0.82	0.07	0.13	0.08	0.12	0.07	0.08	(0.01)	0.09	0.08	0.04	0.04
1999	1.00	0.76	(0.03)	0.04	(0.03)	(0.04)	(0.01)	(0.04)	(0.07)	(0.03)	(0.02)	(0.02)	(0.03)
Palo Verde													
Jan-98	0.84	1.00	(0.11)	0.06	0.08	0.05	0.22	0.06	(0.00)	0.45	0.01	0.10	0.08
Feb-98	0.90	1.00	(0.03)	0.25	(0.16)	(0.07)	0.06	0.14	0.13	0.12	(0.22)	0.07	(0.21)
Mar-98	0.59	1.00	0.29	0.02	0.34	0.41	0.29	0.07	0.28	0.09	0.30	0.22	0.16
Apr-98	0.84	1.00	0.24	(0.03)	0.31	0.24	0.06	0.23	(0.14)	0.28	0.33	0.22	0.27
May-98	0.52	1.00	(0.05)	(0.14)	(0.15)	(0.06)	0.28	(0.22)	0.31	(0.05)	(0.15)	(0.17)	(0.14)
Jun-98	0.88	1.00	(0.24)	0.03	(0.23)	(0.25)	(0.30)	(0.46)	(0.39)	(0.28)	(0.23)	(0.29)	(0.23)
Jul-98	0.81	1.00	0.35	0.34	0.38	0.53	0.38	0.35	(0.03)	0.53	0.36	0.18	0.29
Aug-98	0.92	1.00	(0.04)	(0.16)	(0.06)	0.01	0.10	0.08	0.24	(0.28)	0.02	(0.07)	(0.09)
Sep-98	0.97	1.00	(0.20)	0.13	(0.24)	(0.04)	0.00	0.31	0.10	(0.18)	(0.19)	(0.22)	(0.30)
Oct-98	0.23	1.00	0.19	(0.08)	0.24	0.12	0.04	(0.15)	(0.09)	0.04	0.15	(0.03)	0.25
Nov-98	0.82	1.00	(0.05)	(0.44)	(0.03)	(0.00)	(0.16)	0.37	(0.13)	0.33	0.03	0.17	(0.45)
Dec-98	0.91	1.00	0.72	0.61	0.70	0.34	(0.20)	0.07	0.01	0.66	0.64	0.50	0.22
Jan-99	0.81	1.00	0.32	0.28	0.39	0.29	0.59	(0.11)	0.43	0.38	0.38	0.52	0.50
Feb-99	0.82	1.00	(0.07)	(0.27)	(0.07)	0.28	0.49	0.48	0.45	0.42	(0.10)	(0.00)	0.00
Mar-99	0.81	1.00	0.41	0.47	0.40	0.05	(0.05)	(0.07)	0.40	0.28	0.44	0.13	0.15
Apr-99	0.90	1.00	(0.13)	0.02	(0.19)	0.07	0.22	(0.14)	0.15	(0.62)	(0.13)	(0.08)	0.19
May-99	0.93	1.00	(0.26)	0.08	(0.20)	(0.11)	(0.23)	(0.07)	(0.32)	(0.36)	(0.14)	(0.14)	(0.13)
Jun-99	0.93	1.00	0.04	0.42	0.08	0.15	0.12	0.09	0.02	0.12	0.08	0.06	(0.03)
Jul-99	0.97	1.00	(0.03)	0.03	(0.06)	(0.17)	(0.07)	(0.10)	(0.17)	(0.07)	(0.02)	(0.04)	(0.01)
Aug-99	0.90	1.00	(0.23)	0.05	(0.20)	(0.19)	(0.20)	(0.20)	(0.30)	0.00	(0.24)	(0.20)	(0.30)
Sep-99	(0.18)	1.00	0.23	0.03	0.11	0.22	0.23	(0.05)	0.09	(0.51)	0.13	(0.11)	0.39
Oct-99	0.60	1.00	0.44	0.65	0.29	0.03	(0.26)	(0.19)	(0.21)	(0.24)	0.38	0.10	(0.17)
Nov-99	0.85	1.00	(0.12)	(0.05)	0.01	0.01	0.10		0.17	0.12	(0.12)	(0.03)	(0.30)
Dec-99	0.94	1.00	0.12	0.05	0.24	0.42	0.37		0.24	(0.19)	0.19	0.02	0.03
1998	0.82	1.00	0.09	0.11	0.11	0.15	0.05	0.07	(0.02)	0.06	0.09	(0.01)	(0.01)
1999	0.76	1.00	(0.04)	0.06	(0.03)	(0.05)	(0.01)		(0.08)	(0.04)	(0.02)	(0.03)	(0.03)

Key: Low correlation (less than 0.5) — Moderate correlation (between 0.5 and 0.75) — High correlation (greater than 0.75)

Table B-4
Monthly & Annual Correlation of Daily Regional On-Peak Power Prices (Continued)

Week	COB	Palo Verde	Into Entergy	ERCOT	Into Cinergy	PJM Western Hub	West New York	East New York	New England	MAPP	Into TVA	SERC	Florida/ Georgia Border
Into Entergy													
Jan-98	0.20	(0.11)	1.00	(0.16)	0.84	0.83	0.72	0.38	0.34	0.56	0.87	0.65	0.68
Feb-98	(0.07)	(0.03)	1.00	(0.30)	0.94	0.52	0.38	(0.06)	(0.56)	0.55	0.89	0.74	0.69
Mar-98	0.16	0.29	1.00	0.54	0.94	0.91	0.68	0.49	0.05	0.79	0.96	0.93	0.95
Apr-98	0.30	0.24	1.00	0.27	0.93	0.56	0.20	(0.25)	(0.28)	0.44	0.93	0.66	0.73
May-98	0.11	(0.05)	1.00	0.24	0.86	0.78	0.24	0.70	0.17	0.88	0.91	0.74	0.80
Jun-98	(0.13)	(0.24)	1.00	0.12	0.91	0.73	0.79	0.64	0.65	0.87	0.99	0.93	0.95
Jul-98	0.20	0.35	1.00	0.74	1.00	0.92	0.57	0.51	0.14	0.83	0.99	0.76	0.90
Aug-98	0.08	(0.04)	1.00	0.52	0.94	0.96	0.87	0.91	0.59	0.65	0.99	0.92	0.92
Sep-98	(0.16)	(0.20)	1.00	0.54	0.97	0.83	0.82	0.25	0.70	0.80	0.97	0.88	0.84
Oct-98	(0.24)	0.19	1.00	0.46	0.93	0.61	0.55	0.38	(0.03)	0.34	0.95	0.80	0.65
Nov-98	(0.17)	(0.05)	1.00	0.41	0.85	0.81	0.36	0.19	0.10	0.66	0.91	0.54	0.20
Dec-98	0.61	0.72	1.00	0.68	0.92	0.62	(0.17)	0.24	0.15	0.46	0.96	0.81	0.37
Jan-99	0.18	0.32	1.00	0.59	0.97	0.92	0.81	0.41	0.57	0.62	0.98	0.96	0.90
Feb-99	0.18	(0.07)	1.00	(0.09)	0.86	0.71	0.30	0.47	0.57	0.25	0.86	0.58	0.85
Mar-99	0.31	0.41	1.00	0.58	0.88	0.55	0.48	0.49	0.25	0.51	0.84	0.74	0.61
Apr-99	0.03	(0.13)	1.00	0.79	0.85	0.41	(0.12)	(0.35)	(0.58)	(0.04)	0.91	0.84	0.26
May-99	(0.17)	(0.26)	1.00	0.63	0.65	0.56	0.53	0.43	0.27	0.42	0.82	0.68	0.69
Jun-99	0.05	0.04	1.00	0.42	0.99	0.95	0.84	0.89	0.74	0.82	0.99	0.99	0.94
Jul-99	(0.05)	(0.03)	1.00	0.59	0.99	0.75	0.71	0.61	0.76	0.98	1.00	0.99	0.99
Aug-99	(0.19)	(0.23)	1.00	0.16	0.97	0.96	0.93	0.94	0.54	0.30	1.00	0.98	0.95
Sep-99	(0.05)	0.23	1.00	0.42	0.78	0.79	0.75	0.67	0.68	0.01	0.91	0.83	0.54
Oct-99	0.29	0.44	1.00	0.45	0.88	0.46	0.14	0.03	0.19	0.32	0.94	0.77	(0.14)
Nov-99	0.07	(0.12)	1.00	0.69	0.93	0.89	0.29		0.59	0.74	0.98	0.80	0.56
Dec-99	0.00	0.12	1.00	0.72	0.87	0.60	0.47		0.08	0.56	0.96	0.75	0.70
1998	0.07	0.09	1.00	0.42	0.97	0.80	0.54	0.54	0.22	0.76	0.99	0.76	0.85
1999	(0.03)	(0.04)	1.00	0.40	0.98	0.79	0.75	0.66	0.73	0.91	0.99	0.98	0.97
ERCOT													
Jan-98	(0.28)	0.06	(0.16)	1.00	(0.06)	(0.17)	0.13	(0.26)	(0.00)	(0.03)	(0.01)	0.11	(0.15)
Feb-98	0.40	0.25	(0.30)	1.00	(0.25)	(0.03)	(0.02)	(0.24)	0.52	(0.21)	(0.36)	(0.10)	0.01
Mar-98	0.13	0.02	0.54	1.00	0.35	0.32	0.05	0.34	0.11	0.44	0.43	0.38	0.58
Apr-98	(0.24)	(0.03)	0.27	1.00	0.13	0.11	0.34	(0.56)	(0.14)	0.43	0.31	0.04	0.45
May-98	(0.16)	(0.14)	0.24	1.00	0.26	0.01	(0.24)	(0.06)	0.51	0.12	0.28	0.27	0.32
Jun-98	0.17	0.03	0.12	1.00	0.19	0.19	(0.01)	(0.09)	0.03	(0.07)	0.09	0.16	0.10
Jul-98	0.12	0.34	0.74	1.00	0.76	0.80	0.56	0.39	0.31	0.55	0.70	0.34	0.49
Aug-98	(0.06)	(0.16)	0.52	1.00	0.49	0.41	0.30	0.36	0.10	0.59	0.49	0.49	0.51
Sep-98	0.24	0.13	0.54	1.00	0.41	0.30	0.38	(0.09)	0.41	0.49	0.48	0.42	0.54
Oct-98	(0.15)	(0.08)	0.46	1.00	0.24	0.21	0.12	0.34	0.12	0.01	0.34	0.30	0.22
Nov-98	(0.36)	(0.44)	0.41	1.00	0.25	0.26	0.06	(0.09)	0.50	0.12	0.28	0.25	0.16
Dec-98	0.53	0.61	0.68	1.00	0.61	0.46	(0.15)	0.29	0.29	0.38	0.63	0.54	0.34
Jan-99	0.18	0.28	0.59	1.00	0.54	0.48	0.53	(0.04)	0.61	0.50	0.60	0.52	0.45
Feb-99	(0.20)	(0.27)	(0.09)	1.00	(0.13)	(0.25)	(0.41)	(0.20)	(0.24)	(0.21)	(0.09)	(0.24)	(0.19)
Mar-99	0.30	0.47	0.58	1.00	0.62	0.24	0.26	(0.11)	0.25	0.19	0.63	0.57	0.57
Apr-99	0.18	0.02	0.79	1.00	0.52	0.10	(0.33)	(0.42)	(0.38)	(0.25)	0.66	0.65	0.32
May-99	0.13	0.08	0.63	1.00	0.65	0.60	0.35	0.45	0.23	0.21	0.59	0.54	0.55
Jun-99	0.23	0.42	0.42	1.00	0.42	0.50	0.30	0.38	0.29	0.23	0.44	0.46	0.29
Jul-99	0.03	0.03	0.59	1.00	0.56	0.33	0.29	0.21	0.42	0.59	0.59	0.60	0.59
Aug-99	0.01	0.05	0.16	1.00	0.25	0.15	0.26	0.18	0.32	0.49	0.19	0.24	0.28
Sep-99	0.10	0.03	0.42	1.00	0.13	0.10	0.27	0.19	0.32	0.02	0.33	0.36	0.22
Oct-99	0.20	0.65	0.45	1.00	0.23	(0.06)	(0.11)	(0.06)	(0.40)	(0.04)	0.36	0.21	(0.06)
Nov-99	0.09	(0.05)	0.69	1.00	0.60	0.52	0.63		0.44	0.46	0.70	0.42	0.35
Dec-99	0.02	0.05	0.72	1.00	0.76	0.36	0.21		0.18	0.81	0.66	0.63	0.61
1998	0.13	0.11	0.42	1.00	0.43	0.39	0.21	0.15	0.16	0.22	0.39	0.25	0.29
1999	0.04	0.06	0.40	1.00	0.39	0.27	0.26	0.20	0.31	0.41	0.40	0.41	0.40

Key: Low correlation (less than 0.5) | Moderate correlation (between 0.5 and 0.75) | High correlation (greater than 0.75)

Table B-4
Monthly & Annual Correlation of Daily Regional On-Peak Power Prices (Continued)

Week	COB	Palo Verde	Into Entergy	ERCOT	Into Cinergy	PJM Western Hub	West New York	East New York	New England	MAPP	Into TVA	SERC	Florida/ Georgia Border
Into Cinergy													
Jan-98	0.27	0.08	0.84	(0.06)	1.00	0.74	0.74	0.48	0.41	0.55	0.91	0.54	0.68
Feb-98	(0.18)	(0.16)	0.94	(0.25)	1.00	0.57	0.39	(0.01)	(0.45)	0.53	0.94	0.82	0.77
Mar-98	0.21	0.34	0.94	0.35	1.00	0.93	0.72	0.47	0.04	0.72	0.95	0.94	0.87
Apr-98	0.33	0.31	0.93	0.13	1.00	0.55	0.14	(0.15)	(0.39)	0.37	0.94	0.72	0.60
May-98	(0.08)	(0.15)	0.86	0.26	1.00	0.76	(0.02)	0.65	0.38	0.89	0.99	0.96	0.95
Jun-98	(0.12)	(0.23)	0.91	0.19	1.00	0.83	0.66	0.50	0.61	0.69	0.94	0.96	0.83
Jul-98	0.22	0.38	1.00	0.76	1.00	0.93	0.56	0.48	0.13	0.83	0.99	0.72	0.87
Aug-98	0.05	(0.06)	0.94	0.49	1.00	0.97	0.89	0.94	0.63	0.63	0.92	0.85	0.93
Sep-98	(0.21)	(0.24)	0.97	0.41	1.00	0.89	0.84	0.25	0.71	0.79	0.99	0.92	0.82
Oct-98	(0.18)	0.24	0.93	0.24	1.00	0.68	0.66	0.41	0.00	0.36	0.91	0.79	0.60
Nov-98	(0.27)	(0.03)	0.85	0.25	1.00	0.85	0.54	0.23	0.00	0.55	0.92	0.39	0.31
Dec-98	0.56	0.70	0.92	0.61	1.00	0.63	(0.28)	0.31	0.04	0.53	0.94	0.82	0.22
Jan-99	0.29	0.39	0.97	0.54	1.00	0.94	0.80	0.43	0.50	0.66	0.98	0.95	0.88
Feb-99	0.10	(0.07)	0.86	(0.13)	1.00	0.75	0.53	0.53	0.42	0.47	0.96	0.71	0.75
Mar-99	0.33	0.40	0.88	0.62	1.00	0.69	0.56	0.40	0.06	0.56	0.96	0.82	0.64
Apr-99	(0.13)	(0.19)	0.85	0.52	1.00	0.56	0.07	0.01	(0.39)	0.14	0.95	0.77	0.09
May-99	(0.09)	(0.20)	0.65	0.65	1.00	0.81	0.62	0.57	0.51	0.46	0.90	0.77	0.59
Jun-99	0.08	0.08	0.99	0.42	1.00	0.94	0.85	0.90	0.73	0.85	1.00	0.98	0.95
Jul-99	(0.09)	(0.06)	0.99	0.56	1.00	0.82	0.78	0.67	0.82	0.97	0.99	0.97	0.96
Aug-99	(0.20)	(0.20)	0.97	0.25	1.00	0.93	0.96	0.91	0.62	0.44	0.98	0.99	0.94
Sep-99	(0.17)	0.11	0.78	0.13	1.00	0.80	0.64	0.55	0.54	0.04	0.93	0.75	0.57
Oct-99	0.25	0.29	0.88	0.23	1.00	0.62	0.25	0.16	0.32	0.55	0.94	0.79	0.10
Nov-99	0.24	0.01	0.93	0.60	1.00	0.95	0.35		0.77	0.77	0.94	0.78	0.43
Dec-99	0.17	0.24	0.87	0.76	1.00	0.73	0.58		0.18	0.67	0.91	0.71	0.67
1998	0.08	0.11	0.97	0.43	1.00	0.84	0.51	0.51	0.21	0.72	0.97	0.77	0.80
1999	(0.03)	(0.03)	0.98	0.39	1.00	0.83	0.81	0.71	0.79	0.92	0.98	0.97	0.95
PJM Western Hub													
Jan-98	0.35	0.05	0.83	(0.17)	0.74	1.00	0.77	0.28	0.25	0.49	0.71	0.41	0.73
Feb-98	(0.17)	(0.07)	0.52	(0.03)	0.57	1.00	0.23	0.39	0.13	0.30	0.62	0.44	0.53
Mar-98	0.22	0.41	0.91	0.32	0.93	1.00	0.76	0.47	0.22	0.70	0.96	0.87	0.86
Apr-98	0.05	0.24	0.66	0.11	0.55	1.00	0.29	0.18	(0.26)	0.36	0.45	0.60	0.39
May-98	0.02	(0.06)	0.78	0.01	0.76	1.00	0.45	0.81	(0.02)	0.69	0.77	0.62	0.63
Jun-98	(0.15)	(0.25)	0.73	0.19	0.83	1.00	0.73	0.59	0.61	0.65	0.73	0.79	0.59
Jul-98	0.35	0.53	0.92	0.80	0.93	1.00	0.80	0.68	0.33	0.79	0.93	0.73	0.84
Aug-98	0.13	0.01	0.96	0.41	0.97	1.00	0.91	0.95	0.62	0.54	0.96	0.87	0.91
Sep-98	(0.05)	(0.04)	0.83	0.30	0.89	1.00	0.89	0.44	0.62	0.74	0.90	0.80	0.55
Oct-98	(0.39)	0.12	0.61	0.21	0.68	1.00	0.64	0.34	0.12	0.08	0.52	0.45	0.28
Nov-98	(0.16)	(0.00)	0.81	0.26	0.85	1.00	0.49	0.38	0.06	0.61	0.80	0.40	0.27
Dec-98	0.28	0.34	0.62	0.46	0.63	1.00	(0.10)	0.10	0.08	0.62	0.64	0.51	0.06
Jan-99	0.20	0.29	0.92	0.48	0.94	1.00	0.74	0.64	0.43	0.60	0.94	0.89	0.82
Feb-99	0.40	0.28	0.71	(0.25)	0.75	1.00	0.78	0.69	0.48	0.65	0.64	0.69	0.80
Mar-99	0.04	0.05	0.55	0.24	0.69	1.00	0.59	0.46	0.05	0.29	0.59	0.59	0.44
Apr-99	0.06	0.07	0.41	0.10	0.66	1.00	0.63	0.47	0.03	0.29	0.58	0.47	0.17
May-99	0.03	(0.11)	0.56	0.60	0.81	1.00	0.73	0.73	0.59	0.42	0.79	0.75	0.63
Jun-99	0.16	0.15	0.95	0.50	0.94	1.00	0.92	0.88	0.71	0.70	0.95	0.97	0.86
Jul-99	(0.22)	(0.17)	0.75	0.33	0.82	1.00	0.98	0.91	0.94	0.69	0.72	0.68	0.65
Aug-99	(0.14)	(0.19)	0.96	0.15	0.93	1.00	0.96	0.98	0.55	0.20	0.96	0.93	0.91
Sep-99	(0.22)	0.22	0.79	0.10	0.80	1.00	0.82	0.75	0.77	(0.14)	0.78	0.83	0.38
Oct-99	0.11	0.03	0.46	(0.06)	0.62	1.00	0.34	0.73	0.63	0.36	0.54	0.53	0.10
Nov-99	0.25	0.01	0.89	0.52	0.95	1.00	0.31		0.79	0.76	0.89	0.77	0.46
Dec-99	0.44	0.42	0.60	0.36	0.73	1.00	0.70		0.36	0.33	0.65	0.52	0.38
1998	0.12	0.15	0.80	0.39	0.84	1.00	0.73	0.68	0.30	0.62	0.81	0.69	0.67
1999	(0.04)	(0.05)	0.79	0.27	0.83	1.00	0.94	0.90	0.83	0.62	0.76	0.73	0.69

Key: Low correlation (less than 0.5) — Moderate correlation (between 0.5 and 0.75) — High correlation (greater than 0.75)

Table B-4
Monthly & Annual Correlation of Daily Regional On-Peak Power Prices (Continued)

Week	COB	Palo Verde	Into Entergy	ERCOT	Into Cinergy	PJM Western Hub	West New York	East New York	New England	MAPP	Into TVA	SERC	Florida/ Georgia Border
West New York													
Jan-98	0.36	0.22	0.72	0.13	0.74	0.77	1.00	0.21	0.19	0.66	0.66	0.68	0.72
Feb-98	0.16	0.06	0.38	(0.02)	0.39	0.23	1.00	(0.19)	(0.19)	0.33	0.21	0.21	0.36
Mar-98	0.26	0.29	0.68	0.05	0.72	0.76	1.00	0.44	0.09	0.49	0.73	0.66	0.58
Apr-98	(0.10)	0.06	0.20	0.34	0.14	0.29	1.00	(0.05)	0.12	0.38	0.22	0.09	0.40
May-98	0.14	0.28	0.24	(0.24)	(0.02)	0.45	1.00	0.39	(0.20)	0.18	0.05	(0.12)	(0.03)
Jun-98	(0.21)	(0.30)	0.79	(0.01)	0.66	0.73	1.00	0.80	0.74	0.80	0.74	0.74	0.66
Jul-98	0.34	0.38	0.57	0.56	0.56	0.80	1.00	0.88	0.58	0.44	0.63	0.73	0.68
Aug-98	0.25	0.10	0.87	0.30	0.89	0.91	1.00	0.93	0.69	0.50	0.87	0.70	0.86
Sep-98	0.02	0.00	0.82	0.38	0.84	0.89	1.00	0.40	0.59	0.65	0.84	0.84	0.66
Oct-98	0.15	0.04	0.55	0.12	0.66	0.64	1.00	0.24	0.14	0.24	0.51	0.28	0.10
Nov-98	(0.30)	(0.16)	0.36	0.06	0.54	0.49	1.00	0.24	0.14	0.38	0.46	0.41	0.02
Dec-98	(0.27)	(0.20)	(0.17)	(0.15)	(0.28)	(0.10)	1.00	(0.05)	0.44	(0.27)	(0.10)	(0.15)	(0.12)
Jan-99	0.32	0.59	0.81	0.53	0.80	0.74	1.00	0.13	0.56	0.59	0.78	0.86	0.82
Feb-99	0.44	0.49	0.30	(0.41)	0.53	0.78	1.00	0.70	0.31	0.88	0.43	0.71	0.51
Mar-99	(0.07)	(0.05)	0.48	0.26	0.56	0.59	1.00	0.53	0.18	0.27	0.49	0.47	0.48
Apr-99	0.10	0.22	(0.12)	(0.33)	0.07	0.63	1.00	0.46	0.26	0.21	0.01	(0.17)	0.15
May-99	(0.03)	(0.23)	0.53	0.35	0.62	0.73	1.00	0.66	0.46	0.39	0.69	0.59	0.60
Jun-99	0.19	0.12	0.84	0.30	0.85	0.92	1.00	0.83	0.63	0.71	0.85	0.86	0.80
Jul-99	(0.11)	(0.07)	0.71	0.29	0.78	0.98	1.00	0.92	0.93	0.63	0.68	0.63	0.61
Aug-99	(0.16)	(0.20)	0.93	0.26	0.96	0.96	1.00	0.97	0.72	0.43	0.95	0.95	0.93
Sep-99	(0.17)	0.23	0.75	0.27	0.64	0.82	1.00	0.78	0.85	(0.26)	0.69	0.73	0.34
Oct-99	0.22	(0.26)	0.14	(0.11)	0.25	0.34	1.00	0.27	0.33	0.09	0.24	0.22	0.24
Nov-99	0.13	0.10	0.29	0.53	0.35	0.31	1.00		0.34	0.26	0.35	0.16	0.22
Dec-99	0.39	0.37	0.47	0.21	0.58	0.70	1.00		0.42	0.06	0.52	0.34	0.43
1998	0.07	0.05	0.54	0.21	0.51	0.73	1.00	0.72	0.45	0.50	0.56	0.55	0.59
1999	(0.01)	(0.01)	0.75	0.26	0.81	0.94	1.00	0.87	0.85	0.63	0.73	0.69	0.66
East New York													
Jan-98	0.06	0.06	0.38	(0.26)	0.48	0.28	0.21	1.00	0.57	0.22	0.33	(0.14)	0.11
Feb-98	(0.18)	0.14	(0.06)	(0.24)	(0.01)	0.39	(0.19)	1.00	0.44	0.08	0.14	(0.11)	(0.20)
Mar-98	0.34	0.07	0.49	0.34	0.47	0.47	0.44	1.00	0.21	0.36	0.41	0.40	0.52
Apr-98	0.04	0.23	(0.25)	(0.56)	(0.15)	0.18	(0.05)	1.00	0.21	(0.27)	(0.22)	(0.12)	(0.08)
May-98	(0.12)	(0.22)	0.70	(0.06)	0.65	0.81	0.39	1.00	(0.10)	0.74	0.68	0.53	0.54
Jun-98	(0.40)	(0.46)	0.64	(0.09)	0.50	0.59	0.80	1.00	0.56	0.78	0.60	0.58	0.58
Jul-98	0.30	0.35	0.51	0.39	0.48	0.68	0.88	1.00	0.59	0.45	0.55	0.79	0.69
Aug-98	0.20	0.08	0.91	0.36	0.94	0.95	0.93	1.00	0.62	0.56	0.89	0.79	0.87
Sep-98	0.27	0.31	0.25	(0.09)	0.25	0.44	0.40	1.00	0.18	0.48	0.26	0.19	0.05
Oct-98	(0.25)	(0.15)	0.38	0.34	0.41	0.34	0.24	1.00	0.45	0.10	0.37	0.43	0.07
Nov-98	0.29	0.37	0.19	(0.09)	0.23	0.38	0.24	1.00	(0.27)	0.55	0.17	0.11	0.02
Dec-98	0.08	0.07	0.24	0.29	0.31	0.10	(0.05)	1.00	(0.02)	0.12	0.29	0.40	0.15
Jan-99	(0.08)	(0.11)	0.41	(0.04)	0.43	0.64	0.13	1.00	0.18	0.33	0.44	0.34	0.26
Feb-99	0.55	0.48	0.47	(0.20)	0.53	0.69	0.70	1.00	0.56	0.68	0.50	0.61	0.54
Mar-99	(0.13)	(0.07)	0.49	(0.11)	0.40	0.46	0.53	1.00	0.09	0.45	0.34	0.16	0.21
Apr-99	(0.24)	(0.14)	(0.35)	(0.42)	0.01	0.47	0.46	1.00	0.45	0.63	(0.09)	(0.22)	(0.33)
May-99	0.12	(0.07)	0.43	0.45	0.57	0.73	0.66	1.00	0.64	0.38	0.59	0.65	0.48
Jun-99	0.10	0.09	0.89	0.38	0.90	0.88	0.83	1.00	0.78	0.69	0.88	0.90	0.94
Jul-99	(0.15)	(0.10)	0.61	0.21	0.67	0.91	0.92	1.00	0.92	0.52	0.57	0.54	0.52
Aug-99	(0.13)	(0.20)	0.94	0.18	0.91	0.98	0.97	1.00	0.66	0.28	0.95	0.92	0.90
Sep-99	0.17	(0.05)	0.67	0.19	0.55	0.75	0.78	1.00	0.83	(0.06)	0.62	0.80	0.20
Oct-99	(0.11)	(0.19)	0.03	(0.06)	0.16	0.73	0.27	1.00	0.46	0.38	0.06	0.24	(0.08)
Nov-99													
Dec-99													
1998	0.08	0.07	0.54	0.15	0.51	0.68	0.72	1.00	0.37	0.50	0.56	0.56	0.59
1999	(0.04)	(0.06)	0.66	0.20	0.71	0.90	0.87	1.00	0.83	0.48	0.64	0.62	0.59

Key: Low correlation (less than 0.5) — Moderate correlation (between 0.5 and 0.75) — High correlation (greater than 0.75)

Table B-4
Monthly & Annual Correlation of Daily Regional On-Peak Power Prices (Continued)

Week	COB	Palo Verde	Into Entergy	ERCOT	Into Cinergy	PJM Western Hub	West New York	East New York	New England	MAPP	Into TVA	SERC	Florida/ Georgia Border
New England													
Jan-98	0.04	(0.00)	0.34	(0.00)	0.41	0.25	0.19	0.57	1.00	0.26	0.41	0.22	0.13
Feb-98	0.09	0.13	(0.56)	0.52	(0.45)	0.13	(0.19)	0.44	1.00	(0.36)	(0.44)	(0.27)	(0.18)
Mar-98	0.24	0.28	0.05	0.11	0.04	0.22	0.09	0.21	1.00	(0.07)	0.14	(0.18)	0.05
Apr-98	(0.11)	(0.14)	(0.28)	(0.14)	(0.39)	(0.26)	0.12	0.21	1.00	(0.37)	(0.33)	(0.38)	(0.19)
May-98	(0.02)	0.31	0.17	0.51	0.38	(0.02)	(0.20)	(0.10)	1.00	0.24	0.36	0.52	0.48
Jun-98	(0.29)	(0.39)	0.65	0.03	0.61	0.61	0.74	0.56	1.00	0.57	0.62	0.64	0.58
Jul-98	(0.13)	(0.03)	0.14	0.31	0.13	0.33	0.58	0.59	1.00	0.05	0.16	0.21	0.14
Aug-98	0.34	0.24	0.59	0.10	0.63	0.62	0.69	0.62	1.00	0.04	0.62	0.50	0.62
Sep-98	0.15	0.10	0.70	0.41	0.71	0.62	0.59	0.18	1.00	0.56	0.71	0.71	0.63
Oct-98	0.18	(0.09)	(0.03)	0.12	0.00	0.12	0.14	0.45	1.00	(0.15)	(0.05)	(0.05)	(0.37)
Nov-98	(0.08)	(0.13)	0.10	0.50	0.00	0.06	0.14	(0.27)	1.00	0.02	0.00	0.19	(0.17)
Dec-98	(0.04)	0.01	0.15	0.29	0.04	0.08	0.44	(0.02)	1.00	(0.11)	0.11	0.29	0.17
Jan-99	0.30	0.43	0.57	0.61	0.50	0.43	0.56	0.18	1.00	0.48	0.52	0.53	0.46
Feb-99	0.45	0.45	0.57	(0.24)	0.42	0.48	0.31	0.56	1.00	0.35	0.41	0.13	0.44
Mar-99	0.23	0.40	0.25	0.25	0.06	0.05	0.18	0.09	1.00	0.16	0.10	0.04	0.05
Apr-99	0.02	0.15	(0.58)	(0.38)	(0.39)	0.03	0.26	0.45	1.00	0.14	(0.49)	(0.45)	0.10
May-99	(0.17)	(0.32)	0.27	0.23	0.51	0.59	0.46	0.64	1.00	0.08	0.49	0.51	0.36
Jun-99	0.04	0.02	0.74	0.29	0.73	0.71	0.63	0.78	1.00	0.63	0.74	0.72	0.74
Jul-99	(0.23)	(0.17)	0.76	0.42	0.82	0.94	0.93	0.92	1.00	0.69	0.73	0.71	0.68
Aug-99	(0.19)	(0.30)	0.54	0.32	0.62	0.55	0.72	0.66	1.00	0.74	0.58	0.63	0.62
Sep-99	(0.12)	0.09	0.68	0.32	0.64	0.77	0.85	0.83	1.00	(0.17)	0.60	0.70	0.02
Oct-99	0.09	(0.21)	0.19	(0.40)	0.32	0.63	0.33	0.46	1.00	0.30	0.23	0.20	(0.19)
Nov-99	0.38	0.17	0.59	0.44	0.77	0.79	0.34		1.00	0.51	0.64	0.49	0.15
Dec-99	0.30	0.24	0.08	0.18	0.18	0.36	0.42		1.00	0.08	0.15	0.15	0.17
1998	(0.01)	(0.02)	0.22	0.16	0.21	0.30	0.45	0.37	1.00	0.19	0.24	0.28	0.30
1999	(0.07)	(0.08)	0.73	0.31	0.79	0.83	0.85	0.83	1.00	0.67	0.72	0.71	0.68
MAPP													
Jan-98	0.62	0.45	0.56	(0.03)	0.55	0.49	0.66	0.22	0.26	1.00	0.52	0.50	0.51
Feb-98	0.16	0.12	0.55	(0.21)	0.53	0.30	0.33	0.08	(0.36)	1.00	0.46	0.35	0.10
Mar-98	0.20	0.09	0.79	0.44	0.72	0.70	0.49	0.36	(0.07)	1.00	0.75	0.74	0.81
Apr-98	0.12	0.28	0.44	0.43	0.37	0.36	0.38	(0.27)	(0.37)	1.00	0.49	0.48	0.58
May-98	0.05	(0.05)	0.88	0.12	0.89	0.69	0.18	0.74	0.24	1.00	0.90	0.81	0.88
Jun-98	(0.18)	(0.28)	0.87	(0.07)	0.69	0.65	0.80	0.78	0.57	1.00	0.83	0.78	0.84
Jul-98	0.42	0.53	0.83	0.55	0.83	0.79	0.44	0.45	0.05	1.00	0.81	0.60	0.76
Aug-98	(0.23)	(0.28)	0.65	0.59	0.63	0.54	0.50	0.56	0.04	1.00	0.59	0.55	0.56
Sep-98	(0.13)	(0.18)	0.80	0.49	0.79	0.74	0.65	0.48	0.56	1.00	0.80	0.69	0.64
Oct-98	0.10	0.04	0.34	0.01	0.36	0.08	0.24	0.10	(0.15)	1.00	0.32	0.46	0.27
Nov-98	0.23	0.33	0.66	0.12	0.55	0.61	0.38	0.55	0.02	1.00	0.61	0.30	(0.07)
Dec-98	0.74	0.66	0.46	0.38	0.53	0.62	(0.27)	0.12	(0.11)	1.00	0.45	0.39	0.08
Jan-99	0.29	0.38	0.62	0.50	0.66	0.60	0.59	0.33	0.48	1.00	0.60	0.62	0.44
Feb-99	0.39	0.42	0.25	(0.21)	0.47	0.65	0.88	0.58	0.35	1.00	0.38	0.55	0.40
Mar-99	0.07	0.28	0.51	0.19	0.56	0.29	0.27	0.45	0.16	1.00	0.56	0.26	0.15
Apr-99	(0.66)	(0.62)	(0.04)	(0.25)	0.14	0.29	0.21	0.63	0.14	1.00	0.07	(0.04)	(0.35)
May-99	(0.30)	(0.36)	0.42	0.21	0.46	0.42	0.39	0.38	0.08	1.00	0.43	0.34	0.44
Jun-99	0.13	0.12	0.82	0.23	0.85	0.70	0.71	0.69	0.63	1.00	0.84	0.76	0.77
Jul-99	(0.08)	(0.07)	0.98	0.59	0.97	0.69	0.63	0.52	0.69	1.00	0.99	0.99	0.98
Aug-99	0.01	0.00	0.30	0.49	0.44	0.20	0.43	0.28	0.74	1.00	0.34	0.44	0.41
Sep-99	0.42	(0.51)	0.01	0.02	0.04	(0.14)	(0.26)	(0.06)	(0.17)	1.00	0.06	0.17	(0.13)
Oct-99	(0.16)	(0.24)	0.32	(0.04)	0.55	0.36	0.09	0.38	0.30	1.00	0.37	0.43	0.01
Nov-99	0.27	0.12	0.74	0.46	0.77	0.76	0.26		0.51	1.00	0.72	0.80	0.37
Dec-99	(0.15)	(0.19)	0.56	0.81	0.67	0.33	0.06		0.08	1.00	0.52	0.61	0.46
1998	0.09	0.06	0.76	0.22	0.72	0.62	0.50	0.50	0.19	1.00	0.76	0.64	0.77
1999	(0.03)	(0.04)	0.91	0.41	0.92	0.62	0.63	0.48	0.67	1.00	0.94	0.94	0.93

Key: Low correlation (less than 0.5); Moderate correlation (between 0.5 and 0.75); High correlation (greater than 0.75)

Table B-4
Monthly & Annual Correlation of Daily Regional On-Peak Power Prices (Continued)

Week	COB	Palo Verde	Into Entergy	ERCOT	Into Cinergy	PJM Western Hub	West New York	East New York	New England	MAPP	Into TVA	SERC	Florida/ Georgia Border
Into TVA													
Jan-98	0.19	0.01	0.87	(0.01)	0.91	0.71	0.66	0.33	0.41	0.52	1.00	0.56	0.60
Feb-98	(0.31)	(0.22)	0.89	(0.36)	0.94	0.62	0.21	0.14	(0.44)	0.46	1.00	0.73	0.63
Mar-98	0.15	0.30	0.96	0.43	0.95	0.96	0.73	0.41	0.14	0.75	1.00	0.90	0.91
Apr-98	0.35	0.33	0.93	0.31	0.94	0.45	0.22	(0.22)	(0.33)	0.49	1.00	0.64	0.70
May-98	(0.04)	(0.15)	0.91	0.28	0.99	0.77	0.05	0.68	0.36	0.90	1.00	0.94	0.95
Jun-98	(0.12)	(0.23)	0.99	0.09	0.94	0.73	0.74	0.60	0.62	0.83	1.00	0.95	0.95
Jul-98	0.22	0.36	0.99	0.70	0.99	0.93	0.63	0.55	0.16	0.81	1.00	0.80	0.93
Aug-98	0.14	0.02	0.99	0.49	0.92	0.96	0.87	0.89	0.62	0.59	1.00	0.94	0.91
Sep-98	(0.17)	(0.19)	0.97	0.48	0.99	0.90	0.84	0.26	0.71	0.80	1.00	0.89	0.79
Oct-98	(0.24)	0.15	0.95	0.34	0.91	0.52	0.51	0.37	(0.05)	0.32	1.00	0.82	0.70
Nov-98	(0.24)	0.03	0.91	0.28	0.92	0.80	0.46	0.17	0.00	0.61	1.00	0.51	0.23
Dec-98	0.50	0.64	0.96	0.63	0.94	0.64	(0.10)	0.29	0.11	0.45	1.00	0.80	0.33
Jan-99	0.24	0.38	0.98	0.60	0.98	0.94	0.78	0.44	0.52	0.60	1.00	0.95	0.91
Feb-99	0.02	(0.10)	0.86	(0.09)	0.96	0.64	0.43	0.50	0.41	0.38	1.00	0.70	0.72
Mar-99	0.37	0.44	0.84	0.63	0.96	0.59	0.49	0.34	0.10	0.56	1.00	0.75	0.66
Apr-99	(0.00)	(0.13)	0.91	0.66	0.95	0.58	0.01	(0.09)	(0.49)	0.07	1.00	0.87	0.17
May-99	(0.03)	(0.14)	0.82	0.59	0.90	0.79	0.69	0.59	0.49	0.43	1.00	0.86	0.66
Jun-99	0.08	0.08	0.99	0.44	1.00	0.95	0.85	0.88	0.74	0.84	1.00	0.98	0.93
Jul-99	(0.05)	(0.02)	1.00	0.59	0.99	0.72	0.68	0.57	0.73	0.99	1.00	1.00	0.99
Aug-99	(0.20)	(0.24)	1.00	0.19	0.98	0.96	0.95	0.95	0.58	0.34	1.00	0.98	0.95
Sep-99	(0.11)	0.13	0.91	0.33	0.93	0.78	0.69	0.62	0.60	0.06	1.00	0.79	0.61
Oct-99	0.28	0.38	0.94	0.36	0.94	0.54	0.24	0.06	0.23	0.37	1.00	0.78	0.04
Nov-99	0.10	(0.12)	0.98	0.70	0.94	0.89	0.35		0.64	0.72	1.00	0.76	0.58
Dec-99	0.06	0.19	0.96	0.66	0.91	0.65	0.52		0.15	0.62	1.00	0.74	0.70
1998	0.08	0.09	0.99	0.39	0.97	0.81	0.56	0.56	0.24	0.76	1.00	0.82	0.88
1999	(0.02)	(0.02)	0.99	0.40	0.98	0.76	0.73	0.64	0.72	0.94	1.00	0.99	0.98
SERC													
Jan-98	0.20	0.10	0.55	0.11	0.54	0.41	0.68	(0.14)	0.22	0.50	0.56	1.00	0.67
Feb-98	0.11	0.07	0.74	(0.10)	0.82	0.44	0.21	(0.11)	(0.27)	0.35	0.73	1.00	0.77
Mar-98	0.06	0.22	0.93	0.38	0.94	0.87	0.66	0.40	(0.18)	0.74	0.90	1.00	0.90
Apr-98	0.21	0.22	0.66	0.04	0.72	0.60	0.09	(0.12)	(0.38)	0.48	0.64	1.00	0.44
May-98	(0.12)	(0.17)	0.74	0.27	0.96	0.62	(0.12)	0.53	0.52	0.81	0.94	1.00	0.96
Jun-98	(0.19)	(0.29)	0.93	0.16	0.96	0.79	0.74	0.58	0.64	0.78	0.95	1.00	0.90
Jul-98	0.23	0.18	0.76	0.34	0.72	0.73	0.73	0.79	0.21	0.60	0.80	1.00	0.96
Aug-98	0.00	(0.07)	0.92	0.49	0.85	0.87	0.70	0.79	0.50	0.55	0.94	1.00	0.87
Sep-98	(0.18)	(0.22)	0.88	0.42	0.92	0.80	0.84	0.19	0.71	0.69	0.89	1.00	0.86
Oct-98	(0.23)	(0.03)	0.80	0.30	0.79	0.45	0.28	0.43	(0.05)	0.46	0.82	1.00	0.62
Nov-98	0.11	0.17	0.54	0.25	0.39	0.40	0.41	0.11	0.19	0.30	0.51	1.00	0.08
Dec-98	0.45	0.50	0.81	0.54	0.82	0.51	(0.15)	0.40	0.29	0.39	0.80	1.00	0.47
Jan-99	0.29	0.52	0.96	0.52	0.95	0.89	0.86	0.34	0.53	0.62	0.95	1.00	0.95
Feb-99	0.08	(0.00)	0.58	(0.24)	0.71	0.69	0.71	0.61	0.13	0.55	0.70	1.00	0.79
Mar-99	0.16	0.13	0.74	0.57	0.82	0.59	0.47	0.16	0.04	0.26	0.75	1.00	0.81
Apr-99	0.11	(0.08)	0.84	0.65	0.77	0.47	(0.17)	(0.22)	(0.45)	(0.04)	0.87	1.00	0.32
May-99	(0.10)	(0.14)	0.68	0.54	0.77	0.75	0.59	0.65	0.51	0.34	0.86	1.00	0.64
Jun-99	0.08	0.06	0.99	0.46	0.98	0.97	0.86	0.90	0.72	0.76	0.98	1.00	0.93
Jul-99	(0.06)	(0.04)	0.99	0.60	0.97	0.68	0.63	0.54	0.71	0.99	1.00	1.00	1.00
Aug-99	(0.16)	(0.20)	0.98	0.24	0.99	0.93	0.95	0.92	0.63	0.44	0.98	1.00	0.93
Sep-99	0.10	(0.11)	0.83	0.36	0.75	0.83	0.73	0.80	0.70	0.17	0.79	1.00	0.37
Oct-99	0.16	0.10	0.77	0.21	0.79	0.53	0.22	0.24	0.20	0.43	0.78	1.00	0.15
Nov-99	0.07	(0.03)	0.80	0.42	0.78	0.77	0.16		0.49	0.80	0.76	1.00	0.58
Dec-99	(0.03)	0.02	0.75	0.63	0.71	0.52	0.34		0.15	0.61	0.74	1.00	0.70
1998	0.04	(0.01)	0.76	0.25	0.77	0.69	0.55	0.66	0.28	0.64	0.82	1.00	0.87
1999	(0.02)	(0.03)	0.98	0.41	0.97	0.73	0.69	0.62	0.71	0.94	0.99	1.00	0.98

Key:
- Low correlation (less than 0.5)
- Moderate correlation (between 0.5 and 0.75)
- High correlation (greater than 0.75)

Table B-4
Monthly & Annual Correlation of Daily Regional On-Peak Power Prices (Continued)

Week	COB	Palo Verde	Into Entergy	ERCOT	Into Cinergy	PJM Western Hub	West New York	East New York	New England	MAPP	Into TVA	SERC	Florida/ Georgia Border
Florida/Georgia Border													
Jan-98	0.35	0.08	0.68	(0.15)	0.68	0.73	0.72	0.11	0.13	0.51	0.60	0.67	1.00
Feb-98	(0.11)	(0.21)	0.69	0.01	0.77	0.53	0.36	(0.20)	(0.18)	0.10	0.63	0.77	1.00
Mar-98	0.14	0.16	0.95	0.58	0.87	0.86	0.58	0.52	0.05	0.81	0.91	0.90	1.00
Apr-98	0.11	0.27	0.73	0.45	0.60	0.39	0.40	(0.08)	(0.19)	0.58	0.70	0.44	1.00
May-98	(0.02)	(0.14)	0.80	0.32	0.95	0.63	(0.03)	0.54	0.48	0.88	0.95	0.96	1.00
Jun-98	(0.11)	(0.23)	0.95	0.10	0.83	0.59	0.66	0.58	0.58	0.84	0.95	0.90	1.00
Jul-98	0.25	0.29	0.90	0.49	0.87	0.84	0.68	0.69	0.14	0.76	0.93	0.96	1.00
Aug-98	0.03	(0.09)	0.92	0.51	0.93	0.91	0.86	0.87	0.62	0.56	0.91	0.87	1.00
Sep-98	(0.25)	(0.30)	0.84	0.54	0.82	0.55	0.66	0.05	0.63	0.64	0.79	0.86	1.00
Oct-98	(0.38)	0.25	0.65	0.22	0.60	0.28	0.10	0.07	(0.37)	0.27	0.70	0.62	1.00
Nov-98	(0.46)	(0.45)	0.20	0.16	0.31	0.27	0.02	0.02	(0.17)	(0.07)	0.23	0.08	1.00
Dec-98	0.26	0.22	0.37	0.34	0.22	0.06	(0.12)	0.15	0.17	0.08	0.33	0.47	1.00
Jan-99	0.29	0.50	0.90	0.45	0.88	0.82	0.82	0.26	0.46	0.44	0.91	0.95	1.00
Feb-99	0.19	0.00	0.85	(0.19)	0.75	0.80	0.51	0.54	0.44	0.40	0.72	0.79	1.00
Mar-99	0.10	0.15	0.61	0.57	0.64	0.44	0.48	0.21	0.05	0.15	0.66	0.81	1.00
Apr-99	0.28	0.19	0.26	0.32	0.09	0.17	0.15	(0.33)	0.10	(0.35)	0.17	0.32	1.00
May-99	(0.09)	(0.13)	0.59	0.55	0.59	0.63	0.60	0.48	0.36	0.44	0.66	0.64	1.00
Jun-99	0.00	(0.03)	0.94	0.29	0.95	0.86	0.80	0.94	0.74	0.77	0.93	0.93	1.00
Jul-99	(0.03)	(0.01)	0.99	0.59	0.96	0.65	0.61	0.52	0.68	0.98	0.99	1.00	1.00
Aug-99	(0.26)	(0.30)	0.95	0.28	0.94	0.91	0.93	0.90	0.62	0.41	0.95	0.93	1.00
Sep-99	(0.17)	0.39	0.64	0.22	0.57	0.38	0.34	0.20	0.02	(0.13)	0.61	0.37	1.00
Oct-99	0.14	(0.17)	(0.14)	(0.06)	0.10	0.10	0.24	(0.08)	(0.19)	0.01	0.04	0.15	1.00
Nov-99	(0.12)	(0.30)	0.56	0.35	0.43	0.46	0.22		0.15	0.37	0.58	0.58	1.00
Dec-99	(0.06)	0.03	0.70	0.61	0.67	0.38	0.43		0.17	0.46	0.70	0.70	1.00
1998	0.04	(0.01)	0.85	0.29	0.80	0.67	0.59	0.59	0.30	0.77	0.88	0.87	1.00
1999	(0.03)	(0.03)	0.97	0.40	0.95	0.69	0.66	0.59	0.68	0.93	0.98	0.98	1.00

Key: Low correlation (less than 0.5) · Moderate correlation (between 0.5 and 0.75) · High correlation (greater than 0.75)

C

APPENDIX: THE QUALITY OPTION MODEL FOR VALUING MULTIPLE MARKETS FOR SELLING POWER OR BUYING FUEL

Introduction

The development of futures and options markets for commodities has provided producers and suppliers with a means to reduce price risk. The growth of the futures and options markets has, in turn, spurred the growth of Option Pricing Theory (OPT) tools and techniques to allow the quantification of the benefits from such arrangements so that they can be fairly priced. These analytical tools have been utilized in recent years in applications outside of the financial markets for valuing physical options. This Appendix provides a brief history of the background that provides the framework for valuing access to multiple markets for selling power or buying fuel.

The theoretical framework for valuing the option to obtain an asset at a future time at a fixed price was first presented by Black and Scholes (1973). Their model values the option of a call on an asset based on the assumption that the price of the asset obeys a geometric Brownian motion. The model is a closed-form equation requiring input of five variables. With the exception of the expected volatility of the asset price, all other model variables are readily observable. The simplicity and computational ease of the Black and Scholes model, combined with its demonstrated accuracy and robustness at pricing options, has made this model the standard in the field.

The quality option model has been developed Boyle (1987) as an application of the Black and Scholes model to quantify the benefit to the short position of a futures contract resulting from having flexibility over what is acceptable for delivery at the time of contract expiration. Futures contracts for commodities such as oil or wheat often include a variety of grades, or qualities, that are suitable for delivery since this improves market liquidity. For example, in the case of wheat futures traded on the Chicago Board of Trade (CBOT) there are eleven different varieties of wheat that can be delivered to fulfill the short position.[1]

The empirical studies found that, even with the drawback that the spot prices of the differing commodity grades generally move closely together over time (are highly correlated), there exists a definite and measurable advantage of owning the quality option. That is, for the short position

[1] In most cases a 'bench market' or 'par' commodity is specified with a differential determined for all the other commodities of differing grades or quality that could be freely substituted for one another as a means to equalize prices at the inception of the futures contract.

of a futures contract to be allowed to deliver the cheapest commodity to fulfill the contract at expiration. Not only is this benefit "learnable" by relatively unsophisticated buyers and sellers in commodities markets, but it can also be quantified through the use of a mathematical model.

The Quality Option Model

The formal definition of the quality option is the option to exchange one risky asset for another at zero cost upon expiration of the option contract. Since the option is not exercised before expiration it is known as a European-type option. The mathematical development of this option model was accomplished by Magrabe (1978) and Stulz (1982). Boyle's own work is motivated by Gay and Manaster's (1984) observations of the quality option inherent in futures contracts and is synchronized with refinements in the model formulation made by Johnson (1987).

The quality option model is based upon replicating the futures or forward price using a portfolio consisting of taking a long position in, or buying, a call option at the minimum (less expensive) of two risky commodities, S_1 and S_2, offset by a short position in, or selling, the corresponding put option. This portfolio can be expressed as:

$$C_{min}[S_1, S_2; F....] - P_{min}[S_1, S_2; F....] = 0 \qquad (1)$$

The futures price, *F*, is the exercise price that causes the above relationship to hold. The additional parameters not shown include the correlation and volatility of the prices of S_1 and S_2 and other parameters of the contract. The put-call parity relationship developed by Stulz that incorporates the above relationship for options on the minimum of two commodities is:

$$C_{min}[S_1, S_2; F....] - P_{min}[S_1, S_2; F....] = C_{min}[S_1, S_2; 0....] - Fe^{-rt} \qquad (2)$$

The call option on the right hand side of this equation has a zero exercise price. This call option entitles the owner to freely substitute between the two commodities in order to obtain his own lowest cost to fulfill his obligation. This zero exercise price call option can be evaluated using the same methodology as used in the Black and Scholes Model. This relationship is:

$$C_{min}[S_1, S_2; 0....] = S_1 - [S_1N(d_1) - S_2N(d_2)] \qquad (3)$$

where:

$$d_1 = \frac{\ln\left(\frac{S_1}{S_2}\right) + \frac{1}{2}\sigma^2 T}{\sqrt{\sigma^2 T}} \qquad (4)$$

$$d_2 = d_1 - \sqrt{\sigma^2 T} \qquad (5)$$

$$\sigma^2 = \sigma_1^2 + \sigma_2^2 - 2\rho_{12}\sigma_1\sigma_2 \qquad (6)$$

This model shown in Equation 3 allows us to calculate the value of the quality option. S_1 represents the lowest priced commodity at contract inception. The quantity in the brackets consists of the quality option which is the right to exchange one unit of S_1 for one unit of S_2 at some future point of time (contract expires at time T). If at expiration S_1 remains as the lowest priced commodity then the value of the option is zero. If S_2 is the lowest priced commodity at expiration then the option is exercised (at zero cost) and the net transaction leaves S_2.

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