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Market Design and Price Behavior in Restructured Electricity Markets: An International Comparison[*]

by

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Abstract

This paper argues that the market rules governing the operation of a re-structured electricity market in combination with its market structure can have a substantial impact on behavior of market-clearing prices. Using evidence on the design of electricity markets in England and Wales, Norway, the state of Victoria in Australia and New Zealand, this paper illustrates that market structure and market rules are important drivers of the behavior of prices in a competitive electricity market. The paper first summarizes the important features of the market structure and market rules in each country. One conclusion to emerge from this comparison is that there are many differences in how these markets in each country are organized. I then provide an assessment of the relationship between market rules and market structure and the behavior of prices in each market. The paper closes with a discussion of the available evidence that the behavior of prices in each country is the result of the exercise of market power. Several empirical regularities are suggested by this cross-country analysis. One result is greater unconditional and conditional (on the values of prices from the past week) price volatility in systems dominated by fossil fuels relative to those dominated by hydroelectric power. I also find that electricity supply industries with a larger component of private participation in the generation market tend to have more volatile prices, although the evidence presented also seems to suggest that markets with less participation by government-owned firms also have lower mean electricity prices after controlling for differences in generation technologies used. Electricity spot markets with mandatory participation also tend had more volatile prices than systems with voluntary participation.

1. Introduction

Electricity supply is traditionally viewed as a natural monopoly. Economies of scale in the generation of electricity and the necessity of an extensive transmission and distribution network to deliver it to final customers seem to favor supply by a single firm for a given geographic region. However, Joskow (1987) argues that scale economies in electricity production at the generating unit level are exhausted at a unit size of about 500 MW. More recent econometric work finds that the null hypothesis of constant returns to scale in the supply of electricity (the combination of generation, transmission and distribution) by United States (US) investor-owned utilities cannot be rejected (Lee, 1995).

There is also growing dissatisfaction with limited incentives for efficient operation faced by a cost-of-service regulated or government-owned electric utility. According to this view, even if scale economies in the production of electricity exist, because of the incentives for input choice provided by the regulatory process or by state-ownership, the mode of production chosen by the firm does not allow them to be realized. In addition, the regulated utility and regulatory body joint decision-making process and the state-owned-enterprise decision-making process have historically had difficulty making economically efficient new generation capacity investment decisions, both in terms of the size and fuel type of the generating facility.

As consequence, regulators in the United States and worldwide have recently implemented new regulatory schemes and organizational forms in an effort to improve the incentives for efficient operation of electric utilities. In the US, this restructuring has taken the form of performance-based or incentive regulation plans, where the revenue a utility is allowed to earn is tied less to the cost of providing electricity and more to the attainment of performance goals as quantified by total factor productivity or some other measure of productive efficiency.

Other countries have taken more radical approaches to restructuring their electricity supply industries. Following the privatization of the majority of the generating assets of the formerly state-owned Central Electricity Generating Board (CEGB), the privatization of all of the Area Boards (the local electricity distributors), and the introduction of a market for generation in England and Wales (E&W) on April 1, 1990, many Organization for Economic Cooperation and Development (OECD) member countries have formed wholesale markets for electricity and introduced varying degrees of competition into the retail side of the electricity supply industry. Several other OECD countries are currently in the process of implementing similar reforms. The US has been slow to undertake this radical restructuring process, although many states in the US are currently planning to establish a market for electricity generation similar to those that exist in these countries.[1]

All of these restructurings are consistent with the view that competition should be introduced into the electricity supply industry wherever it is technologically feasible. Only those portions of the production process most efficiently supplied by a single firm remain regulated. The prevailing view is that the technologies for electricity generation and retailing are both such that competition is feasible. As discussed above, economies to scale in generation are exhausted at levels of production significantly below current levels of industry output. It is also difficult to imagine that there are increasing returns to scale in electricity retailing, assuming that all retailers have equal access to the distribution network and electricity from the wholesale generation market. On the other hand, because competition in the transmission and distribution of electricity would require duplication of the current network, these two portions of the electricity supply industry are thought to be the only

[1]The Edison Electric Institute's *Retail Wheeling & Restructuring Report*, Volume 3, Number 3, December 1996, gives a state-by-state summary of restructuring activity in the US.

portions that possess the features of a natural monopoly. Therefore, the transmission and distribution sectors of the electricity supply industries in all of these countries are regulated.

Although privatization is often part of this restructuring process, in all of the developed countries where it has taken place, there are state and privately-owned companies competing in the electricity generation market. Some of these countries only have municipally-owned distribution companies, and others have only privately-owned distribution companies. There are even some countries where the distribution sector is composed of a combination of privately-owned and government-owned companies.

The market structure and rules governing the operation of the electricity industry in these countries are not the direct result of independent actions by market participants—generators, retailers and customers. Consequently, it is perhaps a misnomer to call these markets competitive. Instead, they are the outcome of a deliberate government policy to re-structure (and often privatize) the industry. The final form of the electricity industry in US will be the result of joint decisions by the state regulatory commissions and legislatures, as well as the market participants. In addition, the Federal Energy Regulatory Commission (FERC) must also approve all state re-structuring plans. As I discuss later, there has been an increasing amount of regulatory oversight in the E&W market since the 1990 re-structuring. The other newly established centralized electricity markets are also subject to significant regulatory oversight. All of the plans for establishing electricity markets in US mandate continual monitoring of the industry by both state and federal agencies. For all of these reasons, it is more appropriate to think of these restructured industries around the world and the proposed markets in the US as alternative mechanisms to traditional forms of regulation for achieving the goals of greater economic efficiency in supply electricity.

From the perspective of economic efficiency, the optimal price for electricity should be set to mimic the market price in a competitive industry with many non-colluding firms and minimal barriers to entry. This price has several desirable properties. First, it gives firms the proper signals for the timing and magnitude of new investment expenditures. In addition, because firms have no influence over this market price, they have the maximum incentive to produce their output at minimum cost and can only earn higher profits by cost-reducing innovations not immediately imitated by competitors. The major impetus behind the liberalization of the E&W market was the belief that this new form of market organization would come closer to achieving these regulatory goals for the behavior of electricity prices than the pre-privatization industry structure.[2]

This new form of "regulation" of the electricity supply industry gives rise to a new set of problems associated with achieving economically efficient prices. The problem receiving the greatest attention is market power, which I define as the ability of a firm to cause a significant increase in the market price and profit from this price increase. Firms subject to price regulation (either based on cost-of-service or an incentive regulation plan) have no direct control over the prices they can charge for electricity. Therefore, the explicit exercise of market power is not possible because the regulator, not the firm, sets the market price.

In the markets for electricity currently operating worldwide and those proposed in the US, firms explicitly bid prices at which they are willing to supply electricity. The desire of privately-owned generation companies to maintain and attract shareholders implies that they will attempt to exploit any potential profit-making opportunities through their bidding behavior. For this reason, from the perspective of consumer welfare, the success of a restructured electricity industry can be

[2] An important concern expressed in a 1981 study by the United Kingdom Monopolies and Mergers Commission (MMC) was that the pre-privatization market structure did not provide the proper signals for constructing the optimal amount and type of new generation capacity in a timely manner (Armstrong, Cowan and Vickers, 1994, p. 291).

judged by the degree to which these profit-making opportunities are eliminated by the design of the market rules governing its operation and market structure of the industry.

There are many observable differences in the market structure in the various restructured electricity supply industries. These differences in market structure have led to the imposition market rules designed to mitigate the ability of firms to exercise of market power of the form thought to be most prevalent given the market structure that exists in the industry. There are also many differences in market rules across these electricity industries that are due to historical reasons or because of engineering concerns about network integrity. The interaction of these market rules with the market structure of the industry determines whether economically efficient prices are set by these markets.

The purpose of this paper is to characterize this across-country relationship between market rules and market structure and spot prices for electricity using the restructured electricity markets in England and Wales, Sweden and Norway, the state of Victoria in Australia, and New Zealand. By studying the across-country relationship between market rules and market structure and the behavior market-clearing prices, insights can be gained about how to set market rules to mitigate the incentives for the exercise of market power for a given market structure.

The paper first describes the market structure and market rules governing the operation of each electricity supply industry. Because the E&W electricity market was the first established among OECD member countries, it has served as a model for much of the electricity industry restructuring worldwide. Consequently, I first provide a detailed discussion of the market rules and market structure of this industry. Then I describe these two aspects of the joint Norway and Sweden electricity market (Nord Pool), the Victoria Electricity market (VicPool) and the New Zealand electricity market (NZEM) in light of our discussion of the E&W market. Next I present various views of the time series behavior of spot electricity prices in each of these markets and then relate these differences in the behavior of prices to observable differences in the market rules and market structure governing the operation of these three electricity markets. This discussion focuses on the linking differences in market rules and market structure to differences in the behavior of electricity prices across the countries. Although a detailed analysis of how these across-country differences in market rules and market structure foster or mitigate the exercise of market power is a topic for future research, I will also point out some far from definitive evidence for the exercise of market power in the time series behavior of these spot prices and, where it is possible, I will link this method for the exercise of market power to observable differences across the markets in the rules governing their operation and the structure of the industry.

2. Industry Structure in the England and Wales Electricity Market

The purpose of this section is to summarize the market structure and rules governing the operation of the E&W system. I first describe the restructuring of the electricity industry in England and Wales. I then describe the major players in the market and their relative sizes and mix of generation capacity they own. The discussion then focuses on the rules governing the operation of the E&W electricity market. First I discuss the strategic weapons available to each of the market participants. Then I lay out the various stages of the price determination process and the potential opportunities for the exercise of market power that these rules create. I then discuss the evolution of the regulation of this market attempting to limit market power by the two largest generators in the system.

2.1. Market Structure in England and Wales

Since April 1, 1990, all but a small fraction of electricity consumed in England and Wales must be sold through a day-ahead spot market for electricity with market-clearing prices set on a half-hourly basis. This market was formed as the end result of the break up and privatization of the state-owned Central Electricity Generating Board (CEGB) and the privatization of the 12 Area Boards, the local electricity distribution companies. The generating facilities of the CEGB were separated into three large companies. National Power and PowerGen took over all existing fossil fuel power stations. Nuclear power plants remained state-owned, under the auspices of Nuclear Electric, through the 1995/96 fiscal year.[3] The distribution system was divided into twelve regional electricity supply companies (RECs). The national transmission grid became the National Grid Company (NGC) which was jointly owned by the 12 RECs. It provides transmission services from generators to the RECs, coordinates transmission and dispatch of electricity generators and runs the electricity spot market. In addition to the three large E&W generators, Scottish non-nuclear companies (Hydro-Electric and Scottish Power), Electricity de France (EdF), and a number of independent power producers (IPPs) also sell electricity to the pool. The links to the E&W market from Scotland and France are constrained by transmission capacity at 1.6 GW and 2.0 GW. The maximum capacity available to serve the E&W electricity market is approximately 59 GW and the peak system demand is approximately 48 GW.

This restructuring has transformed the electricity supply industry into four separate sub-industries: (1) generation, (2) transmission, (3) distribution and (4) retail sales. With some minor exceptions to be noted, the electricity supply industries in all subsequent restructurings have been sub-divided in this same manner.

Because the technology of generation is thought to exhibit constant or decreasing returns-to-scale at current levels of production, a competitive market in generation is the foundation of all of the restructured electricity industries I describe. Although the rules governing the operation of the

[3]Fiscal years run from April 1 to March 31 of the following calendar year.

market and the numbers, plant sizes, and mix of generating technologies employed differ greatly across the various industries, all of these markets are designed to foster economically efficient wholesale prices for electricity.

NGC runs both the financial and physical side the E&W electricity market. It serves as both the power exchange (PX) and the independent system operator (ISO), because it determines both half-hourly market-clearing prices and it runs the physical national electricity grid, making generator dispatch decisions in real-time to manage congestion on the gird and provide the ancillary services necessary to guarantee reliable power to all final customers. Originally it was jointly owned by the RECs and generators, but it was recently sold off and is currently a publicly traded corporation.

Both transmission and distribution are thought to be natural monopolies, so that prices for bulk transmission provided by NGC are regulated by a price-cap mechanism. For the same reason, the distribution services provided by each of the RECs to customers in their service areas are regulated by a price cap.

The retail side of the market is divided into franchise and non-franchise customers. Non-franchise customers are given the option of choosing their supplier from any of the 12 RECs as well as National Power or PowerGen directly. Initially, non-franchise consumers, were those with peak demands greater than 1 megawatt (MW). On April 1, 1994, the 1 MW peak demand limit on these non-franchise consumers was reduced to 100 KW. This size restriction on customer peak demand will cease to exist March 31, 1998, when even residential customers will be offered this option (i.e., all customers become non-franchise). RECs are required to allow competitors to transfer electricity over their distribution systems at the same price they charge to themselves to provide this service to their retail customers located in their own service area.

Since the formation of the market, National Power and PowerGen have owned the majority of generating capacity and have produced at least 54.5% of total electricity sold during each of the fiscal years, through 1995/96, the pool has operated. PowerGen and National Power, most notably, have reduced their respective capacities steadily since the pool began. National Power began the 1990/91 fiscal year with approximately 30 GW of capacity and PowerGen had approximately 19 GW of capacity. By the beginning of the 1995/96, fiscal year, these capacities were approximately 20 GW and 15 GW, respectively. Contrary to this trend by the two largest generators, several independent power producers (IPPs) have entered the market, with, most all cases, combined-cycle gas turbine (CCGT) technology generation facilities. The net effect of the deletions and additions to capacity in this market has been a decrease in the total generation capacity serving the market from April 1, 1990 to the present, despite growing electricity consumption in E&W over this same period. The market share of electricity sold by these two dominant producers has also declined, from 46% (National Power) and 28% (PowerGen) in the 1990 fiscal year to 31.38% and 23.1% for the 1995 fiscal year.[4] Another important feature of the market structure is the similarity in fuel mix between National Power and PowerGen. As of April 1, 1995, National Power's capacity had the following approximate (because of fuel switching capabilities) fuel mix percentages, 75% coal, 15% oil, 9% natural gas, and 1% hydro. PowerGen's approximate mix was 70% coal, 16% oil, 13% gas and 1% hydro.

The vast majority of a REC's customers purchase electricity at rates fixed independent of within-year variations in the pool price. All residential customers pay fixed prices that may vary in a mutually agreed-upon manner on a daily or weekly basis, independent of fluctuations in the pool

[4]Nuclear Electric's 1995/96 fiscal year market share was 22.49%, power imported from Scotland and France 8.71%, pumped storage 0.69%, and IPPs and others 13.63% (Electricity Pool of England and Wales, *Statistical Digest*, May 1996).

price, for the entire fiscal year. The most common form of this pricing plan has one fixed price per MWH for all consumption during daylight hours and another fixed price per MWH for consumption during nighttime hours. Almost all commercial and industrial users purchase power through similar annually negotiated fixed price contracts which also vary on a daily or weekly basis, independent of movements in the pool price. Consequently, within-day, day-to-day, or even month-to-month movements in the pool price have no impact on the prices all but a small fraction of customers pay because the pattern of prices they face does not change for the entire fiscal year. Only a very small fraction of E&W total system load, approximately 5%, is purchased by final consumers according to the variations in the half-hourly spot-market price.[5]

Because RECs provide electricity to the vast majority of their customers according to rate schedules fixed well in advance of the realization of pool prices, they normally hedge against this price volatility by purchasing "contracts for differences" (CFDs). CFDs are simply financial instruments insuring prices at which an agreed upon quantity of electricity can be purchased and sold[6]. CFDs have been sold by generators as well as financial institutions and traders that deal in commodity markets and derivative securities. They are **not** contracts to deliver electricity. I should emphasize that the E&W mandatory spot market structure does not allow physical bilateral trades between generators and their customers. Unless a generating facility is dispatched by NGC as part of the day-ahead spot market-clearing process, that plant cannot produce electricity. Consequently, if a customer and generator sign a bilateral contract for electricity supply, this does not guarantee that

[5]Wolak and Patrick (1996a) describes these sorts of retail price contracts in more detail. Patrick and Wolak (1997) analyze the structure of demand under real-time prices for a sample of these customers from one of the RECs..

[6]Most CFDs guarantee a fixed price for a fixed amount of electricity in the following manner. Suppose a generator and a REC write a CFD for 1 MWH of power at a strike price of 20 £/MWH. If the spot price of electricity is greater than 20 £/MWH then the generator pays the REC the difference between the spot price and 20 for the contracted 1 MWH. If the spot price is less than 20 £/MWH, the REC pays the generator the difference between 20 and this spot price for the contracted 1 MWH.

the generator will be dispatched in a manner that matches the customer's half-hourly demands or any pre-specified rate of production. Whether or not a plant is dispatched and the rate at which it is operated in a half-hour is the decision of NGC. A plant that is dispatched by NGC (that is not constrained on) will receive the market-clearing spot price from E&W pool for all MWHs they produce during that half-hour, regardless of the long-term contractual arrangements it has made with a REC or large customer in the CFD market.

CFD contracts were also used in the initial privatization process to maintain employment in the UK coal industry. The Government required National Power and PowerGen to enter into contracts for the purchase of a higher volume of UK coal than they wished at higher-than-world-market prices, thus maintaining employment in the coal mining industry. Vesting CFD contracts between each REC and National Power, PowerGen, and other generators were designed to compensate these generators for the higher prices they paid for UK coal under these coal supply contracts. The strike price of these CFDs allowed the costs of the coal contracts to be passed on to the RECs, and the structure of the REC regulatory process—a price cap with a Y-factor to pass through extraordinary cost increases—allowed these costs to be passed on to final customers in the form of higher prices. In the first two years following privatization, it is estimated that CFD contracts covered 84.3% and 89.1%, respectively, of National Power's and PowerGen's generation, declining to 72.7% and 70.6% over the next two years (Helm and Powell, 1992).

2.2. Market Rules in England and Wales

For trading to take place in the E&W market, participants must know how they are compensated for the bids that they submit, particularly how market-clearing prices are determined and how dispatch decisions for generators are made. Recall that generators offer or "bid" prices at which they will provide various quantities of electricity to the E&W pool from their generating stations throughout the following day. They have two strategic weapons to influence the 48 half-hourly market-clearing electricity prices: (1) the price at which they are willing to supply electricity from a fixed portion of each generating facility for the entire next day, and (2) the half-hourly decision of whether or not to make that portion of each generating facility available to be called upon by NGC to produce power.

The day-ahead bid prices and availability declarations submitted by generators are input into the general ordering and loading (GOAL) program at NGC to determine the merit order of dispatching generation and reserve capacity. The lowest price generating capacity is dispatched first, unless such dispatch will compromise system integrity. Subject to this caveat, dispatching plants in this "least-cost merit order" gives rise to an upward sloping aggregate electricity supply function for each half-hour for the following day. The system marginal price (SMP) for each half-hour of the following day is the price bid on the marginal genset required to satisfy NGC's forecast of each half-hour's total system demand for the next day, i.e., the bid where this expected demand crosses the aggregate supply curve.

The methodology and data input into NGC's forecast of demand are readily available to generators prior to their submissions of bid prices and availability declarations for the next day [Baker (1992), The Electricity Pool (1997), and National Grid Company (1995)]. This implies that the generators can compute NGC's forecast of demand for all 48 load periods during the next day before they submit their bid prices and availability declarations. Wolak and Patrick (1996b) argue that this market rule has important implications for the strategies used by generators to exercise market power. Moreover, this forecast demand is perfectly price inelastic.

The Pool Purchase Price (PPP), the price paid to generators per KWH in the relevant half-hour, is defined as

$$PPP = SMP + CC,$$

where the capacity charge is CC = LOLP×(VOLL - SMP), LOLP is the loss of load probability, and VOLL is the value of lost load. The CC is intended to provide a signal to generators of the necessity of new generation capacity and to signal consumers that their consumption has a significant probability of requiring the maximum amount of generating capacity available in that load period. The VOLL represents the per KWH willingness of customers to pay to avoid supply interruptions. It was set by the Director General of the Office of Electricity Regulation (OFFER) at £2,000 per megawatt-hour (MWH) for 1990/91 and has increased annually by the growth in the RPI since. The LOLP is determined for each half-hour as the probability of a supply interruption due to generation capacity being insufficient to meet demand. The LOLP is a decreasing (at an increasing rate) function of the expected amount of excess capacity available during each half-hour period. The greater the amount of capacity available relative to expected demand in any half-hour, the lower the LOLP and therefore the lower the capacity charge per KWH paid to generators. Wolak and Patrick (1996b) argue that this relationship has important implications for the two largest generators' strategies for obtaining high PPPs.

The pool selling price (PSP) is the price paid mostly by RECs purchasing electricity from the pool to sell to their final commercial, industrial and residential customers. For the purposes of determining this price, the 48 load periods within the day are divided into two distinct price-rule regimes referred to as Table A and Table B periods. During Table A half-hours the PSP is

$$PSP = SMP + CC + UPLIFT = PPP + UPLIFT.$$

UPLIFT is a charge used to collect costs incurred when demand and supply are actually realized each day, is only known *ex post*, is the only price uncertainty from the day-ahead perspective, and is collected over at least 28 Table A pricing periods each day (UPLIFT is zero for Table B pricing periods). Recall that the E&W market is an *ex ante* market in the sense that prices are set based on a demand forecast rather than actual demand. The costs of supplying the difference the forecasted demand and the realized demand for the day is recovered through the UPLIFT charge.

This charge also compensate generators for reserve, plant available but not actually used to meet demand, and startup costs. Generators are paid for being available to produce electricity according to

$$\text{Availability Payment/MWH} = \text{LOLP}\times(\text{VOLL} - \max[\ \text{SMP}, \text{bid price}\ ]).$$

This approach to setting availability payments compensates a relatively high-priced plant that is not used, but is available, less than a plant that bids close to the SMP. The remaining portion of UPLIFT is comprised of NGC's costs of ancillary services (reactive power, frequency control, hot standby, and black-start capability).

By 4 pm each day, the SMP, CC and the identities of the Table A and Table B periods for all 48 load periods for the following day are communicated to pool participants. UPLIFT averages less than 10 percent of the PSP and, as discussed in Patrick and Wolak (1997), it can be accurately forecasted on a day ahead basis. Consequently, a large fraction of the *ex post* PSP is known on a day ahead basis.

2.3. Regulatory Oversight in England and Wales

The Electricity Act of 1989 established the OFFER, with Professor Stephen Littlechild serving as the Director General, to oversee the operation of the re-structured United Kingdom electricity industry, from generation to transmission and distribution to final customers. At privatization there were no explicit controls over the PPP. Since then, Professor Littlechild has instituted several regulatory changes in an attempt to inhibit strategic price and supply schedule offerings by the generators. These include (1) amending the original generation license to require generators to make public their plans on capacity availability, (2) a change in the way LOLP is calculated, (3) price caps on PPP, (4) the divestiture of generating plant, and (5) a price cap on UPLIFT.

The original generation license was revised, following the Pool Price Inquiry in December of 1991, to restrict the ability of generators to manipulate the PPP by reducing the capacity made available to the pool. The changes require generators to provide, for public viewing, reports containing the generator's criteria for determining the availability of their capacity to the pool, closing generating stations, and otherwise reducing generating capacity. Each year, generators must also file a detailed forecast of the availability of each generating unit for the coming year and, at year's end, file a "reconciliation" explaining any deviations from the anticipated availability. This information is also publicly available. However, “Generators are under no obligation under Pool Rules to declare any of their Centrally Dispatched Generating Units (CDGUs) available to generate at any particular time, even though the CDGU may be operationally available.”[7] Wolak and Patrick (1996a) describe various actions by the Director Generator to encourage the generators to declare capacity available.

Due to perceived excessive variability in the PPP, OFFER charged National Power and PowerGen with exercising market power to drive up pool prices. This matter was resolved with the institution of caps on pool prices over the fiscal years 1994/95 and 1995/96 as part of a voluntary agreement, reached February 11, 1994, between National Power, PowerGen, and OFFER after Professor Littlechild threatened to refer these generators to the Monopolies and Mergers Commission.[8] This agreement also included the recently completed divestiture of 4 GW and 2 GW of coal or oil generating plant by National Power and PowerGen, respectively.

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[7] *An Introduction to Pool Rules (Issue 2)*, The Electricity Pool, p. 10.

[8] The Electricity Act of 1989 gives the Director General the authority to refer the firms to the Monopolies and Mergers Commission in order to make changes in the relevant license. Referrals can also be made under the Fair Trading Act of 1973 or the Competition Act of 1980.

As a result of UPLIFT increases in 1993/94, OFFER instituted, in April of 1994, the "uplift management incentive scheme" (UMIS) in an attempt to encourage NGC to minimize “avoidable costs” incurred in operating the E&W power market. UMIS was then replaced with the Transmission Services Project (TSP) on October 1, 1995. TSP divided uplift into the costs associated with reactive power, system constraints, transmission losses, and other ancillary services. Each category has a price cap intended to provide an incentive for NGC to keep these costs down.

3. The Electricity Supply Industry in Norway and Sweden

Beginning January 1, 1996, the world’s only international power exchange opened in Olso, Norway. Statnett Marked AS, a subsidiary of the Norwegian grid company, Statnett SF, has been operating the Norwegian Power Market since 1993. From 1991 to 1993, Statnett SF managed both the national gird and the power market, with was introduced following the Norwegian Energy Act of 1990. With the formation of the international Nordic power market, Statnett Marked AS changed its name to Nord Pool ASA and is currently owned 50/50 by the Statnett SF and Svenska Kraftnätet, the Swedish national grid operator. This power exchange integrates the Norwegian and Sweden electricity systems with 96 Norwegian and 21 Swedish participants as of March 1996. Denmark, Finland, and Russia each have one participant in the market. Statnett SF is owned by the Norwegian government and Svenska Kraft Kraftnätet by the Swedish government.

3.1. Market Structure in Norway and Sweden

There are three major differences between the Nord Pool market structure and the E&W market structure. First, is that 99 percent of installed capacity in Norway is hydropower, with the remaining capacity primarily oil and gas thermal power. In Sweden, approximately half of total installed capacity is hydropower. Nuclear power has the next highest capacity share of approximately 30 percent. Except for a small amount of renewables generation capacity, oil and gas comprise the remaining thermal power capacity. Consequently, more than 85 percent of the generation capacity in Norway and Sweden is either hydropower or nuclear power, technologies which have very low marginal costs of producing electricity. In contrast, more than 80 percent of the generating capacity in the United Kingdom is higher marginal cost coal, oil or gas-fired generating technology.

The second major difference is that Nord Pool is not a mandatory pool. Generators and consumers voluntarily decide whether or not they wish to sell or purchase electricity through this market. As a consequence, the majority of electricity in Norway and Sweden is still traded via bilateral contracts between generators and consumers, with the pool serving primarily as a wholesale market for marginal energy supplies. Nord Pool is actually composed of two markets operating simultaneously with the bilateral contracts market. During any hour in the day electricity is transacted on each of these markets and through bilateral contracts. In addition, there is a futures market where weekly financial futures contracts with maturities ranging from a week ahead to three years ahead are traded. The market most like the E&W market is the Daily Power Market (DPM) or Spot Market. Here fixed quantities of electricity are traded at prices set on a day-ahead basis for 24 hourly periods. Because of differences between the day-ahead electricity consumption plans and actual consumption plans, incremental electricity must be dispatched throughout the day to meet this unexpected demand and to maintain system integrity. This market for within-day electricity is called the Regulation Power Market (RPM) in Norway and the Balancing Market in Sweden.

The final difference between Nord Pool and the E&W industry is that much of the generation capacity is fully or partially state-owned. When the Energy Act of 1990 "deregulated" the electricity supply industry in Norway, Statkraft, the state-owned integrated electricity supplier, was broken up into separate companies providing generation, transmission and distribution services similar to the CEGB in England and Wales, but was not privatized. Statnett SF was created as the state-owned national grid company and system operator. Statkraft SF retained all generating plants. Statnett Marked AS was subsequently formed to run the electricity market. Statkraft SF owns approximately 40% of Norway's hydroelectric capacity and produces approximately 30% of it electricity output. The second largest producer in Norway is Hydro Energy, a subsidiary of Norsk Hydro, the largest industrial end user of electricity in Norway. It produces approximately 10% of Norway's electricity output. There are many other smaller firms which generate the remaining 60% of Norwegian electricity production. The vast majority of this capacity is owned by municipalities. Different from Norway, where there are more than 200 generation companies (many of whom do not trade in the spot market), in Sweden, 10 large generators produce more than 90 percent of Swedish electricity. Vattenfall, the Swedish State Power Board, generates approximately 50% of Swedish electricity. In both countries, the majority of distribution assets are municipally owned. In Sweden, some of the large retail distributors also generate all or a large fraction of the electricity they distribute. For example, Sydkraft and Stockholm Energi, the two largest distribution companies, are the next largest generators after Vattenfall. In Norway, about half of the 200 distribution companies also own generation assets.

3.2. Market Rules for Nord Pool

The rules governing the operation of the Nord Pool DPM differ from those for E&W market in a number of dimensions. First, as discussed above, the DPM only trades a small fraction of the electricity produced within any hour during the day. In 1994, 14.6 Terrawatt-hours (TWH, 1 TWH = 10^9 KWH) of electricity was sold on the Spot market. In 1995, this figure rose to 20.0 TWH. Total Norwegian electricity production in 1994 was 113.6 TWH and 123.5 in 1995, which implies only 12.8% and 16.2%, respectively, of total Norwegian generation was sold through the DPM in these two years. In 1996, 40.3 TWH was sold in the new international DPM. Comparing this figure to 240.9 TWH, the total amount of generation in Norway and Sweden in 1996, implies 16.7% of the production of the two countries is sold through this market. Sales in the RPM have remained stable over the three complete years Statnett Marked has operated, 5.5 TWH of sales in 1993, 6.1 TWH in 1994 and 5.6 TWH in 1995. This is because the primary function of this market is to resolve differences between planned and actual consumption on the DPM. Prices in the RPM very closely track those in the DPM, although they appear slightly more volatile than those from the DPM. With the formation of the international DPM effective January 1, 1996, the Swedish system operator, the national grid company Svenska Kraftnät, formed a similar regulation power market, which it calls the "Balancing Market" (Balansetjänesten).

Originally the Weekly Power Market (WPM) sold forward contracts for physical deliveries in the future. Beginning in 1995 this market was transformed into a futures market that sells what are called termin contracts, which are obligations to buy or sell in at a future time a given quantity of electricity at a price agreed upon at the time the contract is entered into. These termin contracts are standardized along various dimensions. The smallest quantity that can be purchased is 1 MW. There are three different time horizons to the contracts: (1) week-long contracts, ranging from up to 4-7 weeks in the future; (2) block contracts of 4 weeks long, for electricity delivered up to a year in the future; and (3) seasonal contracts for blocks lasting an entire season of the year, for electricity delivered over one year in advance. The final dimension of the contracts is the time period within the day that the contract is valid. There are three types of contracts along this dimension: (1) basic power, all hours in the week (168 hours); (2) day power, from 7 am to 10 pm from Monday to Friday (75 hours); and (3) night power, the remaining hours not covered by the day power contract. There is continuous trading in this market five days each week for 2.5 hours each day, with sellers submitting ask prices for the contracts they wish to sell and buyers submitting bid prices for the contracts they wish to purchase, and trades taking place when bid prices exceed ask prices. These contracts are purely financial contracts in the sense that financial settlement takes place daily for customers holding these contracts, based on the day-to-day changes in the relevant termin prices. During the delivery period financial settlement of the contract takes place at the difference between the last price in the WPM and that hour's price in the DPM. Volume in this market has grown significantly over time. In 1994, total trading volume over all contracts, was 7.1 TWH. In 1995, this figure more than doubled to 15.5 TWH.

The DPM is similar to the E&W market in the sense that generators submit their bids on a day ahead basis to the Nord Pool. However, because this market operates on top of the bilateral contracts market, it is what the Nord Pool calls a "netto-market" in the sense that each customer must be in balance during each hour the following day—its supply obligations must equal the sum of its own generation, bilateral contract purchases from other generators and DPM purchases. Consequently, the bid functions submitted by market participants give the amount of power it will actually sell or buy each hour on the DPM as a function of the market clearing price. In this sense, the DPM differs from the E&W spot market, because in this market generators only submit bid functions giving the amount they are willing to supply to the E&W market and NGC determines how much electricity will actually be supplied to meet demand and maintain system integrity during the next day. Recall that by law all but a very small fraction of total generation in E&W must be sold on the spot market during each half hour. In addition, the aggregate demand determining the market-clearing price in the E&W is the value forecasted by the National Grid Company, whereas in the DPM, the market-clearing price for each half hour is determined at the intersection of the aggregate of the demand and supply bids. For this reason, a more accurate characterization of the DPM is that it is a physical forward market for one-hour deliveries during the following day. Different from the

E&W market, there is no uncertainty in the quantity of electricity that is traded on the spot market the next day.

There is also a geographic dimension to the price-setting process in the DPM that is different from the E&W market where there is a single price for electricity in each half-hour, except for electricity produced by constrained-on generators. Every Wednesday, Nord Pool sends to market participants either electronically or by FAX two types of information about how bids should be submitted for trade in the DPM during the following week. This information defines the geographic areas of Norway and Sweden for which participants will submit bids. These bid areas are determined using historical generation and consumption data, transmission capacity and the description of the electricity grid. If a transmission bottleneck is expected to occur between two geographic areas during the week, then separate bid areas will be defined on either side of the transmission bottleneck. These bids areas can also change over the course of the week based on planned or unplanned bottlenecks in the transmission grid. The second type of information Nord Pool supplies to participants is the bid price interval giving the highest and lowest price that must be covered by a bid from each participant for all hours in the coming week. This is done to guarantee a unique price for each bid area. The bidder can submit a maximum of 14 prices in between these two maximum prices giving the amount it is willing to buy or sell as a function of these prices.

All bids by market participants must be registered in standardized bid forms, one for each bid area, and submitted electronically or by FAX to Nord Pool by noon the day before actual physical delivery takes place. The bid gives the maximum hours the bid is valid (minimum one hour and maximum all of the hours a bid area is valid). These bids must be finalized by noon the day before power will be delivered on DPM. By 2 pm that same day, Nord Pool takes this information determines the market-clearing prices for each of the 24 hourly period starting with midnight and ending at 11 pm the next day. The system price is determined from the intersection of the aggregate electricity supply functions (bids to supply electricity as a function of price) with the aggregate electricity demand functions (bids to consume electricity as a function of price) without taking into account transmission constraints. If there are no transmission constraints, then all generators receive the same price for the electricity they produce.

If there are transmission constraints, generators in different bid areas receive different prices for the electricity they produce in the form of different capacity fees across the different bid areas. Similarly, consumers in these bid areas purchase at different prices because of these capacity fees. In areas where generators want to sell more than can be transmitted, they will be required to pay a capacity fee to do so. Consumers in these bid areas will receive this capacity fee for all of their consumption in this area. In bid areas where bidders want to purchase more than can generators are willing to supply, the price will be increased by a potentially different capacity fee. Generators in this area will receive this capacity fee in addition to the spot price for their generation. Prices in the surplus generation area will fall and prices in the deficit generation area will rise until the amount of electricity generators in the surplus area are willing to transmit to the deficit region equals the amount consumers in the deficit region are willing to take, and both are equal to the transmission capacity between the two bid regions. These actions by Nord Pool end when all transmission bottlenecks are eliminated.[9] Bid areas which set the same prices are aggregated into price areas. Market participants are then notified of these price areas, area prices and the hours they are valid. Each participant is told the contractual amount of electricity he will be called upon to buy or sell in each price area during

[9]Because of a very extensive transmission networks in Norway and Sweden, transmission bottlenecks rarely occur within the two countries. The major source of bottlenecks occurs because of trades across the two countries.

each of these hours and the total amount of power transacted on the DPM during each hour. If there are no transmission bottlenecks then the entire system becomes a single price area.

The forward contract nature of the DPM is another way in which it differs from the E&W spot market. In E&W, generators only know the market-clearing price for the next day, but do not know exactly how much electricity they will be required to supply to the spot market during each half-hour that day until the half-hour actually occurs. However, the presence of regulation power markets in Norway and Sweden, which operate during the next day to balance any discrepancies in a generator's or consumer's contractual supply or demand obligations (including those from the DPM), fulfills this role in the Nordic Power market. These unexpected deviations from plans are made up by purchases or sales into this market, so that the DPM clears the day before actual dispatch takes place. Consequently, the DPM is simply another contractual supply or consumption obligation (similar to a bilateral contract) during the day actual supply or consumption takes place. In the E&W market, NGC serves the function of the RPM, because it dispatches generation during the following day to supply the amount of electricity actually demanded (rather than the expected demand used to set the Pool Selling Price) and to maintain system balance.

During each dispatch day for the DPM, a regulation power market operates in each country. The equation: Production + import = consumption + grid losses + export, must hold for each bid area. In Norway, each day before 7:30 pm bids are registered with the RPM. Generating stations that bid have to be able to alter their production within 15 minutes. A bid is an option for the system operator and can take two forms. An upward regulatory bid indicates the price the market participant demands for an extra amount of power produced. A downward regulatory bid sets the price that actor is willing to pay for buying power (by producing less than planned). All bids are grouped according to price areas and sorted by price. Regulation of each bid area uses these bids to increase of decrease production in these areas. The market participant called upon to increase or decrease their output is given at least 15 minutes notice before they must produce and is given no indication of how long it must produce, but will be given at least 15 minutes notice before it must shut down. When an hour of regulation has passed, the price in the RPM is fixed and there is one price for each price area. After each hour, each participant in the DPM calculates its unbalances in each price area—how much more or less than it contracted for on the DPM did it actually consume or produce in that hour. This unbalance is settled at the RPM. If a participant consumes more than planned, then it must buy in the RPM, and if it consumed less than planned, it must sell in the RPM. This implies that all DPM participants, even if they don't submit bids to the RPM, are involved in this market. The regulation market in Sweden operates in a slightly different manner. It pays for downward adjustments to generation in areas with surplus and for upward adjustments to generation in deficit areas. The costs of these two operations is recovered from the transmission tariffs Sweden generators pay to supply electricity. Because of this congestion management scheme, Sweden is always a single bidding area in the Nordpool bidding process.

3.3. Regulatory Oversight of Nordic Power Market

Up until the formation of the international power exchange between Sweden and Norway, the Norwegian Water Resources and Energy Administration (NVE) oversaw the operations of the Nordic Power market. It is still responsible for monitoring grid operations in Norway and is responsible for setting the tariffs for the local distributions companies throughout Norway. Previously, distribution tariffs were set on a cost-of-service basis, but starting in 1997, NVE implemented a version of price-cap regulation. Because the Nordpool is not required by the Sweden government to operate under any particular license, the majority of formal monitoring duties remain with NVE.

There have been several inquiries into the reasons for high prices in the Nordpool. Following the formation of the Norwegian Power market in 1991, prices were the lowest they have ever been. These prices continued until Statkraft SF publicly announced a policy not to supply to the spot market a prices below 100 NOK/MWH. Statkraft apparently demonstrated its determination to maintain market-clearing prices above this level by punishing deviators by flooding the market and driving prices to zero. Prices subsequently stabilized at significantly higher values. Annual mean prices in the spot market have been above 100 NOK/MWH for all years following 1992. The Norwegian Competition Authority (Prisdirektoratet) investigated whether collusion between generators causes these elevated prices, but found little evidence in favor of this claim. Other periods of extremely high prices seem to be explained by usually dry weather conditions.

4. The Victoria Power Supply Industry

The Victoria Power Exchange (VPX) is the longest running wholesale electricity market in Australia. It was established under the Electricity Industry (Amendment) Act of 1994 and formally began operation on July 1, 1994. New South Wales (NSW) recently established a state-level wholesale market for electricity which began operation May 10, 1996. Effective May 4, 1997 interstate electricity competition between generators in NSW and Victoria to supply electricity to energy retailers in these two states began. Previously trade between NSW and Victoria was limited to long-term contract transactions and any short-term trades were based on system integrity considerations rather than economic considerations. The integration of these two markets to allow all feasible trades between two states is the first stage in establishment of the National Electricity Market for Australia, known as NEM1.

The ultimate goal of this process is first to establish a single electricity market across Queensland, NSW, Victoria and South Australia. Because the eastern seaboard of Australia is currently not a fully integrated system, modifications of the system must be completed before a competitive interstate market can be introduced. Following a process similar to the one that occurred in E&W, the plan is to separate transmission and distribution from generation for all of the vertically integrated and formerly government-owned utilities throughout Australia and privatize or corporatized these new entities. One outcome of this process is a harmonization of the rules governing the operation of two markets currently in operation in Victoria and NSW. The market structures of the two electricity supply industries in Victoria and NSW are also similar in terms of the relative sizes of the generation firms and the mix of generation capacity by fuel type, although the NSW industry is a little less the twice the size (as measured by installed capacity) of the Victoria industry and the largest 3 generators in NSW control a larger fraction of the total generation capacity in their market than the three largest generators in Victoria control of their market. Because the NSW market has operated for such a short time, my discussion will focus on the Victoria industry.

4.1. Market Structure in the Victoria Electricity Supply Industry

Restructuring and privatization of the State Electricity Commission of Victoria (SECV) in 1994 took place at the power station level. Each power station was formed into a separate entity to be sold. Some stations have already been sold and those that remain unsold continue to be operated by SECV. Buyers have come from within Australia and abroad. For example, PowerGen, the second-largest E&W generating company, owns a 49.9% share of Yallourn Energy, along with investors from Japan and Australia. Mission Energy a U.S. company owns 51% of the Loy Yang B station. The distribution sector was formed into five privatized companies: CitiPower, Eastern Energy, PowerCor, Solaris Power and United Energy, which are owned by a combination of U.S. utilities and Australian companies. For example, PowerCor is owned by the U.S. firm PacificCorp and Eastern Energy is owned by Texas Utilities. There is an accounting separation within these distribution companies between their electricity distribution business and their electricity supply business. All other retailers have open and non-discriminatory access to any of the other distribution company's wires. The high-voltage transmission grid remains in state hands, but was renamed PowerNet Victoria. The VPX is separate from all of these entities. Its mission is to manage the wholesale electricity market, manage the security of Victoria's power system and direct the development of the High Voltage transmission system. This is different from the E&W model where the National Grid Company also owns the High Voltage transmission system, in addition to providing these three services. It differs slightly from the Nord Pool model where Stanett SF owns and operates the grid, but Nord Pool ASA, a subsidiary of Statnett SF, runs the wholesale electricity market.

The Victoria Electricity Supply Industry (ESI) is significantly smaller than either the E&W or Norway and Sweden market. Peak demand in this market runs approximately 7.2 GW and maximum amount of generating capacity that can be supplied to the market is approximately 9.0 GW. Because of this small peak demand, and despite the divestiture of generation to the station level, at least three of the largest baseload generators have sufficient generating capacity to supply at least 20% of this peak demand. More than 80% of generating plant is conventional steam coal-fired, although some of this capacity does have fuel switching capabilities. The remaining generating capacity is shared equally between gas turbines and hydroelectric power. In this dimension, the market structure of the Victoria ESI is similar to the E&W market structure where there are two large primarily coal-fired generation companies, National Power and PowerGen, which each control more than 25% of total E&W system capacity.

There are four main classes of participants in the Victoria Pool (VicPool). They are the generators, who produce electricity to sell; the distributors, who purchase wholesale electricity from the pool and retail it to their customers; the large industrial and commercial customers who purchase their electricity directly from the pool; and Traders, who deal with the historic contract obligations of the Victoria ESI prior to reform.

4.2. Market Rules in Victoria Power Exchange

Although there are important differences, the VPX shares several features with the E&W market. In particular, prices are set on a half-hourly basis using bids submitted on a day-ahead basis by generators and demand-side bidders. The rules governing the operation of the VPX have changed several times since the formation of the market in 1994. The latest phase is known as VicPool III enhanced. It commenced operation on September 1, 1996. Three major changes were made to the VicPool at this time. First, daily bidding by generators replaced weekly bidding. Second, more increments where added to the allowed bid functions that generators could submit. Formerly, generators were able to bid the capacity of each generating unit into the pool in only three increments (similar to the E&W market), and up until the end of 1994 generators were only allowed to bid a single increment for each unit. In VicPool III enhanced, generators are able to bid their units into the pool in 10 capacity increments which cannot be changed for the entire trading day—the 24 hour period beginning at 4 am to next day. A third change is that generators now must self-commit their generation capacity. Previously, the VicPool operated on the basis of central commitment, similar to the E&W system. Under central commitment, in their bids generators are required to submit start-up costs, start-up times and minimum on and off times. NGC in E&W (and formerly VPX in the Victoria) analyzes the costs and times presented by each generator and makes the start up and shut down decisions for all half-hours during the following day. Under VicPool III enhanced, generators are required to self-commit, which means that if a unit is committed by its owner, the capacity of the unit will be dispatched up to the point that the bid price for that capacity increment is less than the market-clearing price for that half-hour.

The other major difference between the VicPool and the E&W pool is that VicPool is an *ex post* rather than *ex ante* market. Prices paid to generators are based on the actual demand served in each half-hour rather than on estimate prepared on a day-ahead basis as is the case in E&W. Although an estimate of demand is used to schedule plant and make preliminary determinations of the required ancillary services such as reserve and reactive power, the actual amount of electricity dispatched determines the price all generators will receive for power produced in that half-hour. In contrast, in E&W the System Marginal Price (SMP) is set equal to the point on the aggregate bid function where the NGC's aggregate demand estimate crosses, and the Capacity Charge is based on the expected reserve margin, a function of the total amount of capacity actually submitted and NGC's demand estimate. The sum of these two magnitudes, the Pool Purchase Price (PPP), which is known by 4 pm the day before the electricity is produced, is the price that all generators receive for power sold into the pool during the following day. Because of the *ex post* nature of the VicPool there is no need for either a balancing market similar to that in Nord Pool or an UPLIFT charge, as is the case in the E&W pool.

A participant must not update or alter the self-commitment decision, the incremental prices for each capacity band, and the elbows of the capacity bands for each unit bid after 11:00 am on the day before this bid is active. The available capacity declaration for a unit during a half hour cannot be altered for 37 hours before the start of the day that contains that half-hour period, except to reflect a change in availability of the unit to due to an event or events beyond the reasonable control of that participant, in order to reflect an unexpected increase in availability of the unit, and in response to a change in market conditions that the participant could not reasonably forecast. Prices are computed at five minute intervals. Half hourly market prices, are the computed as time weighted averages of these. Because prices are set in real time, it is not known whether supply will be sufficient to meet demand. If supply is greater than demand, price is set equal to point on the aggregate supply curve where the aggregate demand in that half hour crosses. If demand exceeds supply, then the price is set equal to a Value of Lost Load (VOLL), which is currently set equal to 5,000 $AU/MWH.

There are several mechanisms for managing pool price risk in VicPool. There is no formal futures market similar to the one that exists in Nord Pool. Generators and retailers can hedge against pool price volatility using two instruments: (1) vesting contracts and (2) contestable contracts. Each generator in VicPool holds a vesting contract with each distributor. The vesting contracts cover consumption by franchise customers (those with no choice of electricity supplier) and large industrial customers on fixed-price contracts. The MW risk cover under these contracts declines with the reduction in the size of the franchise market. The supply market becomes fully contestable (all customers can choose supply from any distributor) in December 2000. These vesting contracts are essentially two-sided contracts for differences for pool prices below $300/MWH and one-sided high pool price CFDs for price in excess of $300/MWH. Contestable contracts are CFDs signed between generators and retailers to hedge the risks associated with supplying their contestable customers with electricity at prices that do not vary with the half-hourly changes in the pool price.

4.3. Regulatory Oversight in the Victoria Electricity Supply Industry

The Office of Regulator General in Victoria is responsible oversight of the Victoria Electricity Supply Industry. It sets the prices for both transmission and distribution services, using a price cap regulation plan. Because of the planned integration of the Australian Electricity Supply Industry, recently there has been oversight at the national level of the Victoria Power exchange from the Australia Competition and Consumer Commission.

During the first two years of the operation of the VPX, there were various inquires into the exercise of market power in Victoria Power Exchange because of sustained periods of high prices, despite a significant degree of volatility in these prices. Entry by new generators and changes in firm ownership as more of the new generating companies formed from the SECV have been privatized has led to much lower prices, but an increase in relative volatility as measured by the ratio of the annual standard deviation to annual mean of VPX prices. As a result, concern has died down about the exercise of market power.

5. New Zealand Electricity Supply Industry

Historically, the New Zealand Electricity Supply Industry was dominated by state-owned and operated generation and bulk transmission. Electricity Supply Authorities (ESAs) handled local distribution as local governing bodies (power boards) or under local body ownership (municipal electricity departments). This organizational structure continued largely unchanged until 1987, when the Electricity Division of the Ministry of Energy was restructured as the Electricity Corporation of New Zealand (ECNZ). At the same time, restrictions on entry into generation and wholesaling of electricity were removed. Because of excess capacity in generation, little entry took place. Despite being a state-owned enterprise, ECNZ was expected to earn a competitive rate of return on its assets. In 1988, ECNZ restructured itself into a corporate group with four subsidiaries: Production, Marketing, Trans Power, and the PowerDesignBuild Group. Trans Power owns and manages the national bulk transmission grid and PowerDesignBuild offers consultancy and contracting services. At the present time ECNZ remains state-owned, although eventual privatization has not been ruled out. Since 1992, Trans Power has been a fully independent state-owned enterprise.

Reform of electricity distribution was spurred by the passage of the Energy Sector Reform Bill in 1992, which corporatized the ESAs and removed franchise areas, starting in 1993 for small customers and all customers in 1994. Ownership of the distribution network remained primarily in government hands (primarily as local government-owned trusts or local government authorities), although some privatization has taken place and more is currently underway. Open-access non-discriminatory tariffs must be set by all distribution companies, so that other electricity retailers can supply electricity to customers. The electricity distribution ("wires") business of each distribution company is separate from its competitive supply business.

5.1. Market Structure in New Zealand Electricity Industry

The New Zealand electricity system consists of two alternating current (AC) subsystems, for the North and South Islands, connected by a 1200 MW underwater High-Voltage Direct Current (HVDC) cable. All capacity on the South Island is hydroelectric. There is sufficient capacity on the South Island to serve its annual electricity requirements, as well as export some power to the North Island, where there is both hydroelectric and thermal capacity. Approximately 75% of the North Island demand is met from hydroelectric sources, with the remaining 25% split between geothermal sources and fossil fuel (coal, natural gas and oil) sources, with the fossil fuel generation (primarily from natural gas) approximately twice that of the geothermal. Annual electricity consumption for the entire country is approximately 30 TWH per year, which is approximately one-tenth the annual consumption of the England and Wales, despite the fact that the land area of New Zealand is approximately the same size as the United Kingdom. With only 3.5 million people in New Zealand, transmission and distribution accounts for a relatively large fraction of the cost of delivered electricity relative to the rest of the world.

An additional important aspect of the New Zealand system is that most of the population resides in the northern part of North Island, whereas most of the major hydroelectric resources are in the southern part of the South Island. Consequently, transmission constraints between the South and North Islands can play an important role in the electricity supply process.

The generation side of the industry is dominated by the state-owned ECNZ, which prior to February 1, 1996, owned and operated more than 95% of total New Zealand electricity generating capacity. On February 1, 1996, in preparation for the formation of a wholesale market for electricity, Contact Energy Ltd. was formed as separate state-owned enterprise from ECNZ. It took over more than 30% of New Zealand generating capacity formerly owned and operated by ECNZ. The government also imposed a cap of new capacity by ECNZ until its generation market share falls below 45%. It is also prohibited from owning any of the retail electricity companies. Several of the distribution companies own generating capacity, but none generates more than 250 GWH annually. Despite the retention of state ownership of ECNZ and Contact Energy, the pattern of divestiture of generation from transmission and distribution for New Zealand follows that of the other three industries.

There are currently 38 electricity distribution companies, providing equal access distribution services and electricity supply to customers and one electricity retailer providing electricity supply only. The state-owned corporation, Trans Power owns and runs the bulk transmission grid. In this capacity it is also responsible for the purchase of ancillary services.

5.2. Market Rules in New Zealand Electricity Market

On October 1, 1996, a wholesale electricity market in New Zealand commenced operation under the name Electricity Market Company (EMCO). This market is an *ex post* spot market similar to the VicPool. Similar to the VicPool and Nord Pool, there is separation between the power exchange, which is run EMCO, and the system operator, which is Trans Power. Similar to the Nord Pool market structure, the wholesale electricity market is not mandatory. However, because of the concentration of generating assets in the hands of ECNZ and Contact, the spot market trades a large fraction of the electricity sold in New Zealand. Because of the short time the market has been in operation, no annual figures are available at this time.

Because of concerns about the capacity of the HVDC cable between the North and South Island, separate spot prices are set for the North and South Islands. The New Zealand market operates most like the VicPool. Generators submit bid functions giving the amount of the capacity they will supply as a function of the price for all half-hours during the following day. These bids are used to perform a day-ahead prospective market, which results in proposed dispatch schedule and forecast prices. Offers and bids may be freely changed up to four hours before dispatch occurs. Dispatch must meet actual loads, but to the greatest extent possible, by using a least-cost dispatch based on the latest generator offers. Prices are determined *ex post* by resolving the market-clearing model to meet the actual metered load using the generator offer curves as of the beginning of each half-hour trading period.

5.3. Regulatory Oversight in New Zealand Electricity Supply Industry

There is no explicit regulation of the generation, transmission or distribution sectors, aside from monitoring by the New Zealand Ministry of Commerce. Parties have been left to form arrangements among themselves, with all parties being free to appeal to the Courts and/or the Commerce Commission. The limited experience to date with the NZEM has not led to any significant concerns about the exercise of market power.

6. An International Comparison of the Behavior of Spot Electricity Prices

This section characterizes the time series properties of the spot electricity prices in from England and Wales, Norway and Sweden, Victoria, and New Zealand electricity markets since their inception. Our goal is to characterize the several dimensions of the behavior of prices in these four markets. Our ultimate goal is to relate differences in these dimensions of the behavior of electricity prices across the four markets to differences in market structure and market rules across the four markets. Although this is an extremely difficult task, the analysis to be presented does appear consistent with the view that market structure and market rules cause significant differences in the behavior of spot prices for electricity across the four markets.

One of the most striking features of prices from competitive electricity markets is their tremendous volatility within days and across days within the week. I would like to understand the extent to which this variability in prices is forecastable and how this forecastability varies across the four markets.

Table 1 gives the annual average half-hourly (hourly in the case of Norpool) price and standard deviation of price for each year in our sample in terms of the home currency of that country. For the Nordpool, prices are quoted in Norwegian kroner per MWH. I do not have data for the England and Wales market for 1996 and 1997. The remaining missing entries in the table are due to the fact that the electricity market did not operate during that year. For all markets, I only have data for a portion of the year in which the market began, and data for only the first few months of 1997. The E&W market began March 31, 1990. The Norwegian Spot Market data begins May 1, 1992. The Victoria data begins July 1, 1994. The New Zealand data begins October 1, 1996.

Several conclusions seem consistent with the results in this table. First is that the mix of generation technology has an impact on both the mean and standard deviation of market prices. Prices in the two markets dominated by fossil fuel technology—E&W and Victoria—tend to be much more volatile than the prices in the two markets dominated by hydroelectric capacity—Nordpool and New Zealand. The coefficient of variation, the standard deviation divided by the mean, for almost all years in E&W and Victoria are larger than those in Nordpool and New Zealand.

With exception of Victoria in 1994 and 1995 relative to 1996 and 1997, mean prices in the fossil fuel dominated markets tend to be more stable across years than prices in the hydroelectric dominated systems.[10] The mean prices in the E&W market are much more stable across the years than those in the Nordpool. As discussed above, a major determinant of the level of prices in hydroelectric capacity dominated markets is the amount of water available. If there is little water, then the reservoirs tend to be low and flow slows in the river, so that hydroelectric generators tend to be very reluctant to sell into the spot market during the winter season and spot prices remain high until the late spring and summer when electricity demand is much lower. The supply of energy inputs to fossil fuel-based systems is not nearly as sensitive to local weather conditions. Because there are relatively integrated international coal, natural gas and oil markets, prices for these fuels tend to be stable across years, so that the mean price of electricity from fossil-fuel based market should be stable across years.

There are two alternative explanations for the lower level of volatility in the Nordpool and NZEM relative to the E&W market and VicPool. First, both fossil fuel-based systems, the E&W market and VicPool, are mandatory pools, whereas the two hydroelectric-based systems, the Nordpool and NZEM, have optional day-ahead markets. Consequently, the lower relative volatility in the Nordpool and NZEM could be explained by many of the bilateral contract purchasers of electricity standing ready to sell into the spot electricity market if prices there become sufficiently high. This willingness to sell into the spot market at high prices increases the elasticity of the residual demand faced by any single generator, so that much of the adjustment to high bids in the spot market

[10] As discussed in London Economics (1996), there are several reasons to believe that there was a regime shift in the VicPool before and after January 1, 1996. Before this date, very few of the generators had been sold off, so that the SECV was effectively bidding all plants. In addition, before this date, there were high levels of vesting contracts at prices between $AU 35/MWH and $AU 40 MWH.

will come in the form of reduced amounts transacted rather than increased prices, as is the case in mandatory pools with little, if any, demand-side bidding such as the E&W market, and to a lesser extent VicPool.

A second explanation for the result in Table 1 is that the vast majority of generating capacity in the E&W market is privately-owned and an increasing (over time) fraction of the capacity in the VicPool is privately-owned, whereas both the Nordpool and NZEM are dominated by large state-owned generation companies. One would expect the large state-owned companies to pursue other objectives besides maximizing profits, whereas the major goal of the privately-owned firms would be to maximize profits. Therefore, some of the volatility in the E&W market and VicPool may be explained as episodes of the successful and unsuccessful attempts to exercise market power.

A final aspect of Table 1 deserves comment. Consistent with the description of the differences in market structure between the North and South Islands in New Zealand (cheap, abundant hydroelectric power in the South Island and most of the population in the North Island along with some more expensive fossil fuel-based plants), the mean price in the North is significantly higher than the mean price in the South for both years. In addition, prices in the North are also more volatile than those in the South, particularly for 1996.

To determine which market sells electricity at the lowest price, I convert each hourly or half-hourly price to US$ using the relevant US$ to home currency exchange rate for that day. Table 2 lists the mean and standard deviations of the US$/MWH half-hourly or hourly prices (in the case of the Nordpool). E&W consistently has the highest-priced electricity for the years in which I have comparable data. For both 1994 and 1995, the US$ prices in E&W are significantly higher than those in the Nordpool or Victoria. In both of these years, Nordpool set lower prices on average, although in 1996 and 1997, this order reverses, with VicPool $US prices significantly lower than the $US prices in either the Nordpool or the NZEM. These low prices in Victoria can be explained in part by the extremely inexpensive Australia coal and natural gas purchased to generate electricity. The coal used to produce electricity in E&W is considerably more expensive. UK coal is more costly to mine and purchasing coal from abroad entails significant transportation costs which increase its price in E&W relative to Victoria.

In order to better understand the pattern of volatility in the electricity prices in the four markets, I compute the ratio of the difference between the highest and lowest price over a given time horizon divided by the average value of prices over that same time horizon. For example, for each day in the sample, I compute the difference between the highest and lowest day and divide that by the average price for that day. Repeating this calculation for each day in the sample for each market and computing means, standard deviations, the minimum, and the maximum, yields the values given in Table 3. This table shows that over all time horizons the prices in E&W and VicPool are considerably more variable than those in the Nordpool and NZEM. By this measure of variability, the VicPool prices are more volatile than the E&W prices. The Nordpool prices exhibit the least amount of average variability over the four time horizons.

Because I do not have a complete year's worth of data for the NZEM, I cannot compute the ratio of the difference of the highest and lowest prices within the year divided by the average price for the year for the NZEM prices. The greater variability in the North Island versus the South Island NZEM prices shows up in this measure of price variability for all available time horizons. Although the average variability of these prices is less than that magnitude in either the E&W market or the VicPool, these prices are substantially more variable that the Nordpool prices.

The next step in the across-country analysis of the behavior of prices focuses on the relative forecastability of the daily vector of prices in each country. This requires a model for the time series behavior of the (48x1) vector of half-hourly prices or (24x1) hourly prices for Nordpool, which I denote Y_t. After some preliminary analysis of each vector of prices, I settled on a time-varying mean for Y_t which depends on the day of the week and month of the sample period. I hypothesize that, once M_t, the (48x1) [(24x1) for the case of the Nordpool] vector of means of Y_t, is subtracted from Y_t, the resulting stochastic process is a vector autoregressive model of order 8. The statistical model I hypothesize for Y_t is:

$$\Phi(L)(Y_t - M_t) = E_t \tag{1}$$

where E_t is a (48x1) [(24x1) for the case of the Nordpool] vector-valued white noise process with mean zero and covariance matrix Σ, $\Phi(L) = I - \Phi_1 L - ... - \Phi_p L^p$, where each Φ_i is a (48x48) [(24x1) for the case of the Nordpool] matrix of coefficients and L is the lag operator function which is defined by $Y_{t-k} = L^k Y_t$. The remaining discussion of the model is for case of 48 half-hourly prices, although the modifications necessary for 24 hourly prices are straightforward. Let M_{ti} denote the ith element of M_t. In terms of our above notation, $M_{ti} = X_t'\beta_i$ where X_t is a vector of day of the week and month indicator variables for load period i is and β_i is the vector of coefficients associated with these indicator variables. Excluding the β_i coefficients associated with M_{ti}, for each element of M_t, there are $16,120 = 8\times(48)^2$ elements of $\Phi_1, \Phi_2,...,\Phi_8$ to estimate. Rather than present the more than 18,000 coefficient estimates (including the β_i for each of the 48 load periods) for this model, which are estimated by least squares applied to each of the 48 load period price equations, I provide several summary measures of the adequacy of this model and summarize what insights it provides about the forecastability of Y_t for each market.

To investigate the adequacy of (1) for each country, I compute the multivariate analogue of the Box-Pierce (1970) portmanteau statistic derived by Hosking (1980) for the (48x1) vector of residuals from equation (1). This statistic is computed as

$$P = T \sum_{r=1}^{M} trace(C_r^{\prime} C_0^{-1} C_r C_o^{-1}), \quad where \quad C_r = T^{-1} \sum_{t=r+1}^{T} \hat{E}_t \hat{E}_t^{\prime}$$

where $\hat{E}_t$ is the residual vector from equation (1) for period t and C_0 is the sample covariance matrix of $\hat{E}_t$. Hosking has shown that the asymptotic distribution of P is χ^2 with $N^2 \times (M - p)$ degrees of freedom where p is the order of the autoregressive process and N is the dimension of Y_t. For all of the models estimated, I find little evidence against the null hypothesis that E_t is multivariate white noise.

Table 4 presents the R^2 , the standard error of the regression and mean of the dependent variable for each of 48 ordinary least squares regressions of the half-hourly price on 8 lags of this price and all other half-hourly prices. I find the largest R^2's--all in excess of 0.90--are associated with load periods 33 to 38 which run from 4:00 pm to 7:00 pm, the load periods in the day with highest prices on average as indicated by sample mean of the PSP in each load period given in the third column. Load periods 33 to 38 are also the periods with the six largest estimated regression standard errors. The combination of these two results suggests that the explanatory power of the model is highest for those load periods i=33,..,38 with the highest unconditional variance in Y_{ti}. However, despite the superior explanatory power of the model for these load periods, the level of the estimated forecast variance is higher for these load periods than for any others. Past values of Y_t therefore improve the predictive power of the load period regressions for periods 33-38 significantly more than they do for the other load period regressions, but despite this fact, these load periods are still the most unpredictable in terms of the estimated level of their day-ahead forecast variance. This result is consistent with our view that there are short periods within the day when PSP is above or below its unconditional mean, and the occurrence of these extreme prices in certain load periods within a day make them more likely to occur in the same load periods in neighboring days.

Table 5 presents this same information for the (24x1) vector of daily Nordpool spot prices. The most striking feature of this table is the uniformly high explanatory power of these 24 regressions. In all cases, the R^2 is at least 0.99, which implies that almost all of the variability in hourly prices across days in the Nordpool is forecastable. In addition, none of the hours appear to be significantly more predictable using past prices than other hours. For all hours during the day, the standard errors of the regressions are very similar in magnitude, although the hours during the day with higher average prices do have slightly larger estimated residual variances.

Table 6 presents the information in Table 4 for the VicPool prices. The R^2 from the 48 regressions used to estimate the 8^{th} order vector autoregressive process indicate that VicPool prices are less forecastable than the Nordpool prices. The magnitude of the R^2 are similar to those for the E&W system in Table 4. However, different from the results in Table 4, I find that the higher average price periods do not have higher R^2 from the regression forecasting that price. In fact, the highest average price period, load period 26, has by far the lowest $R^2 = 0.44$. Different from the case of the E&W market, the highest R^2 ‘s occur for load periods with both low and high average prices. Because I only have a very short time series of prices for the NZEM, it is not possible to estimate this vector autoregressive model for these prices.

A final issue associated with the Y_t process is the extent to which 48 (24 in the case of the Nordpool) distinct prices occur within the day. Specifically, are there really 48 distinct sources of stochastic variation in prices over the course of the day? The way I address this question is by asking if E_t possesses a factor structure. By this I mean that E_t can be written as

$$E_t = \Delta V_t + U_t$$

where Δ is a 48×G (G < 48) matrix and V_t is a (G×1) white noise process with mean zero and covariance matrix I_G (the identity matrix of dimension G), U_t is a (48×48) white noise process with mean zero and covariance matrix $\sigma^2 I$, where I is a (48×48) identity matrix. The processes V_t and U_t are assumed to be uncorrelated. This structure imposes restrictions on the form of the covariance matrix of Σ. In general there are ½(48)(49) = 1176 distinct elements of Σ. For example, if I assume that G, the number of common factors, equals 1, then there are 48 elements of Δ and σ^2, which implies that the 1176 elements of Σ can be written as functions of the 48 elements of Δ and σ^2, which implies a significant number of restrictions. The usual way to determine the extent to which there exists a common factor structure for E_t is to compute the principal components of Σ and the eigenvalues associated with these principal components. Defining trace(Σ) as the total variation in Σ, by the properties of the trace operator, the sum of the eigenvalues of Σ equals trace(Σ). Consequently, I can get a measure of the extent to which a single principal component or groups of the orthogonal principal components explain the total variation in Σ. (Another definition often used is the determinant of Σ (det(Σ)) because det(Σ) is the product of the eigenvalues. This would involve computing the ratio of the determinant to the product of a subset of the eigenvalues.) In Table 7, I list the eigenvalues associated with the 48 principal components of the white noise process driving the vector of daily E&W prices. The last column computes the cumulative sum of the eigenvalues up to the number of principal components for that row divided by the trace of Σ. This table indicates that more than 20 percent of the total variation is explained by the first principal component. However, the number of factors necessary to adequately model the structure of Σ appears to be large. For example, the cumulative number of principal components necessary to capture 90% of the total variation in Σ is 24. The large number of factors necessary represent a substantial fraction of the total variation in Σ is consistent with the view that there is not single or even of a small number of independent determinants of the pattern of spot prices within the day in the E&W market.

Table 8 repeats this calculation for the (24x1) covariance matrix of the white noise process driving the Nordpool spot prices. This table is very different from the one for the E&W prices. Over 75% of the total variation Σ is explained by the first principal component. It only takes three factors to explain more than 90% of the total variation in Σ. This factor structure is consistent with the view discussed earlier that there is single determinant of unexpectedly high prices within a day, the uncertainly about the availability of future water supplies.

Table 9 presents the 48 eigenvalues of the estimate of Σ for the VicPool prices. The story that emerges is midway between the one from the Nordpool and the one from the E&W market. Approximately half of the total variation in Σ is explained by the first principal component. Only 15 factors, versus 24 in the E&W market, are required to explain more than 90% of the total variation in Σ.

Several overall conclusions emerge from Tables 4-9. The dynamics of the within day variation in prices in the E&W is more complex than the dynamics of the within day variation in prices in the VicPool. The Nordpool prices show the least complex within-day price dynamics of the three markets. The Nordpool prices are also by far the most forecastable of the three price series, as measured by the R^2.of the prediction regressions. The E&W market prices and the VicPool prices are predictable with approximately the same average R^2 over all half-hour periods in the day. However, the different from the VicPool, the highest-priced load periods in the day in the E&W market are uniformly the most forecastable by this same measure.

I now characterize differences in the behavior of the spot prices within the day and week across the peak and off-peak months of the year. Figure 1(a) plots the average behavior of normalized prices throughout the day for the E&W market in Winter (December, January and February) and Summer (June, July and August). To compute the normalized price for any load period, I divide the actual price by the sample mean price of electricity in the E&W market. Figure 1(b) plots the behavior of normalized prices throughout the week in Summer and Winter. These plots illustrate an important feature of behavior of prices in the E&W market. During the winter months, all weekday prices become very high during load periods 35-37. The average high price during weekdays (excluding Fridays) is more than 4.0 times the sample mean of the spot price in load periods 35-37. In Wolak and Patrick (1996b), we argue that this pattern of prices represents the exercise of market power by National Power and PowerGen, the two major generators in the E&W market.

Figure 2 presents the day and week normalized price plots for the Nordpool. There appears to be little predictable variation in the spot prices within the day and across days of the week in the Nordpool. The major movements in prices appear to be across the peak and off-peak seasons, with average summer prices significantly below average winter prices within the day and within the week.

The average pattern of prices within the day and week in VicPool shares features with both the Nordpool and the E&W market. For consistency with the other two Figures, I have defined Summer to be the months of June, July and August and Winter to be December, January and February. For the most half-hours, average prices in June, July and August (Summer) are higher than those in December, January and February (Winter). The differences in predictable price fluctuations within the day and week across the peak and off-peak seasons is not nearly as pronounced in the VicPool as it is in E&W market. Both seasons exhibit more predictable variation within the day and week than do E&W prices in the Summer.

Because no data exists for New Zealand for the months of June, July and August, Figure 4 plots the average prices in the North and South Islands throughout the day and week. The pattern of average prices within the day for both prices in New Zealand is very similar to the pattern of prices within the day for the Nordpool. A similar statement can be said about the behavior of both New Zealand prices within the week.

Figures 5-7 plot the period level standard deviations of the normalized prices within the day for the E&W market, Nordpool and VicPool. Each point on this plot is the standard deviation of the normalized (by the overall sample mean price) price for that load period within the day for all days within that season. Figure 5 illustrates that although normalized prices in load periods 35-37 are known to be very high, there is considerable uncertainty precisely how high they will be. Figure 6 tells a similar story to case of the mean prices within the day for Nordpool. The uncertainty in normalized prices is uniform within the day in both Summer and Winter, but the uncertainly in normalized prices in uniformly higher in the Summer than the Winter. Figure 7 illustrates that for the most part the degree of uncertainty in normalized prices is very similar across load periods in the VicPool. The only exception is that during the high priced periods in December, January and February (the months of peak demand in Victoria) the uncertainty in normalized prices is highest during the highest priced periods of the day.

Figure 8 computes the load-period level standard deviations in normalized prices for the North Island and South Island prices in New Zealand. The pattern of uncertainty in these prices is very similar to the within-day uncertainty in prices in the Nordpool.

7. Market Structure and Market Rules and the Exercise of Market Power

A significantly more detailed analysis of the behavior of prices, and if, available quantities transacted from each of these markets would be required to draw any firm conclusions about the exercise of market power in these markets. However, the strong influence that both market structure and the market rules appear to exert on the behavior of prices in these markets suggests that such an across-country analysis should have significant promise to yield insights about how the interaction of market rules and market structure combine to allow the exercise of market power.

The dramatically different pattern of average electricity prices within the day and within the week in the E&W market relative to the other three markets does lend further support to the conclusion reached in Wolak and Patrick (1996b) that the two largest generators in the England and Wales market—National Power and PowerGen— possess significant market power that they are able to exercise when certain conditions in the E&W market make the residual demand they jointly face extremely large relative to the capacity of these two large generating companies.

The relatively flat pattern of average prices throughout the day in the VicPool and the very low $US prices for electricity from these market in 1996 and 1997 seems indicative of a very competitive electricity market. The relatively high degree of volatility in prices throughout the day in the VicPool (compared to Nordpool and the NZEM) seems to indicate that generators are sometimes successful at obtaining high prices, but just as often their efforts yield very low prices, so that on average, prices for electricity are very low. Consequently, the VicPool appears to be an example of a market where the efforts of generators to exercise market power are on average unsuccessful. The evidence on the behavior of prices appears consistent with the conclusion that it is a more competitive market than the E&W market. Further research is necessary to determine whether this difference in competitiveness is due to differences in the market structure of the two markets, or the market rules.

Both Nordpool and the NZEM present a more difficult puzzle because both markets are dominated by large state-owned enterprises. We would not expect these firms to exercise market power with the same vigor that privately-owned firms would. Nevertheless, both of these electricity supply industries produce the vast majority of their power from very inexpensive hydroelectric resources, so the higher $US dollar prices in these two market relative to Victoria does raise suspicions about the exercise of market power by the large state-owned firms. As discussed earlier, in the fall of 1992, Statkraft publicly announced a policy to keep spot price above 100 NOK/MWH, although subsequently rices have fallen below this level for long periods of time. However, the relatively low variability in prices within the day, despite the fact the most electricity in both systems is produced by near zero-marginal cost hydroelectric power, is consistent with the view that some market power is being exercised in both the Nordpool and the NZEM. Simple theoretical models of price competition with fixed costs and low marginal costs, imply a significant amount of price volatility that does not appear to be present in either market. In total, the evidence from the behavior of prices in both Nordpool and the NZEM relative to prices in Victoria and the E&W market seems to indicate that some market power is being exercised. In this case it appears that the large state-owned generators are the price-leader with the remaining firms serving as a competitive fringe. Further analysis of both of these markets is necessary to reach a more definitive conclusion about the source of this market power and what modifications of the market rules or market structure would make this type of behavior less likely.

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Table 1: Annual Means and Standard Deviations (SDs) of Spot Price of Electricity in Home Currency per MWH										
Year	Mean (EW) £	SD (EW) £	Mean (NW) NOK	SD (NW) NOK	Mean (VIC) $AU	SD (VIC) $AU	Mean (NZN) $NZ	SD (NZN) $NZ	Mean (NZS) $NZ	SD (NZS) $NZ
1990	17.38	5.38	na	na	na	na	na	na	na	na
1991	22.50	12.65	na	na	na	na	na	na	na	na
1992	23.42	6.28	58.10	44.38	na	na	na	na	na	na
1993	27.14	7.86	80.28	41.02	na	na	na	na	na	na
1994	24.73	18.73	182.67	49.29	36.72	18.24	na	na	na	na
1995	26.15	50.89	117.69	38.92	41.94	30.02	na	na	na	na
1996	na	na	253.52	44.62	21.11	19.30	39.36	17.00	28.53	6.53
1997	na	na	150.63	42.90	22.96	59.05	45.06	9.42	38.50	8.79

Notes: EW = England and Wales Pool, units = £/MWH; NW = Nord Pool, units = NOK/MWH; VIC = Victoria Power Exchange, units = $AU/MWH; NZN = New Zealand North Island, units = $NZ/MWH; NZS = New Zealand South Island, units = $NZ/MWH.

Table 2: Annual Means and Standard Deviations (SDs) of Spot Price of Electricity Converted to $US/MWH on Using Daily Exchange Rate										
Year	Mean (EW)	SD (EW)	Mean (NW)	SD (NW)	Mean (VIC)	SD (VIC)	Mean (NZN)	SD (NZN)	Mean (NZS)	SD (NZS)
1990	31.84	10.25	na	na	na	na	na	na	na	na
1991	39.80	22.71	na	na	na	na	na	na	na	na
1992	41.32	11.31	9.20	6.73	na	na	na	na	na	na
1993	40.80	11.91	11.28	5.62	na	na	na	na	na	na
1994	38.00	29.37	25.97	7.04	27.42	13.65	na	na	na	na
1995	41.10	79.15	18.50	5.89	30.95	21.94	na	na	na	na
1996	na	na	39.26	6.86	16.53	15.03	27.78	11.93	20.13	4.59
1997	na	na	22.50	7.14	17.83	46.00	31.38	6.48	26.78	5.92

Notes: EW = England and Wales Pool, NW = Nord Pool, VIC = Victoria Power Exchange, NZN = New Zealand North Island, NZS = New Zealand South Island.

Table 3: Ratio of (Highest Price - Lowest Price) ÷ (Average Price) over Various Time Horizons										
(Highest Price in Day - Lowest Price in Day) ÷ (Average Price for Day)						(Highest Price in Month - Lowest Price in Month) ÷ (Average Price for Month)				
	Mean	Std	Min	Max			Mean	Std	Min	Max
NW	0.18	0.19	0.00	2.04		NW	0.86	0.54	0.12	2.22
NZN	0.72	0.74	0.03	3.15		NZN	3.09	0.80	1.91	4.09
NZX	0.39	0.44	0.01	2.86		NZS	2.47	1.68	0.52	3.94
EW	1.31	1.23	0.23	12.12		EW	4.43	6.36	0.89	45.08
VIC	1.78	1.45	0.03	26.58		VIC	7.81	19.20	1.96	117.29
(Highest Price in Week - Lowest Price in Week) ÷ (Average Price for Week)						(Highest Price in Year - Lowest Price in Year) ÷ (Average Price for Year)				
	Mean	Std	Min	Max			Mean	Std	Min	Max
NW	0.44	0.38	0.04	2.21		NW	2.48	0.99	1.14	4.00
NZN	1.80	1.08	0.23	3.31		NZN	na	na	na	na
NZS	1.11	1.17	0.18	3.90		NZS	na	na	na	na
EW	2.42	3.19	0.54	37.84		EW	17.70	16.60	4.07	46.37
VIC	3.97	8.51	0.80	102.22		VIC	43.16	72.23	4.37	151.46

Notes: EW = England and Wales Pool, NW = Nord Pool, VIC = Victoria Power Exchange, NZN = New Zealand North Island, NZS = New Zealand South Island.

Table 4: R-Squared, Standard Error, and Sample Mean of Dependent Variable for Regression Forecasting Half-Hourly Pooling Selling Price in England and Wales							
Load Period	R-Squared	Standard Error of Regression	Sample Mean of Price in £/MWH	Load Period	R-Squared	Standard Error of Regression	Sample Mean of Price in £/MWH
1	0.83	2.33	15.65	25	0.78	5.84	29.77
2	0.84	3.40	17.84	26	0.77	5.32	28.48
3	0.84	3.87	19.09	27	0.80	3.73	25.10
4	0.83	4.31	20.17	28	0.81	3.30	23.44
5	0.83	3.64	18.87	29	0.77	3.69	22.24
6	0.84	3.35	18.01	30	0.81	3.44	21.73
7	0.83	3.09	17.11	31	0.82	3.62	21.22
8	0.84	2.55	15.98	32	0.84	7.01	22.96
9	0.83	2.38	15.25	33	0.89	16.26	31.41
10	0.86	2.00	14.80	34	0.91	25.43	42.19
11	0.85	2.17	14.99	35	0.92	27.76	46.75
12	0.86	2.23	15.11	36	0.92	21.90	42.96
13	0.82	2.56	15.61	37	0.90	14.08	33.42
14	0.80	3.28	18.21	38	0.90	6.90	28.57
15	0.84	3.07	20.66	39	0.87	4.81	26.38
16	0.81	3.94	22.31	40	0.85	3.72	24.81
17	0.80	4.84	24.24	41	0.79	4.01	23.78
18	0.79	5.24	25.58	42	0.79	3.85	24.07
19	0.70	6.81	27.18	43	0.82	3.60	24.59
20	0.71	7.09	28.44	44	0.83	3.64	24.46
21	0.71	6.70	28.23	45	0.83	3.63	22.85
22	0.70	6.26	27.50	46	0.81	3.37	20.31
23	0.77	5.22	27.96	47	0.78	2.89	17.75
24	0.76	5.95	29.45	48	0.81	2.45	16.05

Table 5: R-Squared, Standard Error, and Sample Mean of Dependent Variable for Regression Forecasting Hourly Spot Price from Nord Pool							
Load Period	R-Squared	Standard Error of Regression	Sample Mean Price in NOK/MWH	Load Period	R-Squared	Standard Error of Regression	Sample Mean Price in NOK/MWH
1	0.99	7.31	137.99	13	0.99	9.41	149.57
2	0.99	9.72	136.28	14	0.99	9.46	149.07
3	0.99	8.87	135.38	15	0.99	9.39	148.76
4	0.99	7.46	134.86	16	0.99	9.33	148.53
5	0.99	7.40	135.05	17	0.99	9.03	148.00
6	0.99	7.65	136.82	18	0.99	9.06	148.70
7	0.99	8.84	142.69	19	0.99	8.92	148.98
8	0.99	10.33	148.90	20	0.99	8.69	148.41
9	0.99	10.72	151.05	21	0.99	8.44	147.81
10	0.99	10.65	151.93	22	0.99	8.48	147.69
11	0.99	10.17	151.87	23	0.99	7.99	145.43
12	0.99	10.01	151.49	24	0.99	10.01	141.79

Table 6: R-Squared, Standard Error, and Sample Mean of Dependent Variable for Regression Forecasting Half-Hourly Spot Price from VicPool							
Load Period	R-Squared	Standard Error of Regression	Sample Mean Price in $AU/MWH	Load Period	R-Squared	Standard Error of Regression	Sample Mean Price in $AU/MWH
1	0.89	9.23	32.22	25	0.89	16.56	37.50
2	0.89	9.12	29.06	26	0.44	113.75	40.80
3	0.87	10.49	33.47	27	0.81	18.47	38.20
4	0.87	9.72	29.36	28	0.81	18.39	37.86
5	0.87	8.59	24.82	29	0.80	18.73	37.21
6	0.86	7.77	20.92	30	0.78	18.80	36.31
7	0.86	7.15	17.40	31	0.79	18.03	35.90
8	0.84	6.94	14.73	32	0.79	18.77	35.92
9	0.83	6.34	12.85	33	0.80	17.62	35.76
10	0.80	6.64	11.95	34	0.79	17.22	36.15
11	0.77	9.10	13.69	35	0.80	17.49	37.59
12	0.78	9.51	16.28	36	0.82	17.55	39.92
13	0.79	11.16	22.35	37	0.77	21.82	39.84
14	0.81	13.29	28.56	38	0.81	18.28	38.08
15	0.84	11.35	29.47	39	0.84	14.66	35.50
16	0.85	13.39	34.02	40	0.81	14.64	34.39
17	0.83	14.97	36.46	41	0.86	14.24	33.80
18	0.82	16.37	37.00	42	0.86	13.85	32.33
19	0.84	15.55	37.81	43	0.83	13.26	29.87
20	0.84	15.71	38.03	44	0.83	12.28	26.52
21	0.85	15.43	37.99	45	0.82	12.09	25.21
22	0.85	16.08	38.19	46	0.80	12.08	24.74
23	0.84	15.93	37.38	47	0.79	14.60	34.18
24	0.87	15.06	37.26	48	0.80	13.76	33.31

Table 7: Eigenvalues of Residual Covariance Matrix from Vector Autoregressive Model used to Forecast Vector of Daily Pool Selling Price in England and Wales					
Principal Component	Eigenvalue	Percent of Total Variance	Principal Component	Eigenvalue	Percent of Total Variance
1	11.081	0.2308	25	0.392	0.9146
2	4.550	0.3256	26	0.362	0.9222
3	4.136	0.4118	27	0.350	0.9295
4	2.730	0.4687	28	0.332	0.9364
5	2.520	0.5212	29	0.319	0.9430
6	2.143	0.5658	30	0.264	0.9485
7	1.806	0.6035	31	0.254	0.9538
8	1.691	0.6387	32	0.238	0.9588
9	1.577	0.6715	33	0.225	0.9635
10	1.414	0.7010	34	0.213	0.9679
11	1.268	0.7274	35	0.198	0.9720
12	1.104	0.7504	36	0.186	0.9759
13	0.981	0.7709	37	0.181	0.9797
14	0.881	0.7892	38	0.161	0.9830
15	0.812	0.8061	39	0.150	0.9862
16	0.738	0.8215	40	0.136	0.9890
17	0.665	0.8354	41	0.122	0.9915
18	0.566	0.8472	42	0.118	0.9940
19	0.556	0.8587	43	0.091	0.9959
20	0.487	0.8689	44	0.078	0.9975
21	0.476	0.8788	45	0.055	0.9986
22	0.462	0.8884	46	0.041	0.9995
23	0.446	0.8977	47	0.015	0.9998
24	0.419	0.9065	48	0.009	1.0000

Table 8: Eigenvalues of Residual Covariance Matrix from Vector Autoregressive Model used to Forecast Vector of Daily Spot Prices in Nord Pool					
Principal Component	Eigenvalue	Percent of Total Variation	Principal Component	Eigenvalue	Percent of Total Variation
1	18.089	0.7537	13	0.060	0.9923
2	2.795	0.8702	14	0.050	0.9944
3	0.757	0.9017	15	0.040	0.9960
4	0.481	0.9218	16	0.023	0.9970
5	0.412	0.9389	17	0.017	0.9977
6	0.328	0.9526	18	0.013	0.9982
7	0.253	0.9632	19	0.012	0.9987
8	0.197	0.9714	20	0.011	0.9991
9	0.154	0.9778	21	0.009	0.9995
10	0.122	0.9829	22	0.006	0.9998
11	0.100	0.9871	23	0.003	0.9999
12	0.064	0.9897	24	0.002	1.0000

Table 9: Eigenvalues of Residual Covariance Matrix from Vector Autoregressive Model used to Forecast Vector of Daily Spot Prices in VicPool

Principal Component	Eigenvalue	Percent of Total Variation	Principal Component	Eigenvalue	Percent of Total Variation
1	23.405	0.4876	25	0.187	0.9587
2	4.694	0.5854	26	0.183	0.9625
3	3.231	0.6527	27	0.158	0.9658
4	2.208	0.6987	28	0.145	0.9688
5	1.829	0.7368	29	0.133	0.9716
6	1.433	0.7667	30	0.124	0.9742
7	1.254	0.7928	31	0.123	0.9767
8	0.927	0.8121	32	0.120	0.9793
9	0.898	0.8308	33	0.100	0.9813
10	0.785	0.8472	34	0.099	0.9834
11	0.711	0.8620	35	0.088	0.9852
12	0.567	0.8738	36	0.085	0.9870
13	0.511	0.8844	37	0.078	0.9886
14	0.480	0.8944	38	0.072	0.9901
15	0.439	0.9036	39	0.070	0.9916
16	0.381	0.9115	40	0.066	0.9929
17	0.344	0.9187	41	0.060	0.9942
18	0.299	0.9249	42	0.052	0.9953
19	0.284	0.9308	43	0.050	0.9963
20	0.262	0.9363	44	0.044	0.9973
21	0.255	0.9416	45	0.042	0.9981
22	0.236	0.9465	46	0.034	0.9988
23	0.208	0.9508	47	0.029	0.9995
24	0.190	0.9548	48	0.026	1.0000

Figure 1(a)

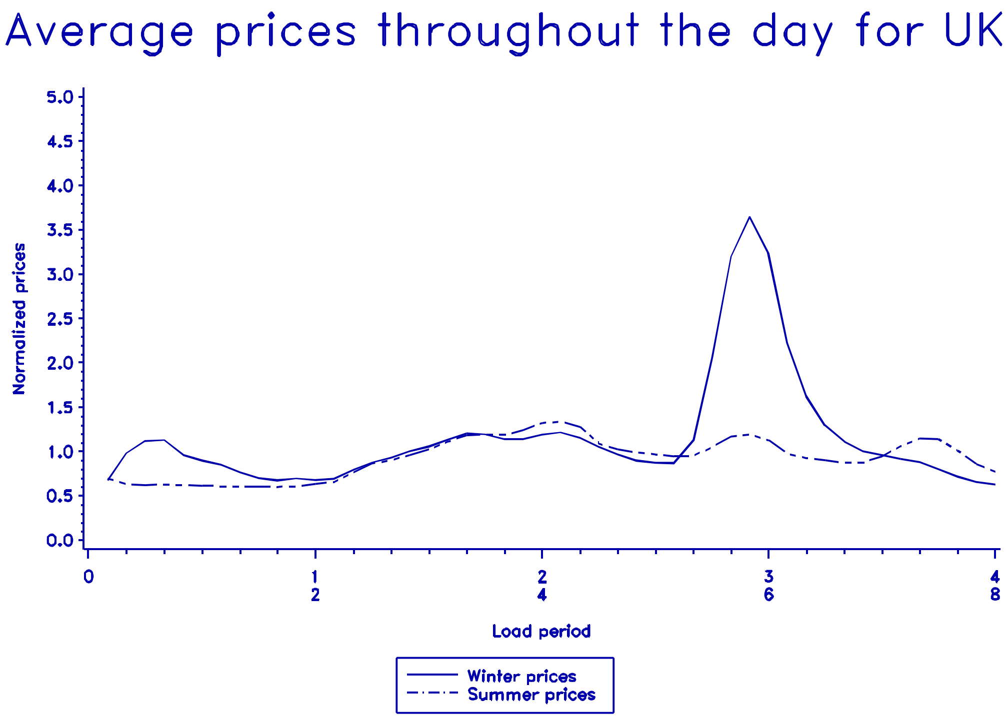


Figure 1(b)

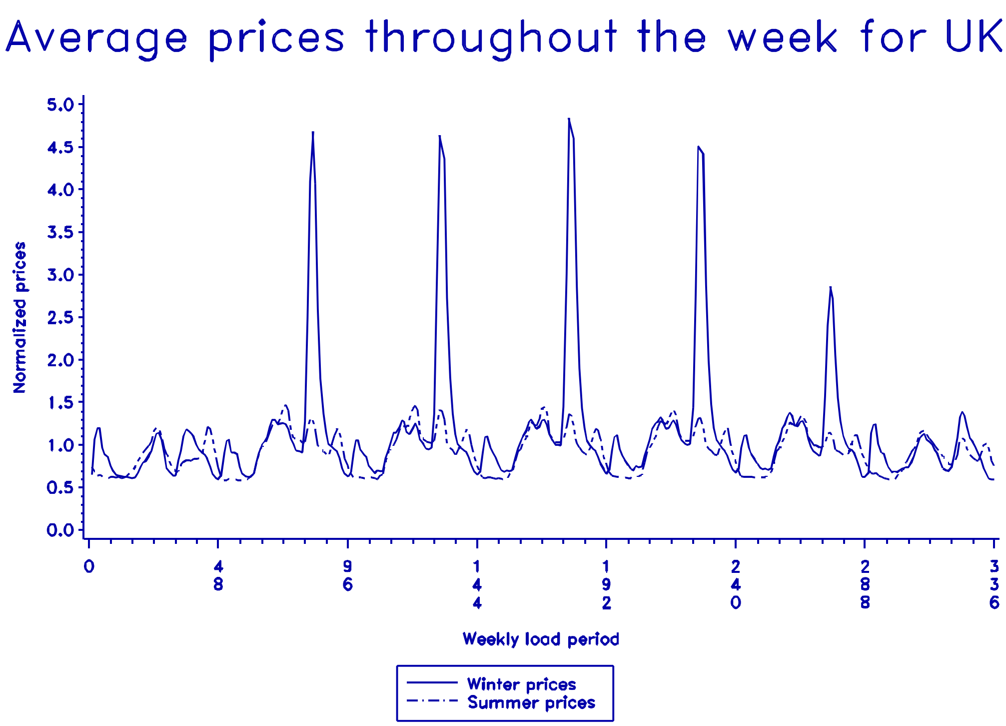
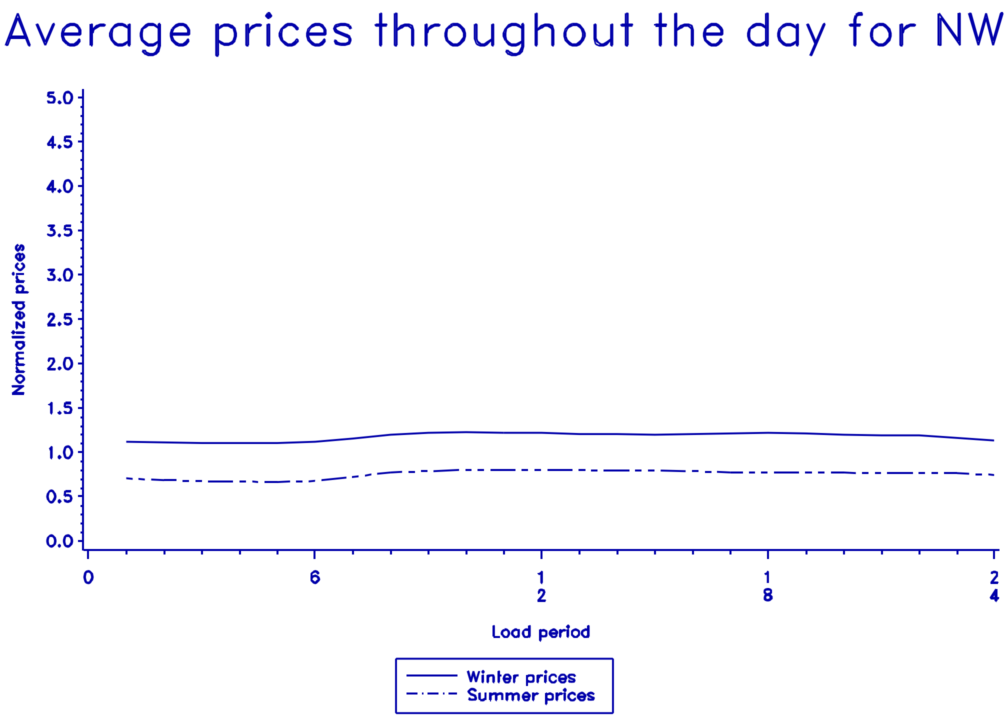


Figure 2(a)



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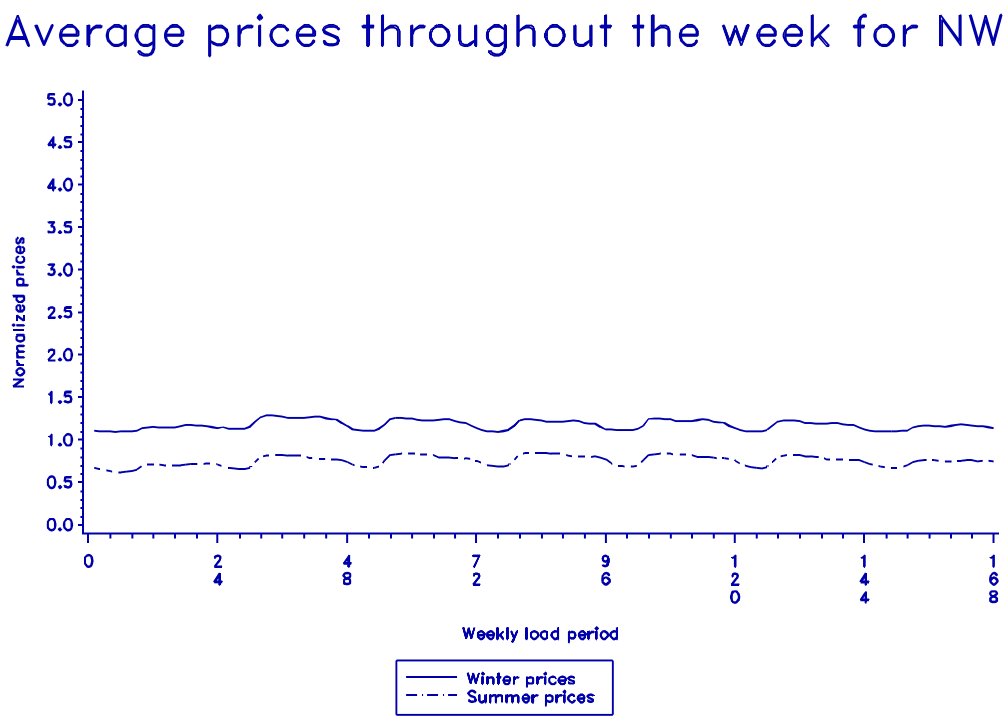

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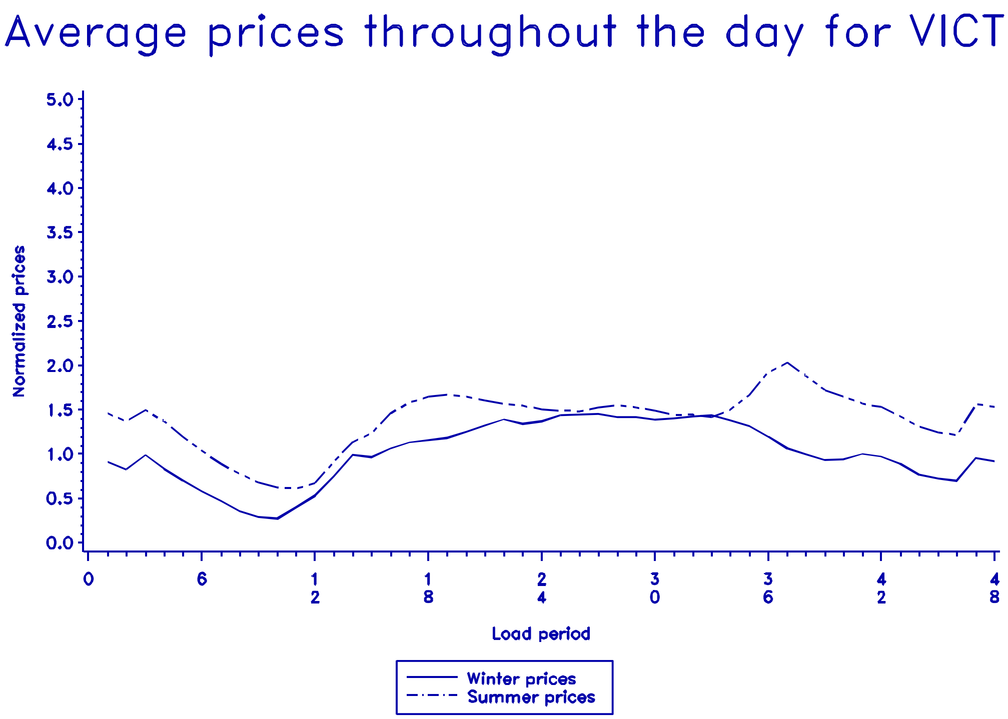

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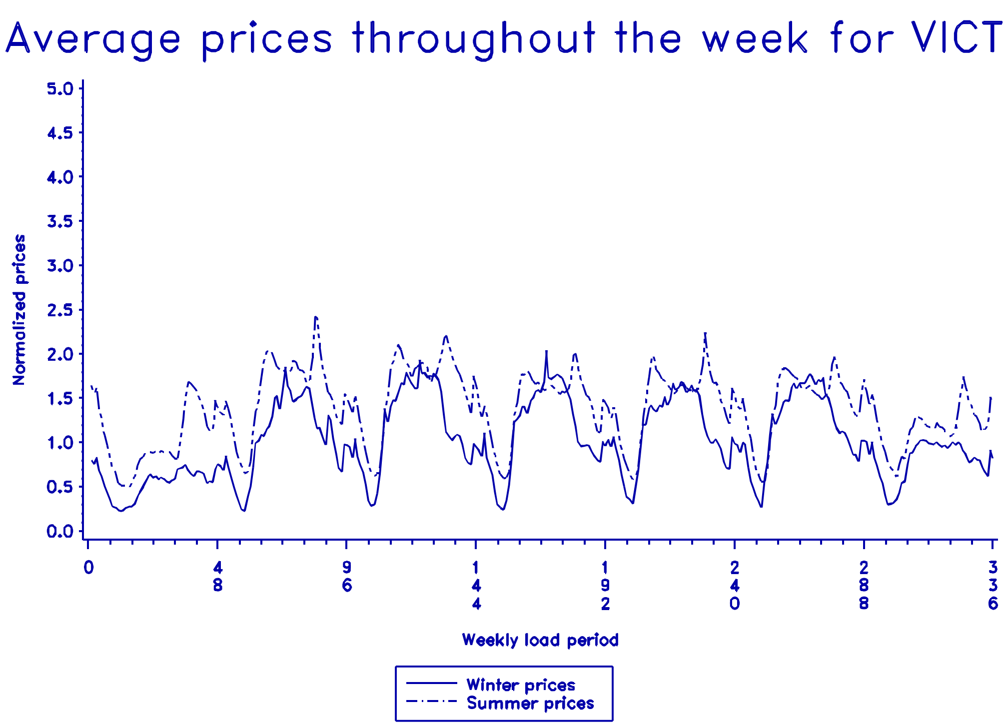

Figure 4(a)

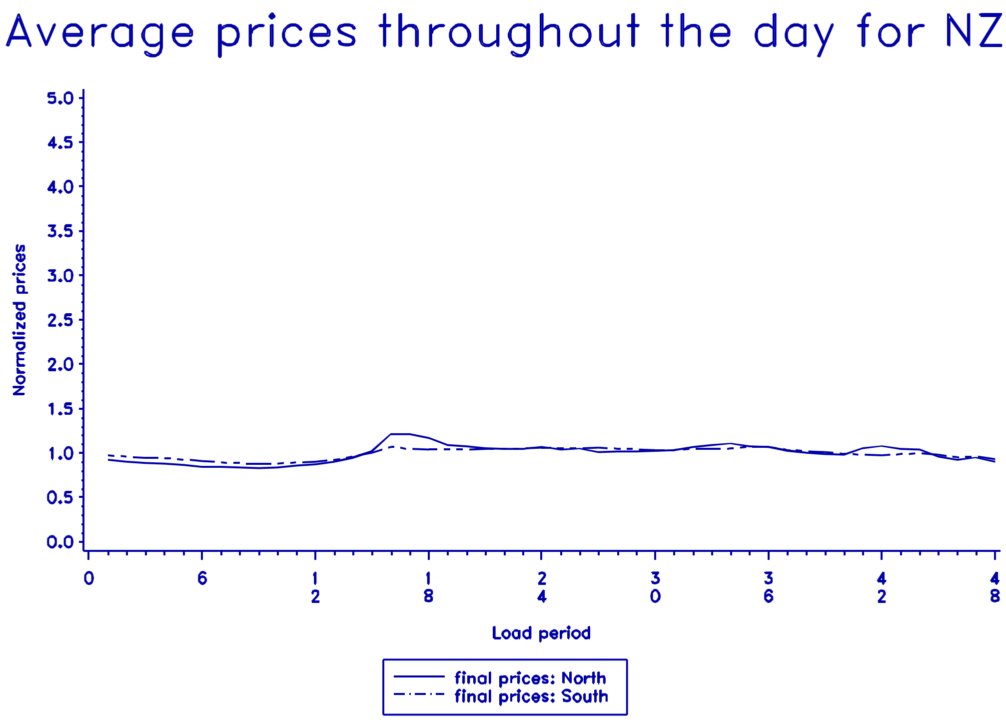

Figure 4(b)

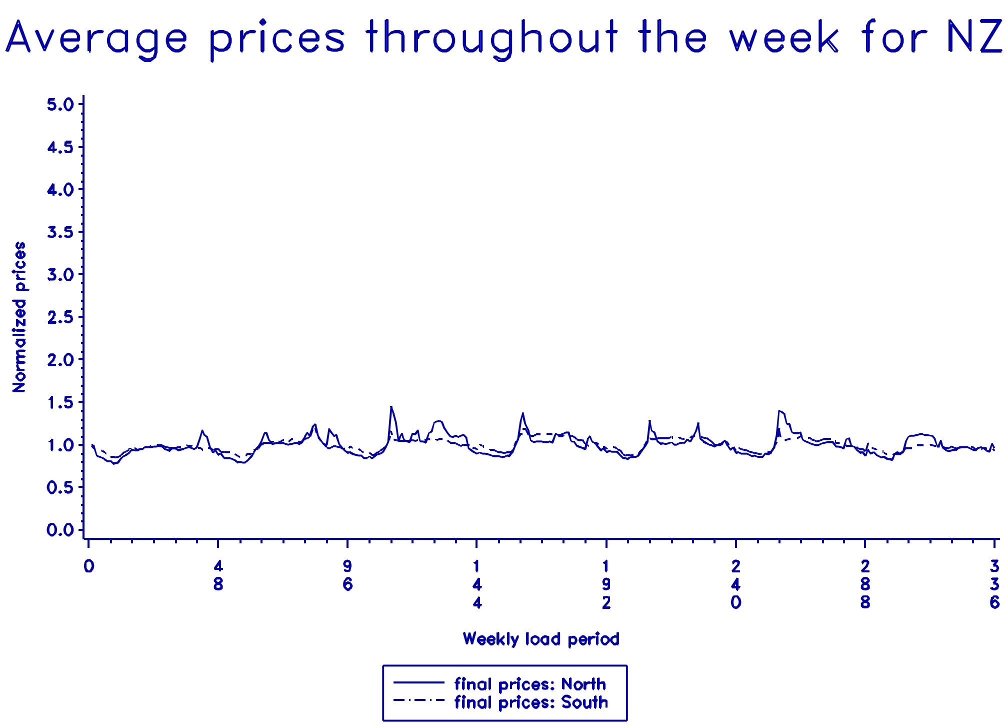

Figure 5

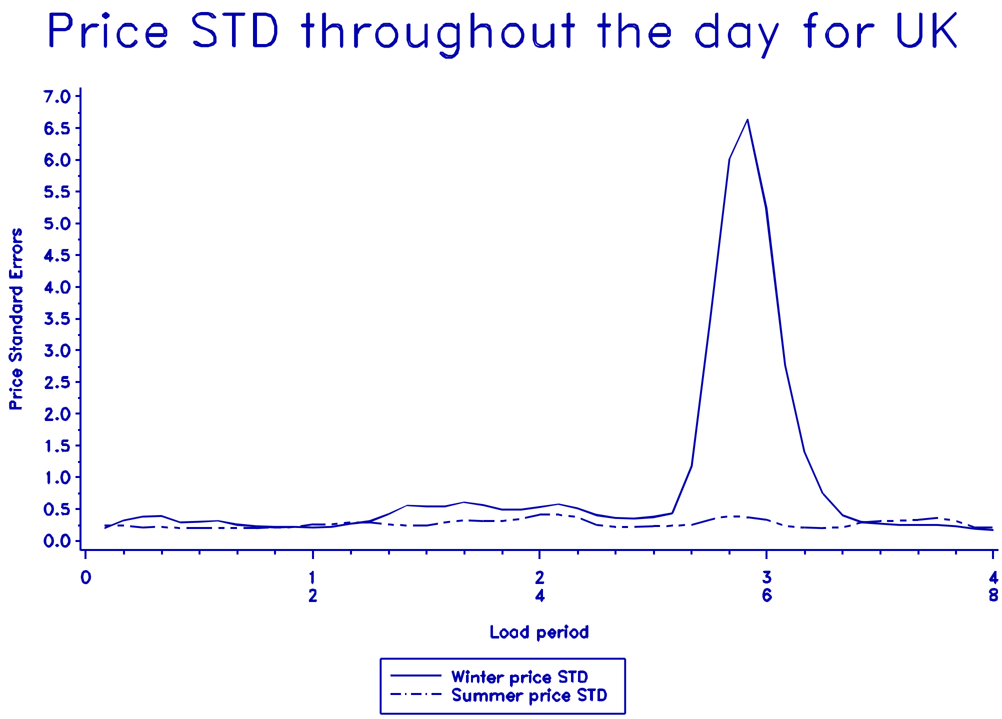

Figure 6

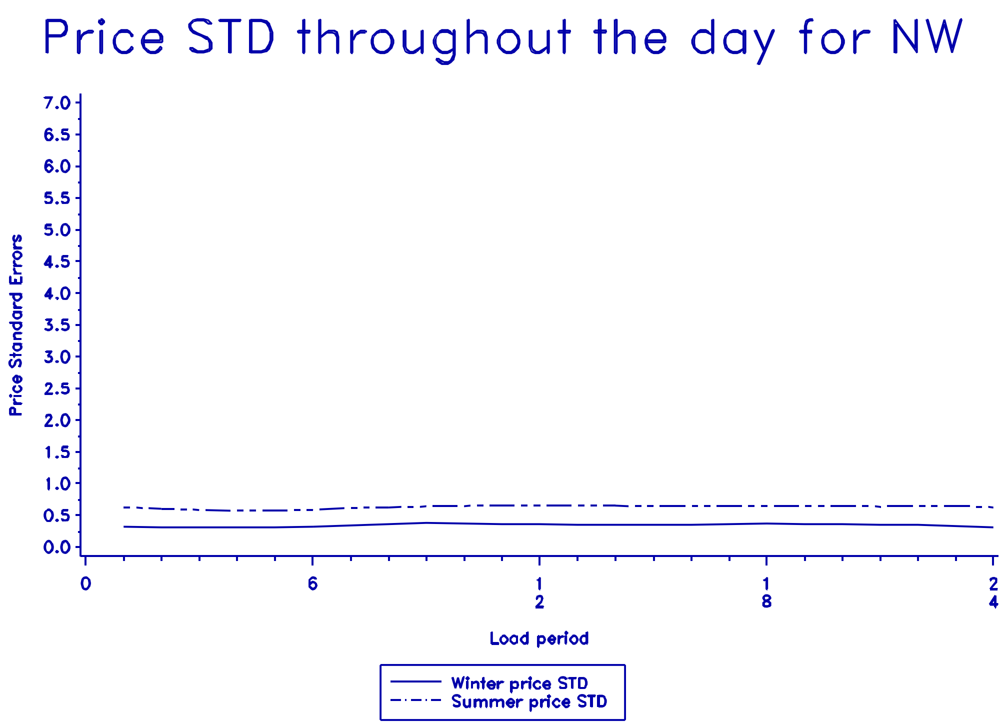

Figure 7

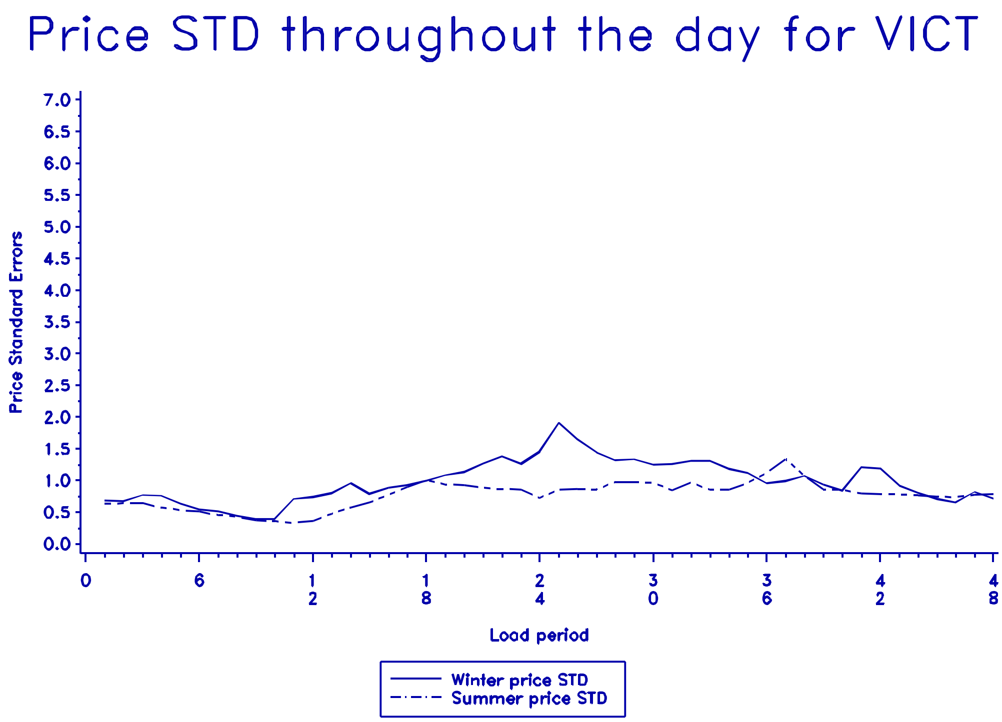

Figure 8